Decisions and Orders

Massachusetts Energy Facilities Siting Council

Volume 13

DECISIONS AND ORDERS

Massachusetts Energy

Facilities Siting Council

Volume 13

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COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

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FINAL DECISION

William S. Febiger
Hearing Officer

August 1, 1985

On the Decision:

Carolyn Ramm
Senior Counsel

The Energy Facilities Siting Council ("Council") hereby APPROVES, in part, and REJECTS, in part, subject to conditions, those portions of the First Annual Supplement to the Second Long Range Forecast of Electric Power Needs and Requirements of the Nantucket Electric Company ("the forecast") that were not addressed in the Partial Decision on the forecast adopted by the Council on April 25, 1985. As discussed herein, the Council APPROVES, subject to conditions, the demand portion of the forecast, and REJECTS that part of the supply portion of the forecast not addressed in the Partial Decision adopted April 25, 1985.

I. INTRODUCTION AND HISTORY OF THE PROCEEDINGS

A. Overview

The Nantucket Electric Company ("Nantucket" or "the Company") is an investor-owned utility that provides electric service to the Island of Nantucket, exclusively. The Company is unique among Massachusetts electric utilities in the fact that it is not in any way interconnected to the New England Power Pool ("NEPOOL"). Nantucket is one of the smallest electric companies in the Commonwealth, having annual sales totalling approximately one-tenth of one percent of electric sales in Massachusetts as a whole.

Seven diesel generators with a total capacity of 19.95 MW provide power to the system from the Company's plant in downtown Nantucket. The units, installed between 1948 and 1978, range in size from 0.7 MW to 6.9 MW.

The Company's forecast of sales and peak loads through 2008 are documented in a report entitled "Development of a Master Plan" prepared by the consulting firm of Charles T. Main Corporation in May of 1981 and updated in March of 1984. This update forecasts that Nantucket's annual sales will increase from 51,794 MWH in 1983 to 79,900 MWH in 1993. Summer peak load is expected to grow from 15.0 MW to 18.4 MW over the same period. The forecast continues to point up the concern expressed in the Siting Council's last decision that Nantucket will have inadequate reserve margin capacity -- based on loss of its largest generator (6.9 MW) -- without additional generation.

B. History of the Proceedings

Nantucket filed with the Siting Council a petition requesting approval of its forecast on May 11, 1983. The Siting Council received timely petitions to intervene in Docket No. 83-28 from the Attorney General of the Commonwealth of Massachusetts; a conservation organization known as the Nantucket Land Council ("NLC"); a group of individual customers of Nantucket styling themselves Worried Electric Consumers about Rates and the Environment ("WECARE"); and the Siting Council staff. After some preliminary debate over the propriety of these interventions, conducted through motions, memoranda of law, and a prehearing conference, all of these intervenors were admitted as parties to the proceeding. Procedural Order, EFSC Docket No. 83-28, August 11, 1983.

The procedural history following the admission of intervenors as parties is long and complex. Nearly two years after the Company's initial petition, a Partial Decision was adopted by the Council addressing Nantucket's need for additional generating capacity and a proposed program for conservation and load management, both of which had been agreed to under settlement among the parties in the proceeding.

The Partial Decision adopted by the Council on April 25, 1985 provides a description of the procedural history through that date. 12 DOMSC at 157-160. A summary of the sequence and nature of documents that make up the Company's demand forecast, and which are addressed in detail in this decision, appears, infra, in Section II-A-1.

The review of the demand forecast, beyond intervenor discovery of the Company's case (which occurred between November, 1984 and February, 1985), proceeded according to a schedule issued by the Hearing Officer February 13, 1985 with later revisions. The Attorney General filed a direct case on demand March 15, 1985. Company discovery was completed of the Attorney General's case in April, and three days of hearings on the demand forecast were held April 30, June 11 and June 12, 1985. Briefs on the demand forecast were filed by the Company, the Attorney General, the EFSC Staff Intervenor, and WECARE on July 15, 1985. Although not anticipated in the schedule, reply briefs were filed by the Company and the Attorney General on July 19, 1985.

With respect to the supply forecast, the Partial Decision of April 25, 1985 was followed by correspondence from the Company responding to conditions in the Partial Decision. Company letters, May 10, 1985 and May 17, 1985. The Company insisted that a lead time of eleven months was required between ordering a new generator and having such a generator on line. An updated contingency plan for meeting capacity shortfalls due to equipment failures was provided.

The Hearing Officer convened a pre-hearing conference May 6, 1985 on the scope of the further review of the supply plan. At the request of the Hearing Officer, the Company, the Attorney General, WECARE and NLC provided follow-up written comments on scoping. On May 23, 1985, a procedural order was issued setting the scope and schedule for an expedited EFSC review of remaining supply issues. The order also directed the Company to provide by June 5, 1985 additional information concerning 1) the need for an eleven-month lead time to order a new generator, and 2) the status and schedule for other state agency environmental reviews related to the Company's capacity expansion plans.

On June 5, 1985, the Company provided its response to the procedural order issued May 23, 1985. The response failed to provide the information requested by the Hearing Officer. Instead, the Company suggested an indefinite delay or elimination of hearings on the supply plan, and proposed that technical working sessions be held on the supply plan.

On June 6, 1985, the Hearing Officer declined to approve the Company's proposal, noting the inabiltiy of technical working sessions to provide an adequate record and the failure of the Company to provide the information requested in the procedural order of May 23, 1985. On the last day of hearings on the demand forecast, June 12, 1985, the Company confirmed that it would not participate in hearings on the supply plan scheduled for June 18, 19 and 20, 1985.

II. DEMAND ANALYSIS

A. Background

Nantucket's forecast currently is based on econometric models for three classes of sales -- residential, commercial and street lighting -- as well as for peak system loads during both the June-to-September summer season and the November-to-February winter season. Introduced in the 1981 Report Development of a Master Plan, prepared by C.T. Main, the Company's forecast modeling methodology was found in the previous Council decision, EFSC 81-28, to be highly commendable for a Company of Nantucket's size. 8 DOMSC at 260-261. A number of conditions were included in that decision, however, in order to meet Council standards of review. The conditions focused on the historical data base and customer projections, rather than on the sales and peak load models themselves.

1. The Current Filing

In the course of the current proceeding, Nantucket has filed a number of analyses serving to update the previous demand forecast. The updated analyses address not only the assumptions as to past and future levels of independent variables, but also the forecast model methodology and specifications.

The Company initially concentrated--in its Petition of May, 1983 and Addendum of October, 1983--on improving its assumptions as to customer numbers and usage levels. These analyses were in direct response to the Council conditions in EFSC 81-28. See infra, Section II-A-3.

In early 1984, as part of a new study conducted to support the Company's evolving capacity expansion plans, an updated demand forecast was prepared. The new analysis, Evaluation of Future Capacity Additions by C.T. Main (Exh. NEC-2), was intended to respond to concerns raised by intervenors in the ongoing EFSC proceeding (see Transcript, Prehearing Conference, December 8, 1983) and to orders of the Department of Public Utilities in the Company's most recent rate case. Nantucket Electric Company, D.P.U. Docket 1530 (1983). Completed in March, 1984, the updated forecast was filed in the then-joint EFSC-DPU proceeding under this docket and DPU Docket 84-55.

As in its earlier analyses, Main tested both linear and double-log transformation models, using various independent variables relating to personal income, price of electricity, number of customers by class, and heating degree days. The 1984 update provided some further analyses--for example, dummy variables to reflect seasonal visitation levels or anomalies for individual summer months and for major holidays such as Christmas. The 1983 adjustments to the data base that were done in response to previous Council conditions also were generally reflected in the new models.

Finally, in June 1984, the Company provided the required EFSC forms E-1 through E-25 (Exh. EFSC-1) as had been requested by the Hearing Officer. Filed at that time, it was possible for the information in the E-tables to be based on the updated Main forecast. However, in one area--the break out of residential energy consumption and usage factors for customers with electric heat and customers without electric heat--the Company did need to perform further analysis beyond that done as part of the forecast model update.

2. Review Criteria

As part of its statutory mandate "...to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost" (Mass. Gen. Laws Ann. ch. 164, sec. 69H), the Siting Council determines whether "projections of the demand for electric power ...are based on substantially accurate historical information and reasonable statistical projection methods" (Mass Gen. Laws Ann. ch. 164, sec. 69J). The Siting Council applies three standards of review: the reviewability of the forecast (whether the results can be evaluated and duplicated by another person, given the same level of technical resources and expertise); its appropriateness (whether it is technically suitable to the size and nature of the utility's system); and its reliability (whether it instills confidence that its data, assumptions and judgements produce a forecast of what is most likely to occur). In Re Northeast Utilities, 11 DOMSC 1, 4 (1984); In Re Boston Edison, 10 DOMSC 203,209 (1984).

3. Compliance with Previous Conditions

The Council's previous decision in EFSC 81-28 included five conditions -- four concerning demand and one concerning reserve margin. The issue of reserve margin (Condition No. 5) was addressed in the partial decision adopted by the Council in the current proceeding on April 25, 1985. 12 DOMSC at 162. Compliance with the four demand conditions is discussed below.

Condition No. 1 required the Company to provide accurate historical data and reasonable statistical projections of the total number of residential customers. These considerations relate to the reliability and reviewability of the forecast. Data on number of customers has continued to be a major issue in the current proceeding.

With regard to the first part of the condition, concerning historical data, findings in this decision suggest that the Company reasonably responded to the Council's concerns as articulated in EFSC 81-28. First, the forecast was adjusted to reflect August customer numbers (coincident maximum), rather than an aggregate of rate-by-rate monthly maximum customer levels (non-coincident maximum). Second, the Company has been responsive through discovery in explaining discrepancies in the different customer counts that have been prepared at various times under the current and previous dockets. Exh. EFSC - 4; EFSC - 24.

The second part of the condition concerns the need for reasonable statistical projections. The findings in this decision indicate that the Company did seek out judgements from various local sources concerning future growth expectations and qualitatively relate current and recent customer trends to experience with recent residential construction, particularly that since the 1982 building cap. Exh NEC-2, P. 4-13; Tr. I at 110, 141; Tr. II at 119. However, the Company's methods and reasons for applying such background information to the forecast are not adequately explained in the forecast documents, and have become apparant only through cross-examination. What's more, the approach as more fully explained by the Company does not represent a "statistical method" consistent with the Council's reviewability standard. Thus, this decision specifies further steps to improve projections of total customers in future filings. See infra, Section II-B-1.

Condition No. 2, aimed at forecast reliability, required the Company to provide historical residential electric heat usage levels for every year from 1979 on. As a first step to developing a more reliable basis for calculation of usage levels, the Company physically inspected the premises of all customers taking service under rate R (a rate for year-round customers with electric hot water heaters) to determine the number of such customers also having electric space heating. Conducted in November and December, 1982, this inspection survey provided the basis for updated estimates of the number of space heating customers and their usage levels presented in the May, 1983 petition. The 1983 estimates include customers under both Rate R and Rate E (a rate for seasonal heating customers) for the years 1979 through 1982.

The 1984 Main Update resulted in further modified figures for the number of space heating customers, aggregating rate classes and more systematically reflecting the average number of such customers over the calendar year. The corresponding adjustments to usage levels first appeared in EFSC Table E-1 (Exh. EFSC-1), filed in June 1984. The actual method for deriving the usage levels was not presented in the Company filings, and only became apparent during cross-examination. See infra, Section II-C-1.

The Company's use of annual average data for space heating customers has been questioned in the proceeding, especially as compared with its use of August data for non-space-heating customers. See infra, Section II-C-1. In addition, the Council recommends further analysis by the Company to improve its ability to track usage factors by seasonal and year-round heating customers. See infra, Section II-C-2. However, the Council concludes that the Company made reasonable efforts to address the stated terms of Condition 2.

Condition No. 3 required that the Company provide future growth projections in the number of electric space heating customers that reflect historical trends, or explain any deviation from such trends. This condition relates to the Council's requirement that the forecast be reviewable.

The 1984 Update presents space heating penetration assumptions for new homes that indicate an initial increase in penetration through 1985 followed by a specified constant level of penetration thereafter. Conversions from gas or oil heat are assumed to be zero. The actual rate of projected annual space heating customer additions rises and then falls, as a result of the interplay of Main's penetration assumptions with those concerning change in total customers. See infra, Section II-C-1.

Averaged over the ten-year forecast period, the projected trend is in fact close to the historical trend, averaged over the preceeding five years. However, the year-by-year additions dropped dramatically between 1979 and 1983. Thus, fuller explanation and justification of Nantucket's assumptions are appropriate for future filings, as follow-up to the Company's efforts in addressing Condition 3.

Condition No. 4 required that the Company provide updated projections of its overall residential usage factors that are reasonably reflective of the Company's compliance with Conditions Nos. 1-3. The Company initially concluded in its May, 1983 Petition that, based on its assumptions made at that time in compliance with Conditions 1-3, overall usage levels would remain at about 7600 kwh over the forecast period (no year-by-year estimates were provided).

In the 1984 Main Update, new customers numbers were developed for both total customers and space heating customers. The corresponding E-tables, showing usage factors for both space-heating customers and non-space-heating customers, were later filed. Exh. EFSC-1. As noted above, with respect to previous Condition No. 2, the combined use of these usage factors is problematical in that non-heating customers is considered to be the difference between total customers in August and heating customers averaged over all twelve months of the year. Thus, while the condition has been met for heating customers (Exh. EFSC-1, Table E-1), it is not clear that the usage factors for non-heating customers (Exh. EFSC-1, Table E-2) are meaningful and thus not possible to relate them to overall usage factors over the forecast period.

B. Forecasts of Independent Variables

The independent variables on which the selected models are based include number of customers, price of electricity, and heating degree days (annual and peak day). Customer data are reflected in all the forecast models, price data in all but the commercial sales model, and heating-degree-day data in all but the street lighting sales and summer peak demand models.

1. Number of customers

Like the original 1981 Study, the Main Update includes assumptions as to annual customer additions for a number of discrete periods extending through the forecast period and beyond. As shown in Table 1, the assumed annual additions in both the 1981 and the 1984 studies decline over time. However, the annual additions are on average approximately twice as large in the later study with respect to the overlapping years 1983 through 2000.

Table 1

Assumed Annual Additions of Total
Residential Customers: 1981 and 1984 C.T. Main Studies

Period	1981 Study	1984 Study
1983-1988	100	200
1988-1990	100	150
1990-1993	50	150
1993-2000	50	100
2000-2003	--	100
2003-2008	--	50

The Company has not, in either study, explicitly related customer numbers to any data on past or projected population. In the 1981 study, available population studies[1] were consulted, but apparently not used "in any way other than to qualitatively look at them and say there was an extremely wide range." Tr. I at 131. In the 1984 Update, available population studies were viewed as outdated and not used. Id.

In an attempt to gain more up-to-date insights concerning island growth, C.T. Main personnel in 1982 conducted interviews with six local experts--the director of the Nantucket Planning and Economic Development Commission (NPEDC), an assistant to the Town Building Inspector, the director of the Nantucket Land Council, two unidentified builders, and an unidentified banker. Exh. EFSC - 28. The interviews were not

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1 Including projections prepared by the Nantucket Planning and Economic Development Commission (1978) and the Office of State Planning (1976), and analysis included in the "208" Water Quality Plan.

designed to collect statistics but rather to "get a qualitative understanding of what was going on on the Island." Tr. I at 160.[2] The interviews were not based on a set of prepared questions, and not all conducted by the same person. Tr. I at 159-160. The results of the interviews were however documented in handwritten notes. Exh. EFSC-29.

The EFSC Staff Intervenor and the Intervenor WECARE both argue that Nantucket's customer projections do not meet Council standards for a reviewable forecast incorporating reasonable statistical projection methods. Tr. I at 106. Exh. EFSC-7. EFSC Staff Brief at 10. WECARE Brief at 15-17. The EFSC Staff also argues that the 1984 Update does not explain or justify the projections in accordance with EFSC Rule 63.5. EFSC Staff Brief at 10.

In explaining their arguments, both intervenors cite the subjective and unsystematic nature of the interview approach. EFSC Staff Brief at 8. WECARE Brief at 7-15. Both intervenors also note that the forecast ignores a 1975-1980 drop in population census figures for the Island as well as the population projections prepared by other organizations several years earlier and referenced in the 1981 Main analysis. Exh. EFSC-14. EFSC Staff Brief at 9. WECARE Brief at 18-21. WECARE goes on to suggest that a 1982 population estimate of 7000 year-round residents, cited in the NPEDC interview, is at odds with the 1980 population census figure of 5087. Tr. II at 132, 133. Exh. EFSC 14. WECARE Brief at 20.

The Company argues that it was justified in basing its forecast of August customers on recent historical experience and interviews with prominent local officials and businesses. Furthermore, the Company asserts that the intervenors have not demonstrated that the forecast of customer numbers is incorrect. Company Brief at 37.

In support of its argument concerning use of recent historical experience and interviews, the Company cites the views of its C.T. Main witness, Mr. Greer, that there are no up-to-date documents predicting future residential construction on the island, and that the sources chosen by the Company are certainly more current and probably more accurate than older studies. Tr. I at 118 and 132. What's more, the Company argues, the effects of the soon-to-expire building cap has been considered. Tr. I, at 24-25, 114-116. Company Brief at 38.

The EFSC Staff Intervenor supplements its arguments concerning reviewability with a specific recommendation concerning future customer projection methods. It is suggested that Nantucket should project future growth in the number of residential customers in terms of potential bands of growth, or growth scenarios. EFSC Staff Brief at 13-14.

In support of its recommendation, the EFSC Staff Intervenor points out that growth scenarios would reflect the fact that growth on

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[2] Some quantitative judgements nevertheless emerged, including an estimate of 7200 year-round residents in 1982 and an estimate of 200 new homes/year through 1986. Exh. EFSC-28.

Nantucket is affected by many factors, the duration and effect of which are impossible to quantify. A number of factors that are special to Nantucket -- building caps and the undulations of island tourism and second home development -- are cited. EFSC Staff Brief at 14. It is argued that applying the Company's current high projected rate of growth over a relatively long planning horizon could lead easily to over investment in expensive generation in the event of unsustained long-term growth. Id.

The Council will consider, first, the intervenors' underlying methodological criticism -- that the Company chose customer projection methods that do not meet the Council's standard of reviewability as a statistical method. The more specific arguments may be grouped as follows: (1) one of the Company's two recognized principal sources of information -- the interviews -- is itself unreviewable; (2) the inference of customer projections from both of the Company's principal sources -- the interviews and recent historical trends -- is unreviewable; and (3) a potential source of information which might have contributed to the reviewability of the forecast -- available population studies -- was disregarded.

As argued by WECARE, there is clear EFSC precedent concerning the unacceptability of an unsystematic interview approach as a reviewable forecasting method. In Re Commonwealth, 6 DOMSC at 1 (1981). Although a single-town service area such as Nantucket may not present all the problems faced in a larger multi-town service area, there are nevertheless many standardization and design considerations in using an interview approach. The record shows that, in Nantucket's case, the interviews were unsystematic, unsummarized, and overly dependent on the subjective viewpoints of a few individuals. Thus, the Council concludes that the 1982 interviews conducted by the Company can not represent a reasonable statistical method for forecasting.

The second and broader reviewability concern is the overall basis for the Company's projection of customer additions. It is not clear how the projected rates of increase in total customers over time are derived (see Table 1).

It can be recognized that the forecast does incorporate, as shown in Table 1, a long-term drop off in rates of increase in total customers. Such a drop off also was incorporated in the 1981 study, when expected short-term increases were themselves much lower. Clearly, the Company seems to recognize a point that intervenors emphasize -- namely that current rates of customer growth will not be sustained indefinitely.

The question that arises is just how does the Company arrive at the extent and timing of the long term declines in the projected rates of increase in total customers. What, for example, dictates that the shift in expected annual customer additions between the 1981 and 1984 studies should, in essence, be a proportional one over the later as well as the earlier years forecast in the two studies (i.e., 1983 through 2000)?

As argued by the EFSC Staff Intervenor, the derivation of future annual customer additions is neither sufficiently documented nor adequately described to allow the Council to understand the forecast. EFSC Rule 63.5(c). EFSC Staff Brief at 5, 7 and 10. There is no apparent basis in the interviews or other cited sources for construing a declining rate of future annual additions. Exh. EFSC-14. While a declining rate of future annual additions was incorporated in the 1981 Main Study, there is no apparent justification for retaining this pattern in the 1984 study while doubling the rate of annual additions on a long term as well as a short term basis. Thus, the Council concludes that the forecast of future customer additions is unreviewable.

It is a CONDITION of this decision that in future filings, the Company shall precisely and fully explain and justify the forecast of total customers, using statistical or extrapolative methods that can be duplicated by another analyst given the same forecast determinants.

The third concern, which is related to the issue of the reviewability of the methods that the Company did use, is the reasonableness of the Company's decision not to use other methods that might have met reviewability concerns. Despite the belief of intervenors that certain available population studies should not have been simply ignored, the Company defends its preference for other sources to the exclusion of these population studies, which it believes to be outdated. supra.

Clearly, the intervenors' position would not be defensible if it were to mean that the results of the population studies should be accepted without question merely because they are officially adopted and presumably based on statistical methods. In the Council's view, the Company would have not only the right, but the obligation, to question use of population projections that bear no rational relationship to more recent observed conditions.

It must also be acknowledged that the available studies, for the most part, do not provide single growth projections, but rather high-moderate-low projections -- or growth bands. Exh. EFSC-14. Thus, considerable judgement could be required in order to either select one of the several growth scenarios in the available studies or assess the consistency of separate Company projections with such studies. Indeed, it was Mr. Greer's impression of the available population data, which he reviewed as part of the 1981 Main analysis, that "there was an extremely wide range and that somehow or other we had to come up with a number for the population and residential customer growth." Tr. I at 131.

Nevertheless, the Council attributes signficance to the available population projections for two reasons. First, EFSC regulations provide that an electric utility must explain whether and, if so, how it takes into account population in projecting future demand. EFSC Rule 65.3 (b)(i). The Council in the past has expressed its scepticism of simply extrapolating customer trends without reference to available population data and analysis. See e.g., In Re Fitchburg, 5 DOMSC at 43-44.

Second, given the difficulty of the Company in locating other sources and methods which meet Council standards for reviewability, the population studies would provide at a minimum some benchmarks against which to judge the Company's forecast. Based on the record in this proceeding, the problem is not necessarily that the Company disregarded the population studies by purposefully adopting inconsistent projections. Rather, the problem is that the population studies and the Company's customer projections cannot even be compared. To the extent that population trends are a likely determinant of customer trends, an inability to compare population and customer levels is yet another facet of the reviewability problem in the Company's forecast.

The fact that the available population studies are somewhat outdated, and can only become more so, does not excuse the Company from understanding population/customer relationships. Results of the 1985 mid-decade state census should soon be available. Interest in relative trends in year-round and seasonal population growth on Nantucket will likely result in further official analyses of current population characteristics and trends, if not published updates to actual projections of population. It is the Council's view, then, that the Company should work on improving its ability to relate population and customer trends.

It is a CONDITION of this Decision that in future filings, the Company shall analyze the relationship of customer trends and projections to population trends and projections, taking into account available information on such factors as persons per household and ratio of year-round to peak seasonal population. The Company shall also consider and report on the feasibility of using a statistical model to explain customer/population relationships.

Having addressed the specific methodological concerns, the Council returns to the broader question of what these customer projections mean for the overall forecast. It does not appear that intervenors are suggesting -- nor that the record could support -- a finding that recent and expected near-term increases in summer peak-season customers are being grossly overestimated. The rate of annual increase in number of August bills (total customers) does appear to have steadily increased from just over 100 per year, on average, in 1978 and earlier years, to approximately 200 per year in 1982 and 1983. Exh. AG-1. Indeed, in the words of the EFSC Staff Intervenor, "the important point is not that Nantucket's projections of residential customers may be too high -- in fact the projections could be too low." EFSC Staff Brief at 11.

Rather, the concern appears to be that longer term forecasting based on the Company's current high projected rate of growth in the number of residential customers could lead to over-investment in expensive generation, in the event current rates of growth are not sustained. The volatility of Nantucket's growth, due to the building cap and other factors affecting Island tourism and second-home development, has been noted. And, as indicated by Mr. Greer, Nantucket's projection of future peak summer demand is highly sensitive to the number of residential customers. Tr. I at 178-79.

In this context, the Council agrees with the EFSC Staff Intervenor and WECARE that the Company's method of projecting number of residential customers deserves close scrutiny. What's more, the level of uncertainty that may inevitably remain in the later years of the forecast period must be recognized. The Council agrees with the EFSC Staff Intervenor's position that scenarios be incorporated in future forecasts to help delineate the range and significance of such uncertainty.

It is a CONDITION of this Decision that in future filings, the Company shall provide high, low and most likely scenarios of customer change and explain any assumptions as to determinants of island growth underlying respective scenarios, or explain why use of scenarios is not an appropriate forecasting technique for Nantucket.

2. Price of Electricity

Nantucket used its systemwide real average price of electricity as an independent variable in the residential, street lighting and both peak load models. Projections of real price increases over the forecast period were incorporated, reflecting both real oil price trends and expected costs of capacity expansion. Exh. NEC-2 at 4-12.

The price assumptions for the 1984 Main Update are shown in Table 2, along with the comparable assumptions used in the 1981 Main Study. Analysis of system costs was conducted in support of the 1981 Main Study, and qualitative adjustments, primarily reflecting expectations for continued stabilization of world oil prices, were made for the 1984 Update. Tr. II at 80. Exh. Nec-2 at 4-12, 4-13; EFSC-30; AG-4.

Table 2

Assumptions as to Increases in
System Real Average Price of Electricity
1981 and 1984 Main Studies

Period	1981 Study	1984 Study
1983/84	3%	1%
1984/85	3	2
1986/2000	3	1
2000/2008	-	1

The Intervenor WECARE argues that the Company's price forecast is methodologically flawed in ways that do not meet EFSC review standards. First, WECARE asserts that use of a system price cannot reflect the prices seen by customers in respective classes, and in fact introduces statistical bias. Tr II at 74-79. WECARE Brief at 43-47, 50-56.

Second, WECARE argues that the price forecast is not reviewable because it is based on the 1981 Main Study with certain qualitative adjustments. Exh W-5. WECARE Brief at 57-61.

In support of its arguments, WECARE reviews evidence showing that rates and terms are significantly different for the various customer classes. Tr. II at 69-72. Exh. AG-16A. It is asserted that, because the rate classes' prices have not and cannot shift in a consistent manner, bias exists in the forecast and the forecast is thus not a reasonable statistical method pursuant to EFSC Rules 62.9, 63.5 and 69.3. WECARE Brief at 55-56. WECARE also claims that the long term inflation and oil rates are adjusted in the 1984 Update based on opinion. Exh. EFSC-30; AG-4. WECARE Brief at 58.

The record does not show that the Company disputes the existence of judgement and possible bias in the instances cited by WECARE. However, Mr. Greer did testify that, if average system price reflects year-to-year changes in prices that individual customers face, then it's more than adequate. Tr. II at 76-77. The Company also notes that rate changes did occur in the base period, and differential price changes did not detract from the statistical significance of the Company's systemwide price term. Company Brief at 14.

The Council observes that the methodological concerns raised by WECARE are theoretically valid. However, with respect to the bias issue, it must be recognized that disaggregeting the price variable beyond the level of disaggregation in the Company's models would have little if any benefit. And, given that the residential and commercial models each involve multiple rate classes, bias would still exist even if separate price terms were developed for the residential and commercial models.

Even with some unavoidable bias, it is possible that the forecast's accuracy could be improved if separate price terms were developed for each model. The degree of improvement would depend on the extent to which average price of electricity, and the historical pattern of change in such average price, differs among the major classes being modeled. The Council therefore recommends that, in conjunction with Nantucket's cost of service study, consideration be given to the advantages and the feasibility of disaggregating, for EFSC forecast purposes, the price term in the historical data base by major customer class.

With regard to the derivation of the Company's assumptions as to future oil price changes, the Council expects that a documentable methods will be used in future forecasts.

Beyond the above concerns, which at least partly concern reviewability, intervenors raised additional issues related solely to the accuracy of the price forecast. WECARE argues that the price forecast should reflect capacity expansion plans based on a 3.6 mw addition, rather than the 5-7 mw addition recognized in the 1981 Main Study. Tr. II at 80-81. Exh. W-6. WECARE Brief at 59-60. WECARE and the Attorney General assert that changes to Nantucket's rate design structure are likely, based on findings in the Company's last rate case (DPU 1530), and that these must be reflected to obtain an accurate forecast. Attorney General Witness Geller's Testimony at 19. Tr. II at 94-95. WECARE Brief at 62-68.

In support of their arguments concerning rate trends, both intervenors cite the apparent disparities among Nantucket's existing rates, especially tail-block rates. Exh. AG-16A. Geller Testimony at 16-18. Tr. II at 70-72. WECARE Brief at 66. WECARE reviews recent DPU decisions which WECARE contends indicate a trend toward phasing out "promotional" or low tail block rates in favor of more economically based rates.[3] Tr. II at 87-90. WECARE Brief at 63-65.

The Company argues that the revision of capacity expansion plans to a 3.6 mw increment occurred only in settlement with intervenors after the Company's preparation of the forecast. Company Brief at 39. With regard to the effect of rate changes on the price term, the Company asserts that future changes are not known, and that average system price requires no assumption about cost allocation anyway, as long as full systemwide cost recovery is assumed. Company Brief at 15.

The Council agrees with the Company that the resizing to 3.6 mw and the impact of prospective future rate changes could not be reasonably known for purposes of running forecast models under the current filing. Indeed, the future rate changes are still not known, pending a new cost of service study and DPU review.

However, the Council does believe it is reasonable for the Company to think in terms of different price scenarios. Assuming disaggregation of the price term by major customer classes in future forecasts (see supra), rate change assumptions could become significant for the average price terms for the respective forecast classes. Admittedly, other price related factors--for example, differing assumptions about oil price changes--may be equally or more significant. The point is that testing of price scenarios at one or two representative levels puts the Company in a better position to comment on the significance of any concerns raised about the accuracy of the price term. The Council recommends this approach as a practical way to put issues relating to price uncertainty in their proper perspective.

3. Heating Degree Days

Weather data were obtained from the National Oceanic and Atmosphere Administration. Data for the Nantucket station were used until September 1982 (when the station was closed); thereafter (i.e., through 1983) data for the Edgartown station were used. Exh. MEC-2 at 4-1.

The Company's C.T. Main witness, Mr. Greer, testified as to the consistency of Nantucket and Edgartown data. While indicating that the two sets of data, averaged over several years, are fairly close, he admitted that regression analysis shows that "the degree of fit is not that good." Tr. I at 134.

[3] Nantucket Electric Company, DPU 1530 (1983); Boston Edison Company, DPU 1720 (1984); and Western Massachusetts Electric Company, DPU 84-25 (1984).

The impact of any inconsistency on the current forecast is probably very limited. But "in terms of where we go down the road, it doesn't seem like we have a winning option," according to Mr. Greer. Id.

The Council believes the problem warrants some more investigation. The Company is requested to review the temperature data with an eye to whether the larger (daily) inconsistencies are concentrated in any particular season. In addition, for a selection of dates which show relatively large inconsistencies, the Company is requested to review records concerning other meteorological conditions (e.g., wind direction) to determine whether any significant patterns exist.

C. Disaggregation of the Forecast

A major area of contention by intervenors has been that the Company fails to adequately and properly disaggregate the data base and the forecast models, as needed to achieve an acceptable forecast. The two areas of concern that stand out are disaggregation by basic residential class (regular, electric hot water, electric heat) and disaggregation into year-round and seasonal customer demand.

The Company did attempt to distinguish heating customer numbers and usage levels to a certain degree in the forecast -- these results are discussed, first, below. Then, the broader question -- the Company's failure to more systematically disaggregate its forecast, at all stages, into seasonal and year round use and residential heating and non-heating use -- is discussed.

1. Residential heating customers and usage factors

The Company distinguishes residential space heating data at two points in its forecasting process. First, as follow-up to the forecast of total residential customers (see supra, Section II-B-1), a separate forecast of residential heating customers is developed. The forecast of residential heating customers is an input to the residential sales and winter peak load models. See infra, Sections II-D-1 and II-E.

Second, the results of the customer projections and the later forecast model runs are analyzed to determine residential heating usage factors, and to infer projected numbers of non-heating customers and their usage factors. These further analyses are needed to fill out the "E-tables" -- specifically Tables E-1 and E-2 -- that are required as part of an EFSC forecast filing. See Exh. EFSC-1.

The forecast of heating customers is based on the forecast of annual additions of total customers, and the assumed penetration rates for electric space heating in new homes over the forecast period. The Company assumes that the space heating penetration rates during the forecast period will be 50 per cent in the first year, 55 per cent in the second year, and 60 per cent thereafter. Exh. NEC-2 at 4-14.

The Council concludes that the basis for the Company's assumptions concerning space heating penetration rates is not adequately explained. Neither the relationship to the trend in the historical ratio as shown in Table 3, nor the reason for the increase in assumed penetration rates during the first two years of the forecast period, are made clear.

It is a CONDITION of this decision that the Company shall provide, in its next filing, a more reviewable forecast of the number of residential space heating customers. In addition to any other indicators deemed appropriate by the Company, the forecast shall include a description of historical trends and their implications, beginning with the year 1979.

After forecasting electricity sales and peak loads as part of the 1984 Update, the Company turned to the task of inferring both historical and projected usage factors for residential heating and non-heating customers respectively -- information not required as part of the selected forecast model methodology. Tr. I at 99. The principal problem was to disaggregate the electricity sales for Rate Class R -- a class made up of hot water customers both with and without electric heat.

In comparing usage levels of Class R with usage levels of other classes in which electric heat was either totally present or absent, the Company determined that, in 1983, heating customers used roughly 2.1 times the energy used by non-heating customers. Tr. I at 100. After allocating historical sales for Class R customers based on the estimated 1983 ratio of usage factors, disaggregated residential usage factors then were inferred for all historical and forecast years required in EFSC Table E-1. Id.

The next step was to determine non-heating usage factors, as required in EFSC Table E-2, based on the appropriate measure of non-heating customers. The Company considered the difference between total customers (measured as August bills) and heating customers (measured as annual average monthly bills) to be an appropriate measure. See Exh. EFSC-1. As argued by the Attorney General, however, the number of non-heating customers appears to be overestimated by such an approach because total customers and heating customers are not counted on comparable terms. Geller Testimony at 10-11.

The Council believes that consistency -- both within Nantucket's forecast and relative to forecasts of other electric companies -- would be enhanced if customer numbers in the E-tables were all on an average annual basis. Although Nantucket does not forecast average annual customer levels, the relationship of this measure to August customer levels appears to show a year-to-year time-trend relationship. See Exh. AG-2. Indeed, the relationship may be relevant to broader disaggregation issues raised in the proceeding. See infra, Section II-C-2.

Table 3 shows the calculations of residential heating customer additions and compares the resultant future trends with the historical trends for five preceeding years. As noted by WECARE, the forecast penetration rates are much higher than that shown for 1983. <u>WECARE Brief</u> at 22. The significance of the 1979-1983 decline in penetration rates, if any, is also ignored.[4]

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[4] The ratio of heating customer additions to total customer additions is close to or in excess of 1.00 for seven of the eight years 1971 through 1978, as well as for 1979. See Exh. AG-1. This could, in the Company's view, reflect conversions from oil heat to electric heat, although the Company has stated elsewhere that such conversions are minimal on Nantucket. Exh. NEC-2 at 4-14; AG-13; Tr. I at 35.

It also could reflect methods used by the Company to estimate numbers of heating customers in years prior to 1982 (the year of the first physical inspection). Such estimates have been made in the past for the years 1965, 1970, 1975, and 1980. 8 DOMSC at 264. Exh. NEC-2 at 4-2. As suggested by the Attorney General and agreed by the Company, there could be, for example, the appearance of a greater increase in heating customers than actually occurred if number of heating customers was estimated based on monthly bills, and the ratio of number of monthly bills to number of heating customers was in fact increasing. Tr. I at 36.

Table 3

Recent and Forecast Trends in
Total Residential Customer Additions and
Residential Heating Customer Additions

Year	Change in Number of Residential Customers From Previous Year: Total (historical)	Heating (historical)	Ratio (Heating ÷ Total)
1979	+155	+167	1.08
1980	160	123	.77
1981	152	113	.74
1982	190	115	.61
1983	216	48	.22
	(Forecast)	(Forecast)	
1984	200	100	.50
1985	200	110	.55
1986-1988	200/yr.	120/yr.	.60
1989-1993	150/yr.	90/yr.	.60

It is a CONDITION of this decision that the Company, in its next filing, shall present residential customer usage factors in EFSC Tables E-1 and E-2 on a consistent basis, reflecting average annual customer levels, or if presented according to a different method, shall explain why such different method is more appropriate.

2. The Need for More Disaggregation

The Intervenors Attorney General and WECARE argue that the Company's forecast is inaccurate because it fails to distinguish demand for seasonal and year-round customers. Exh. EFSC-8; AG-6. Tr. I at 108. Geller Testimony at 6. WECARE Brief at 27. WECARE argues further that the forecast is inaccurate, and fails to meet EFSC requirements under EFSC Rule 63.7, because residential sales with and residential sales without electric heat are not modeled separately. Exh. EFSC - 8; AG - 6. Tr. 5 at 108. WECARE Brief at 26.

In discussing the need for seasonal disaggregation, the Attorney General emphasizes the importance of such disaggregation for the winter peak load model (see infra, Section II-E), and for the forecast assumption about electric heating penetration in new homes (see supra, Section II-C-1). Geller Testimony at 10-11. WECARE cites the possibility of differing responses to price among seasonal and year-round customers. Tr. I at 52. WECARE also suggests, with respect to both seasonal use and thermal end uses, that if the Council required disaggregation as suggested by WECARE, it would complement the DPU's action requireing a cost of service study for Nantucket. Nantucket Electric Company, DPU 1530 (1983). WECARE Brief at 31.

The Company argues that, while EFSC Rule 63.7 requires that the residential forecast be disaggregated into with-electric-heat and without-electric-heat categories, EFSC regulations do not specify at what point in the forecasting process such disaggregation must occur. Noting that heating customer data has been disaggregated back to 1979, the Company stresses the need for more passage of time to allow the data series to build up, before considering more disaggregated models. The Company asserts that the burdens of disaggregating historical data, given the status of the Company's records and staffing capabilities, would be excessive. Tr. I at 63-66, 176; Tr. III at 8-10. Company Brief at 34-37.

The Council notes that, while the intervenors support disaggregation of the Company's forecasting, they are not clear as to whether this must be done immediately, at whatever cost to the Company in terms of reformulating the data base over a sufficient number of historical years to be statistically significant. The Company, for its part, does not appear to rule out appropriate disaggregation of sales data, provided such analysis applies only to current and future years. The Company believes, and correctly so, that the degree of sophistication expected in its forecasting should be appropriate for Nantucket's size.[5]

[5] Nantucket has approximately one-fourth the customers and one-sixth the sales of the next largest electric utility (Taunton Municipal Lighting Plant) having its own generation and forecasts with the EFSC.

However, the Council believes that the Company has articulated a narrow interpretation of EFSC Rule 63.7. To assume that the required disaggregation of heating-customer usage and non-heating-customer usage applies only to the presentation of forecast results is somewhat inconsistent with the emphasis that the Council places on meeting certain reviewability and reliability standards. See supra, Section II-A-2. Indeed, although not made an issue in this proceeding, the techniques that the Company used to infer disaggregated sales for purposes of completing EFSC Tables E-1 and E-2 could likely be questioned on grounds of reviewability and accuracy. See supra, Section II-C-1.

The Council notes that the Company has developed the capability to begin compiling information on residential sales by heating and non-heating customers. Exh. AG-8; W-11. It is a CONDITION of this decision that the Company, in its next filing, present an annual summary of residential billing data on customers and usage disaggregated by heating-customer and non-heating customer categories for the base year of the Third Long-Range Forecast, and that the Company in the future provide similar compilations for all later years. The Company shall also provide heating and non-heating customer usage for all years from 1979 on, consistent with the above compilations.

The Council recognizes that the above condition is not explicit as to whether the break down of customer usage in the Rate R Class from 1979 through 1983 should be determined based on a complete inventory of bills in that class, or on estimating techniques such as were used in the current forecast. See supra, Section II-C-1. The choice is a difficult one for any electric utility -- and no less so for a Company the size of Nantucket. The choice may depend on changes that the Company considers or incorporates in its forecast models -- for example, the winter peak demand model. See supra, Section II-E-2. The Council will evaluate the Company's choice of methods in future filings based on the importance of the data to the Company's overall forecast -- and, in particular, to the overall reviewability and reliability of the forecast -- as presented in such filings.

With respect to disaggregation of seasonal and year-round customers, the record in this decision appears to suggest that the distinctions are harder to define than for heating and non-heating customers. Because "seasonal homes" to varying degrees may be occupied during week-ends and holidays in the off-season, or may be heated minimally even when unoccupied in the off-season, there apparently is not a clear dichotomy between the monthly sales profiles in seasonal and year-round homes. What's more, evidence seems to suggest that there may be a trend toward more off-season usage in "seasonal" homes, thus further blurring the distinctions as revealed in monthly billing data. Exh. AG-2.

The Company has a simple definition of "seasonal," appearing in its rate schedules -- service shall be considered seasonal when the kwh used in the eight months October to May are less than the kwh used in the four months June to September of the previous year. Exh. AG-16A.

What's more, the Company has previously compiled customer and usage data by year-round and seasonal customers, and analyzed trends for at least selected years in the period 1976 to 1983. Exh. NEC-2 at 7-4.

The Council believes that the Company, as a response to concerns raised about the limited attention in the forecast to seasonal use patterns and trends, should demonstrate a fuller understanding of the distribution of use profiles among its seasonal customers. Information better characterizing the range of use patterns and trends for such customers is needed to determine whether and how the Company should further reflect disaggregated seasonal and year-round customers in its forecasting.[6]

It is a CONDITION of this decision that the Company shall present, in its next filing, an analysis of the distribution of seasonal use profiles among customers, based on ratios of summer-peak-season usage to total-year usage, and assess trends in such use profiles, for a sampling of customer bills in 1979, 1983 and 1985. The information on use profiles and trends shall be related, as possible, to the presence or absence of electric space heating. Council staff is available to assist the Company in determining an approach to meet this condition.

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[6] Another factor in the determination is the availability of independent variable forecasts relating to seasonal residency. See supra, Section II-B-1.

D. Electricity Sales Forecast Models

1. Residential Sales

The residential sales forecast is based on a log-linear, dynamic[7] model of sales per residential customer. The independent variables are average system price, number of residential heating customers, annual heating degree days, and sales per residential customer (the dependent variable) lagged one year. The model explains 97.8 per cent of the historical variation in the dependent variable. Exh. NEC-2 at 4-3.

The number of total residential customers, discussed supra in Section II-B-1, is thus not directly included in the residential sales model. However, projections of number of residential heating customers, which is an independent variable, are based on the application of assumed penetration rates to projections of the number of total residential customers. See supra, Section II-C-1.

In the Company's previous filing, EFSC 81-28, residential sales was likewise modeled as residential sales per customer. However, the model selected in the 1981 forecast differs in that it was linear, included a heating response variable specified as residential heating customers divided by total residential customers multiplied by heating degree days, and omitted the lagged-dependent-variable term.[8]

As part of its direct case, the Intervenor Attorney General asserts that the residential sales model contains a number of flaws, which make it an inaccurate model of the causal factors that drive residential demand. These include: 1) modeling sales per residential customer as a function of heating customers, 2) not excluding seasonal (summer) heating customers from the heating-customer variable, 3) not specifying the heating-degree-day variable as dependent upon the percentage of customers who have electric heat, and 4) using the lagged dependent variable, inappropriately, in parallel relationships with other independent variables. Geller Testimony at 19-22.

As is suggested in Ms. Geller's discussion of the perceived flaws, the three flaws relating to the specification of the heating-customer and heating-degree-day variables are linked to the combined modeling of heating customers and non-heating customer sales. Thus, disaggregation of the data base and models to isolate heating customers would avoid such flaws. See supra, Section II-C-2.

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[7] The dependent variable lagged one year is used as an independent variable.

[8] C.T. Main, Development of a Master Plan for Nantucket Electric Company, 1981, pp. 6-12.

The last flaw suggested by the Attorney General -- concerning the lag structure in the model -- was the subject of substantial debate in the proceeding. In essence, Ms. Geller suggests that the lagging effect -- which could carry forward over several annual iterations of the model before dissipating -- is reasonable in relation to the price term but not in relation to the heating-customer or heating-degree-day terms. The latter two terms theoretically should have only a short-run effect, and an adjustment therefore would be required to remove any long-run effect built into the model. Ms. Geller also notes the unusually high short-run price elasticity of the model, and claims that this reflects misspecification of the model in general, and the lag structure in particular. Geller Testimony, p. 23.

In defending the residential sales model, the Company focuses on the Attorney General's criticisms concerning the lag structure and high short-run elasticity. A number of references from the literature on forecasting are produced, suggesting in the Company's view that the short-run elasticity -- although high -- is not unreasonable, and that an adjustment for long-run lag effect is not really that necessary. Exh. NEC-2 at 4-7; NEC-6; NEC-7; NEC-8; NEC-9; NEC 13. Tr. III at 80-83, 92-100. Company Brief at 21-25.

The Council recognizes that, in EFSC 81-28, the Company's modeling methodology was strongly commended and no conditions provided concerning the models themselves. See supra, Section II-A. It was the intention of the Hearing Officer in the current Supplement proceeding that the decision would focus on the accuracy of the data base and projections of independent variables -- areas which earlier appeared to be the most problematical. Order of Hearing Officer, December 28, 1984.

However, as noted supra, the specification of independent variables in the model has changed substantially since the last filing. Much of the Attorney General's criticisms appear to relate to features which are new. What's more, the explanatory power of the 1981 model was -- at 97.5 per cent[9] -- virtually as good for the pre-1980 data base as the new model is for the current data base.

The issues raised by the Attorney General -- particularly those concerning lag structure -- are statistically complex. One might question whether a Company the size of Nantucket should be accountable to such criticism, based on grounds of appropriateness. See supra, Section II-A-2. One might equally question, however, why a Company the size of Nantucket would choose such a theoretically complex model.[10]

The Council expects the Company, in its next filing, to choose and defend its choice of models based on theoretical qualities -- including straight-forwardness and ease of understanding -- as well as statistical explanatory abilities. There should be a significant gain in

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[9] See Footnote No. 8

[10] It is noteworthy that the Company plans to transfer its forecasting function to Company personnel. Tr. II at 108.

explanatory power to justify introducing models with theoretical underpinnings that are difficult to interpret and test for the given data base. Where the theoretical workings of a model are unclear, possibilities for distortion and any necessary adjustment must be considered, and the argument that such models are used by others without such adjustment will not necessarily be an acceptable defense.

2. Commercial Sales

The commercial sales forecast is based on a log-linear model, using total residential customers (August bills) and heating degree days as independent variables. The model explains 98.5 per cent of the variation in the dependent variable. Exh. NEC-2 at 4-8.

The inclusion of heating degree days represents a change since the 1981 model, which was based only on total residential customers.[11] The measure of total residential customer has itself changed. Supra, Section II-A.

Use of the model must be justified based on the ability of total August bills to serve as a surrogate measure of person-days on the island. In order for this to happen, in theory, change in August bills must reflect change in residency, as averaged over the year, and change in non-resident tourist visitation.

The historical ratio of total residential bills (the best measure of residency over the year) to August bills is actually not a constant one. Exh. AG-2. However, although the ratio has increased over the years, it has done so steadily (Id.), which may allow the model coefficient to effectively account for the change.[12]

The Company apparently has not reviewed data on tourist visitation trends. The Attorney General recommends that the Company not only consider, but actually incorporate in the commercial sales model, some variable reflecting the level of the tourist trade.[13] Geller Testimony, at 24.

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[11] See Footnote No. 8.

[12] It also has been argued that heating in unoccupied homes has increased -- a phenomenon likely to lead to additional monthly residential bills without increased commercial activity.

[13] WECARE argues that the Company relies far too heavily on the residential customer numbers as an independent variable in its models generally, and fails to reflect wider ranges of causal factors which explain demand. WECARE cites EFSC precedent that is critical of such emphasis on a single driving independent variable, particularly when accompanied by extreme response elasticities in the dependent variable. In Re Taunton, 10 DOMSC at 252, 255-6, 259-62, 276 (1984). WECARE's general inference--that EFSC precedent supports use of models that include sufficient variable to explain demand--is clearly correct. However, it may be noted that the cited problems in the Taunton case were more extreme than in Nantucket's case. Not only were the elasticities higher, but Taunton also had failed to test log-linear models and had thus chosen linear models with high negative intercepts.

The Council believes the Company should at least have an idea of whether tourism accounts for a growing, constant or declining share of commercial activity on the island. The Council recommends that, as local and state agencies are contacted in order to monitor year-round population data and studies (see supra, Section II-A), inquiry also be made into year-by-year seasonal population and overnight (tourist) room occupancy trends. The Council expects the Company in future filings to report any available up-to-date information on tourism trends, and update its assessment as to the feasibility of reflecting such trends in the commercial sales model.

The Attorney General also criticizes the absence of price in the commercial sales model, arguing that it is a priori an important variable that should not be rejected without strong justification. Geller Testimony at 13. It is asserted that NEPOOL has estimated a long-run commercial price elasticity of about 0.8, and that Nantucket's annual commercial customers can be expected to be comparable to the average New England commercial customer with respect to the magnitude of price elasticity. Geller Testimony at 14.

The Company argues that price is not a priori an important variable for Nantucket. Rather, price is viewed as a variable for which an explanatory effect may be -- and indeed was -- hypothesized and tested. Tr. I at 54. Company Brief at 25. However, the Company considered the resultant coefficient to be small and the t-statistic to be "at a level which most people consider statistically insignificant." Tr. I at 51. The Company cites the technical literature to support its decision to reject a variable not found to be statistically significant. Exh. W-18; NEC-5; NEC-6. Tr. III at 58-61. Company Brief at 28-31.

It is evident from the record that the debate over whether to retain the price variable stems from a broader disagreement about whether commercial customers on Nantucket are likely to respond to price increases by implementing conservation. Geller Testimony at 13-16. It is also evident that the seasonality of Nantucket's commercial activity is at the heart of the broader disagreement -- the Company's arguments concerning conservation essentially focus on the distinctiveness of Nantucket's tourist economy. Tr. II at 30-31, 188. Indeed, the Attorney General's argument about comparability to the rest of New England is limited to annual commercial customers (although these too experience seasonal demand). supra.

The Council believes that better information on the prospects for conservation and load management by commercial customers is needed. The Commercial and Apartment Conservation Service (CACS) program being implemented by the Massachusetts Executive Office of Energy Resources will help meet this need. The Council also expects the Company to go an additional step by aggressively pursuing the complementary energy audit program for large commercial users, included in the Stipulation as to Conservation, Rate Structure and Load Management agreed to by all parties to this proceeding and approved by the Siting Council. Exh. EFSC-2. 12 DOMSC at 167-169.

It was not the intention of the Hearing Officer to focus on the Company's choice of models and independent variables in this decision. See Order of Hearing Officer, December 28, 1984. The Council notes that such choices may be scrutincized in future proceedings. It appears, however, that further commercial audit work is currently the highest priority for Nantucket in the area of commercial conservation and load management.

E. Peak Demand

The forecast results indicate that Nantucket is and will remain a summer peaking system. As noted by intervenors, however, the recently observed 1984-85 winter peak of 14.3 mw[14] was extremely close to the 1984 summer peak of 14.4 mw observed just a few months earlier (both observations post-date the 1984 Main Update). Tr. II at 177. A major concern in the proceeding has been the Company's forecast that summer peak will exceed winter peak by nearly 90 per cent in 1993. Exh. NEC-2 at 4-18.

1. Summer Peak Model

The summer peak forecast is based on a linear model of monthly peaks (June through September, all years). The independent variables include number of total residential customers (August bills), price of electricity, and dummy variables for June, July and September peaks. The model explains 95.6 per cent of the variation, measured for the seasonal peaks. Exh. NEC-2 at 4-11 to 4-12.

The inclusion of the price term and the monthly dummies is new in the 1984 model, as compared to the 1981 model.[15]

The model results are adjusted to account for estimated load reduction being achieved through Nantucket's water heater control program. The adjustment to summer peak load is based on an assumption that there were 2801 controlled water heaters in 1983, that the annual increase in such water heaters is 70 per cent of the annual increase in residential customers, and that each such water heater reduces peak load by 0.9 kw. Exh. NEC-2 at 4-16.

Methodologically, the summer peak model raises few special problems -- beyond the general concerns discussed elsewhere in this decision relating to the specification of independent variables and the level of aggregation in the forecast.[16] However, as the driving determinant of the Company's capacity requirements, the summer peak forecast is logically a principal point of reference for another major issue in the proceeding -- conservation and load management. Indeed, the water

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[14] The winter peak is forecast to decline between 1993 and 2008.

[15] See Footnote No. 8.

[16] WECARE argues that the model is driven almost entirely by a single variable -- number of customers -- and is thus not sufficiently reflective of causal factors. See Footnote No. 13.

heater control adjustment is an example of this relationship. The significance of conservation and load management for Nantucket's forecasting is reviewed in Section II-F.

2. Winter Peak Model

The winter peak forecast is based on a log-linear model of monthly peaks (November through February, all years). The independent variables include number of residential heating customers, price of electricity, a temperature variable for the coldest day, and a dummy variable for Christmas visitation. The model explains 89.5 per cent of the variation, measured for the seasonal peaks. Exh. NEC-2 at 4-10.

The 1981 model was linear, and differed further from the current model in that the number of total residential customers was included, the Christmas dummy was absent, and the product of the temperature term and the number of heating customers was used.[17]

The model results are adjusted to account for estimated load reduction being achieved through Nantucket's water heater control program. The adjustment is assumed to be 80 per cent of that for the summer peak forecast. See supra, Section II-E-1. Exh. NEC-2 at 4-16.

The Attorney General and WECARE argue that the results of the winter peak forecast are inconsistent with those of the summer peak forecast to the point of implausibility. The forecast winter peak is flat while the summer peak increases rapidly. Inconsistency with historical trends in winter peak and with the Company's estimates of kwh per year-round customer is also cited. Exh. NEC-2 at 4-18, 7-4. Geller Testimony at 4-6.

As the principal cause of the apparently implausible winter peak forecast, the Attorney General cites the Company's failure to disaggregate seasonal from annual customers and their usages, both for residential and commercial classes. It is argued that the annual load patterns, as well as the causal factors that drive electric demand, differ between seasonal and year-round customers. The winter peak forecast, in particular, is faulty, having been modeled as a function of the average number of monthly bills of all residential heating customers. Geller Testimony at 9-10.

The Company, for its part, concedes that the winter peak model "has some problems in it," and indicates that for future filings "the Company anticipates that it will examine some additional models there." Tr. I at 21. It is also conceded, with respect to heating customers in the R class, that use of average annual rather than maximum monthly data is "more appropriate for an energy model, although probably not as good for a winter peak model". Exh. EFSC-24.

[17] See Footnote No. 8.

In a somewhat different viewpoint from that of the intervenors, however, the Company mentions only trends in the number of total residential customers, and in non-heating components of demand, as notable factors requiring future investigation for their influence on winter peak. Company Brief at 32. Indeed, as noted supra, the number of total residential customers, although absent in the current model, was in fact included in the 1981 model.

However, the 1981 model also used maximum monthly data rather than average annual data for the number of heating customers. Given that the Company concedes the probable superiority of the monthly maximum data, the Council believes the Company must give equal attention in the future to testing the influence of different specifications of heating customers and their usage levels such as to better reflect winter demand patterns.

It is a CONDITION of this decision that the Company, in its next filing, demonstrate testing of alternative model specifications reflecting heating customers and their usage patterns during the winter peak season, and reflecting the non-heating component of demand by customers during the winter peak season, for both residential and commercial customers.

F. Conservation and Load Management

A plan for conservation and load management, agreed to under a stipulation of all parties in the proceeding, was previously approved by the Siting Council as part of a Partial Decision on supply issues in the proceeding. The plan includes a range of techniques--subsidized conservation materials, energy audits, efficiency standards for new customers, appliance purchase rebates, and a solar water heater deomonstration project--and provides estimates of the expected energy savings for some of the techniques. 12 DOMSC at 167. Exh. EFSC-2.

All of the intervenors stress the need for the Company to explicitly reflect and evaluate the effectiveness of conservation and load management measures as part of the Company's demand forecasting. The Attorney General and WECARE assert that the Company is inconsistent in that it now questions whether significant energy savings will result from the very measures that are included in the stipulation to which the Company agrred. Tr. II at 30-31. The EFSC Staff Intervenor submits that the forecast must explain whether and how conservation and load management are taken into account. EFSC Rule No. 63.5(b)(IV). It is further agrued that merely capturing the effects of conservation through econometrics does not constitute compliance with Rule No. 63.5. EFSC Staff Brief at 12.

As acknowledged by the EFSC Staff Intervenor, the water heater adjustments included in the Company's peak load forecasts are at least one example of the reflection of conservation and load management measures in the forecast. See supra, section II-E. Indeed, such an analysis is also recognized by the Company as the first step in determining the cost effectiveness of such measures. Tr. I at 148-49.

The next step would be to estimate the cost of the reduction in demand. Tr. I at 150. It is in this way that the explicit reflection of conservation and load management in the demand forecast relates to the determination of a least-cost supply plan.

The Council agrees that the Company must interrelate its demand and supply forecasting functions with respect to conservation and load management. In future filings, the Company's forecast must show reasonable accuracy in reflecting such measures--not only to provide a reliable forecast but also to provide a reliable basis for evaluating the cost effectiveness of conservation and load management programs.

The Council believes that the Company must conduct analysis to allow it to present well-supported positions on respective conservation and load management measures--particularly in light of the range of such measures that have been approved as part of the Company's supply plan. It is a CONDITION of this decision that the Company, in its next and future filings, shall demonstrate reasonable progress in explicitly reflecting in its demand forecasting the effects of a range of conservation and load management measures as identified in the Company's supply plan.

III. SUPPLY ANALYSIS

The Partial Decision adopted by the Siting Council in this proceeding on April 25, 1985 addressed three supply-related issues: 1) the Company's need for an additional 3.6 mw of capacity (site undetermined), 2) the Company's plan for conservation and load management, agreed to under a stipulation of all parties in the proceeding; and 3) the status of the Company's contingency planning to meet reserve margin problems in the short run. Other supply plan issues, particularly the issue of where additional capacity would be sited during the forecast period, were deferred for further review during the remainder of the proceeding. 12 DOMSC at 155.

As already mentioned, a pre-hearing conference was convened May 6, 1985 and a procedural order issued May 23, 1985, concerning the scope of the remaining supply plan review. However, the Company later determined that it would not comply with certain provisions of the procedural order, and the scheduled hearings on supply were cancelled. See supra, Section I-B.

The Company's position in opposition to the review scope and schedule set by the Hearing Officer was explained, less than two weeks before the scheduled hearings, as follows:

> The EFSC has also scheduled three days of hearings (June 18, 19 and 20) on the location of the stipulated new 3.6 Mw generator. This location matter is already the subject of extensive, expensive and lengthy consideration by other state agencies as acknowledged in the EFSC's Procedural Order dated May 10, 1985. Of particular and specific relevance is the EIR, now in its final stages. The Secretary of Environmental Affairs has required that the EIR include a full description of the Company's planning process for the stipulated 3.6 Mw generator, and also for any future generators which may be necessary.
>
> letter to Hearing Officer from
> Counsel for Nantucket, June 5, 1985

Based on this position, the Company proposed eliminating or deferring hearings, and holding working sessions instead.

The Attorney General argues that the Company's overall forecast should be rejected, based on the refusal of the Company to participate in hearings with respect to supply issues scheduled for the week of June 17, 1985. Attorney General's Brief at 9-11. The EFSC Staff Intervenor argues that the portion of the Company's supply plan not previously addressed in the Council's Partial Decision (April 25, 1985) should be rejected, based both on the Company's refusal to participate in hearings and on the absence of evidence in the record of "a planning process for future supply." Tr. III at 158. EFSC Staff Brief at 13.

In explaining the perceived deficiencies in the Company's supply plan with respect to planning process, the EFSC Staff Intervenor states the following:

> The 1984 C.T. Main Report (Ex. NEC-2), does not contain any explanations of the Company's planning process, the criteria and timing to be used in the future for determining the need for supply additions, the criteria which will be used to select or evaluate the alternatives for meeting demand, or the criteria for selecting the preferred supply. Instead, the 1984 C.T. Main Report sets forth a rigid plan for supply additions beyond the year 2000.
>
> Id.

The Council observes, at the outset, that the Company does not appear to have disagreed with the emphasis placed by the EFSC on having an adequate planning process. This review perspective was stated in the Hearing Officer's Order of May 23, 1985:

> As is the case with its review of supply planning generally, the EFSC is primarily concerned with how the Company approaches the question of where future capacity (in such increments or range of increments as appear warranted based on the Company's forecast of resources and requirements) should be sited. In such a context, the Company's recognition of general long-term constraints relevant to cost, reliability and environmental concerns, rather than its detailed analysis of project information which may have only a minor impact on such concerns, is at issue.

It is the same review perspective that the EFSC Staff Intervenor cites as a basis for partially rejecting the Company's supply plan.[18]

Rather, it appears that the Company has acted based on its views concerning the inter-related and overlapping review functions of other state agencies--notably, in this case, the Environmental Impact (or MEPA) review process of the Executive Office of Environmental Affairs. As suggested by the EFSC Staff Intervenor, the Company may or may not have felt that the subject of the EFSC hearings on the supply plan would be environmental in nature.[19] EFSC Staff Brief at 13.

In fact, the designated scope of the EFSC review included a number of issues, besides the issue of environmental constraints, relating to

18 Lack of a planning process for addressing projected capacity deficiencies recently has been found as the basis for rejection of a utility's supply plan. See In Re Commonwealth, 12 DOMSC at 39.

19 As indicated in the Certificate of the Secretary of Environmental Affairs on Nantucket's Environmental Notification Form (EOEA File No. 5369, November 8, 1984), an Environmental Impact Report can constitute a "planning tool" (301 CMR 10.01 (3)). As indicated in the Certificate of the Secretary of Environmental Affairs on Nantucket's Draft Environmental Impact Report (March 29, 1985), however, the Company's discussion of planning in the EIR was found to be "disappointing".

the Company's long term planning for capacity location. In addition to planning for future capacity expansion, other issues included planning with respect to location of replacement generation in the event of unit retirements at the Company's existing plant, and planning with respect to reliability of operating units at more than one site.

With regard to environmental issues themselves, EFSC regulations do not provide that utility forecast or facility reviews must incorporate, or await, results of Environmental Impact Reports (EIR). In practice, draft EIR's are frequently used to complement the EFSC's adjudicatory reviews. However, given the statutory deadlines for EFSC review, final EIR's are less likely to be available for use in EFSC hearings.[20]

The Council concludes that the MEPA review process cannot replace EFSC supply plan review, even with respect to environmental issues. Furthermore, while MEPA review can complement EFSC review, it cannot dictate the timing of EFSC review.[21] Given the age of the current proceeding, and the failure of the Company to cooperate in the determination of any workable schedule for integrated state agency review, the Council believes the current EFSC proceeding must be terminated.

The Council finds that the Company has failed to provide a supply plan adequately describing its long term plans and its planning process with respect to the need for additional capacity and the location of future generating capacity over the forecast period, which was the scope of review set in order to expedite completion of this proceeding. Accordingly, the portion of the supply plan not previously addressed by the Siting Council on April 25, 1985 is hereby Rejected.[22]

20 Counsel for the Company indicated, in his letter of May 10, 1985, that "the EFSC is itself a cause of the delay" in the Company's placement of an order for a new generator. In his order of May 23, 1985, the Hearing Officer set an expedited schedule for EFSC review to avoid further delay, but requested that the Company report by June 5, 1985 the status and schedule for completion of environmental agency reviews. In his letter of June 5, 1985, Counsel for the Company requested an indefinite delay of the EFSC hearings pending completion of the Final EIR, but failed to provide any information on the status or scope of continuing environmental reviews as ordered by the Hearing Officer.

21 Pending the actual filing of the Final EIR, the Company is in control of the schedule.

22 The Council's review and findings concerning Nantucket's supply plan are distinct from and in no way relate to the Council's authority to approve or disapprove a proposal to construct a generating facility of over 100 mw in Massachusetts. Mass. Gen. Laws Ann., Ch. 164, Sec. 69H. The approval of the Council is not required for Nantucket's installation of the 3.6 mw diesel generator as discussed in the Council's recent decision, 12 DOMSC 155 (1985).

IV. DECISION AND ORDER

The Council hereby APPROVES, in part, and REJECTS, in part, subject to conditions, those portions of the forecast that are not addressed in the Partial Decision on the forecast adopted by the Council on April 25, 1985. The Council REJECTS that portion of the supply plan not addressed in the Partial Decision adopted by the Council On April 25, 1985. The Council APPROVES the demand portion of the forecast subject to the following conditions:

1. That in future filings, the Company shall precisely and fully explain and justify the forecast of total customers, using statistical or extrapolative methods that can be duplicated by another analyst given the same forecast determinants.

2. That in future filings, the Company shall analyze the relationship of customer trends and projections to population trends and projections, taking into account available information on such factors as persons per household and ratio of year-round to peak seasonal population. The Company shall also consider and report on the feasibility of using a statistical model to explain customer/population relationships.

3. That in future filings, the Company shall provide high, low and most likely scenarios of customer change and explain any assumptions as to determinants of island growth underlying respective scenarios, or explain why use of scenarios is not an appropriate forecasting technique for Nantucket.

4. That the Company, in its next filing, shall present residential customer usage factors in EFSC Tables E-1 and E-2 on a consistent basis, reflecting average annual customer levels, or if presented according to a different method, shall explain why such different method is more appropriate.

5. That the Comapny shall provide, in its next filing, a more reviewable forecast of the number of residential space heating customers. In addition to any other indicators deemed appropriate by the Company, the forecast shall include a description of historical trends and their implications, beginning with the year 1979.

6. That the Company, in its next filing, shall present an annual summary of residential billing data on customers and usage, disaggregated by heating-customer and non-heating-customer categories, for the base year of the Third Long-Range Forecast, and that the Company in the future shall provide similar compilations for all later years. The Company shall also provide heating and non-heating customer usage for all years from 1979 on, consistent with the above compilations.

7. That the Company shall present, in its next filing, an analysis of the distribution of seasonal use profiles among customers, based on ratios of summer-peak-season usage to total-year usage, and assess trends in such use profiles, for a sampling of customer bills in 1979, 1983, and 1985. The information on use profiles and trends shall be related, as possible, to the presence or absence of electric space heating. Council Staff is available to assist the Company in determining an approach to meet this condition.

8. That the Company, in its next filing, shall demonstrate testing of alternative model specifications reflecting heating customers and their usage patterns during the winter peak season, and reflecting the non-heating component of demand by customers during the winter peak season, for both residential and commercial customers.

9. That the Company, in its next and future filings, shall demonstrate reasonable progress in explicitly reflecting in its demand forecasting the effects of a range of conseration and load management measures as identified in the Company's supply plan.

The Company,s Third Long-Range Forecast will be due on or before December 31, 1985.

William S. Febiger

William S. Febiger
Hearing Officer

Unanimously APPROVED by the Energy Facilities Siting Council on August 1, 1985, by those members and designees present and voting: Chairperson Sharon M. Pollard (Secretary of Energy Resources); Sarah Wald (for Secretary of Consumer Affairs, Paul W. Gold); Stephen Roop (for Secretary of Environmental Affairs, James S. Hoyte); Madeline Varitimos (Public Environmental Member); Joseph W. Joyce (Public Labor Member). Ineligible to vote - Dennis J. LaCroix (Public Gas Member).

Sharon M. Pollard

Sharon M Pollard
Chairperson

8 August 1985
Date

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

Essex County Gas Company) Docket No. 84-15

FINAL DECISION

James G. White, Jr.
Hearing Officer

August 1, 1985

The Energy Facilities Siting Council ("Siting Council") hereby APPROVES, subject to conditions, the Third Supplement to the Second Long-Range Forecast of natural gas requirements and resources of Essex County Gas Company ("Essex" or the "Company") for the period 1984-85 through 1988-89.

The Company's Third Supplement is virtually unchanged from its Second Supplement in terms of presentation and narrative discussion, and the methodology of projecting gas sendout requirements. Accordingly, the Siting Council's decision in this proceeding is brief, and focuses on the principal items of concern to the Siting Council.

I. Procedural History

Essex filed its Third Supplement on November 5, 1984. In this Supplement, Essex does not request approval to construct any facilities. Essex provided public notice of its filing by publication and posting. On December 14, 1984, Distrigas of Massachusetts Corporation ("DOMAC") filed a Petition to Intervene, which was granted.

In this proceeding, the Company has responded to two sets of Information Requests of the Siting Council Staff. In addition, the Company participated in a technical session attended by representatives of the Siting Council Staff and DOMAC. The Record in this proceeding consists of the Company's Third Supplement, the responses to the Information Requests, various charts indicating the Company's weekly sendout and supply data on a weekly basis during the 1984-85 heating season, and a letter from Essex to Bay State Gas Company discussing LNG prices.

II. Sendout Methodology

A. Customer Use Factors

As explained in last year's decision,[1] Essex projects gas sales for three firm customer categories namely residential general (non-heat), residential heat, and commercial and industrial, <u>Essex County Gas</u>

[1] The Second Supplement was approved by the Siting Council on October 24, 1984, <u>Essex County Gas Co.</u>, 11 DOMSC 305 (1984). The Company's methodology for projecting sendout is discussed in that decision.

Company, 11 DOMSC at 308-312.[2] Essex adds unaccounted for gas based on a historical fraction of monthly sales, and also adds Company use gas to arrive at total projected sendout.

For each rate class[3] and each month, Essex calculates the total projected sales by adding the base load and heat use. The monthly base use is the average daily base use per customer times the number of customers and days in the month. For each of the three classes, Essex projects annual base use factors for each year in the forecast period based on historical trends in the base use factor in Mcf per customer per day. See Supplement Exhibit 5. Essex does not change the base use factor for different months in the year. The base factor is based on July and August sales data, Supplement at 5.

The monthly heat use is the daily heat use per customer (in Mcf/DD) times the number of customers times the effective billing degree days in the month. Essex calculates the heat factor for the month of January, and then determines monthly heat factors from the projected January figures using monthly "historical percentage variations," Supplement at 8, Supplement Exhibit 8. Again, Essex projects the monthly heat factors (Mcf/customer/DD) for each of the three classes for each split-year in the forecast period.[4]

2 Essex uses the total of the twelve averages of degree days for each month for the period September 1961 - August 1983 for its normal weather year of 6926 degree days, Supplement at 1. The design weather year is 7788 degree days representing the coldest split-year experienced in the same period. The peak day standard is 76 degree days experienced once in the last twenty years, Supplement at 2. Essex uses billing degree days to project sales, Response to Information Requests SO-2. Regarding the design year standard, the Siting Council observes that the narrative to the Supplement on page 2 and the Table on Degree Day Data do not clearly indicate the time period used to determine the standard (i.e., the last 20 years versus "1917 to present"). Also, the billing degree days for the coldest split-year (7761 degree days) as shown on Exhibit 1 to the Supplement are not consistent with the Company's standard. Essex should update its weather standards to incorporate data from the last two years, and should resolve these inconsistencies.

3 Essex indicates that the same basic methodology is employed for each rate class, Supplement at 8. Exhibit 5 to the Supplement addresses the residential general, residential heat and commercial and industrial classes. But, Essex does not explain how these three classes correspond to its rate classes, i.e., General Service Rate A; Commercial and Industrial Rate B; Residential (over 65) Service Rate G; and Outdoor Gas Lighting Rate E. Essex should clarify its filing in this areas.

4 Actually, Essex utilizes a September through August year.

The Company's projected heat and base use factors in the current Supplement do not conform in each instance to the trends in the Second Supplement. In the residential heat class, Essex projects slightly lower base and heat factors than projected in last year's filing for the same future split-year.[5] Again, in the residential general class, Essex projects lower base use factors than projected last year throughout the forecast period.[6] This year, the Company projects the heat factor for the residential general class will remain constant throughout the forecast period at a level much lower than projected in the Second Supplement in which Essex projected a rise in the heat use factor. And, in the commercial-industrial class, Essex now projects that the base use factor will decline annually throughout the forecast period as opposed to a projected increase in the Second Supplement.

The Siting Council is concerned about the possible impact of these changes in projections as part of the Company's planning process. The Company's current Supplement offers no meaningful explanation for any of the described changes.[7] And more importantly, Essex does not describe the significance, if any, of these changes on the overall projected sendout requirements throughout the forecast period. Rather, the changes in trends appear to result merely from the inclusion of an additional year of historical data.[8]

In future filings, the Siting Council requests that Essex describe in detail the changes in the projected customer use factors and the impact on the Company's overall sendout requirements.[9]

B. Customer Projections

Essex projects that the number of residential heating customers will grow from 19,748 in 1983-84 to 23,069 in 1988-89. This growth

5 E.g. For 1987-88, the Second Supplement projected base and heat factors of .0790 Mcf/customer/day and .0124 Mcf/customer/DD. In the Third Supplement the corresponding figures are .076 Mcf/customer/day and .0120 Mcf/customer/DD.

6 E.g. For 1987-88, The Second and Third Supplements project .0484 and .0476 Mcf/per customer/day.

7 The "trend lines" shown on Supplement Exhibit 5 do not appear always to portray any trend, e.g., the residential general heat use factor.

8 See Responses to Information Requests SO-8; SO-10; SO-11; SO-12. The Siting Council has expressed criticism of the use of a single historical data point as well as the use of judgmental trending to project future gas sendout requirements, Fall River Gas Co., 12 DOMSC 11, 17 (1985). While Essex does not appear to use a single historical data point, the Siting Council believes that any projection method which places unexplained emphasis on the most recent historical data and on unexplained trends is similarly subject to criticism.

9 In its decision on the Company's Second Supplement, the Siting Council recommended without apparent result that Essex discuss certain aspects of its methodology, 11 DOMSC 305 (1984).

rate is faster than projected a year ago. And, Essex projects the number of residential non-heating customers will decline more rapidly than projected a year ago.[10] Essex states that its Marketing Department "closely tracks" customer changes on a monthly basis for load distribution. Essex also presents monthly customer projections by class, and uses Census data to determine "empirically" that the residential customer projections are reasonable. Supplement at 3, Supplement Exhibit 4. Essex projects the growth in the number of larger commercial and industrial customers on an individual basis, while smaller ones are calculated based on "historical data," Supplement at 3. For these larger customers, Essex does present statistics on installed, committed, and "pending" customers in the commercial-industrial class, Supplement Exhibit 2. Essex, however, does not explain its use of these charts to project the number of customers or the method for combining the projections for the "larger" and smaller industrial customers.[11]

The Company projects 3,319 commercial-industrial customers in 1987-87, which is a sizable increase over the projected number of approximately 3100 in the Second Supplement for the same split-year, Supplement Table G-3; 11 DOMSC at 308.[12] As with the customer use factors, the Siting Council notes the absence of discussion or description in the current Supplement on the method of projecting numbers of customers in each of the three classes or the method of "empirical" checking through independent census data on the residential customers.[13] And again most importantly, the Supplement does not describe the impact of its shifting projections of customer numbers on its total sendout requirements throughout the forecast period. Last year, the Siting Council encouraged Essex without avail to reexamine its projection methods. This year, the Siting Council will require Essex to address its customer number projections, and describe the impact on its overall supply requirements, particularly heating season requirements. See Condition One.[14]

10 E.g. For 1987-88, the Second Supplement projected approximately 21,500 heating customers and 7100 non-heat customers. The corresponding figures for the Third Supplement are 22,323 and 6936, Supplement Tables G-1 and G-2.

11 Essex does not describe the distinction between these two sets of customers in the same class.

12 The increase in customer numbers is coupled with the projected increases in the heat use factors for this class. See Supplement Exhibit 5.

13 The Company states the Census reports are used subjectively as a confirming source of trends, Response to Information Request SO-7.

14 "The Company's forecast really is based on a trend of the number of new customers," Response to Information Request SO-4.

C. Design Year and Peak Day Projections

Essex has not altered its method of calculating design weather year sendout requirements since last year. Essentially, Essex generates design year sales projections by using effective design year degree days in place of normal effective year degree days. See 11 DOMSC at 311.

The peak day methodology, however, appears to be slightly different. As before, Essex uses the total of the daily base uses of all classes plus the heat use calculated using factors from December through February, Supplement at 9. In the Second Supplement, Essex apparently utilized January heat factors. Given the importance of projections of peak day sendout requirements, the Siting Council will require that Essex describe its peak day methodology in greater detail accompanied by a worksheet demonstrating the calculations of sendout requirements. See Condition Two.

III. Supply Resources and Facilities

As described in the decision on the Second Supplement, Essex relies on pipeline gas delivered by Tennessee Gas Pipeline Company ("Tennessee"), underground storage gas, LNG and propane to meet the sendout requirements of its customers, 11 DOMSC at 312. However, the Company's supply resources appear to be constantly shifting as the Federal Energy Regulatory Commission attempts to implement new regulatory policies, and as the various gas supply projects evolve into new forms. As indicated in the last decision, Essex has requested increases in its MDQ and AVL purchased under the CD-6 Rate Schedule from Tennessee. Tennessee has applied to the Federal Energy Regulatory Commission ("FERC") to increase the Company's MDQ from 14.519 to 20.882 MMcf and the AVL from 4,100 MMcf to 5,487 MMcf.[15]

Essex decided not to request an upgrade to firm of the approximate one-third of Tennessee's transportation of the Company's storage gas which remains interruptible.[16] Essex has indicated that Tennessee already delivers two-thirds of its storage gas from Penn-York Energy Corporation, and Consolidated Gas Transmission Corporation on a firm basis. Essex indicated the cost of upgrading the remaining interruptible transportation would outweigh the benefits because the Company already has sufficient responses to meet peak day requirements, Response to Information Requests S-6 and S-7.[17]

15 "Notice of Amendment and Petition to Amend," Tennessee Gas Pipeline, Co., FERC Docket No. CP84-441-003 (April 29, 1985) at 10.

16 See "Order Modifying and Approving Contested Settlement," Tennessee Gas Pipeline Co., et. al., FERC Docket Nos. RP83-8-000, CP84-441-002, et. al., in which FERC approved certain firm transportation of storage gas for certain distribution customers in Massachusetts.

17 Essex feels the delivery performance by Tennessee of the interruptible transportation of Essex' storage gas may improve as a result of the FERC Order described in footnote 16.

Last year, the Siting Council recognized the importance of LNG to Essex as a peak shaving fuel and reported on the Company's request for increased quantities of DOMAC LNG. The Siting Council recognizes that the status of Essex' request for increased volumes of LNG is uncertain. Indeed, the Economic Regulatory Administration and FERC have not acted on the necessary applications which have been pending for some time.[18] As an additional complication, the applicability of FERC Order No. 380 to DOMAC's LNG sales, is under court review.[19] Certainly, there are many factors which will influence the availability of DOMAC LNG to Essex.

Essex reports that assuming a full storage levels of LNG and the availablity of propane, Essex would have sufficient supplies to meet peak day, cold snap, and design year sendout requirements, Response to Information Request S-23. Given the importance of LNG to Essex, the Siting Council requested that Essex address the availability of LNG from other sources in the event of disruption of DOMAC quantities.[20] Essex indicated its belief that there are other LNG sources, and pointed to the liquefaction capability of some other Massachusetts companies. Response to Information Request S-9. Essex stated, however, that it does not have a specific contingency plan in the event of non-delivery of DOMAC LNG.

[18] See "Order For Applicant to Report on Negotiations," Distrigas Corporation, ERA Docket No. 82-13-LNG (March 20, 1985); "Notice of Petition to Amend," Distrigas Corporation, FERC Docket No. CP77-217-001 (October 15, 1982).

[19] "Petition for Review", Distrigas of Massachusetts Corp. and Distrigas Corp. v. FERC, Docket No. 85-1215 (D.C. Cir.). FERC Order No. 380 ostensibly allows a distributor to refuse gas deliveries from suppliers based on economic considerations. The supplier ostensibly must attempt to market the refused volumes elsewhere. As an example, Essex referred to FERC Order No. 380 in requesting Bay State Gas Company to adjust its LNG price to Essex "to a more competitive level." See Response to Information Request S-9. And, two to purchase distribution companies have utilized Order No. 380 to refuse LNG from DOMAC.

[20] The Siting Council's concern at this point is the overall future prospects for the availability of the DOMAC LNG supply in light of FERC Order No. 380, the uncertain status of the FERC and ERA applications filed by Distrigas and DOMAC, and the actions of other participants in the DOMAC LNG project.

Another apparent change since last year's filing, is the Company's plan to use increased Tennessee pipeline volumes to offset the once-anticipated volumes from Phase 2 of the Boundary Gas project.[21] Another change is the Company's plan to purchase the North Avenue LNG facilities.[22]

The Company's plans for its gas resources in the next five years have changed radically since the Supplement was filed last November. Given this situation the Siting Council believes the most appropriate course of action is to require Essex to file its Third Long-Range Forecast on October 1, 1985, and address in detail the comparison of its requirements and resources under its updated supply plan.[23] The Siting Council specifically requests that Essex discuss each of its projected supplies in depth, including anticipated on-line dates and volumes, and the cost, and delivery terms and reliability of the supplies. As Condition Three to this decision, the Siting Council will Order that Essex discuss in detail the availability of LNG from sources other than DOMAC for the forecast period (with identification of the potential suppliers and the terms of possible supply contracts). Essex shall also discuss the status of the Distrigas Corporation and DOMAC applications, and the impact of Order No. 380 on the ability of DOMAC to serve Essex.

[21] The Company's Response to Information Request No. D-5 reveals no reliance on Bounday Gas supplies during the forecast period. Instead reliance is placed on increased Tennessee volumes.

[22] Essex County Gas Company, DPU No. 8547. See Response to Information Request D-14.

[23] The narrative portion of the Company's Supplement on supply resources must be expanded to provide more details on future supplies, specifically including the Tennessee expansion program in FERC Docket No. CP84-441-003, the pending Distrigas applications at FERC and ERA, and the impact of FERC Order No. 380 on the Company's supply plans.

IV. Order

The Siting Council APPROVES the Third Supplement to the Second Long-Range Forecast of gas requirements and resources of Essex County Gas Company subject to the three following conditions which are to be met in the Third Long-Range Forecast to be filed on October 1, 1985:

1. Essex shall describe in detail the basis for projecting customer numbers in each class including the reason for selecting any trends, and the method of utilizing data from the Marketing Department, and independent data from census reports or other available sources. A statement that such data is used "judgmentally" will not satisfy this condition. Essex shall describe the impact of projections of customer numbers on its sendout requirements in the heating season.

2. Essex shall present a detailed description and analysis, with supporting documentation, of its peak day sendout requirements, and the supply resources available to meet the requirements.

3. Essex shall present a detailed discussion on its plans and contingency plans for LNG. The discussion shall include: the status of the Distrigas and DOMAC federal govenment applications; the impact of Order No. 380 on DOMAC's ability to supply Essex with LNG; and identification of other potential suppliers of LNG, and possible terms of delivery.

James G. White, Jr.

James G. White, Jr.
Hearing Officer

August 1, 1985

Approved unanimously by the Energy Facilities Siting Council on August 1, 1985 by those members and designees present and voting: Sharon M. Pollard, Chairperson (Secretary of Energy); Sarah Wald (for Paula W. Gold, Secretary of Consumer Affairs); Stephen Roop (for James S. Hoyte, Secretary of Environmental Affairs); Dennis LaCroix (Public Gas Member); Madeline Varitimos (Public Environmental Member); Joseph Joyce (Public Labor Member).

Sharon M. Pollard

Sharon M. Pollard
Chairperson

8-13-85
Date

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of the City of Holyoke Gas and Electric Light Department for Approval of the 1984 Supplement to the Second Long-Range Forecast of Gas Requirements and Resources	)	Docket No. 84-23

FINAL DECISION

Carolyn E. Ramm
Hearing Officer

Calvin Young
Analyst

July 24, 1985

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I. Introduction

The Energy Facilities Siting Council ("Council") APPROVES the 1984 Supplement to the Second Long-Range Forecast of Gas Requirement and Resources ("Supplement") of the City of Holyoke Gas and Electric Light Department ("Holyoke" or "Department"), subject to the Conditions imposed herein.[1]

A. History of Proceedings

Holyoke filed the current Supplement on November 30, 1984. Holyoke provided public notice of the filing by publication and posting of the Notice of Adjudication. The Council received no intervention petitions. Holyoke submitted responses to one set of Document and Information Requests.

B. Background

Holyoke is a municipal utility and is the ninth largest distributor of natural gas in the Commonwealth in terms of annual gas sendout.[2] Table A reflects Holyoke's total annual gas sendout and the average number of customers for split year 1983/84 by customer class.

Table A. Total Annual Firm Sendout and Average Number of Customers for 1983/1984.

Class of Customer	Annual Sendout (MMcf)	Average Number of Customers
Residential Heat	559	6316
Residential Non-Heat	74	3431
Industrial	125	4
Commercial & Industrial	791	945
Company & Unaccounted	672	---
	2221	10696

Of the 10,696 customers, 91% were residential customers and of the approximately 2,221 MMcf of firm sendout, 91 percent went to residential gas heat customers, commercial and industrial customers, and company and unaccounted-for sendout.

1. The Energy Facilities Siting Council approved the Second Annual Supplement to the Second Long Range Forecast in October, 1984. City of Holyoke Gas and Electric Light Department, 11 DOMSC 291 (1984). There were no conditions imposed by the Council in its last decision.

2. G. Aronson, Report of the Energy Facilities Siting Council, "The Gas Industry in Massachusetts," (March, 1983).

Holyoke suffered a decline in the number of customers in each customer class from split year 1982/83 to 1983/84. Holyoke lost 23 customers in the residential with gas heat class, 121 customers in the residential without gas heat class, 1 customer in the industrial class and 25 customers in the commercial-industrial class.

II. Scope and Standard of Revision

The Commonwealth of Massachusetts mandates that the Council review sendout forecasts of each gas utility to ensure the accurate projection of gas sendout requirements of a utility's market area. The Council's Rules 62.9(2) (a), (b) and (c), require the use of accurate and complete historical data and a reasonable statistical projection method. In its review of a forecast, the Council determines whether a projection method is reasonable according to whether the methodology is: (a) appropriate or technically suitable for the size and nature of the particular gas utility's system; (b) reviewable or presented in a way such that the results can be evaluated and duplicated by another person given the same information; and (c) reliable, that is, provides a measure of confidence that the gas utility's assumptions, judgements and data will forecast what is likely to occur. The Council applies these criteria on a case-by-case basis.

In order to ensure that the required gas is supplied to a utility's customers with a minimum impact on the environment at lowest cost, the Council focuses its supply review on the adequacy, cost and reliability of gas supplies needed to meet projected sendout requirements. The adequacy of supply is measured by the company's ability to meet projected peak day, cold-snap, and total annual firm sendout requirements with sufficient reserves. The review of cost of supply addresses minimization in concert with notions of by adequacy and reliability of natural gas supply. The reliability of supply reviews the probability that a specific source of natural gas will be available to meet or contribute to meeting sendout requirements for peak load, cold snap or firm sendout requirements.

III. Forecast of Sendout Requirements

A. Overview of Forecast Methodology

The Council appreciates the extensive narrative included in the 1984 Supplement. Holyoke forecasts its sendout requirements using "A Simplified Approach to Forecast Gas Sales and Revenues for the small gas Distribution Company," (the "AGA Approach") which it adopted for the first time in the 1982 Supplement.[3] The AGA Approach employs historical data on base and heating use per customer and the number of customers to forecast sendout for residential with heating, residential without heating, commercial-industrial and industrial customer classes. Total firm sendout is the sum of the sendout for each class and estimates of company use and unaccounted-for gas.

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3. See American Gas Association, A Simplified Approach to Forecast Gas Sales and Revenues: For the Small Gas Distribution Company, 1983.

Sendout for each customer class is the sum of the sendout for the heating and non-heating seasons, where the heating season is from November through March. In a year with normal weather, the heating season for each class is calculated in the following manner: [5 x (class monthly base use per customer) x (the number of customers) + (the class heating load factor) x (heating season normal year's degree days) x (the number of customers)].

For each class the non-heating season sendout in a normal year is:

[7 x (class monthly base use per customer) x (the number of customers) + (the class heating load factor) x (non-heating season normal year's degree days) x (the number of customers)].

The design year heating season and non-heating season sendout requirements are calculated in a similar fashion.

Holyoke uses actual 1983-84 sales data to derive class base use per customer and heating load factors. These are adjusted judgementally by 1.5 percent each year of the forecast period in order to account for conservation. The method employed to project the number of customers for each forecast year is unclear.[4]

Holyoke uses a split year's total of 6505 degree days to forecast a sendout requirements in a normal weather year, a split years total of 6985 degree days to forecast sendout requirements in a design weather year, and 68 degree days to forecast sendout requirements for a peak day.

Peak day sendout is equal to:

(1) (daily base use per customer) x (the average number of customers)

added to

(2) (heating use per degree day) x (peak degree days)

for each customer class. Summing across customer classes gives a peak day sendout. Daily base per customer is obtained by dividing heating period base use per customer by 151 days. Heating use per degree day is obtained by dividing heating use per customer by a normal years degree-days.

4. In response to Information Request No. A. 5.b, Holyoke states that it relies upon historical data to project the number of customers. However, for the customer classes of residential with heating, residential without heating, and commercial-industrial, the number of customer exhibits a declining trend even though Holyoke projects increases in the number of customers for each of these classes.

B. Forecast of Sendout by Customer Class

1. Residential with Gas Heat

Holyoke projects total heating season use per customer for the residential with gas heating class to decline from 67.82 Mcf in 1984/85 to 64.02 Mcf in 1988/89.[5] Non-heating season total use per customer declines from 24.0 Mcf to 22.56 Mcf. The number of customers is projected to increase by 25 each year rising from 6341 in 1984/85 to 6441 in 1988/89. The importance of conservation measures by customers is reflected by the projected decline in forecast sendout from 582 MMcf in 1984/85 to 557 MMcf in 1988/89.[6]

The Council is concerned about Holyoke's projected decline in sendout. In the 1983 Supplement, the forecasted sendout for split year 1983-84 was 563 MMcf. When split year 1983/84 sendout is normalized the sendout is 598 MMcf. This is a difference of about 6 percent. There was a larger than expected actual 1983/84 total heating season use per customer. The total heating season use per customer forecasted in the 1983 Supplement was 62.35 Mcf of gas while the actual total use per customers was 68.77 Mcf of gas. Holyoke attributes the increase in total use per customer to the decline in the number of residential with heating customers.[7]

2. Residential without Gas Heat

For residential without gas heat customers, Holyoke projects that total use per customer will decline from 8.77 in 1984/85 to 8.25 in 1988-89 during in the heating season and from 12.43 in 1984/85 to 11.67 during the non-heating season. The decline reflects the anticipated effect on sendout of conservation measures of customers. The number of customers is projected to increase by 10 each year rising from 3441 in 1984/85 to 3481 in 1988/89. Total sendout declines from 73 MMcf in 1984/85 to 69 MMcf in 1988/89.

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5. In response to Information Request No. A.5.a, Holyoke says the decline of 793 customers since 1980-81 was due to demolition of apartment buildings and fires which exceeded the additions for the period. Also, many of the new developments opted to use electricity for residential space heating. In spite of the demoliton and fires, projecting an increase of twenty-five customers per year "appeared reasonable" to Holyoke.

6. Holyoke uses 1983-84 sales data to calculate total normalized use per customer. Total use per customer is adjusted only for conservation.

7. Response to Information Request No. A.5.b. However, no explanation is given to explain lower than average usage of the customers lost to demolition and fire.

The actual sendout for 1983/84 of 74 MMcf doesn't change when the sendout is adjusted for weather. The 1983 Supplement forecasted 73 MMcf. However, the 1983 filing projected 3562 customers while the actual 1983/84 number of customers was 3431. Adjusting the number of customers for 1983/84 to 3562 yields a sendout of 78 MMcf.[8] Holyoke attributes the less than expected increase in customers to loss of apartment buildings through demolition and fires.[9] Also, there was conversion of gas appliances to electric appliances.

3. Commercial and Industrial

For commercial and small industrial customers, Holyoke projects that sendout will decline from 818 MMcf in 1984/85 to 803 MMcf in 1988/89. Holyoke forecasts an increase of 10 customers a year from a base of 955 in 1984-85. Again the decline in sendout reflects projected reductions in total use per customer due to conservation.

The 1983 filing forecast for split year 1983/84 was 843 MMcf. The 1983/84 normalized sendout is 818 MMcf. However, the forecasted number of customers was 980, while the actual number of customers was 945. When the actual sendout is adjusted to 980 customers, this calculated sendout is 874 MMcf.

In response to Information Requests No. 7, Holyoke states that the loss of 25 customers was caused by high gas costs. Many commercial-industrial customers had dual fuel equipment and elected to use oil instead of gas. The increase in the number of customers of ten per year for the forecast period is based upon considerable activity in the commercial-industrial market. The Department received "a number of inquiries from commercial-industrial customers concerning the use of natural gas for heating and for hot water requirements."[10]

4. Industrial

Holyoke projects no change in the number of customers. Forecast sendout declines from 124 MMcf in 1984/85 to 116 MMcf in 1988/89 reflecting adjustments in sendout due to conservation.

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8. This assumes that the additional customers have the same usage rates as existing customers.

9. Response to Information Requests No. 6. a.

10. Response to Information Request No. A. 7. b.

During 1983/84, Holyoke lost 1 industrial customer, which converted to steam.[11]

5. Company and Unaccounted for

Company and unaccounted for sendout in heating and non-heating seasons during the forecast period are calculated as being equal to 4 percent of sendout for the 4 firm customer classes in each year of the forecast period. Internal use of gas is comparatively large because Holyoke uses gas to power its district steam system. As shown in Table C a significant drop in sendout is projected to begin in 1987/88, when the construction of an energy resource recovery plant will replace Holyoke's steam plant in the district steam system. The steam produced by the energy resource recovery plant will be purchased by the Department.

Table C - Company and Unaccounted for Sendout

Split Year	Non-Heating Season	Heating Season
1984/85	469	207
1985/86	467	207
1986/87	466	206
1987/88	185	206
1988/89	133	206

6. Resale and Interruptible

In the past, Holyoke has resold gas to Bay State, most recently, in November of 1982.[12] Holyoke anticipates no resale to Bay State in the future.

Holyoke forecasts a significant increase in interruptible sendout in both the heating and non-heating seasons in 1984/85. A large-volume customer was added beginning in November, 1984, which accounts for the increase in sendout above 1983/84 levels for the forecast period.[13]

C. <u>Forecast of Total Firm Sendout</u>

1. Normal Year

In both the 1983 and 1984 Supplements, Holyoke projects that total firm sendout will decline for each year of the forecast period. Table D compares the current forecast with last year's forecast for split years 1984/85 to 1987/88. The 1984 Supplement forecasts a nine percent increase in sendout over the 1983 Supplement for split years 1984/5,

11. Response to Information Requests No. A.7.d.

12. Response to Information Requests No. 10.

13. Response to Information Request No. A.11.d.

1985/86 and 1986/87. In split year 1987/88, the 1984 Supplement projects significant a drop in the 1984 Supplement due to construction of an energy resource recovery plant which will replace a steam plant in Holyoke's district steam system.

2. Design Year

Total firm sendout for a design year is projected to decline each forecast year of the 1984 Supplement, as was the case in the 1983 Supplement. Total sendout is about 9 percent greater in the 1984 Supplement over the 1983 Supplement for split years 1984/85 through 1986-87. The 1984 Supplement forecasts a significant drop in sendout beginning split year 1987-88 for reasons mentioned above. Again, the Council is concerned that design-year forecasts are underestimated because Holyoke employs an inappropriate conservation adjustment factor adopted from the AGA approach.

Table D Total Company Firm Sendout

	1983 Supplement (MMcf)		1984 Supplement (MMcf)	
Split Year	Normal	Design	Normal	Design
1984/85	2078	2176	2273	2350
1985/86	2060	2156	2257	2233
1986/87	2043	2138	2243	2315
1987/88	2025	2123	1951	2022
1988/89	----	----	1885	1952

Heating use per degree day increased in 1983/84 for both residential and commercial-industrial customers. Hence, the difference in total sendout for a design year and a normal year is greater in the 1984 Supplement than the 1983 Supplement (See Table-D).

D. Impact of Weather and Conservation

1. Weather Data

Holyoke uses a 65° Fahrenheit standard as the temperature above which heating load is zero. Holyoke employed this standard to derive degree days -- which is a measure of coldness used in determing normal and design year criteria -- and to forecast heating load increments. The normal year standard of 6505 degree days is the average of thirty split years degree-day data. The design year standard of 6985 was the coldest split year in thirty years. The peak day of 68 is the coldest 24 hour period in thirty years.

Table E - Degree Day Data

Split Year	Non-Heating Season	Heating Season	Total Split-Yr.	Peak Day
1979/80	1458	5010	6448	50
1980/81	1235	5396	6631	68
1981/82	1411	5175	6586	65
1982/83	1221	4633	5854	60
1983/84	1238	4842	6080	60
Normal	1321	5184	6505	---
Design	1373	5612	6985	68

2. Peak Day Requirement

In split year 1983/84, the actual peak day was 60 degree days and the sendout was 11.9 MMcf. The design forecast declines from 12.6 MMcf in 1984/85 to 12.3 MMcf in 1988-89. The forecast projects a decrease in peak day sendout because of adjustments in total use per customer for conservation.

3. Cold Snap Requirements

The coldest two-to-three week period for Holyoke occurred in January, 1982, from the 10th day of the month to the 27th day. Degree days ranged from a low of 42 to a high of 67. The total degree days for the 18 day period was 982, averaging approximately 55 degree days per day. Holyoke projects that 172 MMcf of sendout will be required for the period. Sendout would range from 8.5 MMcf at 42 degree days to 12.5 MMcf at 67 degree days. The average sendout is 9.6 MMcf.

4. Conservation

Holyoke adjusts total use per customer in each class by approximately -1.5 percent for each forecast year to account for the expected impact of conservation. Customers are encouraged to insulate, to use time-of-day thermostats, and to participate in the Mass Save program. In addition, the Department sponsored a home insulation program. Approximately, 100 homes were insulated under this program.[14] Also, Holyoke expects more efficient appliances to reduce sendout.

Further evidence of conservation by residential customers is the change in the load during the 8 a.m. to 4 p.m. and 7 p.m. to 11 p.m. time periods on week days. Loads in these periods have declined significantly since 1980/81.[15]

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14. Response to Information Request No. A.16.

15. ibid.

However, total use per customer in each customer class does not indicate any consistent pattern of decline excepting industrial customers during the heating season. The Council is concerned that continued projection of a decrease in sendout by 1.5 percent may lead to an underestimation of sendout requirements.

Table F Total Use Per Customer by Class

	Resid. w Ht.	Resid. w/o Ht.	Comm.-Indust.	Indust.
		Non Heating Season		
1980/81	25.08	11.34	---	---
1981/82	26.02	11.62	312.0	13,531.7
1982/83	26.49	12.20	318.1	13,808.0
1983/84	24.36	12.62	299.7	15,238.6
		Heating Season		
1980/81	62.01	8.10	---	---
1981/82	64.81	8.30	588.4	19,452.7
1982/83	63.30	8.61	555.0	18,209.0
1983/84	68.77	8.90	570.2	16,327.1

E. Summary and Conclusions

The Council finds Holyoke's methodology to be sound and appropriate for a company of its size and resources. The Council appreciates the backup workpapers provided in the 1984 Supplement and given in response to the Documents and Information Requests. These workpapers were necessary in order to make the 1984 Supplement reviewable. These workpapers should be incorporated into future filings.

However, the Council notes that the AGA Approach, and hence the sendout forecast, is only as reliable as the underlying data and the intimate knowledge of community activity used in making judgemental adjustments to the data. In particular, the Council is concerned about the mechanical procedure of reducing total usage per customer for the 4 customer classes by approximately 1.5 percent. While, other factors affecting total usage per customer, such as gas prices, and oil prices, indicating the level of economic activity, such as employment and income, are ignored. The Council recommends that Holyoke reassess its method of adjusting total usage per customer and that Holyoke consider factors other than conservation when adjusting total usage per customer.

Furthermore, it is not clear how Holyoke forecasts the number of customers. Therefore, the Council requests that Holyoke provide an explanation of its forecast of the number of customers for the residential with heating, residential without heating, and commercial-industrial classes.

IV. Resources and Facilities

Holyoke's gas supplies and facilities remain basically unchanged since the Council's last decision. Holyoke relies on pipeline gas purchased from Tennessee Gas Pipeline Company ("Tennessee") to meet Holyoke's requirements. Holyoke also sends out LNG and propane air.

Holyoke purchases gas under Tennessee's G-6 Rate Schedule pursuant to a contract dated June 4, 1981. The initial termination date of the contract is November 1, 2000, with automatic extensions unless canceled on 12 month written notice of either party. The maximum daily quantity ("MDQ") is 7.875 MMcf. The Annual Volumetric Limitation ("AVL") is 2,787 MMcf.

The Council notes that Holyoke is negotiating with Tennessee for additional gas quantities under the G-6 Rate Schedule. A Precedent Agreement between Tennesee and Holyoke would increase the MDQ to 10.22 MMcf and the AVL to 3,287.9 Mmcf beginning in the second year of the contract, if the contract is executed. Holyoke does not expect to construct additional pipeline facilities, if these negotiations are successfully completed. The existing facilities at the city gate is sufficient to handle the increase quantities. The Council requests that Holyoke provide economic studies justifying the need to increase MDQ and AVL for Tennessee. The Condition addresses this concern.

Holyoke purchases gas from Bay State Gas Company ("Bay State") under a contract dated October 25, 1978 as amended, on June 26, 1981 and on August 23, 1982. The contract contains an original termination date of March 31, 1988, but will continue in effect on a contract year basis thereafter until cancelled on 12 months written notice of either party. As amended, the agreement provides for 157.5 MMcf firm volumes and 52 MMcf of optional volumes. The firm volumes are purchased on a take-or-pay basis. Holyoke exercises its option to purchase additional volumes by written notice to Bay State 10 days before the beginning of the month in which gas is to be purchased. The elected quantities becomes a take-or-pay responsibility of Holyoke. In future filings, the Council requests that Holyoke provide economic studies concerning the need for Bay State Gas.

Under the Bay State contract, Holyoke is obliged to use its best efforts to receive gas by displacement through interconnections with Bay State on the Willimansett Bridge in Holyoke and on Balboa Drive in West Springfield. Holyoke must give Bay State an hours notice when it request delivery by displacement. The maximum hourly take by displacement at these points are 125 Mcf and 50Mcf respectively. There was no instance during 1983/84 wherein Bay State was unable to deliver gas through displacement when requested. If gas cannot be taken by displacement, delivery is made by trucking LNG or propane on 24 hours notice. Bay State has responsibility for providing the trucking service.

Holyoke's four LNG facilities have a storage capacity of 14.7 MMcf and a daily design sendout of 12 MMcf. Holyoke's propane storage and vaporization facility has a storage capacity of 18.4 MMcf and a design daily sendout of 2.4 MMcf.

Holyoke entered into contracts with 3 propane suppliers.[16] The total firm and optional quantities were 27 MMcf and 54 MMcf, respectively. Holyoke anticipates contracting for propane throughout the forecast period. Holyoke will continue to purchase propane at reduced levels if the Precedent Agreement is executed. In future filings, the Council requests that Holyoke provide economic studies addressing the need for propane, if the Precedent Agreement is executed.

During split-year 1983/84, there was no instance in which a propane company was unable to deliver propane within 24 hours of the request.

V. Comparison of Resources and Requirements

A. Normal Year

Table G portrays Holyoke's plan for meeting sendout requirements in a normal year. Requirements are met with purchases of Tennessee pipeline gas, Bay State pipeline displacement and Bay State LNG, LNG from storage, and propane. Throughout the forecast period Holyoke sends out all of its firm Bay State LNG and firm propane quantities. Less than the available Tennessee G-6, Bay State optional LNG and optional propane are used. The projected excess Tennessee G-6 gas above projected firm requirements is 413 MMcf in 1984-85 and 506 MMcf in 1988-89.

B. Design Year

Table G also shows Holyoke's plan for meeting sendout requirements in a design year. Requirements are met with Tennessee G-6 gas, Bay State LNG and displacement, LNG from storage and propane gas. Throughout the forecast period Holyoke sends out all of its firm Bay State LNG and firm propane quantities. In split years 1985-86 and 1986-87, all of its optional Bay State LNG and propane will be sent out. Less than the available Tennessee quantities will be used. The excess Tennessee G-6 gas is expected to be 310 MMcf in 1984-85 and 443 MMcf in 1988-89. Only in 1985-86 and 1986-87 will service to interruptible customers be curtailed.

16. Annually, Holyoke receives public bids for its propane supply. See 11 DOMSC at p. 298.

Table G

Comparison of Resources and Requirements
during a Normal Year
(MMcf)

	84/85	85/86	86/87	87/88	88/89
Requirements					
Firm	2273	2257	2243	1951	1885
Interruptible	347	439	439	439	439
LNG Storage Refill	--	--	--	--	--
Total	2620	2696	2682	2390	2324
Resources					
Tennessee G-6	2374	2409	2404	2145	2279
Bay State	187	195	186	170	--
LNG (storage)	30	30	30	30	--
Propane	29	62	62	45	45
Total	2620	2696	2682	2390	2324

Comparison of Resources and Requirements
During a Design Year
(MMcf)

Requirements					
Firm	2350	2333	2315	2022	1952
Interruptible	405	412	424	439	439
LNG Storage Refill	--	--	--	--	--
Total	2755	2745	2739	2461	2391
Resources					
Tennessee G-6	2477	2368	2361	2216	2346
Bay State	180	230	230	170	--
LNG (storage)	30	30	30	30	--
Propane	68	117	118	45	45
Total	2755	2745	2739	2461	2391

a. In spilt-year 1988/89, Holyoke resources reflect the non-renewal of the Company's contract for supplemental gas from Bay State.

C. Peak Day

In addition to having sufficient gas supplies to meet seasonal and annual requirements of its customers, a gas utility must have sufficient supplies to meet peak day requirements.

Holyoke projects a peak-day sendout which declines from 12.6 MMcf to 12.3 MMcf during the forecast period. Holyoke intends to maintain its propane storage and LNG storage facilities at 50 and 70 percent of capacity respectively. Under the two assumptions, 2.4 MMcf of propane, 10.0 MMcf of LNG and 7.9 MMcf of Tennessee G-6 gas will be available to meet a peak day's sendout. These sum to 20.3 MMcf. In addition, 4.2 MMcf of Bay State displacement is available. Also, Holyoke may be able to receive Bay State LNG and propane by truck.

In 1988/89 only Tennessee G-6 and propane will be available to meet a peak-day sendout. As of now Holyoke will be unable to meet a peak day sendout in 1988/89. The shortfall will be 2 MMcf.

D. Cold Snap

The Council has defined a "cold snap" as a period of peak or near-peak weather conditions, similar to the two-to-three week period experienced during the 1980/81 heating season. The Department's ability to meet the requirements of its customers during a cold snap depends on its daily pipeline entitlements, its daily supplemental sendout capacity and its storage inventories.

For the split years 1984/85 through 1987/88, the Company is in a comfortable position with regard to its ability to meet sustained periods of extreme sendout. Only at degree days exceeding 62 would Holyoke have to use gas other than Tennessee pipeline and Bay State displacement.[18] 62 degree days was exceeded only twice during the cold snap of 1981/82. On such days, Holyoke would have to produce at most 0.5 Mmcf of supplemental sendout during the forecast period. Given the daily supplemental sendout capacity of 12.4 MMcf, Holyoke would be able to meet peak day production of 0.5 Mcf even if storage is well below capacity. Holyoke's estimate of its ability to provide service during a cold snap is based on assumptions that: 1) no LNG or propane would be available by truck, 2) LNG storage is at 70 percent, and 3) propane storage at 50 percent of capacity. In this scenario, 12.4 MMcf is available for sendout in addition to 12.1 MMcf of daily pipeline supply.

E. Summary and Conclusion

The Council's mandated task is to review gas utilities' plans to meet forecasted sendout requirements to ensure adequacy, reliability, and minimum cost, taking into account the variability of sendout due to weather and other considerations. The Council finds Holyoke's plan to

18. In Response to Information Request No. B.3.f., Holyoke states it has experienced no difficulties with Bay State displacement. Bay State indicates that it guarantees delivery through pipeline interconnection on a peak day to Holyoke. See 12 DOMSC at p. 146 fn 75.

meet forecasted sendout requirements during a design year, a cold-snap and peak day to be adequate and reliable.

On a peak day, pipeline supplies are 12.1 MMcf. Under reasonable assumptions of storage reserves, Holyoke would have available an additional 7,570 Mcf of gas, well above peak day requirements approximating 12.6 MMcf. Pipeline supplies would be sufficient to meet daily requirements on most days and only on days where degree days exceed 63 would the 10,191 MMcf of stored supplemental capacity be needed.

Therefore, the Council APPROVES the supply portion of the 1984 Supplement subject to the CONDITION imposed in Section VI.

VI. Order

The Council APPROVES the 1984 Supplement to the Second Long Range Forecast of the City of Holyoke Gas and Electric Light Department subject to Holyoke's compliance with the following condition in its next Supplement, which is due November 1, 1985:

1. That Holyoke provide cost studies determining the levels at which its MDQ and AVL for Tennessee gas should be set and the quantity of Bay State and propane gas supplies it will need, or provide other justification for such quantities.

Energy Facilities Siting Council

Carolyn E. Ramm by Susan Tierney

Carolyn E. Ramm

Unanimously APPROVED by the Energy Facilities Siting Council on August 1, 1985, by those members and designees present and voting: Chairperson Sharon M. Pollard (Secretary of Energy Resources); Sarah Wald (for Secretary of Consumer Affairs, Paula W. Gold); Stephen Roop (for Secretary of Environmental Affairs, James S. Hoyte); Madeline Varitimos (Public Environmental Member); Joseph W. Joyce (Public Labor Member); and Dennis J. LaCroix (Public Gas Member).

Sharon M. Pollard

Sharon M. Pollard
Chairperson

16 August 1985

Date

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Boston Edison Company for Approval of its Third and Fourth Supplements to its Second Long-Range Forecast (1985-1994) of Electric Power Needs and Requirements	EFSC No. 85-12 Phase I

FINAL DECISION

Carolyn E. Ramm, Esq.
Hearing Officer

October 31, 1985

TABLE OF CONTENTS

The Energy Facilities Siting Council ("Siting Council") hereby APPROVES, subject to CONDITIONS, the Petition of Boston Edison Company ("Boston Edison" or "the Company") to construct an underground 345 kV transmission line between the Company's Mystic Station, Everett, and the New England Electric System's Golden Hills Station, Saugus.

I. INTRODUCTION AND HISTORY OF THE PROCEEDINGS

A. Description of the Company

Boston Edison is an investor-owned utility that produces, purchases, sells and distributes electricity to approximately 600,000 retail customers in the City of Boston and 39 other cities and towns in the greater Boston area. In 1984, Boston Edison had actual retail sales of 10,646 Gigawatt-hours ("GWh") and an actual summer peak load of 2387 megawatts ("MW"), making it the second largest electric utility in the Commonwealth. In addition, Boston Edison sells wholesale electricity to 20 customers (mostly municipal light boards), and produces, distributes, and sells steam energy.

With this filing, Boston Edison requests the Siting Council's approval to construct an underground 345 kV transmission line. The proposed line would run from the Company's Mystic substation in Everett for a distance of 6.3 miles through public streets in the Cities of Boston, Everett, Malden and Melrose and the Town of Saugus, to the New England Electric System's Golden Hills substation in Saugus. The estimated present value of the cost of the line is 16.7 million dollars (1985 dollars). Boston Edison proposes to have the line in service by 1988.

B. History of the Proceedings

Boston Edison timely filed Volume I of its Long-Range Forecast of Electrical Power Needs and Requirements ("the Forecast") on February 1, 1985. Volume II of the Forecast was filed on March 1, 1985, pursuant to an extension of time granted by the Hearing Officer. Volume I contains the Company's demand forecast for the years 1985-2000, and Volume II contains its supply plan for the years 1985-1994. As noted above, Volume II also contains a proposal to build the 345-kV underground transmission line referred to herein as the Mystic-Golden Hills line (Forecast, Vol. II, Appendix B).

On March 8, 1985, the Hearing Officer issued a Notice of Adjudication, which the Company duly published and posted in accordance with the Hearing Officer's instructions. By April 5, 1985, the intervention deadline established in the Notice of Adjudication, one petition to intervene had been received from the Conservation Law Foundation ("CLF"). The Company opposed this petition as lacking specificity and failing to comply with the Siting Council's rules governing interventions. The Hearing Officer agreed that CLF's petition was fatally deficient, but allowed CLF the opportunity to amend its petition to cure the deficiencies. A Procedural Order to this effect was issued on June 4, 1985. Rather than file an amended petition to intervene, CLF elected not to participate further. Thus, this proceeding was left in an uncontested posture.

A prehearing conference attended by representatives of the Company and of the Siting Council Staff ("the Staff") was held on July 2, 1985. In view of the absence of intervenors it was agreed that a formal adjudicatory hearing would probably not be necessary, although both the Company and the Staff reserved the right to request one at a later date. Instead, it was contemplated that the record in this proceeding would be developed through discovery. A discovery schedule was established in a Procedural Order dated July 2, 1985 and was adhered to by both the Company and the Staff to an admirable extent. The discovery process was completed by September 13, 1985.

To comply with Rule 62.7 of the Siting Council's Regulations, requiring public informational hearings to be held in the localities where proposed energy facilities are to be constructed, a hearing was held in Everett, Massachusetts on September 11, 1985. The Company made a presentation describing the need and construction plans for the Mystic-Golden Hills line and answered questions from the public (Transcript, EFSC Docket No. 85-12, September 11, 1985, at 7-44). The Hearing Officer reopened the proceeding to interventions or motions to participate as interested persons limited to issues relating to the Mystic-Golden Hills line, but none were received by September 25, 1985, the deadline established for such filings.

Upon consideration of the Company's responses to the Staff's First Set of Document and Information Requests, Parts Two and Three, the Hearing Officer became convinced that an expedited review of the Company's proposal for the Mystic-Golden Hills line would be in the public interest. Accordingly, on October 10, 1985, she issued a Procedural Order severing that portion of the Forecast review concerned with the proposed Mystic-Golden Hills line, designated as EFSC Docket No. 85-12, Phase I, from the Siting Council's review of the demand forecast and supply plan segments of the Forecast, designated as EFSC Docket No. 85-12, Phase II. The present Tentative Decision is limited to Phase I of this proceeding, and is being made on a record consisting of (1) the Company's responses to Staff Document and Information Requests Nos. TF-1 to TF-17 and associated correspondence; (2) the transcript of the public informational hearing in EFSC Docket No. 85-12 held in Everett, Massachusetts on September 11, 1985; and (3) historical and system data provided in the Company's Forecast that are related to the construction proposal, including all of Appendix B and Volume II, pages II-1 to II-18 and II-29.

Additionally, official notice is hereby taken of the Siting Council's past decisions in <u>In Re Boston Edison Company et al</u>, EFSC Docket No. 83-12, 10 DOMSC 203 (March 5, 1984), and <u>In Re Boston Edison Company</u>, EFSC Docket No. 76-12, 2 DOMSC 58 (December 21, 1977). While recognizing that the demand forecast and supply plan contained in the Company's current Forecast have not yet been adjudicated, the Hearing Officer expressly finds that the Company's proposal to build the Mystic-Golden Hills line is "consistent with the [Company's] most recently approved long-range forecast or supplement thereto...", i.e. that approved in EFSC Docket No. 83-12, as required by Mass. Gen. Laws c. 164, §69I.

As will be discussed in greater detail at section IV infra, the petition to construct the Mystic-Golden Hills line is intimately linked to the construction of a 345 kV underground transmission line running from the Company's Mystic substation to a new substation to be built in the vicinity of South Station in downtown Boston. This second line, originally known as the Mystic-Lincoln Street line[1], was approved in EFSC Docket No. 76-12, 2 DOMSC 58, 60 (December 21, 1977). However, no in-service date for the line has yet been approved. 2 DOMSC at 62-63. The present Tentative Decision clarifies the decision in EFSC Docket No. 76-12 as to the in-service date of the Mystic-Lincoln Street line and also as to the status of certain other proposed transmission lines which were approved in that decision, but which have never been built and which appear to be no longer needed. See Forecast, Vol. II, at II-1 - II-2.

II. REVIEW OF THE NEED FOR THE PROPOSED FACILITIES

A. Scope of Review

Before approving an application to construct facilities under its jurisdiction, the Siting Council must find that the construction is consistent with its mandate to "provide a necessary energy supply for the commonwealth with a minimum impact on the environment at the lowest possible cost." Mass. Gen. Laws Ann. Ch. 164, Sec. 69H. In so doing, the Siting Council determines whether plans for construction of the applicant's proposed facilities are "...based on substantially accurate historical information and reasonable statistical projection methods." Mass. Gen. Laws Ann. Ch. 164, Sec. 69J.

In practice, the Siting Council requires applicants to justify facility construction proposals in three phases.

First, the Siting Council requires the applicant to show that facilities are needed. For an electric transmission system, the Siting Council has found that the inability of the existing system to withstand the loss of any single major component is sufficient to justify the need for facilities to maintain reliability. In Re Taunton Municipal Light Plant, 8 DOMSC 148 at 154; In Re Com/Electric, 6 DOMSC 33 at 44-47; et al. Alternatively, the Siting Council might base its determination of need on other considerations of reliability, on forecasted reliability

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1. This line was originally proposed to run from Mystic to the Company's proposed Lincoln Street substation. By letter dated August 16, 1985 the Company has notified the Siting Council that it now plans to build the proposed substation in the form of an addition to its existing Kingston Street substation. In this Decision, the proposed line from Mystic to Downtown Boston will be referred to either as the "Mystic-Lincoln Street line" or as the "Mystic-Downtown line", as the context warrants.

problems associated with load growth, or on trade-offs between environmental impacts and cost.[2]

Next, the Siting Council requires the applicant to present construction plans for facilities that satisfy the previously identified need. Along with the proposed facilities, the Siting Council requires an applicant to identify a reasonable range of practical alternatives, including non-construction alternatives. See Siting Council Administrative Bulletin 78-2, "High Voltage Transmission Facilities," at 8.

Finally, the Siting Council requires the applicant to show that the proposed construction plan is superior to the proposed alternatives. The proposal and the alternatives are compared on the basis of the environmental impact and cost of maintaining a secure source of power, consistent with the Siting Council's statutory mandate.

B. Description of the Existing System

Figure 1 is a geographic map of the major existing 345 kV transmission lines, substations, and generating stations in the area immediately north of the City of Boston. The map shows the locations of 345 kV substations in Tewksbury, Woburn, Lexington, North Cambridge, and Everett, and the Golden Hills substation in Saugus, as well as the locations of the New Boston and Mystic generating stations. The map also shows schematically the locations of existing 345 kV transmission lines between the Tewksbury and Woburn substations ("the Woburn-Tewksbury line"); between the Woburn and North Cambridge substations ("the North Cambridge-Woburn line"); between the North Cambridge and Mystic substations ("the Mystic-North Cambridge line"); and between the Tewksbury and Golden Hills substations ("the Tewksbury-Golden Hills line"). Not shown are the Kingston Street substation in downtown Boston ("Downtown Station"), and Boston Edison's lower voltage transmission system, including the 115 kV lines that run from the Mystic generating station to the New Boston generating station via Kawkins Street Station.

As the map shows, there are only two major sources of power to the northern portion of Boston Edison's service territory -- power generated at the Mystic generating station, and power that is imported from north central New England over the existing Woburn-Tewksbury line. Power from these two sources is distributed to retail customers via lower voltage lines that originate at five large autotransformers on the 345 kV system.

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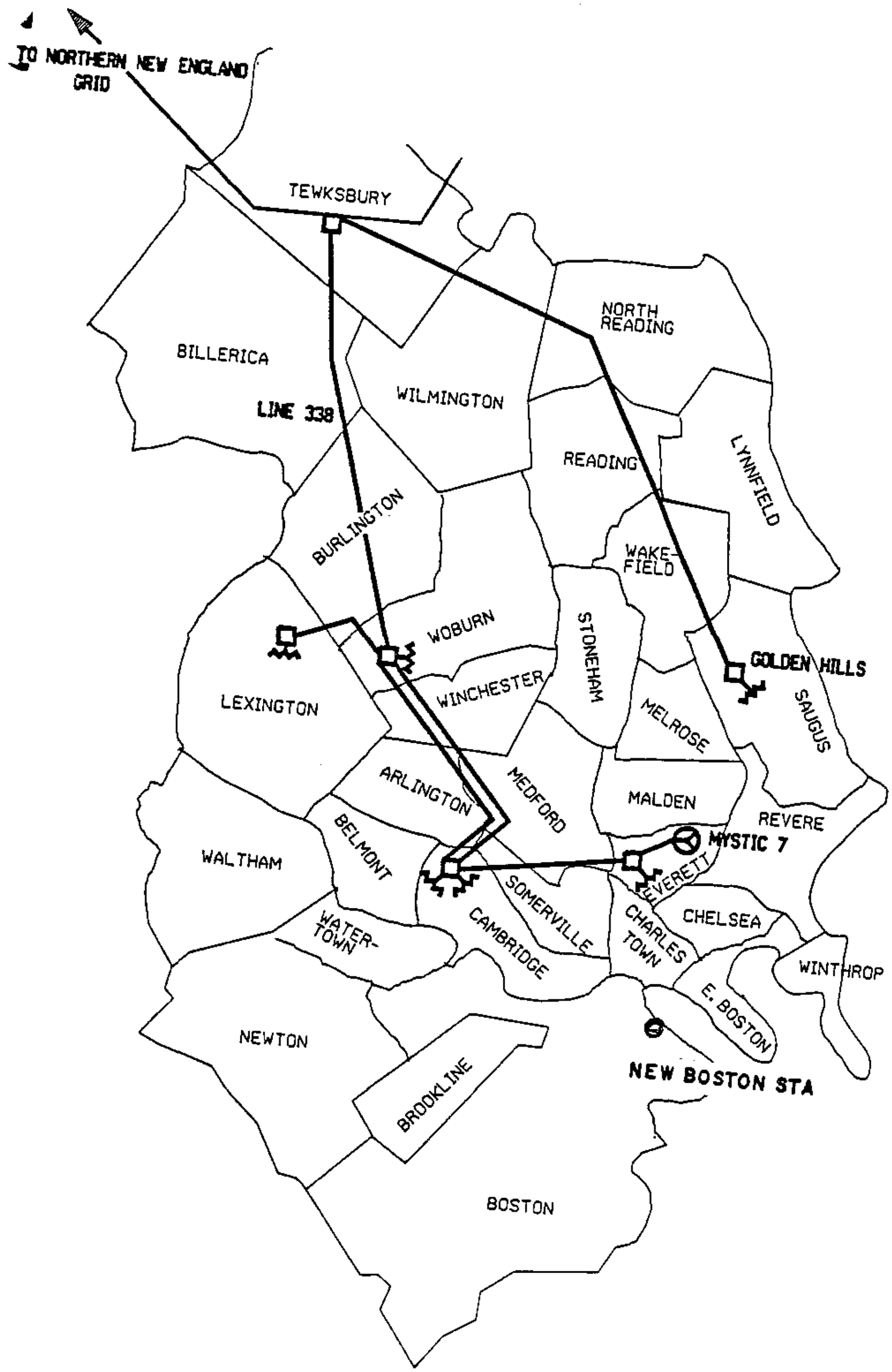
2 The Siting Council has approved a proposal to construct facilities without explicitly determining that the proposed facility was necessary to provide an energy supply. In that case, the approval was based on economic considerations. The Siting Council found that the balance between cost and environmental impact was favorable because the environmental impact was minimal. In Re Boston Gas, 11 DOMSC 159 at 163.

Figure 1. Northeastern Massachusetts 345 kV Transmission System.



Source: Forecast, Vol. II, Appendix B at 7.

C. Adequacy of the Existing System

Boston Edison asserts that new facilities are needed because the Company's existing facilities are inadequate to ensure a reliable supply of power to the northern part of its system. Specifically, loss of the existing Woburn-Tewksbury line under severe load and generation conditions that have actually occurred would cause thermal overloads and voltage degradation, and that would necessitate disconnection of major amounts of load. (Forecast, Vol. II, Appendix B at 5 and 10.)

In support, Boston Edison provides reliability standards for evaluating the adequacy of its transmission system; describes its methods and assumptions for calculating loadings on individual system elements; and shows that, in several instances, the loadings calculated for several system elements exceed the capacity limits dictated by the Company's reliability standards.

For reliability standards, Boston Edison presents the "Reliability Standards for the New England Power Pool" ("NEPOOL standards") and the "Basic Criteria for Design and Operation of Interconnected Power Systems" of the Northeast Power Coordinating Council ("NPCC standards"). The NEPOOL and NPCC standards both require that all equipment operate within normal capacity limits when there is no contingency and within emergency capacity limits following any reasonably expected contingency. These standards also require that transmission systems be designed so that loss of critical system elements will not adversely affect the stability of the system.[3] In addition, Boston Edison requires all transmission system voltages be equal to or greater than 95 percent of the nominal values to assure safe operation of the Company's and all customers' equipment. (Forecast, Vol. II, Appendix B at 10; Response to Staff Information Request TF-1.)

The Siting Council concurs that reliable transmission systems should have line loadings that are below normal ratings under normal conditions and below emergency ratings after a contingency. In addition, the Siting Council concurs that the Boston Edison system should maintain its stability and its required voltage levels despite the occurrence of a contingency. Failure for the system to meet these standards might reasonably be proof that the existing system is inadequate.

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3 "Normal" and "emergency" limits refer to the maximum amount of power (in MVA) that a transmission line can carry under normal and emergency conditions. A transmission line that is loaded beyond its capacity limits can suffer permanent physical damage, shortened life expectancy and increased probability of failure in service. "Stability" refers to the ability of an AC power system to continue to keep all of its generators at the same constant speed after a disturbance. The possible consequences of instability include permanent damage to generators and widespread loss of electrical service to customers for a long period of time. A "disturbance" or "contingency" might be the loss from service of a major system element, such as a major transmission line, transformer, or generating unit.

To calculate loadings on individual system elements, Boston Edison uses the technique known as "load flow analysis." Using load flow analysis, the Company determines voltages at certain key points in the system, as well as the loadings on specific transmission lines and transformers, under pre-specified conditions. The Company compares these voltages and line loadings with equipment ratings to determine if reliability standards are being violated. The pre-specified conditions include assumptions as to the level of system demand; the distribution of demand among various points in the system; the amount of power provided by individual generating units; the operating characteristics (e.g., voltage or resistance) of relevant transmission lines and transformers; and the configuration of relevant transmission lines, transformers, generators, demand nodes, and breakers. A full analysis also requires specification of the contingencies that the system should be able to withstand.

In several previous cases, the Siting Council has accepted load flow analysis as a reasonable calculation method. See In Re Boston Edison, 3 DOMSC 81 (1979); et al. However, in each of these cases, the Siting Council has taken great care to review the assumptions used to specify the inputs to the analyses.

Likewise, in this case, the Siting Council finds that the use of load flow analysis is appropriate. Nonetheless, the Siting Council reviews in detail the Company's input assumptions, including the record of actual occurrences of the conditions that are used to show the need for the line. Of special interest are the Company's demand assumptions; the assumed status of generating facilities; and the specification of the contingencies that the system is required to withstand.

In this case, the contingency that concerns Boston Edison is the loss of the existing Woburn-Tewksbury line under severe load and generation conditions. In its base case load flow analyses, the Company assumes that the demand on its system is 2450 MW, 60 percent of which is supported by the five autotransformers that serve the northern portion of the Company's service territory. The Company identifies two generation conditions for which an outage on the Woburn-Tewksbury line might require load disconnection: "State A", in which Mystic 7, at least one of the New Boston units, and any one of the Mystic 4, 5, or 6 units are out of service simultaneously; and "State B", in which Mystic 7 and both New Boston units are out of service simultaneously.

Using load flow analysis, Boston Edison asserts that an outage of the Woburn-Tewksbury 345 kV line at a system demand level of 2450 MW and generation conditions corresponding to State A would cause unacceptable overloads on three 115 kV lines, as shown below:[4]

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4 Overloads would also occur on an existing 115 kV line between Walpole and Needham. Boston Edison plans to install two phase angle regulating transformers at Baker Street Station to address this problem. Response to Staff Information Request TF-5B.

115 kV Line	Emergency Rating (MVa)	Line Loading (MVa)
Woburn-Tewksbury #1	125	185
Woburn-Tewksbury #2	125	185
Mystic-Everett	151	226

Source: Forecast, Volume II, Appendix B at 8.

Moreover, under these conditions, the results of the load flow analysis show that voltages at several points in the Company's system are within 0.2 percent of the limits imposed by the reliability standards (Id., at B.2.3).

Further, Boston Edison states that the instances and severity of line overloads and low voltage problems increase as the system demand level increases. At a Company load of 2770 MW (forecasted to occur by 1987), Boston Edison forecasts overloads on six 115 kV transmission lines and additional low voltage problems, despite the scheduled reconductoring of several 115 kV lines and the planned addition of 400 MVa of capacitors for reactive compensation to support voltage levels.

The Siting Council agrees that the potential for line overloads and low voltage problems is sufficiently serious to require significant response, subject to the reasonableness of the Company's input assumptions.

Inasmuch as the Woburn-Tewksbury 345 kV line is a major component of Boston Edison system that has experienced outages in the past,[5] the Siting Council finds that an outage of the Woburn-Tewksbury 345 kV line is a reasonable contingency to consider when determining the adequacy of the existing system.

The reasonableness of the Company's generation assumptions is more complicated to determine. However, the historical record indicates that States A and B have occurred with discomforting frequency. From 1981-1984, the Company states that State A occurred 63 times with an average duration of 15.6 hours, and that State B occurred 4 times with an average duration of 6.2 hours (Response to Staff Information Request TF-2). Indeed, on March 29, 1984, an outage occurred on the existing Woburn-Tewksbury 345 kV line while generation conditions corresponded to State A. Had the level of system load been substantially higher at that time, load disconnection would have been required.

Therefore, the Siting Council finds that the Company's generation assumptions are reasonable for determining the adequacy of the existing system, because they are based on accurate historical information.

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5 Boston Edison cites three outages that have occurred on the Woburn-Tewksbury 345 kV line since 1976. Response to Staff Information Request TF-4A.

Finally, in view of the Company's historical peaks of 2387 MW in summer, 1984, and 2416 MW in August, 1985 (Response to Staff Information Request TF-7B), and the Company's forecasted summer peak of 2719 MW by 1988 (from the Company's unreviewed 1985 Forecast), the Company's choice of 2450 MW for system demand appears to be within the range of reasonableness for determining the adequacy of the existing system within the lead time required for construction of the line.

However, the reasonableness of the method for projecting 2450 MW for system demand need not be determined here, because the need for the line can be based solely on actual historical information. Boston Edison cites 13 instances between June, 1984, and August, 1985, when REMVEC[6] notified the Company that outage of the Woburn-Tewksbury 345 kV line would cause severe line overloads and voltage degradation. The Company's daily peak load on these days ranged from 2044 MW to a low of 1642 MW, well below the actual historical peak of 2416 MW.

Indeed, the historical record shows that levels of system demand that have actually occurred, if combined with contingencies and generation conditions that have actually occurred, would result in transmission system conditions that the Siting Council considers unacceptable. Consequently, the Siting Council finds that the Company's existing facilities are inadequate to ensure a reliable supply of power to the northern part of the Company's system. This finding is based entirely on accurate historical information.

D. Non-Construction Alternatives

Boston Edison indicates that load disconnection might be required at Company load levels as low as 1950 MW. Thus, to solve the problems cited above, a non-construction alternative must account for load reductions of at least 500 MW, and possibly as much as 800 MW, below the actual 1985 summer peak of 2416 MW. Moreover, these load reductions must occur within the lead time required to construct the proposed transmission line (i.e., by 1988) to be effective.

Boston Edison states that conservation and load management options analyzed to date offer a potential reduction of 58 MW by the year 1989. Though these estimates are preliminary, the Company states that the required load reduction of 500 MW is not achievable on a firm basis by 1988 through conservation or load management (Response to Staff Information Request TF-6B). The Company does not have an estimate of the total amount of interruptible load obtainable from existing

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6 The Rhode Island Eastern Massachusetts Vermont Energy Control ("REMVEC") is the satellite station of NEPOOL that operates the major transmission lines of the utilities located in its jurisdiction. As a precaution, REMVEC monitors transmission system performance for potential contingencies under system conditions each day, and notifies affected utilities of any contingency with the potential to cause overloads or instability. Response to Staff Information Request TF-3C.

customers, but does not believe it would be feasible to obtain 500-800 MW by 1988. In support, the Company states by way of example that a 500 MW reduction would require total interruption of the majority of the Company's G-3 customers over an extended period of time (Response to Staff Information Request TF-6C). A third alternative examined by the Company is construction of additional generation at Mystic. However, construction of 800 MW of generation could not likely occur by 1988; even if it could, the existing transmission system is not capable of supporting this generation development at Mystic (Response to Staff Information Request TF-6A). Finally, Boston Edison does not anticipate the addition of an adequate amount of new cogeneration or small power production in the downtown area (Response to Staff Information Request TF-7B).

The Siting Council finds that the Company has considered non-construction alternatives adequately, and that there is a need for additional transmission facilities to ensure a reliable supply of power to the northern part of the Boston Edison system.

III. COMPARISON OF PROPOSED FACILITIES AND ALTERNATIVES

A. Description of Company Proposal and Alternatives

To satisfy the need for facilities identified in the previous section, Boston Edison proposes to construct an underground 345 kV transmission line from the Company's Mystic substation in Everett to the Golden Hills substation of the New England Electric System in Saugus. Construction of the proposed line would allow Boston Edison to bring power to the northern part of its service territory via the Tewksbury and Golden Hills substations, thereby enabling the system to withstand the loss of the Woburn-Tewksbury 345 kV line (see Figure 1).

The proposed line is 6.3 miles long and has an estimated present value cost of 16.7 million dollars (1985 dollars). The proposed route goes from Mystic station north along Alford Street in Boston, Broadway in Everett, Main Street in Everett, Malden and Melrose and Green Street in Melrose, then east along Howard Street in Melrose and Saugus to the Golden Hills substation. Construction requires digging a trench four feet wide by five feet deep for installation of two underground 10.75-inch steel pipes to hold the 345 kV pipe-type cable lines. All construction is proposed to occur in city streets except at the terminal stations.

Boston Edison also proposes an alternate route between Mystic and Golden Hills substation. The alternate route also goes north from Mystic station along Alford Street in Boston and Broadway Street in Everett. Unlike the proposed route, the alternate route continues north along Broadway Street past Main Street through Everett and Malden, then goes northwest along Lebanon Street through Malden and Melrose to Main Street, where it rejoins the proposed route. The alternate route is 6.8 miles long and has an estimated installed cost 1.45 million dollars greater than the proposed route (Forecast, Vol. II, Appendix B at 20).

Additionally, the Company proposes an alternate method to satisfy the need for facilities ("the alternate plan"). In particular, the Company considers installing a second overhead 345 kV line between Woburn and Tewksbury substations on the existing right-of-way, thereby enabling the system to withstand the loss of the first Woburn-Tewksbury 345 kV line. The second 345 kV line would be constructed in the space formed by removal of one of the two existing 115 kV lines on the right-of-way. All construction would occur on existing right-of-way in the Towns of Tewksbury, Billerica, Burlington and Woburn, and no additional clearing would be required. The new 345 kV line would be 12.7 miles long, and would have a construction cost of 9.2 million dollars (1985 dollars), including the cost of removing the existing 115 kV line.

If the second Woburn-Tewksbury 345 kV line were to be constructed, Boston Edison states that it would also need to increase the capacity of the two existing Woburn-North Cambridge 345 kV lines. To do so, the Company proposes to install a pipe between Woburn and North Cambridge. The pipe would circulate oil to remove heat from the existing Woburn-North Cambridge lines during peak load periods, thereby increasing their capacity. Boston Edison estimates the cost of the 6.0-mile pipe to be 7.8 million dollars (1985 present value). Thus, the present value of the cost of the second Woburn-Tewksbury 345 kV line and the Woburn-North Cambridge pipe is a total of 17.0 million dollars.

Boston Edison asserts that the choice between the preferred and alternate plans has a major impact on its plans to reinforce its transmission system in the downtown Boston area. In 1977, the Siting Council approved an application by Boston Edison to construct an underground 345 kV transmission line between the Company's Mystic station in Everett and a new proposed Lincoln Street substation in downtown Boston (the "Mystic-Lincoln Street" or "Mystic-Downtown" line; see In Re Boston Edison, 2 DOMSC 58 (1977)).[7] The Mystic-Downtown line would reinforce the downtown Boston transmission system by providing access to power from the Mystic generating units and from north-central New England via the Tewksbury substation and the intermediate 345 kV lines between Tewksbury and Mystic (see Figure 1). However, should the Woburn-Tewksbury line be constructed instead of the Mystic-Golden Hills line, Mystic substation would be linked to north-central New England via the heavily loaded Mystic-North Cambridge 345 kV line. In that event, Boston Edison would prefer to build a 345 kV line directly from North Cambridge to Downtown substation ("the North Cambridge-Downtown line") instead of the Mystic-Downtown line.

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7 The 1977 Decision on the Mystic-Lincoln Street line approved the need for the line, but did not approve or reject a specific route for the line. In this case, Boston Edison presents new information on possible routes and costs of the line, including the prospect of eliminating the construction of a new Lincoln Station substation in favor of an expanded Kingston Street substation to be called "Downtown Station." See 2 DOMSC at 58 (1977); Forecast, Vol. II at II-15 and Letter from C.B. Damrell dated August 16, 1985.

Therefore, Boston Edison asserts, the choice between the preferred and alternate plans should be considered a choice between the two sets of facilities with the costs shown below:

Preferred Plan		Alternate Plan	
Facilities	1985 Present Worth Costs	Facilities	1985 Present Worth Costs
Mystic-Golden Hills 345 kV line	16.7	Woburn-Tewksbury 345 kV line	9.2
Mystic-Downtown 345 kV line	35.1	Woburn-North Cambridge pipe	7.8
Miscellaneous associated work	2.4	North Cambridge-Downtown 345 kV line	36.7
		Miscellaneous associated work	2.4
Total (millions of dollars)	54.2	Total (millions of dollars)	56.1

Source: Response to Staff Information Request TF-12, as updated by letter from M.E. Stanton dated September 13, 1985.

B. Adequacy of the Range of Practical Alternatives

There are several conceivable alternatives to the proposed and alternate plans for importing power into the northern part of Boston Edison's service territory with an outage on the Woburn-Tewksbury 345 kV line. Boston Edison might consider construction of a transmission line on new right-of-way from Golden Hills to Woburn; from Golden Hills to North Cambridge; or from Tewksbury directly to North Cambridge, Lexington, or Mystic (See Figure 1). Alternatively, Boston Edison might consider construction of a transmission line on new right-of-way from other points on the New England 345 kV transmission system (e.g., Sandy Pond) to the Lexington, Woburn or North Cambridge substations (Forecast, Vol. II, at II-29).

However, none of these alternatives appears practical when compared to the proposed Mystic-Golden Hills or Woburn-Tewksbury lines. The Siting Council believes that the proposed and alternate plans are shorter and require less right-of-way -- and are likely to be less costly and have less environmental impact -- than any of the conceivable alternatives mentioned above.

Hence, the Siting Council finds that Boston Edison has examined a reasonable range of practical alternatives for importing power into the northern part of Boston Edison's service territory.

Regarding the two integrated plans presented for comparison, the Siting Council notes that reinforcement of the downtown Boston transmission system from the north requires connection of the proposed Downtown substation with either the North Cambridge substation or the

Mystic substation. If the Mystic-Golden Hills line is constructed, then the Mystic substation becomes a more secure source of power to Downtown Station than the North Cambridge substation. Likewise, if the second Woburn-Tewksbury 345 kV line is constructed, then the North Cambridge substation becomes a more secure source of power to Downtown Station than the Mystic substation. The converse of each proposed plan (i.e., the Mystic-Golden Hills line coupled with the North Cambridge-Downtown line, or the Woburn-Tewksbury line coupled with the Mystic-Downtown line) is less practical, because each relies somewhat on the heavily loaded Mystic-North Cambridge line. An outage of the Woburn-Tewksbury line might cause overloads on the Mystic-North Cambridge line in either case (Responses to Staff Information Requests TF-8B and TF-8C). And, as before, reinforcement of downtown Boston from the north via a direct connection to Tewksbury or other points on the New England 345 kV system would likely require longer and more expensive lines than have been proposed.

Therefore, the Siting Council finds that the Company has examined a reasonable range of practical alternatives for reinforcing the transmission system in downtown Boston from the north.

C. Comparison of the Proposed and Alternate Plans

The Siting Council compares the proposed and alternate plans by reviewing the cost, environmental impact, and reliability of each plan.

1. Cost

As shown earlier, Boston Edison states that the 1985 present worth of the construction cost of the Mystic-Golden Hills line (16.7 million dollars) is less than the corresponding figure for the Woburn-Tewksbury 345 kV line and the Woburn-North Cambridge pipe (17.0 million dollars). Likewise, the 1985 present worth of the cost of the preferred plan (54.2 million dollars) is less than that of the alternate plan (56.1 million dollars). Line losses and operation and maintenance costs, not included in these estimates, should be about equal for both plans. Hence, the preferred plan appears to be less costly than the alternate plan.

Appearances, however, can be deceiving. The Siting Council notes that the Company's estimated costs for individual components of the proposed and alternate plans have changed over time, and that the changes are substantial when compared to the 1.9 million-dollar difference between the two plans. The estimates of the 1985 present worth cost of each plan, as provided in the Company's original filing (Forecast, Vol. II, Appendix B at 15) are 18.4 million dollars for the Mystic-Golden Hills line, 15.8 million dollars for the Woburn-Tewksbury line and Woburn-North Cambridge pipe, 52.3 million dollars for the proposed plan, and 48.6 million dollars for the alternate plan. Using these estimates, the alternate plan appears less costly than the preferred plan.

These costs might change again in the future. The Company has not yet determined the exact route of the Mystic-Downtown line, and unanticipated changes in the route might cause unanticipated changes in the cost of that line. Likewise, the Company has not done detailed design work on the Woburn-North Cambridge alternate line, and the Siting Council must consider its cost to be uncertain.

Hence, the Siting Council cannot make an affirmative finding that the preferred plan is less costly than the alternate plan. Considering the proximity of the cost estimates for each plan, however, the Siting Council finds that there is no compelling difference in the costs of the proposed and alternate plans.

2. Environmental Impact

Boston Edison proposes to build the Mystic-Golden-Hills line as an underground line below city streets. Thus, there will be no permanent impacts affecting land use, water resources, air quality, solid waste, radiation or noise. Instead, the major impacts will occur during construction. At the public hearing, residents of the affected communities voiced their concerns about the short-term impacts of construction on local noise level, fugitive dust, and traffic patterns. Tr., Sept. 11, 1985, at 23-32; 41-43. These impacts are worthy of note, but are not permanent impacts that influence substantially the choice of alternatives.

The Company would build a second Woburn-Tewksbury 345 kV line as an overhead line. The permanent environmental impacts of construction this line would be minimal, because construction would occur on existing right-of-way adjacent to an existing 345 kV line on the site of an existing lower voltage line. No additional clearing of land would be required. There would be some permanent aesthetic impacts resulting from an increased tower height to an average of 80 feet from an average of 55 feet for the existing lower voltage line, and some impacts resulting from tower construction in wetlands. Construction will generate some noise, dust and solid waste on a short-term basis. Again, these short-term impacts are worthy of note, but are not sufficiently large to influence substantially the choice of alternatives.

The environmental impacts of the other elements of the preferred and alternative plans (the Woburn-North Cambridge pipe, the North Cambridge-Downtown 345 kV line, and the Mystic-Downtown 345 kV line) must be considered uncertain. Because each of these three facilities would be constructed underground, the major environmental impacts would occur during construction. The magnitudes of the impacts necessarily depend on the routes of each facility. These routes are uncertain. For example, Boston Edison has not yet designated a single route as the proposed route for the Mystic-Downtown line. The Company has not chosen a route for crossing the Mystic River and the Charles River, so the amount of dredging and the requirements for disposal of dredged material are not known.

With these uncertainties, the Siting Council cannot make an affirmative finding that the preferred plan has less of an impact on the environment than the alternate plan. However, in view of the relatively minor nature of these impacts, and in recognition of the opportunities for mitigation (See Section III, infra), the Siting Council finds that there is no compelling difference in the environmental impacts of the proposed and alternate plans.

3. Reliability

The reliability of the transmission system under the preferred plan differs from that of the alternate plan in two ways. First, the Mystic-Golden Hills line would be constructed underground, while the new Woburn-Tewksbury 345 kV line would be constructed overhead. Second, the Mystic-Golden Hills line would provide a new and separate path for delivering power from north-central New England, while the new Woburn-Tewksbury 345 kV line would be constructed on the same right-of-way as, and immediately adjacent to, the existing Woburn-Tewksbury 345 kV line whose outage is the critical contingency.

Upon request, Boston Edison provided historical data comparing the frequency and average duration of outages on overhead and underground transmission lines, as shown below:

Line Type	Voltage	Circuit Miles	# of Outages 1979-1984	Average Duration (Hours)
Underground	345 kV	10.98[a]	0	N/A
	230 kV	0.0	0	N/A
	115 kV	125.9	10	49.4
Overhead	345 kV	131.3	10[b]	14.1
	230 kV	35.7	1	7.0
	115 kV	199.5	18	8.5

Source: Response to Staff Information Request TF-4C, as updated on September 13, 1985.

Notes:
a. See Forecast, Vol. II at II-4. Does not include the second Woburn-North Cambridge 345 kV line which is not yet in service.
b. Includes two outages of the existing Woburn-Tewksbury 345 kV line -- one of which occurred during a major storm; the other of which occurred on the portion of the line owned by the New England Electric System. Responses to Staff Information Requests TF-4A and TF-4C.

Boston Edison states that it

"...does not feel that one system is necessarily more reliable than the other. Even though the mean duration of 115 kV cable failures is much higher than the duration of 115 kV overhead line failures, cable failures are less frequent." (Response to Staff Information Request TF-4C).

The Siting Council notes that the data provided above do not include failures that occurred during major storms, which would tend to affect overhead lines more than underground lines. No outages were reported on underground 345 kV lines from 1979-1984; however, Boston Edison has too few circuit miles of underground 345 kV cable for a comparison with overhead 345 kV lines to be valid. Further, the outage record for overhead and underground 115 kV lines does not reveal a clear advantage for either type of line. In the absence of additional information about the comparative operating experience of overhead and underground 345 kV lines, and in the absence of compelling evidence on the cost and environmental impacts of each type of line, the Siting Council cannot base its findings in this case on the reliability of overhead or underground lines.

Regarding the second reliability issue, the use of a new right-of-way as compared to the placement of a new overhead line immediately adjacent to an existing overhead line, the record is more clear. The NEPOOL reliability standards specifically account for the loss of all transmission circuits on a common right-of-way as a so-called "possible but improbable" ("PBI") contingency that requires development of plans or procedures to mitigate the consequences or reduce the probability of occurrence (Response to Staff Information Request TF-1A, section 5). Similarly, the NPCC standards refer to the loss of all transmission circuits on a common right-of-way as an "extreme contingency" (Response to Staff Information Request TF-1B, section 7.0). Construction of the second Woburn-Tewksbury 345 kV line would expose Boston Edison's system to load disconnection under a PBI contingency (loss of both Woburn-Tewksbury 345 kV lines). Construction of the Mystic-Golden Hills 345 kV line would avoid this exposure. Though PBI contingencies are infrequent, they are not unknown: Boston Edison cites 13 instances since 1972 when two or more circuits failed on the same right-of-way (Response to Staff Information Request TF-4B) and alludes to PBI contingencies on other systems that had severe consequences (Forecast, Vol. II, Appendix B at 17).

Indeed, Boston Edison states that the increased system security associated with a geographically separate 345 kV corridor is the primary advantage of the Mystic-Golden Hills line and the proposed plan (Forecast, Vol. II, Appendix B at 18). The Siting Council agrees that the Mystic-Golden Hills plan offers significant advantages in system reliability and flexibility when compared to the Woburn-Tewksbury alternative.

4. Conclusions

The Siting Council notes that the NEPOOL and NPCC standards both assign less priority to PBI contingencies than to other contingencies that occur more often (e.g., generator outages). Nonetheless, the Siting Council believes that PBI contingencies are worthy of serious consideration for system design. And, in the absence of compelling evidence on differences in cost or environmental impact between the proposed and alternate plans, the Siting Council believes that the avoidance of exposure to a PBI contingency is an adequate basis to find that construction of the Mystic-Golden Hills line is superior to construction of a second Woburn-Tewksbury 345 kV line.[8]

IV. RECONCILIATION WITH PREVIOUS APPROVALS

The Company's application to construct the Mystic-Golden Hills 345 kV line is intimately linked to an earlier Siting Council Decision on the Company, In Re Boston Edison 2 DOMSC at 58 (1977). In that Decision, the Siting Council granted the Company partial approval to construct several transmission lines, including:

- o a second Woburn-Tewksbury 345 kV overhead line;
- o the Mystic-Lincoln Street 345 kV underground line;
- o two underground 115 kV lines from Hyde Park substation to Dewar Street (Dorchester) substation in Boston.

The Siting Council's Decision approved the siting, general need, and project cost for these lines, but did not approve the in-service dates (2 DOMSC at 62 (1977)). Several Conditions applied to the approvals, including the following:

> Because type of construction, exact location, and ultimate design have not been finally determined for the above lines, any party or state or local governmental agency may negotiate or enter into agreements with the Company as to matters of final design, engineering, and construction. 2 DOMSC at 63-64 (1977) [Condition 2].

For each of the lines named above, the terms and conditions of this previous Decision require reconciliation with the instant Decision.

The second Woburn-Tewksbury 345 kV line, approved by the Siting Council in 2 DOMSC at 58, is the same line that the Company presents in the instant case as the alternate plan. However, the Siting Council finds in section III.C.4., supra, that construction of the Mystic-Golden Hills line is superior to construction of the previously approved Woburn-Tewksbury line. The Company has shown the need to construct only one of the lines. Boston Edison confirms that the second Woburn-Tewksbury 345 kV line will not be needed over the forecast period if the Mystic-Golden Hills and Mystic-Downtown lines are constructed as proposed (Response to Staff Information Request TF-8A1).

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8 If a party had shown that one of the two plans had a substantially lower cost than the other, or that one of the two plans had a substantially lower impact on the environment than the other, then the Siting Council might find that cost or environmental considerations were more important than avoidance of exposure to a PBI contingency. In this case, however, there are no intervenors, and the differences in cost and environmental impact between the two alternatives are not compelling.

The Siting Council believes it undesirable to allow approvals to remain outstanding for two lines when only one line is needed. In light of this belief and the emergence of the Mystic-Golden Hills line as a preferred alternative (See Section III, supra), the Siting Council hereby CONDITIONS its approval of the Mystic-Golden Hills line by withdrawing approval of the Woburn-Tewksbury 345 kV line as approved in 2 DOMSC at 58 (1977). If Boston Edison wishes to construct the second Woburn-Tewksbury 345 kV line at some future time, the Company will need to demonstrate a new need for the line and the superiority of its proposal to a reasonable range of practical alternatives.

The two underground Hyde Park-Dewar Street 115 kV lines, also approved in 2 DOMSC at 58, were orginally intended to transmit power into the Boston area from the south. Now, Boston Edison anticipates that "...the increased power flows into the Company's system will be from the north, eliminating the need for the Hyde Park-Dewar Street lines out through at least 1994" (Forecast, Volume II at II-2; Response to Staff Information Request TF-8A2).

The Siting Council believes it undesirable to allow an approval for a transmission line to remain outstanding when the line is no longer needed. Therefore, the Siting Council hereby CONDITIONS its approval of the Mystic-Golden Hills line by withdrawing approval of the Hyde Park-Dewar Street 115 kV underground transmission lines as approved in 2 DOMSC at 58 (1977). If Boston Edison wishes to construct the Hyde Park-Dewar Street 115 kV lines at some future time, the Company will need to demonstrate a new need for the line and the superiority of its proposal to a reasonable range of practical alternatives.

The Siting Council hereby APPROVES an in-service date of 1989 for the Mystic-Downtown 345 kV underground transmission line. The Siting Council reminds the Company that Condition 2 to its 1977 Decision, quoted above, is still in effect. The Siting Council encourages the Company to cooperate with the appropriate governmental permitting agencies to resolve outstanding issues regarding final design, engineering and construction. Finally, because construction of the Mystic-Downtown line is intimately linked to construction of the Mystic-Golden Hills line, the Siting Council has an interest in monitoring the progress of the resolution of outstanding environmental and cost issues. Consequently, as a CONDITION to its approval of the Mystic-Golden Hills line, the Siting Council ORDERS the Company to provide copies of the Final Environmental Impact Report ("FEIR"), the FEIR acceptance certificate (if and when it is issued), and permits issued by the agencies identified in Section I.G. of the Environmental Notification Form (Response to Staff Information Request 13A at p.3); and to notify the Siting Council of substantial changes in the estimated cost of the facilities.

V. DECISION AND ORDER

The Siting Council hereby APPROVES the Petition of the Boston Edison Company to construct an underground 345 kV transmission line between the Company's Mystic Station, Everett, and the New England Electric System's Golden Hills Station, Saugus. As CONDITIONS to this approval, the Siting Council hereby WITHDRAWS its previously granted approvals of a second Woburn-Tewksbury overhead 345 kV transmission line and the two Hyde Park-Dewar Street underground 115 kV transmission lines, and ORDERS:

1. That the Company provide the Siting Council with copies of the FEIR, the FEIR acceptance certificate, and other permits required by the agencies identified in Section I.G. of the Environmental Notification Form if and when these permits are issued. Further, the Company shall notify the Siting Council of substantial changes in the estimated cost of the facilities.

Carolyn E. Ramm
Hearings Officer

On the Decision
George Aronson

Dated at Boston, Massachusetts, this 31st day of October, 1985.

Unanimously APPROVED by the Energy Facilities Siting Council on October 31, 1985, by those members and designees present and voting: Chairperson Sharon M. Pollard (Secretary of Energy Resources); Joellen D'Esti (for Secretary of Economic Affairs, Evelyn Murphy); Sarah Wald (for Secretary of Consumer Affairs, Paula W. Gold); Stephen Roop (for Secretary of Environmental Affairs, James S. Hoyte); Joseph W. Joyce (Public Labor Member); Patricia L. Deese (Public Engineering Member). Ineligible to vote - Dennis J. LaCroix (Public Gas Member); Elliot J. Roseman (Public Oil Member). Absent - Madeline Varitimos (Public Environmental Member).

Sharon M. Pollard
Chairperson

18 November 1985
Date

COMMONWEALTH OF MASSACHUSETTS

Energy Facilities Siting Council

In the Matter of the Petition of Fitchburg Gas and Electric Light Company for Approval of the Second Supplement to the Second Long-Range Forecast of Electric Requirements and Resources

Docket No. 84-11B

Final Decision

James G. White, Jr.
Hearing Officer

John Dalton
Staff Analyst

October 31, 1985

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The Energy Facilities Siting Council (Siting Council) REJECTS the Second Supplement to the Second Long-Range Forecast of electric requirements and resources ("Supplement") of Fitchburg Gas & Electric Light Company ("Fitchburg" or the "Company"). The rejection applies both to the electricity demand and supply portions of the Supplement.

I. PROCEDURAL HISTORY

Fitchburg filed the current Supplement on November 1, 1984, and provided public notice of the filing through publication and posting of the Notice of Adjudication. On January 29, 1985, the Attorney General of the Commonwealth of Massachusetts filed an intervention petition. Subsequently, the Company filed a Motion requesting the Hearing Officer to compel a more responsive intervention petition. In the Motion, the Company noted that the Attorney General was involved in three proceedings at the Department of Public Utilities ("DPU") involving Fitchburg. The Company's Motion also stated that in the event of a clearer statement of reasons for intervention by the Attorney General, "perhaps many of the issues could either be narrowed or stipulated to between the parties." The Company indicated this request was important to the Company given the time-consuming and financially draining proceedings at the DPU. To the extent possible, the Siting Council has attempted to compile the necessary information in this proceeding without burdening unduly the Company.

On March 19, 1985, the parties met at the Siting Council offices and discussed the conduct of the proceeding. On April 3, 1985, the Attorney General and the Siting Council Staff submitted statements or lists of demand-side issues.

Subsequently, the Siting Council Staff issued two sets of demand side information requests. The responses were provided primarily in the form of written summaries of oral answers provided by Company officials at two technical sessions.

Thereafter, on August 2 and 9, 1985, the Attorney General submitted information from the Company's financing proceeding at the DPU in Docket Nos. 84-49/50, and from the "generic Seabrook" proceeding in DPU Docket No. 84-152. In summary, the documents from the DPU proceedings included the prepared testimony of Dr. David Nichols (the Attorney General's witness), the prepared testimony of Mr. David K. Foote on behalf of the Company, certain Company responses to discovery questions of the Attorney General, and portions of transcripts of the DPU proceedings. Certain documents were afforded confidential treatment based on similarly afforded treatment at the DPU.

On August 12, 1985, the Siting Council Staff issued supply-side document and information requests. The Company provided responses to the majority of the requests on September 11, 1985.

On August 16, 1985, the Attorney General filed a Notice of Withdrawal from the proceeding.

Finally, on October 8, 1985, the Siting Council conducted a hearing on supply-side issues. The Siting Council Staff cross-examined Mr. David K. Foote and Mr. David Graham.

The Siting Council acknowledges the thorough and complete cooperation of Company officials in providing information during this proceeding.

II. OVERVIEW

Fitchburg is an electric utility under the jurisdiction of the Siting Council, Mass. Gen. Laws Ann. ch. 164, Sec. 69G. As a small investor-owned utility, Fitchburg provides electric service to approximately 24,000 customers in the City of Fitchburg, and the Towns of Ashby, Townsend, and Lunenburg. In 1983, sales to industrial customers accounted for 54.0 percent of the Company's total requirements; sales to residential customers, 26.9 percent; sales to commercial customers, 11.5 percent; and street lighting sales and system losses accounted for 7.6 percent. With total energy output of 383.1 million KWh in 1983, and a 1983 peak load of 69.02 MW, Fitchburg is the second smallest investor-owned electric utility in Massachusetts in terms of electric energy sales.

Fitchburg's energy supply is provided primarily by five sources: 1) the 26.2 MW oil-fired combustion turbine leased by Fitchburg; 2) a 20.1 MW unit purchase of New Haven Harbor, an oil-fired cycling unit; 3) a 1.1 MW unit purchase of Wyman #4, an oil-fired cycling unit; 4) a 40 MW capacity purchase from Boston Edison Company (BECo) with energy priced at the BECo system's average cost; and 5) economy energy purchases from other electric utilities through the New England Power Exchange (NEPEX).

Fitchburg has been beset with financial problems. In May 1985, Fitchburg announced that it was discontinuing indefinitely its bimonthly payments to support the Seabrook project. At the time, Fitchburg also announced that it was laying off one-third of its work force, Tr. at 37. The Company states that it took this action to forestall a liquidity crisis since the Company had been precluded by the DPU from raising capital to finance its Seabrook 1 investment and from recovering funds invested in Seabrook 2 which has been tentatively cancelled,[1] Tr. at 37-40. Fitchburg announced on October 3, 1985 that it had reached an agreement with the Attorney General which, if approved by the DPU, would allow the Company to recover 60 percent and 55 percent of its after-tax investment in Seabrook Units 1 and 2. Tr. Vol. 1 at 32; see also Fitchburg's press release dated October 3, 1985. The Company believes that DPU approval of this proposal will go a long way towards remedying its financial health. However, the Company believes that the "effects" of the approval would have to be flowing for several months before the

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[1]On May 21, 1985 the DPU gave Fitchburg approval to issue up to $10 million in bonds, subject to the condition that the Company continue to withhold all payments to the Seabrook 1 project.

Company's financial situation would be perceived by others as improved, Tr. at 85-86.

Fitchburg's long-range supply situation is dire, and the demand forecasting methodology requires immediate improvement. Fitchburg's own forecast shows a potential supply (i.e., capacity and energy) shortfall as early as November 1986. Further, the Siting Council finds that the Company's demand forecast methodology is unreliable and that the resulting projections do not constitute a sound basis for supply planning.

III. REVIEW OF THE DEMAND FORECAST

A. Scope of Review

As part of its statutory mandate "...to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost," Mass. Gen. Laws Ann. ch. 164, sec. 69H, the Council determines whether "projections of the demand for electric power...are based on substantially accurate historical information and reasonable statistical projection methods." Mass. Gen. Laws Ann. ch. 164, sec. 69J.

To ensure that the foregoing standard is met the Siting Council applies three standards to demand forecasts: 1) reviewability, i.e., whether the results can be evaluated and duplicated by another person, given the same level of technical resources and expertise; 2) appropriateness, i.e., whether the forecast methodology is technically suitable to the size and nature of the utility's system; and 3) reliability, i.e., whether the methodology instills confidence that the data, assumptions and judgments produce a forecast of what is most likely to occur. In Re Boston Edison Company, 10 DOMSC 203, 209 (1984).

B. Previous Demand Forecast Reviews

In its most recent review of the Company's forecast methodology, the Siting Council recommended that "the Company consider development of econometric models to more expeditiously meet the Council's concerns for reviewability and reliability." In Re Fitchburg Gas and Electric, 11 DOMSC 29, 32 (1984). The two demand side conditions elucidated the Council's intent. Specifically, Fitchburg was ordered to: 1) "review its residential and commercial forecast methodologies and related data collection needs ... and develop a plan for addressing Council concerns regarding reviewability and reliability..."; and 2) "begin development of a reviewable industrial forecast methodology which includes consideration of macroeconomic variables... ." In Re Fitchburg Gas and Electric, 11 DOMSC 29, 59 (1984) (emphasis added).

To allow the Siting Council to monitor the Company's compliance with these directives, Fitchburg was also ordered to submit a preliminary Compliance Plan within 90 days, Id.

On August 20, 1984, the Company submitted its compliance plan, containing a preliminary outline for a more rigorous, econometrics-based methodology for all three sectors. Fitchburg promised in the Compliance Plan to examine "statistical relationships and... [evaluate] them for designing FGE's future forecasts." Supplement, Appendix B2, page 2.

C. Forecast Results

Table 1 summarizes Fitchburg's demand forecast. Table 2 compares each sector's annual compound growth rate and percentage share of the Company's total energy requirements.

In Fitchburg's 1983 Supplement, the Company projected that its total requirements would grow at a 2.4 percent annual compound rate. See Table 3. In the current forecast, Fitchburg projects that total system requirements will increase at a 2.2 percent average annual compound rate over the forecast period. Industrial sales are projected to grow at a 3.0 percent annual average compound rate, faster than any other sector. Fitchburg projects that sales to commercial and residential customers will grow at a slower rate than the total system requirements, at 1.9 percent annually for commercial customers, and 0.5 percent annually for residential customers.

Fitchburg projects that total system peak load will increase 1.8 percent a year from 1984 to 1993.

Fitchburg's expectations concerning its industrial sales appear to have changed significantly since the Supplement was submitted in November 1984. At the hearing on October 8, 1985, a Company witness indicated that the paper industry's economic prospects have dimmed considerably: "during the last several months, in particular, the paper industry in Fitchburg has been significantly impacted by economic conditions... ." Tr. at 65. As a result, Fitchburg's weekly loads to date in 1985 are running approximately 4 percent below 1984 levels, Tr. at 98. Further, the Company's peak loads for the winter 1984-85 and the summer of 1985 were 5.8 and 9.5 percent below the forecasted peaks, Tr. at 98.

D. Overview of the Forecast Methodology

Fitchburg's demand forecast is based in large part on an interview technique. For example, Fitchburg projects industrial sales to new customers through information gathered from economic development specialists, private developers, and local officials concerning the development prospects for specific parcels of land (e.g., when vacant lots will be filled and what types of industries will occupy the sites). For the first few years in the forecast period, Fitchburg projects the requirements from known commercial developments based on information supplied by customers. However, for the "out years," Fitchburg projects commercial sales on the basis of the historic relationship between the growth in commercial energy requirements and the increase in residential meters. Fitchburg also makes adjustments for energy-efficient appliance replacement and the penetration of wood stoves. Fitchburg assumes that losses will be 8.0 percent of the Company's total sales throughout the forecast period.

Table 1

FITCHBURG ELECTRIC FORECAST OF ENERGY REQUIREMENTS AND PEAK LOAD

	Total Energy Output Requirements (Thousands of Megawatt Hours)						Total System Peak Load (Megawatts)	
Year	Res.	Com.	Ind.	Street Lighting	Losses	Total Require-ments	Summer	Winter
1983	103.00	44.2	206.7	3.6	25.6	383.1	66.9	69.0
1984	104.40	44.9	221.8	3.4	30.0	404.6	72.7	72.9
1985	105.10	46.7	236.3	3.5	31.3	422.9	75.7	76.1
1986	106.10	48.1	240.4	3.5	31.8	429.9	76.8	77.6
1987	106.70	49.1	246.5	3.5	32.5	438.3	77.5	78.4
1988	107.10	50.6	256.8	3.5	33.4	451.4	79.1	80.2
1989	107.50	51.1	263.3	3.6	34.2	459.7	80.6	81.6
1990	108.10	51.6	273.9	3.6	35.0	472.2	82.1	82.9
1991	108.50	62.1	282.1	3.6	35.7	482.0	83.6	84.2
1992	108.90	52.6	289.8	3.7	36.4	491.4	85.1	85.5
1993	109.30	54.1	297.4	3.7	37.1	501.6	86.6	87.3

Source: Supplement, Table E-17 and Appendix W.

E. Industrial Forecast Methodology

Fitchburg forecasts industrial sales to existing customers by determining the "underlying average MWh growth" from 1975 to 1983 for industrial customers within its service territory. Fitchburg estimates this underlying growth by calculating the average annual change in energy requirements for this eight year period. This underlying growth rate is adjusted by subtracting from Fitchburg's 1975 industrial energy requirements the requirements of those industrial customers which have gone out of business since then, and by subtracting from the 1983 totals the requirements of three paper companies whose loads were added after 1975.

In addition to this underlying growth rate estimate, the requirements of paper and plastic companies for 1984 are further adjusted. Fitchburg assumed that the reduced energy requirements for the paper companies experienced in 1978 and 1980 would be totally recovered by 1985. By 1984, 80 percent of this decline had been recouped. Fitchburg assumed that roughly 4.0 MWh would be recovered in 1985. The Company also assumed that sales to plastics companies would continue to experience the growth witnessed in the first eight months of 1984. This lead to a 4.0 MWh adjustment to the energy requirements of plastic companies.

TABLE 2

FITCHBURG ELECTRIC
COMPARISON OF ANNUAL COMPOUND GROWTH RATES
(Millions of Kilowatts)

Year	Residential	Commercial	Industrial	Street Lighting	Losses	Total Requirements
1983	103.00	44.2	206.7	3.6	25.6	383.1
% Total Requirements	26.89%	11.54%	53.95%	0.94%	6.68%	---
1984	104.40	44.9	221.8	3.5	30.0	404.6
% Total Requirements	25.80%	11.10%	54.82%	0.87%	7.41%	---
% Change 1983-84	1.36%	1.58%	7.31%	-2.78%	17.19%	5.61%
1993	109.30	54.1	297.4	3.7	37.1	501.6
% Total Requirements	21.79%	10.79%	59.29%	0.74%	7.40%	---
% Change 1984-93	4.69%	20.49%	34.08%	5.71%	23.67%	23.97%
% of Total Change 1984-93	5.05%	9.48%	77.94%	0.21%	7.32%	---
Annual Compound Growth	0.46%	1.88%	2.98%	0.56%	2.15%	2.17%

Note that 1983 data are actual data.

SOURCE: Supplement, Table E-8

Table 3

Fitchburg Electric
Comparison of Company Forecasts of Total Energy Requirements
(Millions of kWh)

Year	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	% Annual Growth
Actual	397.4	388.8	362.7	383.1	392.6										
Requirements		-2.2%	-7.2%	5.3%	2.4%										-0.3%
1981 Supplement		409.3	436.1	449.1	455.1	459.5	463.9	470.2	475.2	480.1	485.2	490.1			
(June 1981)			6.1%	2.9%	1.3%	1.0%	0.9%	1.3%	1.1%	1.0%	1.1%	1.0%			1.8%
1983 Supplement				381.5	400.8	413.5	421.6	429.7	441.6	453.5	465.1	474.6	483.6		
(April 1983)					4.8%	3.1%	1.9%	1.9%	2.7%	2.6%	2.5%	2.0%	1.9%		2.4%
1984 Supplement					404.5	422.8	429.9	438.2	451.3	459.6	472.1	482.0	491.3	501.6	
(November 1984)						4.3%	1.6%	1.9%	2.9%	1.8%	2.7%	2.1%	1.9%	2.0%	2.2%

Source: 1981 Supplement, Appendix W; 1983 Supplement, Appendix W;
1984 Supplement, Appendix W; Uniform Statistical Report - Year Ended December 31, 1984.

Fitchburg forecasts the energy requirements of new industrial customers on the basis of information collected through interviews and periodic informal contacts with local developers, city industrial development officials, and in some instances, prospective customers. Response to Information Request CIF-1. For major industrial developments, the Company often has contact with prospective customers up to two years before the load is added. Id. During this time, the Company is usually provided with information on the customer's energy requirements so that the customer can obtain an estimate of its anticipated electricity costs.

For sites in existing industrial parks where no tenant has been identified, the Company "projects future loads and energy requirements by determing the size of the building which is likely to be built on the lot and then estimating the energy consumption per square foot based on the Company's assessment of what type of industry is likely to locate at the site." Response to Information Request CIF-1. On-line dates for new commercial and industrial customers are based on information provided by the Fitchburg Planning Board and the Fitchburg Industrial Development Commission. The Company keeps informed about development projects through the Company's industrial engineer who is a member of the Fitchburg Industrial Development Commission.

1. Review of the Industrial Forecast Methodology

In its most recent review of the Company's industrial forecast, the Siting Council questioned "the reliability of a forecast that incorporates perceived prospects for economic recovery and growth in the absence of any consistent and explicit consideration or documentation of regional and national trends." In Re Fitchburg Gas & Electric, 11 DOMSC at 42 (1984). The Council has the identical concerns with the instant forecast, reflecting the Company's lack of progress in meeting the concerns expressed by the Council in its previous decision.

For example, the Company projects the energy requirements of existing customers on the basis of the adjusted historical growth rate for existing customers, and the energy requirements of new industrial customers based on interviews with developers and public officials. The projections for existing customers are subjectively adjusted and the projections for new industrial customers are subjectively-based. Therefore, both projections are susceptible to bias and could result in unreliable forecasts.

The Siting Council believes that adjustments to historical growth rates are appropriate in those instances when historical relationships have changed in known and measureable ways, or when events which influence the data cannot be expected to occur again. Fitchburg provided no evidence of the existence of either condition in its Supplement. Therefore, the Siting Council finds that this adjustment reduces the reliability of the Company's industrial forecast. A more detailed discussion of this adjustment and its affect on the reliability of the Company's industrial forecast follows.

a) Review of the Forecast Methodology for Existing Industrial Customers.

The Company's projections of the underlying growth rate for existing customers implicitly assume that Fitchburg's existing industrial customers will not repeat the experience of the nine customers who since 1975 either have gone out of business or have left Fitchburg's service area.[2] The Company provides no support for this assumption. The Council observes that the assumption as of November 1984 apparently conflicts with Fitchburg's own current expectations for those industries which account for much of Fitchburg's energy requirements - the paper and plastic industries, Tr. at 65. (Table 4 provides a breakout of Fitchburg's sales to industrial customers). Further, the Siting Council notes that since the instant forecast was submitted, the Company's expectations of industrial sales have changed significantly: "at least two of the paper companies representing 8 to 10 megawatts of Fitchburg's load potentially may not be able to continue in business in Fitchburg," Tr. at 65. This statement provides direct support that projections of industrial demand are out of line with actual conditions.

The Siting Council notes that Fitchburg's sales forecast for existing industrial customers took no account of the potential increases in Fitchburg's electric rates which might be expected when the Company's Seabrook 1 investment eventually was to be added to the Company's rate base.[3] The Siting Council believes it is possible that the Seabrook-related rate shock could have been enough to drive some industrial customers out of Fitchburg's service territory, or to cause firms with a number of different locations throughout the United States (e.g., James River Graphics) to significantly reduce output at its facilities in Fitchburg's service territory. Fitchburg, however, does not use electricity prices to project energy requirements in spite of the importance of electricity prices in determining the demand for

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[2]Fitchburg adjusted the underlying growth rate by subtracting out from the 1975 industrial sales totals the 1975 energy requirements of the nine customers who were no longer serviced by Fitchburg in 1983. The net effect of this adjustment is to change the averge annual growth rate from 2.46 MWh per year to -.32 MWh, a net loss in sales. This fact further calls into question the credibility and hence reliability of the Company's forecast.

[3]This discussion relates to the Seabrook-related assumptions relevant at the time the Company was preparing its Supplement. At that time, Fitchburg was relying on Seabrook 1 as part of its future supply mix, and was making assumptions about the timing and magnitude of cost recovery for the Company's investments in both Seabrook 1 and Seabrook 2. The Siting Council is aware that such assumptions have changed, and that the Company has entered into a Seabrook-related settlement with the Attorney General, which both Fitchburg and the Attorney General hope will be approved by the DPU.

Table 4

Fitchburg Electric
Disaggregation of Sales to Industrial Customers by Industry
(1984 kWh Sales in Thousands)

Industry	SIC Code	1984 kWh Sales	% of Industrial Sales	% of Total Sales
Paper & Allied Products	26	79,647	39.2%	22.0%
Misc. Manufacturing Industries	39	56,850	28.0%	15.7%
Rubber and Misc. Plastic Products	30	26,787	13.2%	7.4%
Fabricated Metal Products (1)	34	14,574	7.2%	4.0%
Machinery (2)	35	14,513	7.1%	4.0%
Other		10,980	5.4%	3.0%
TOTAL		203,351	100.0%	56.3%

(1) Except Machinery and Transportation Equipment

(2) Except Electrical

Source: Uniform Statistical Report - Year Ended December 31, 1984 electricity. This is a serious deficiency in the Company's forecast which, if rates had risen sharply, could have resulted in an over-forecasting of energy requirements.

The net effect of Fitchburg's failure to account for the characteristics of industrial firms in the Company's service territory and for the impact of major economic variables, is that the Company's forecast of the annual growth in requirements for existing industrial customers is unreliable and, in the Siting Council's view, could well overstate the sales growth of this sector.[4] If, as the Siting Council believes, the sales forecast methodology for existing customers could result in an over-estimate of demand, then the magnitude of the shortfall discussed infra could be smaller than the Company expects, and could lead Fitchburg to contract for more replacement capacity than its needs. However, given that other aspects of the demand forecast are also unreliabile (See discussion infra), the Siting Council cannot predict the net effect on the total sales forecast of weaknesses in component parts of the forecast methodology.

Since a reliable forecast methodology is the foundation for a reliable long-range forecast, which the Siting Council believes is a prerequisite for supply planning, the Siting Council finds that the Company needs to begin immediately the development of a reliable industrial forecast methodology. This need for improved forecasting capabilities is exacerbated as a result of the Company's own forecast showing a capacity shortfall may occur as early as November, 1986.

Therefore, the Conditions attached to this Supplement are imposed and intended by the Siting Council to provide the Company with guidance in improving the reliability of its long-run demand forecast.

b) Forecast of the Requirements of New Industrial Customers.

Fitchburg's forecast methodology for projecting sales to new industrial customers is a subjective interview technique which has the potential for over optimistic bias. For example, the people interviewed - local and private development officials - are for the most part promoters and thus may be optimistic about the number, size, and timing of industries locating in the Company's service area. Fitchburg is aware of this potential bias and "revises Fitchburg Planning Board estimates to reflect past experience [over optimistic estimates]."

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[4] The Siting Council observes that the Attorney General specifically raised a concern about the "over-forecasting" of industrial electricity sales. The Attorney General alleged that the industrial sales were substantially lower in 1983 than 1976, and yet are forecasted to grow at approximately 3 percent per year in the current Supplement. The Attorney General also suggested that there has been a gradual erosion in Fitchburg's mature industries and that economic trends might cause further paper industry cut backs.

Response to Information Request CIF-2. However, the Council is unable to evaluate how these revisions affect the reliability of the industrial forecast given the unreviewable nature of the interview process and the subjective nature of the revision process.[5]

In previous reviews, the Council has found that for an interview technique to be reviewable and reliable, "the data it collects must be reviewable, objective, and quantifiable." In Re Com/Electric, 6 DOMSC 3, 10 (1981). The interview process as implemented by Fitchburg does not meet this standard.

Therefore, the Council finds that the Company's interview technique, and the Company's industrial forecast in general, does not constitute a reasonable statistical projection method.

Last year, the Siting Council indicated its concern for a methodology which did not account for regional or national economic trends. The Company's forecast methodology is unchanged. Thus, the Council has the same concern with the current Supplement. In particular, the Council is concerned that with no explicit consideration or treatment of national and regional economic projections (e.g., relating to industrial output) or other critical variables (e.g., electricity prices), the subjective nature of the Company's forecast approach could lead to unreliable projections.

The Siting Council believes that many of its concerns with Fitchburg's current forecast methodology have been corroborated by the recent decline in the sales to industrial customers. By failing to account for regional economic trends and considerations, and by basing the forecast on time series data which was selectively adjusted to conform to the Company's sales outlook, the Company's existing industrial forecast methodology failed to capture the effect of exogeneous economic variables.

To remedy this failing the Council ORDERS the Company to implement a new industrial forecast methodology which follows the basic structure outlined by the Company in the Compliance Plan submitted to the Council. This new forecast methodology shall consider electricity prices, and a more independent, less subjective assessment of the economic prospects

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[5]Again, the Attorney General raised a concern about the subjective and thus allegedly "improper" estimates of new industrial customers.

and electricity demand of industrial firms in the Company's service territory. The Siting Council Staff is available for consultation concerning this condition.

F. Commercial Forecast Methodology

Fitchburg forecasts commercial energy requirements based on the changes in energy requirements relative to the previous year's sales totals. Fitchburg forecasts the normal growth in commercial usage based on the historic relationship between the increase in commercial requirements and the increase in residential meters, and on the projected increase in the number of residential meters for each year of the forecast. For the first two years of the forecast period, Fitchburg also forecasts the requirements of new commercial customers based on preliminary contacts concerning the electricity service required by the prospective customer. If the growth in requirements from commercial developments exceeds the normal growth then the project-based figure is used.

Fitchburg assumed that the normal growth in sales to commercial customers will be 500,000 KWh/year, a 67 percent increase over the estimated normal growth in the previous supplement.

1. Review of the Commercial Forecast Methodology

The Siting Council notes several potential problems in Fitchburg's commercial forecast. First, based on the forecasted energy requirements of new commercial customers Fitchburg projects commercial energy requirements will increase by an average of 1,261 MWh per year from 1984 to 1986. However, after 1986, commercial requirements are expected to increase at an annual rate of 500 MWh per year. Yet, Fitchburg gives no explanation why the rate of increase in commercial requirements after 1986 falls to approximately 40 percent of the rate forecasted for 1984-86.

When two different forecast methodologies used to construct portions of a long-range commercial forecast provide such disparate results, the Siting Council believes that the entire forecast is discredited. While a case could be made that any bias in one methodology is compensated by an opposing bias in the other, and that the final forecast figure for 1993 is reliable, the Company did not provide a supporting rationale. Moreover, the Council is not solely interested in the reliability of the projection for the final year, but is concerned with the reliability of the estimates for each year of the forecast. If the Company is to plan for an adequate supply of power at the lowest possible cost throughout the forecast period, a reliable forecast estimate for each year is required.

The Siting Council believes the commercial methodology also is subject to question due to wide divergences in projected requirements in different Supplements. In the 1983 Supplement, Fitchburg projected the normal annual growth in commercial requirements to be 300 MWh, whereas in the 1984 Supplement Fitchburg projected the normal annual growth to be 500 MWh, an increase of 67 percent. This increase stems from the increased ratio experienced in 1982 and 1983 of commercial energy use to new residential meters.

A change of this magnitude in an annual average that results from the addition of just two years of new data suggests that the relationship between the increase in commercial energy use and new residential meters is not stable,[6] at least over the short number of years used in the current methodology. Therefore, the relationship over the past eight years as captured by an average is not necessarily likely to continue over the next ten years. Further, Fitchburg provides no justification why this relationship should be stable in the future. Therefore, the Siting Council questions the reliability of the use of this average to project the increase in commercial energy requirements. Without justification, continued use of this average to forecast commercial requirements is unacceptable.

Therefore, the Siting Council ORDERS the Company to develop a new method for forecasting commercial requirements and to present the method in its next filing. The Siting Council Staff is available to assist the Company with this Condition.

G. Residential Forecast Methodology

Fitchburg forecasts the requirements of residential heating and non-heating customers separately. However, the same methodology and many of the same assumptions are used for both groups.

Fitchburg projects the energy requirements of both groups on the basis of changes in energy requirements relative to a 1983 base year. Actual 1983 sales were adjusted to account for "normal growth" (historical growth in use per meter), new construction, and the impacts of energy efficient replacement appliances, audit-induced conservation, and for heating customers - the penetration of wood stoves.

Fitchburg projects an increase in energy requirements for existing customers (i.e., normal growth) based on the average annual increase in energy use per customer from 1976 to 1983. The energy requirements from new construction of apartments and large developments are based on discussions with developers.

The impacts of appliance efficiency improvements are projected by calculating annual energy savings for each relevant appliance. The annual energy savings for each appliance are estimated by first determining the total energy requirements of the appliance based on appliance usage estimates and appliance saturation rates. The total energy requirements of the appliance are then multiplied by a percentage improvement in appliance efficiency, which is based on assumed replacement rates and the percentage efficiency improvement of the new appliance.

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[6] Table 5 demonstrates the instability of this relationship.

Table 5

Fitchburg Electric
Evaluation of The Stability of the Relationship Between the
Increase in Commercial Sales and the Increase in Residential Meters

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1975-1983
Number of Residential Meters	18,809	18,852	19,066	19,309	19,538	20,112	20,387	20,523	20,893	---
Increase in Residential Meters	---	43	214	243	229	574	275	136	370	2084
Commercial Requirements (MWH)	27.21	28.23	29.04	30.24	31.49	32.33	33.62	34.88	37.33	---
Increase in Commercial Requirements (MWH)	---	1.02	0.81	1.2	1.25	0.84	1.29	1.26	2.45	10.12
Increase in Commercial MWH per Increase in Residential Meters		23.720	3.785	4.938	5.459	1.463	4.691	9.265	6.622	4.856

Increase in Commercial MWH per Increase in Residential Meters from 1975 - 1983	4.856	Average of Annual Estimates of Increase in Commercial MWH per Increase in Residential Meters	7.493

Source: 1983 Forecast Supplement, Appendix S; 1984 Forecast Supplement, Appendix S;

1. Review of the Residential Forecast Methodology

In general, Fitchburg's residential forecast methodology suffers from the same flaws as the methodology for the industrial sector. There is a lack of empirically derived estimates of the relationship between electricity consumption and the variables which determine electricity use. For the most part, Fitchburg bases electricity usage on average historical usage. Little consideration is given to the factors which might change historical usage patterns such as electricity prices, appliance prices, the introduction of new types of appliances, the prices of alternative energy sources, and changes in personal income. For example, Fitchburg assumes that the average use per new single family home will not change throughout the forecast period even though electricity prices could increase sharply in upcoming years depending on Fitchburg's allowed recovery for its Seabrook investment .

The Siting Council therefore ORDERS the Company to develop a new residential forecast methodology which considers these factors. Again, the Siting Council Staff is available to discuss this condition.

The Siting Council recognizes the Company's fragile financial situation. Nonetheless, the Siting Council views Fitchburg's potential supply short-fall and the deficiencies in forecast methodology as serious, requiring the Company's full attention. To ensure that attention is given to these areas the Council uses the strongest tool available to it - rejection of the forecast Supplement.

IV. ANALYSIS OF THE SUPPLY PLAN

A. Standard of Review

In keeping with its mandate to "provide a necessary power supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost," Mass. Gen. Laws Ann. ch. 164, sec. 69H, the Siting Council consistently reviews three dimensions of a utility's supply plan: adequacy, diversity, and cost. The adequacy of supply is a utility's ability to provide sufficient capacity to meet its peak loads and reserve requirements throughout the forecast period. The diversity of supply measures the relative mixture of supply sources and facility types. The Siting Council's working principle is that a more diverse supply mix, like a diversified financial portfolio, offers lower risks. The Siting Council also addresses whether a supply plan minimizes the long-run cost of power subject to trade-offs with adequacy, diversity, and the environmental impacts of construction and operation of new facilities. In Re Com/Electric, 12 DOMSC 39, 72 (1985).

Recently, the Siting Council has started reviewing in greater detail the supply planning processes utilized by utilities. Recognizing that supply planning is a dynamic process undertaken under evolving circumstances, the Siting Council believes that a utility's supply plan should identify a variety of supply options based on identified and explained criteria. A company's consistent and systematic application of such criteria to supply planning decisions would instill confidence in the Council that a company is fully evaluating new projects, contracts, or purchases, and alternatives. See Fall River Gas Co., 12 DOMSC 11, 23 (1985); In Re Com/Electric, 12 DOMSC 39, 81 (1985).

In this proceeding, the Company has indicated that Unitil Service Corporation ("Unitil") will provide long-term power supply planning services for Fitchburg for the period beginning in November, 1986 after expiration of the current BECo contract, Tr. at 80-82. Fitchburg will perform its own short-term supply planning primarily for short-term economy purchases from NEPOOL, Id. Unitil is not directly involved in Fitchburg's demand forecasting, Tr. at 82.

Given the Siting Council's concern with supply planning processes, the Council ORDERS the Company to include in its next Supplement detailed descriptions of the supply planning services performed by Unitil on behalf of the Company and of the supply planning performed by the Company. The description of the Company's relationship with Unitil shall address the nature of Unitil's services, the authority of Unitil to act on behalf of the Company in securing supplies (Tr. at 83), the Company's mechanism for review or monitoring of Unitil's activities, and the reasons why this planning arrangement is beneficial to the Company.

B. Previous Supply Plan Reviews

The Siting Council's two most recent reviews focused on the adequacy of the Company's supply sources in light of the anticipated expiration of the BECo contract for 40 MW in October 1986. In its Decision on the 1981 Supplement, the Siting Council expressed its "extreme concerns about the Company's potential for unacceptable reserve margins." In Re Fitchburg Gas and Electric, 7 DOMSC 238, 254 (1982).

In its decision on Fitchburg's 1983 Supplement, the Siting Council reiterated its concerns on the adequacy of the Company's planned supply and stated that "[c]apacity shortages are unacceptable to the Council for any year of the Forecast period." In Re Fitchburg Gas and Electric, 11 DOMSC 29, 56 (1984). The Company's forecast failed to identify replacement capacity for the BECo system contract. The Siting Council's approval of Fitchburg's supply plan rested "on Fitchburg's representation that a replacement contract will be negotiated with Boston Edison," 11 DOMSC at 56 (1984). To allow the Siting Council to monitor the Company's progress in securing additional capacity, the Council approved the 1983 Supplement subject to two Conditions relating to the adequacy of supply in the Company's supply plan, and one condition on conservation and load management.

The first condition required the Company to submit a detailed report regarding the status of discussions or negotiations for all base and intermediate load capacity purchases.

The second condition required in part that the Company "in all future filings identify by source the capacity ranges of any significant unit purchases proposed, or planned, on a contingency basis." In Re Fitchburg Gas and Electric, 11 DOMSC at 50 (1984). To ensure that conservation and load management programs were evaluated on an equal footing with conventional sources of supply, the Siting Council ordered the Company to present in its next filing "a preliminary evaluation of both active and passive conservation-load management technologies, and describe its efforts and/or plans to demonstrate an integrated evaluation of the most promising conservation-load management techniques with the Company's options for capacity expansion," 11 DOMSC at 60 (1984) (emphasis added).

In response to the first supply-side condition, Fitchburg submitted an interim report on July 30, 1984, outlining the status of its discussions and negotiations for replacement capacity. This interim report identified a number of supply alternatives and briefly discussed the relative advantages and disadvantages of each alternative. The Siting Council finds that the Company satisfied the condition requiring submission of the interim report.

Fitchburg addressed the other two conditions in the current Supplement. Supplement at 15-19, 80-84. The Company's current filing dedicates four pages to a discussion of potential supply sources including a brief discussion of possible purchases from NEPOOL members. The Company, however, does not discuss possible contingency purchases from NEPOOL members or the effect of regional competition on the Company's ability to obtain additional capacity.[7]

In response to the Siting Council's condition on evaluating conservation and load-management on an integrated basis with traditional capacity expansion options, the Company dedicated four pages to an evaluation of the cost-effectiveness of residential programs and its opinion concerning its proper role in promoting conservation for its industrial and commercial customers.[8] The Company concluded that there were no residential conservation programs with net benefits large enough to justify implementation. The Company did not present an integrated analysis of conservation and load management techniques and traditional supply sources. See Section III.D.3., infra. for the Siting Council's evaluation of the Company's analysis.

The Siting Council finds that the Company did not meet these two conditions in the manner intended by the Council.

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[7]The amount of information provided in the current Supplement, however, was less detailed and less thorough than the information provided in the interim report, possibly due in part to the Company's concern that public dissemination of the information on supply options could damage the Company's bargaining positions, Tr. at 4. The Siting Council observes that its Rule Nos. 30-34 provide a mechanism for protection of confidential information. Thus, the Company should provide substantial information on its supply planning options in future filings.

[8]The Company stated "[t]he commercial or industrial customer is in the best position to evaluate and implement load management into their own business." Supplement at 16.

C. Overview of the Supply Plan

In November 1984, Fitchburg had under contract, lease and/or unit purchase 94.1 MW of generating capacity to serve current requirements. The majority of this capacity is oil-fired, with the remainder being hydro and nuclear.[9] Table 6 lists the unit, type of unit and fuel, the capacity available to the Company, and the contract expiration date or projected operational date for Fitchburg's owned, purchased, and planned capacity.

In addition to its existing capacity, Fitchburg has a 2.5 MW entitlement to Millstone 3 which the Company assumes will be available in May 1986 and a 0.4 percent share of Phases I & II of the Hydro-Quebec project. NEPOOL has determined that each Phase of the Hydro-Quebec project has an inherent capacity value. Phase I is being treated by NEPOOL as a 600 MW reduction in the NEPOOL system's required reserves level. NEPOOL treats Phase II as a 900 MW capacity credit. Fitchburg's share of each project translates into a 2.5 MW reduction in the Company's capability responsibility for Phase I, and a 4 MW capacity credit for Phase II, Tr. at 18. For supply planning purposes Fitchburg treats the reduction in its capability responsibility from Phase I as a capacity credit since NEPOOL reserve requirements are subject to change, Tr. at 19. For the purposes of analyzing the adequacy of Fitchburg's capacity, the Siting Council will consider the net effect of Fitchburg's share of Phase I to be a capacity credit.

Particularly significant in an overall evaluation of Fitchburg's supply plan are the expiration of the 40 MW BECo contract in October 1986, and the Company's stated intention to get out of the two Seabrook projects, Tr. at 26.

D. Adequacy of Supply

Table 7 provides a comparison of Fitchburg's projected net capacity, peak demand, and reserve requirements for each winter of the forecast period. Fitchburg forecasts that its peak load will grow at a 1.8 percent average annual rate over the forecast period. Fitchburg has assumed for planning purposes a 21 percent reserve requirement through 1989 and 23 percent thereafter.[10]

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[9]Fitchburg's system contract with BECo entitles the Company to a proportional share of BECo's capacity, including its jointly owned units. Tr. Vol. 1 at 20-21. Fitchburg's nuclear capacity is provided by its system purchase from BECo. The BECo system contract also provides Fitchburg with gas-fired generation since three of BECo's oil-fired units burn natural gas on an interruptible basis.

[10]The NEPOOL target reserve ranges from 20 to 23 percent depending on the individual utility's load duration curve, the number of nuclear units in operation, and how long the new units have been in operation, Tr. at 7.

Table 6

Fitchburg Electric
Owned, Purchased, and Planned Capacity

	Source/Seller	Unit	Type/Fuel	Company Capacity (MW)	Company Interest	Contract Expiration or In-Service Date
LIFE OF UNIT CONTRACTS						
		New Haven Harbor	Steam/No. 6 Oil	20.12	Unit Purchase (4.5%)	
		Wyman #4	Steam/No. 6 Oil	1.13	Unit Purchase (.18%)	
			TOTAL CAPACITY	21.25		
CAPACITY PURCHASES						
	Mass. Hydro Assoc.		Hydro	0.50		12/31/84
	Maine Electric	Coleson Cove	Steam/No. 6 Oil	3.08		11/1/85
	Boston Edison	System Purchase	BECo Cap. Mix	40.00		10/30/86
	Linweave		Hydro	3.10		8/3/92
	Ind. Leasing Corp.	Fitchburg #7	Turbine/No. 2 Oil	26.20	Unit Lease	3/31/98
			TOTAL CAPACITY	72.88		
			TOTAL CAPACITY (as of 11/84)	94.13		
PLANNED UNITS						
		Millstone 3	Steam/Nuclear	2.5	Joint Ownership (.217%)	May 1986
		Hydro Quebec (Phase I)	Hydro	2.5	Project Participant (.4%)	July 1986
		Hydro Quebec (Phase II)	Hydro	4.0	Project Participant (.4%)	December 1990
			TOTAL PLANNED CAPACITY	9.0		

Source: Supplement, Tables E-12, E-14, and E-24.

All capacities are winter ratings.

Table 7

Fitchburg Electric
Projected Winter Net Capacity, Peak Demand, and Reserve Requirements from 1984-93
(MW)

		1984-85	1985-86	1986-87	1987-88	1988-89	1989-90	1990-91	1991-92	1992-93	1993-94
a.	Existing Facilities	47.4	47.4	47.4	47.4	47.4	47.4	47.4	47.4	47.4	47.4
b.	Planned Units	---	---	5	5	5	5	9	9	9	9
c.	Total Planned & Existing (a+b)	47.4	47.4	52.4	52.4	52.4	52.4	56.4	56.4	56.4	56.4
d.	Capacity Purchases	46.7	43.6	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
e.	Net Capacity Available (c+d)	94.1	91.0	55.5	55.5	55.5	55.5	59.5	59.5	59.5	59.5
f.	Projected Peak Load	68.7	76.1	77.6	78.4	80.2	81.6	82.9	84.2	85.5	87.3
g.	NEPOOL Reserve Requirements	14.4	16.0	16.3	16.5	16.8	18.8	19.1	19.4	19.7	20.1
h.	Capability Responsibility (f+g)	83.1	92.1	93.9	94.9	97.0	100.4	102.0	103.6	105.2	107.4
i.	Excess (Deficit) Capacity (e-h)	11.0	-1.1	-38.4	-39.4	-41.5	-44.9	-42.5	-44.1	-45.7	-47.9
j.	% Excess (Deficit) Capacity (i/h)	13.2%	-1.2%	-40.9%	-41.5%	-42.8%	-44.7%	-41.6%	-42.5%	-43.4%	-44.6%

SOURCE: Supplement, Table E-17.

The 1984-85 peak load is the actual peak recorded by the Company, Tr. at 98.
Existing facilities include Fitchburg unit # 7 (26.2 MW), unit purchase of New Haven Harbor (20.1 MW), and unit purchase of Wyman #4 (1.1 MW).
Millstone 3 assumed to come on line May 1986; Hydro Quebec Phase I in July 1986; Phase II in December 1990.
Hydro Quebec Phase I is treated as a capacity credit rather than a reduction in the Company's capability responsibility.
NEPOOL Reserve Requirements are based the reserve requirements Fitchburg uses for planning purposes: 21 percent through 1989 and 23 percent beyond.
Assumes that the Company's BECo contract expires in November 1986 and is not extended or renegotiated.

Based on Fitchburg's forecast of its peak load and available capacity, the Company's capability responsibility could potentially exceed its net capacity as soon as the winter of 1985-86. However, the Company's projected peaks for the previous two capability periods were 5.8 percent and 9.5 percent above the actual recorded peaks for the periods and if this trend continues then the Company's existing capacity would be sufficient to cover its capability responsibility in the winter of 1985-86. If Fitchburg's actual peak is in line with the projected peak, however, the Company could meet its capability responsibility with short-term capacity purchases.

Fitchburg's capacity problems begin in earnest in November 1986, when its system contract with BECo for 40 MW expires, thereby reducing the net capacity available for meeting load by approximately 39.4 percent, and causing the Company's capacity to fall below the projected peak load for the winter period by 28.5 percent. By the winter of 1993-94, the Company's existing and planned capacity is 31.2 percent lower than the projected peak load and 44.6 percent below the projected capability responsibility.

The Siting Council recognizes that at the current time this projected capacity deficiency does not pose an immediate threat to the reliability of electric service in Fitchburg's service territory when load exceeds available capacity, because the most current NEPLAN load and capacity forecast indicates that NEPOOL will have adequate capacity through the early 1990's. But, Fitchburg will have to take rapid steps to remedy this deficiency.

Fitchburg can respond to this projected capacity shortfall in three ways: 1) purchase replacement capacity from other utilities or from small power producers; 2) reduce peak load by promoting demand management in its service territory; or 3) do nothing and incur NEPOOL capability responsibility adjustment and deficiency charges.

Fitchburg has ruled out the third alternative: "[t]he Company does not consider NEPOOL capacity deficiency payments as an alternative available to it rather than arranging for its own power supply contracts." Response to Information Request PCS-7. The Company believes that willfully failing to meet its capability responsibility by not contracting for capacity "could be considered as grounds for termination as a NEPOOL member." Response to Information Request PCS-7. See New England Power Pool Agreement, Sec. 16.2, Paragraph C; Tr. at 15. The Siting Council agrees that such a policy is unacceptable. Therefore, the Siting Council will review and evaluate only the opportunities for capacity purchases and demand management and the Company's efforts in both these areas.

1. Purchase of Capacity

In the current Supplement, Fitchburg identifies a number of options for meeting its energy requirements and capability responsibilities through capacity purchases. These options were outlined by the Company in greater detail in an interim report filed with the Siting Council in

August 1984, and in responses to the Siting Council Staff's information requests in the current proceeding.

In its forecast Supplement and its interim report on capacity negotiations submitted in August 1984, Fitchburg identified the following potential sources of firm capacity: 1) Northeast Utilities (NU) has at least 100 MW of oil-fired capacity available until late 1990 which has been publicly offered to electric utilities; 2) BECo had 35 MW of fossil-fired capacity through late 1989; 3) the New Brunswick Electric Power Commission has export approval for 105 MW of uncommitted Pt. Lepreau #1, and at least 100 MW of the Coleson Cove Units;[11] and 4) one preliminary offer for 35 MW of firm capacity through late 1991, based on coal, Canadian hydro, natural gas and oil-fired generation. Supplement at 81-82.

To date, Fitchburg has not identified a source or group of sources to remedy its deficiency beginning in November 1986. However, Fitchburg has identified sources which will not be used to remedy the deficiency. First, Fitchburg does not expect to be a participant in Seabrook 1 and is not including Seabrook as a supply source for planning purposes, Tr. at 21. Under conditions contained in the DPU's Decision in Canal Electric Co., et al. (DPU Docket No. 84-152, April 4, 1985), the Company was prevented from conducting additional financing for the Seabrook project unless it agreed to rate conditions placing the risk of future investment in Seabrook Unit No. 1 on the shareholders and not the ratepayers, Response to Information Request SS-1.

Since May 1985, the Company has withheld payments of construction and other costs of Seabrook. And on May 29, 1985, the Company received a Request for Arbitration by six of the Seabrook participants under the Seabrook Joint Owners Agreement dated May 1, 1973, as amended. At this time, the Company cannot predict the outcome of withholding Seabrook project payments or the impact on its supply planning, Response to Information Request SS-1; see also Tr. at 29-30, 38-41.

Even though Fitchburg has been seeking a replacement for its BECo system contract for well over a year and "replacement of the Boston Edison contract for the post 1986 period is [was] a corporate goal of Fitchburg in 1984," Fitchburg has not yet negotiated a contract for replacement capacity for the BECo contract. (See letter from Fitchburg Gas and Electric to the Siting Council, dated April 30, 1984). The Company's Supplement indicated that BECo's offer of fossil fuel capacity through 1989 did not appear "as good" as other potential sources, Supplement at 84. And, effective July 19, 1985, Fitchburg was informed that BECo has no capacity available for sale due to load growth in its own territory, Response to Information Request PCS-3.

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[11] According to the Company, the attractiveness of the New Brunswick Power contracts is limited by transmission constraints which could significantly limit the availability of power: "the risks of

(Footnote Continued)

And, the Company now reports that the preliminary attractive offer of 35 MW from a source outside New England is no longer available due to Fitchburg's financial situation, Response to Information Request PCS-4.

Fitchburg has indicated that "No traditional utility sources [of capacity] are being offered on a long-term or life of unit basis and no new utility plants are currently being committed" (emphasis added), Response to Information Request PCS-2.[12] "Right now, no utility companies have offered power to Fitchburg on longer than a three- to five year basis," Tr. at 25. Further, as noted above, Company's financial problems affected the willingness of potential suppliers to enter into contracts with the Company, Tr. at 54. NU was "hesitant to sell to FGE on even a short-term basis unless FGE agreed to pay daily and wire transfer the funds." However, "[n]ow that FGE has done its long-term financing, NU appears willing to sell in the short-term market and will most likely be willing to sell in the mid-term market," Response to Information Request PCS-6. NU has made a general offering regarding a unit sale from the Montville 6 and Middletown 4 units, and Fitchburg has had discussions with NU.

On October 3, 1985, Fitchburg announced that it had reached a settlement agreement with the AG concerning the Company's recovery of its Seabrook investment. Fitchburg believes its ability to secure capacity contracts with electric utilities will be enhanced if the DPU approves the settlement agreement coupled with "[t]he financing that the Company was able to do in August... reasonably makes it possible for the Company to execute contracts with other utilities in the short to mid-term, at least." Tr. at 24-25.

2. Small Power Producers and Cogeneration

In November 1984, the Company included 8.6 MW of capacity from Ware Cogen Unit 1 in the supply plan effective November 1, 1985. But, the DPU did not approve the Company's contract with Ware Cogen and Ware Cogen has contracted to sell the power to others, Response to Information Request WCS-1; Tr. at 54. Also, Ware Cogen 2 is not on the drawing board, Tr. at 54.

Similarly, the possibility of purchasing power in the future from the 5 MW AETA project is remote because the project has not been developed and, in any event, the developers have not offered it for sale to Fitchburg, Tr. at 63. It does not appear that a potential

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(Footnote Continued)
interruption on the transmission line are greater than would warrant a contract with them [New Brunswick]... ." Tr. at 57.

[12]The Siting Council notes, however, that plans have recently been announced for a 446 MW gas-fired combined-cycle power plant in Burrillville, Rhode Island. Electric Utility Weekly, September 30, 1985, p. 1. The Company has not been invited to participate in this project, Tr. at 53-54.

cogeneration project at Technographics will not be forthcoming based, inter alia, on inadequate supplies of interruptible natural gas, Response to Information Requests APS-10; APS-11. The expander turbine at the Company's Tennessee Gas Pipeline Company reducer station is a possibility, but the Company has not yet updated its preliminary cost estimates of the expander turbine concept, and present flow rates of natural gas are not sufficient, Response to Information Request APS-14. However, Fitchburg plans to study this option, Tr. at 75-76.

Fitchburg is relatively optimistic about the ability of small power producers ("SPP") and cogenerators to meet the Company's long-term capacity and energy requirements: "Cogeneration or small power production is a likely source for future long-term base-load power supply needs." Response to Information Request PCS-2. Further, Fitchburg believes that SPP and cogenerators are competitive with conventional sources of supply: "There is a need for base-load capacity ... on a long term basis that the small power producers and cogenerators are probably in a position to produce it more cheaply than the utilities currently can in the overall status of regulations and size of plants." Tr. at 89-90.

In spite of the opportunities that SPP and cogeneration offer FGE as a supply source, "the Company has not undertaken any programs which would promote or assist small power producers or cogenerators in the Company's service territory" due to its limited financial resources.[13] Response to Information Request APS-9.

However, Fitchburg's financial situation also hampers the Company's efforts to sign contracts with SPPs and cogenerators. For example, one cogenerator was unable to secure financing for its project because of Fitchburg's "very poor credit rating at this time." Response to Information Request WCS-1. Fitchburg acknowledges that "[a]cquisition of these supplies [SPP and cogenerators] may be dependent on the ability of a supplier to obtain financing of the project with FGE as the buyer," Response to Information Requests PCS-2.

However, if the Seabrook cost recovery settlement agreement is approved by the DPU, the Company believes small power producers and

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[13] One such policy is the standard contract offer which outlines the terms under which Fitchburg is willing to contract for SPP and cogeneration. Utility contracting policies for SPPs and cogenerators are the subject of a DPU proceeding on amendments to the DPU's PURPA rules and regulations. DPU No. 84-276. The interim order issued by the DPU in this proceeding indicated that significant changes in the current rules are likely. For example, the Department found that "the use of a standard contract is necessary to overcome nonprice barriers to the development of QFs." Interim Order at 20. In regard to long-term pricing strategies, the Department found "that without long-term fixed-price contracts, QF development that would otherwise meet our goal of optimality may be discouraged." Interim Order at 30.

cogenerators would be more willing to enter into a contract with the Company and be more likely to be able to secure long-term financing. Tr. at 85.

3. Load Management

Fitchburg's discussion of load management programs was limited to programs for residential customers. Fitchburg believes that "the commercial or industrial customer is in the best position to evaluate and implement load management into their business." Supplement at 16. Therefore, the Company believes it is inappropriate to develop programs to promote commercial and industrial load management other than rate design which provides customers the appropriate economic signals. Fitchburg appears to some extent, to have altered its thinking on promoting load management to commercial and industrial customers. At hearing, a Company witness stated "the Company has now begun to formulate a program that would move forward with both the review of data collection that would impact potentially on its large power customers...and other programs that fall within the conservation and load management area... ." Tr. at 36.

The Siting Council urges Fitchburg to develop load management promotional programs for the industrial and commercial sectors.

Fitchburg asserts that the only residential appliance that lends itself to load control is the electric water heater and that the maximum potential for direct control of these water heaters is 500-1000 kW. Supplement at 18. Fitchburg concludes that "this is not enough to warrant exhaustive studies." Supplement at 18. The Siting Council acknowledges that there are economies of scale to the evaluation of load management programs. Nonetheless, the Siting Council believes that load control programs have been evaluated by a wide enough range of utilities with different operating characteristics that Fitchburg can adequately evaluate a water heater load control program by referencing other studies and that "exhaustive studies" are not needed.[14]

To ensure that Fitchburg gives load management proper consideration in its supply planning, the Siting Council ORDERS the Company to report in its next filing on potential load management programs, specifying the expected reduction in load from the programs; cost estimates; and the lead time required from the start of program implementation to the attainment of the peak load reduction target. This analysis shall be <u>integrated</u> into the Company's supply planning process.

4. Conclusions

Fitchburg is confronted with a serious capacity deficiency. The Company's BECo contract expires in October, 1986. In 1984 this contract

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[14] Fitchburg used such a study to estimate the contribution to peak load from water-heating.

provided approximately 40 percent of the Company's total capacity and 38 percent of its total energy requirements. Fitchburg's ability to respond to this projected deficiency is severly hampered by the Company's financial situation. Utilities have been reluctant to enter into short and medium-term capacity contracts with the Company given Fitchburg's poor financial standing. Further, the one alternative that the Company considers able to meet its long-term capacity and energy requirements - small power production and cogeneration - is not being promoted or aggressively pursued by the Company. On the other hand, the ability of SPPs and cogenerators to meet the Company's capacity and energy requirements is also limited by the Company's financial standing which could prevent SPPs and cogenerators from securing financing.

The Siting Council finds unacceptable Fitchburg's failure to present a plan which outlines how the Company is going to secure replacement capacity throughout the forecast period, particularly in light of the numerous obstacles identified to securing capacity. As noted previously, the Council has expressed its serious concern about the adequacy of the Company's supply plan in the last two Decisions. Thus, the Council REJECTS Fitchburg's supply plan on adequacy grounds.

The Siting Council ORDERS the Company to describe how the Company plans to meet its NEPOOL capability responsibilities for each year of the forecast period.

E. Supply Planning Process

In the current Supplement, the Company indicated it worked actively during the summer of 1984 to identify economic solutions to its projected capacity deficiency, Supplement at 80. The Company indicated, however, that regulatory proceedings at the DPU were consuming the time and efforts of Company personnel and that no further progress to obtaining replacement capacity would occur until at least December 1984, Supplement at 80-81. The Company stated its resources directed at Siting Council filings were "strained" due to the Company's financial plight, and that the financial situation had "worsened," Supplement at 80.

The Siting Council believes the Company's Supplement is deficient not only because it reveals insufficient supplies to meet forecasted needs, but also because it does not identify the processes or mechanisms by which the Company selects certain supply options or the criteria used to evaluate alternatives.

The Siting Council must review a company's supply planning process and the criteria used to evaluate supply options to ensure that the supply options provide an adequate supply of energy at the lowest possible cost. With no plan presented by Fitchburg for remedying its capacity deficiencies, the Council's review of the supply planning process and supply planning evaluation criteria takes on added importance.

During the course of this proceeding, documents were submitted which reveal information about the Company's planning process not presented in the Supplement.[15] In particular, Fitchburg prepared direct testimony and a computer analysis of the Company's supply situation and options under a number of different scenarios (e.g., no load growth, 2 percent load growth with and without Seabrook Unit No. 1) to support one of its cases at the DPU, Tr. at 42-46. The Company had not performed such an analysis prior to that time, Tr. at 46.

As part of its summer 1984 efforts mentioned above, Fitchburg also evaluated each potential source of supply on the basis of the amount and type of capacity, (i.e. base-load, cycling, peaking, etc.), the potential timing of a contract, the fuel and energy and capacity costs, the various risks associated with the contract, and the Company's assessment of the probability of securing the contract. The Company submitted the evaluations to the Attorney General as part of the discovery process in the DPU proceedings, and the evaluations or "worksheets" were the subject of cross-examination in the DPU proceedings, Tr. 69-71. The evaluation indicated the benefits of each source. Positive attributes included the availability of a long-term contract, high annual capacity load factors (i.e. base load supplies) a stable supplier, and no capital requirement of the Company. Risks included the possibility of sale to others, and exposure to a highly regulated review process including the magnitude of environmental regulation. The Company ranked the supplies in high, moderate, and low categories depending on the chances of obtaining the supply, Tr. at 70-72. Finally, the Company prepared computer analyses of hypothetical gas turbine and oil fired units.

The Siting Council believes the computer analysis and the source evaluations were very useful in its review of Fitchburg's supply plan. These types of analysis would serve to enhance greatly the Company's planning and forecasts if accompanied by appropriate textual discussion.

Therefore, the Siting Council hereby ORDERS Fitchburg to present in its next filing a planning process evaluating and comparing supply options available to the Company, inlcuding the criteria used and the process for applying those criteria.

F. Diversity and Cost of Supply

Fitchburg is the second most oil dependent utility in the state. In 1984 oil-fired generation accounted for 89.8 percent of the Company's total generation; hydro-electric generation provided 5.2 percent; and nuclear generation, 5.0 percent. Response to Information Request NGS-1.

Fitchburg's electricity rates are among the highest in Massachusetts, reflecting the Company's reliance on oil.

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[15]The subject of the DPU proceedings was the cost of Seabrook power as compared to alternatives. While not precisely relevant to the current review, the Siting Council believes the information was important in terms of illustrating Fitchburg's planning process.

U.S. Department of Energy, Typical Electric Bills - January 1, 1984, December, 1984.

Fitchburg is or will be a joint owner or participant in three projects which will reduce the Company's reliance on oil: the Millstone 3 nuclear project; Hydro Quebec Phase I and Hydro Quebec Phase II. Table 8 shows the change in the Company's energy mix over the first four years of the forecast period when the first two of these investments are scheduled to come on line and before the BECo system contract expires.

Fitchburg recently announced that as part of its settlement agreement with the Attorney General, the Company was attempting to sell its share of the Seabrook nuclear projects (10 MW for each unit). Seabrook 1 was Fitchburg's largest planned capacity source. Therefore, the loss of this capacity has a major impact on the diversity and cost of the Company's supply. The Siting Council has been unable to determine the extent of this impact given the late date at which the action was announced in the proceeding. Therefore, to a large extent the Siting Council is unable to make findings on the diversity and cost of the Company's supply plan. However, the Siting Council notes that unless non-oil-fired base-load replacement capacity is found, the loss of Seabrook 1 increases Fitchburg's reliance on oil and its need for base-load capacity.

The Siting Council is deeply concerned about the extent of the Companys reliance on oil and its need for firm energy and capacity. The Siting Council urges the Company to pursue all programs and options which will reduce its reliance on oil and reduce or satisfy its requirements for energy and base-load capacity.

Table 8

Fitchburg Gas & Electric
Actual and Forecasted Energy Mix
for 1984 and 1986

	1984	1986
Residual Oil	84.4%	79.9%
Distillate Oil	5.4%	1.2%
Nuclear	5.0%	14.6%
Hydro	5.2%	5.3%

1984 percentages are based on actual generation statistics. Estimates do not include cogeneration supplied by James River Graphics or natural gas-fired generation from BECo.

Source: Response to Information Request NGS-1.

V. ORDER

In this Decision, the Siting Council is imposing several broad conditions requiring the Company to improve its demand forecasting methodology and supply plan. The Siting Council has provided general guidance in this and prior Decisions involving Fitchburg, and in Decisions on the forecasts of other electric companies. Also, the Siting Council Staff is available to assist the Company.

The Siting Council REJECTS the Company's Second Supplement to its Second Long-Range Forecast and imposes the following conditions to be met in the Company's next Supplement due on July 1, 1986:

1. The Company shall develop and implement a new industral forecast pursuant to the Compliance Plan submitted by the Company pursuant to the Siting Council's decision in Docket No. 83-11B. The methodology shall consider electricity prices, and a less subjective assesment of economic development and energy demand for industrial customers in Fitchburg's service territory.

2. The Company shall develop and implement a new methodology for forecasting commercial and residential requirements.

3. The Company shall describe the supply planning services performed by Unitil on behalf of the Company and those supply planning functions performed by the Company. The Company shall discuss the nature of Unitil's services, the Company's mechanism for reviewing Unitil's actions; and Unitil's authority to act on behalf of the Company in securing supplies.

4. The Company shall present a supply plan indicating how it plans to meet its capability responsibility under NEPOOL for each year in the forecast period. The Company shall indicate how it has evaluated all cost-effective supply options, including Company investments in facilities and demand-management programs and Company purchases of supplies from other parties. In particular, the Company's plan shall include an analysis of potential load management programs; the expected load reduction from the programs; cost estimates; and the lead time required for program implementation. This analysis shall be integrated into the supply plan.

5. The Company shall present a description of its planning process for evaluating supply options including an identification of the criteria utilized in the decision process and a discussion of the use of the criteria.

6. The Company shall submit a detailed interim report on or before March 1, 1986, regarding the status of discussions and negotiations for all base and intermediate load capacity purchases.

James G. White, Jr.

James G. White, Jr.
Hearing Officer

October 31, 1985

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council by the members and designees present and voting: Chairperson Sharon M. Pollard (Secretary of Energy Resources); Sarah Wald (for Paula W. Gold, Secretary of Consumer Affairs); Joellen D'Esti (for Evelyn F. Murphy, Secretary of Economic Affairs); Stephen Roop (for James S. Hoyte, Secretary of Environmental Affairs); Joseph W. Joyce (Public Labor Member); Patricia Deese (Public Engineering Member). Ineligible to vote: Dennis LaCroix (Public Gas Member); Elliot Roseman (Public Oil Member).

Sharon M. Pollard

Sharon M. Pollard
Chairperson

4 November 1985
Date

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Massachusetts Electric Company, New England Power Company, Yankee Atomic Electric Company and New England Hydro-Transmission Electric Company, Inc., for Approval of the Amendment to Supplement 2C to the Second Long-Range Forecast of Electric Requirements and Resources	)	Docket No. 84-24A

Final Decision

James G. White, Jr.
Carolyn E. Ramm
Hearing Officers

Susan Tierney
George Aronson
Clifford Cook
John Dalton
William Febiger
Juanita Haydel
Calvin Young

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The Energy Facilities Siting Council ("Siting Council") APPROVES the Amendment to Supplement 2C to the Second Long-Range Forecast of electricity requirements and resources of Massachusetts Electric Company, New England Power Company, Yankee Atomic Electric Company, and New England Hydro-Transmission Electric Company, Inc., subject to the CONDITIONS imposed herein.

I. OVERVIEW

A. Summary of the Proposed Project and Facilities

On November 30, 1984, the Massachusetts Electric Company ("Massachusetts Electric," or "MECo"), New England Power Company ("New England Power," or "NEPCo"), Yankee Atomic Electric Company, and New England Hydro-Transmission Electric Company, Inc. ("New England Hydro," or "NEH"), (collectively the "Companies") filed an Amendment to Supplement 2C to the Second Long-Range Forecast of Electric Power Needs and Requirements ("the Amendment").[1]

In the Amendment,[2] the Companies request approval to construct in Massachusetts a 12.2-mile ±450 kilovolt ("kV") direct current ("DC") overhead transmission line, 52.1 miles of 345 kV alternating current ("AC") overhead reinforcement transmission lines, and an 1800 megawatt ("MW") DC-AC converter terminal station, and to relocate and reconstruct certain existing transmission lines within existing rights of way. Once constructed, these facilities would complete an electric interconnection between generating facilities in James Bay, Canada, and load centers in southern New England. Amendment, Vol. 1 at 2; Tr. 2 at 8, 9, 12, and 15.

The Companies have proposed these facilities on behalf of the members of the New England Power Pool ("NEPOOL")[3] participating in the

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[1]New England Hydro, Massachusetts Electric, and New England Power are subsidiaries of the New England Electric System ("NEES"). New England Hydro, however, is expected to become an affiliate of NEES, rather than a wholly owned subsidiary. NEES anticipates retaining 51 percent ownership of New England Hydro and selling the remaining 49 percent to other utilities in New England, which will become equity owners of New England Hydro. Tr. 2 at 37.

[2]On April 12, 1985, the Companies filed an Amendment Update ("Amendment Update") reflecting various changes in fuel price forecasts and supply plans of New England electric utilities. Ex. ROB-1.

[3]At this writing, the prospective Hydro Quebec Phase 2 participants include: Bangor Hydro-Electric Company, Boston Edison Company, Canal Electric Company, Central Maine Power Company, Chicopee Municipal Light Plant, Connecticut Light and Power Company, Connecticut Municipal Electric Energy Cooperative, Fitchburg Gas and Electric Light Company,

(Footnote Continued)

proposed Hydro Quebec Phase 2 project ("Project"), pursuant to a preliminary power purchase agreement ("Preliminary Agreement") entered into in June 1984 between NEPOOL and the Canadian electric utility, Hydro Quebec. The Preliminary Agreement provides for NEPOOL participants to obtain from Hydro Quebec 7 billion kilowatt hours ("kWh") a year for 10 years starting in September 1990. The Agreement calls for a maximum transmission of 2000 MW at any point in time. Amendment, Vol. 1 at 3.

The proposed Project is in addition to the existing Phase 1 contract between NEPOOL and Hydro Quebec which provides for a total of 33 billion kWh over the 11 power years from 1986/87 through 1996/97. Amendment, Vol. 1 at 1; Tr. 2 at 69-70. The Phase 1 facilities originate in Sherbrooke, Quebec at the interconnection of Hydro Quebec transmission and AC-to-DC conversion facilities. The 107-mile ±450 kV DC transmission line facilities traverse Vermont and part of New Hampshire, and terminate at a 690 MW DC-AC converter terminal at Monroe, New Hampshire. Tr. Vol. 2 at 28.

The proposed Phase 2 transmission facilities would begin at Monroe and link the Phase 1 DC transmission line to a second DC-AC converter terminal located closer to load centers in southern New England. The proposed site for the Phase 2 converter terminal spans the town line between Groton and Ayer, Massachusetts. In order to move power away from the proposed converter terminal and bolster the reliability of the existing AC transmission system, the Companies also propose to construct two new 345 kV AC transmission lines to reinforce New England's bulk power transmission system. These two new lines would be located on existing rights-of-way between Ayer and Millbury, Massachusetts, and between Millbury and Medway, Massachusetts. See Figure 1.

Two of the NEES wholesale power companies would build the proposed Phase 2 facilities.[4] New England Hydro would construct, own and operate

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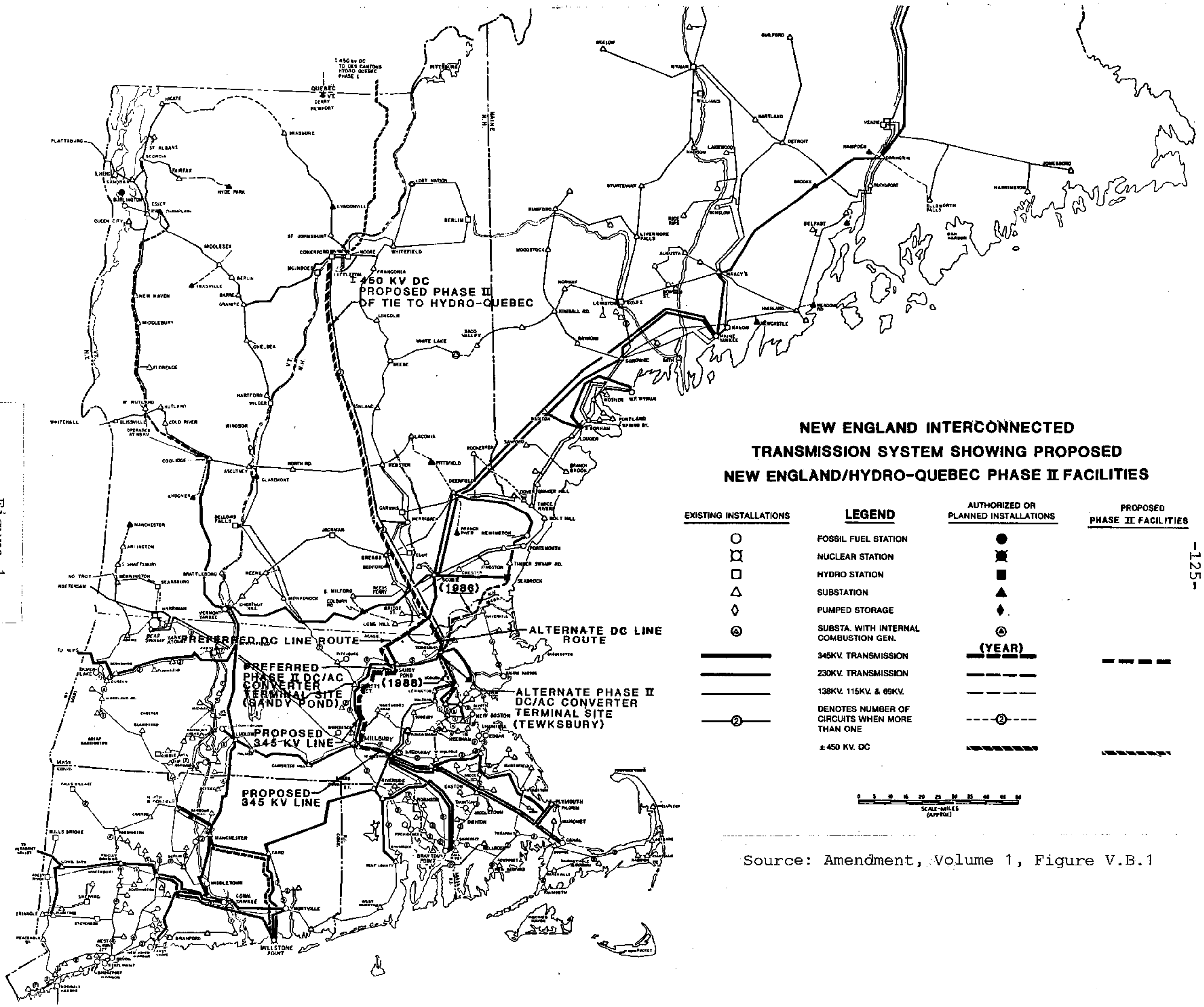
(Footnote Continued)
Holyoke Power and Electric Company, Holyoke Water Power Company, Massachusetts Municipal Wholesale Electric Company, Montaup Electric Company, New England Power Company, Newport Electric Company, Public Service Company of New Hampshire, Taunton Municipal Light Plant, United Illuminating Company, Vermont Electric Power Company, and Western Massachusetts Electric Company. EFSC Ex. 1 at 12-15.

[4] Although the Phase 2 facilities were initially conceived and planned by committees of NEPOOL, NEES volunteered to assume the lead role in designing, licensing and building the facilities for several reasons. Initial planning studies indicated that the preferred route for Phase 2 AC transmission facilities was on rights-of-way owned by New England Power; the Phase 1 converter station and part of the Phase 1 DC transmission lines were being designed, licensed and constructed by NEES companies; and NEES was in a better financial position than other members of NEPOOL. NEPOOL participants signed a preliminary agreement
(Footnote Continued)

Figure 1
-3-



NEW ENGLAND INTERCONNECTED TRANSMISSION SYSTEM SHOWING PROPOSED NEW ENGLAND/HYDRO-QUEBEC PHASE II FACILITIES

Source: Amendment, Volume 1, Figure V.B.1

the DC transmission line and converter terminal in Massachusetts. New England Power would construct, own and operate the two new AC reinforcement lines and would relocate and reconstruct various existing 115 kV and 69 kV transmission lines on the same rights-of-way. Tr. 2 at 31-32.

The Companies have petitioned the Siting Council to approve the construction of the proposed new transmission facilities and the relocation and reconstruction of certain existing transmission lines. Additionally, the Companies have asked the Siting Council to determine that the proposed facilities are needed to bring Canadian hydroelectric power into Massachusetts with a minimum impact on the environment at the lowest possible cost. Tr. 2 at 16-17.

The Companies have asserted that New England utilities will need relatively cheap energy and additional power supplies to meet customer demand in the 1990's. In power year[5] 1990/91, the Companies project that without Hydro Quebec Phase 2, New England utilities[6] will generate approximately 24 percent of their electricity from oil and that by 1999/2000, this oil dependency would increase 38 percent. EFSC Ex. 117. Additionally, the Companies estimate that New England will need additional capacity starting in the mid-1990's. EFSC Ex. 33 at 3; EFSC Ex. 10 at 3.

With Phase 2 as a power resource for New England, the Companies estimate that Hydro Quebec would provide 10 percent of New England's energy needs in the early 1990s. Amendment, Vol. 1 at 3; Tr. 2 at 157. Oil usage would be cut by a quarter in 1990/91, so that New England would depend upon oil for only 18 percent of its generation in 1990/91 and 33 percent in 1999/2000. EFSC Ex. 117. Since the Companies estimate that Phase 2 "firm energy" would have a capacity value of 900 MW, they project that New England could postpone its need for new capacity for an additional two or three years. Amendment, Vol. 1 at 4; EFSC Ex. 10 at 3; and EFSC Ex. 33 at 3.

The Companies expect substantial economic benefits from the Project. As currently proposed, firm energy purchases from Hydro Quebec would be priced at a percentage of New England's average fossil fuel generation costs in the previous year, and would largely displace oil.

(Footnote Continued)
giving NEES companies the lead responsibility for obtaining regulatory approvals for the Phase 2 facilities. EFSC Ex. 1; Tr. 2 at 27-31.

[5]A power year is defined by the Companies as a 12-month period beginning on December 1 of one calendar year and ending on November 30 of the following calendar year. Tr. 2 at 11.

[6]In this discussion, "New England utilities" is used to mean "NEPOOL member utilities," even though a few New England utilities do not belong to NEPOOL. NEPOOL utilities own approximately 99.5 percent of New England generating capacity. EFSC Ex. 10 at 1.

The Companies project these estimated "savings" -- the difference between the fuel costs that New England participants can avoid paying and the costs they expect to pay to Hydro Quebec for the firm energy purchases -- will increase from $155 million in the first year of the Project to approximately $507 million in the final year. Amendment Update, Vol. 1 at 76. Cumulative savings would total $1,749 million, in 1990 dollars.[7] Amendment Update, Vol. 1 at 78.

In contrast, the Companies estimate that the annual carrying charges to cover Phase 2's $585-million construction costs would start at $191 million in 1990/1991, and drop to $128 million in 1999/2000. Amendment Update, Vol. 1 at 76. The Companies estimate the net result to be $897 million in cumulative present worth project carrying charges. (Amendment Update, Vol. 1 at 78.) These cost projections include the costs of mitigating any adverse environmental impacts associated with designing and constructing the facilities at the preferred site and routes.

Overall, then, the Companies estimate a cumulative savings for New England consumers of $852 million (in 1990 dollars) over the 10-year period of the Phase 2 project.

B. Procedural History

The Companies filed the Amendment to the Supplement on November 30, 1984. The Companies provided public notice of this proceeding through publication and posting of a Notice, which also provided notice of proceedings at the Department of Public Utilities ("DPU") and of the Environmental Impact Review of the MEPA Unit of the Executive Office of Environmental Affairs.[8]

The Siting Council, the DPU, and the MEPA Unit conducted three local hearings to receive public comment concerning the proposed

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[7]The Companies have estimated the "cumulative present worth" of project savings and facility revenue requirements. These calculations represent a projection of the present worth of the total cumulative savings and costs (1990 dollars) over the ten-year life of the Phase 2 Project. Savings include net fuel cost savings, capacity credits, and energy loss savings. Costs include capital costs, and operation and maintenance costs.

[8]See Mass. Gen. Laws Ann. Ch. 164 Sec. 69Q. In DPU Docket Nos. 84-246 and 84-247, New England Hydro and New England Power seek a determination that the proposed electric transmission lines are necessary and would serve the public convenience and be consistent with the public interest, and seek an exemption of the transmission lines from certain zoning bylaws of various towns. In DPU Docket No. 84-248 these two companies seek an exemption for the proposed converter terminal from the zoning bylaws of the Towns of Groton and Ayer. The MEPA docket number is EOEA No. 5446.

Phase 2 Hydro Quebec project and facilities. The agencies jointly conducted the hearings in Groton on February 5, 1985, in West Boylston on February 7, 1985, and in Milford, Massachusetts on February 12, 1985. See Siting Council Rule 62.7.

The Siting Council received three petitions to intervene.[9] Ultimately, the New England Fuel Institute, the Conservation Law Foundation, and Robert and Carol Driscoll, abutters to the proposed transmission facilities in Dunstable, were granted intervenor status.[10] Subsequently, however, in May 1985, each of these parties withdrew from the proceeding.

Prior to their withdrawals, each of the parties, as well as the Siting Council Staff, had submitted numerous document and information requests. In return, the Companies supplied responses.

The Companies filed their direct testimony on May 28, 1985, consisting of prepared written testimony of ten witnesses covering the various issues in this proceeding.[11] The Siting Council and DPU conducted joint hearings on nine days in June and early July 1985. These hearings consisted almost entirely of the Siting Council Staff's cross-examination of the Companies' witnesses.

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[9] The Attorney General of the Commonwealth of Massachusetts was an intervenor in Docket No. 84-24 involving Supplement 2C. New England Hydro was not a petitioner in Docket No. 84-24. The Hearing Officer notified the Attorney General that a separate intervention petition would be required for the proceeding in Docket No. 84-24A. The Attorney General, however, did not file an intervention petition.

[10] The New England Fuel Institute's ("NEFI") participation was limited to non-environmental interests and was based on the asserted competitiveness of NEFI's members in the residential heating market with the electric utilities participating in the proposed Phase 2 project. "NEFI" and Robert and Carol Driscoll filed intervention petitions prior to the February 25, 1985 deadline for such petitions. At the Prehearing Conference on March 4, 1985, the Conservation Law Foundation ("CLF") orally requested leave to intervene. At the Prehearing Conference, the Hearing Officer requested all three parties to supplement their intervention petitions. Each party complied with the request. The Companies filed responses to the intervention petitions of the Driscolls and NEFI, but did not oppose CLF's intervention.

[11] R. O. Bigelow (project need, benefits, and costs); R. H. Snow (power engineering); L. P. Sicuranza (environmental impact/mitigation); F. S. Smith (description, cost and zoning for transmission facilities); D. L. Holt (description, cost and zoning for converter terminal facilities); R. Van Bossuyt (right-of-way maintenance); G. B. Johnson (AC and DC electrical phenomena); E. L. Carstensen (AC biological effects); J. M. Charry (DC biological effects); and R. S. Banks (DC public health studies).

Following the hearings, the Siting Council Staff issued additional information requests.[12] The majority of the Companies' responses were admitted into evidence with the Companies' consent.

The Companies filed their Post-Hearing Brief on October 18, 1985.[13]

The record in this proceeding consists of 96 exhibits of the Companies, and 209 Siting Council exhibits. The Siting Council also has taken official notice of certain documents with notice of this action provided to the Companies. Siting Council Rule 14.5.

C. General Scope of Siting Council Review

The Siting Council's mandate is to ensure a necessary energy supply for the Commonwealth with minimum impact on the environment at the lowest possible cost. Mass. Gen. Laws Ann., Ch. 164, Sec. 69H.

The Siting Council's jurisdiction over energy facilities is based upon the size and nature of the proposed facilities, and the nature of the company proposing the facilities. The proposed facilities fall within Siting Council jurisdiction due to their location within Massachusetts, the petitioners' status as Massachusetts "electric companies," and the nature and size of the facilities (transmission facilities greater than 69 kV in voltage and one mile or more in length), and ancillary structures. Mass. Gen. Laws Ann., Ch. 164, Sec. 69G. The Siting Council must approve the proposed site and facilities before a construction permit may be issued by another state agency. Mass. Gen. Laws Ann. Ch. 164, Sec. 69I.

As stated above, the Siting Council's broad statutory mandate is to implement energy policies to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

The statute also establishes the requirements for the contents of a Long-Range Forecast or Supplement, Mass. Gen. Laws Ann. Ch. 164, Sec. 69I.[14] The statute also specifies that the Council shall approve a

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[12] The Siting Council Staff also met in a technical session with the Companies' representatives concerning the Companies' production cost models.

[13] On October 31, 1985, the Companies also filed a Memorandum of Law on certain legal questions posed in the Hearing Officer's Procedural Orders dated October 4, and 7, 1985.

[14] A Forecast or Supplement must contain a description of planned actions including but not limited to, *inter alia*, the construction of additional facilities, other sources of electrical power, and no additional electrical power. Mass. Gen. Laws Ann. Ch. 164, Sec. 69I(3).
(Footnote Continued)

Long-Range Forecast or Supplement, Mass. Gen. Laws Ann. Ch. 164, Sec. 69J:

> if [the Council] determines that [the Forecast or Supplement] meets the following requirements: all information relating to current activities, environmental impact, facilities agreements and energy policies as adopted by the commonwealth is substantially accurate and complete; projections of the demand for electric power, ... and of the capacities for existing and proposed facilities are based on substantially accurate historical information and reasonable statistical projection methods, ... projections relating to service area, facility use and pooling or sharing arrangements are consistent with such forecasts of other companies subject to this chapter as may have already been approved and reasonable projections of activities of other companies in the New England area; plans for expansion and construction of the applicant's new facilities are consistent with current health, environmental protection, and resource use and development policies as adopted by the commonwealth; and are consistent with the policies stated in [Ch. 164] section sixty-nine H to provide a <u>necessary</u> power supply for the commonwealth with a minimum impact on the environment at the lowest possible cost;

In this proceeding, the applicants filed an Amendment to a Supplement to a Long-Range Forecast. Therefore, the applicants must meet the above standards.

The Siting Council clearly possesses wide latitude to consider the many factors listed in the Statute. In this proceeding the Council has focused on

* Whether the Project is needed to meet electric generating capacity and energy needs of New England, of Massachusetts, and of the customers of Massachusetts electric companies.

* Whether the capacities of the proposed facilities are based on substantially accurate historical information, and reasonable statistical projection methods.

* Whether the Project and proposed facilities are superior in terms of cost and environmental impact to alternatives for meeting any identified need for energy or capacity.

As directed by the statute, the Siting Council has considered projections of demand for electric power, the Forecasts and Supplements of Massachusetts electric companies filed at the Council, and projections of other companies (i.e., NEPOOL) in the New England area in

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(Footnote Continued)
The Siting Council evaluates conservation and load management as a source of energy, <u>In Re COM/Electric</u>, 12 DOMSC 39, 50 (1985).

the course of its current review. The Siting Council also has been mindful of its duty to insure that construction plans are consistent with health, environmental protection, and resource use and development policies of the Commonwealth.

In this Decision, the Siting Council first reviews the Phase 2 Project as a whole (i.e., needs, benefits, and costs), and then examines the proposed facilities (need, benefit, costs).

II. ANALYSIS OF THE PROPOSED HYDRO QUEBEC PHASE 2 PROJECT

A. Is the Proposed Project Needed?

1. New England's Need for Low-Cost Energy

The Companies base their case for the Phase 2 project largely on New England's need for low-cost energy as a way to "help keep down energy costs of consumers and ... reduce our region's dependence on oil." Amendment, Vol. 1 at 1.

The Companies believe that oil will be New England utilities' highest-cost fuel by a wide margin throughout the 1990s. Ex. ROB at 7; Amendment Update, Vol. 1 at 16-17. The Companies' most recent fuel price forecasts, prepared for NEPOOL by Data Resources, Incorporated ("DRI"), and dated January 1985[15] show oil prices increasing at approximately 0.5 percent a year from 1984 through 1990 and 6.4 percent annually through the 1990s.[16] DRI projects coal prices will rise much faster, (7.1 percent a year until 1990, and then 7.5 percent a year through the 1990s), but it expects coal prices will remain substantially below oil prices from now through the 1990s. The Companies estimate that without the Phase 2 Project, New England's utilities will generate approximately 24 percent of their electric energy from oil in 1990/91; by 1999/2000, this oil dependency would increase to 38 percent.[17] EFSC

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[15]The previous DRI fuel price forecast for New England, dated November 1983, predicted much higher growth in oil prices over the next 15 years. Amendment, Vol. 1 at 16-17.

[16]These statistics refer to the estimated growth rates for #6 oil (medium sulphur -- 1 percent). This 1/1985 forecast shows the 1984 oil price to be $4.80/MBtu, rising to $4.93 in 1990, and $12.98 in the year 2000. Amendment Update, Vol. 1 at 16-17. In contrast, the 11/1983 forecast had estimated the 1984 price to be $4.39/MBtu, the 1990 price to be $6.75, and the 2000 price to be $17.34. These estimates represented a 7.4 percent annual growth rate from 1984-1990, and a 9.9 percent average annual increase in the 1990s. Amendment, Vol. 1 at 16-17.

[17]These estimates reflect the demand and generation assumptions of the Amendment Update. The energy forecast information comes from the (Footnote Continued)

Ex. 117. In contrast, while coal would also provide about 22 percent of electric power generation in 1990/91, it would account for just 20 percent by 1999/2000. EFSC Ex. 117.

Part of the reason for these fuel-reliance projections is that while the Companies expect additional coal units to be built or converted from oil through the 1980s and 1990s, they also expect that rising energy demand and improving load factors, will combine to require the running of baseload and peaking facilities -- including oil plants -- during longer numbers of hours each year. The Companies project that energy demand will grow at an average of 2.5 percent a year through the 1990s and load factors will increase from 64.3 in 1989 to 67.2 in 1999. EFSC Ex. 87 at 1-2.

Given the expected growth in energy demand, the projected high oil-coal price differentials, and NEPOOL's expectations that oil will be the marginal fuel in New England for at least the next fifteen years, the Companies seek to lessen oil usage in order to reduce consumers' electricity bills and vulnerability to possible, unexpected high oil price increases in the future.

The Companies see Hydro Quebec Phase 2 as a principal means to back out oil usage. Since NEPOOL can pre-schedule Phase 2 deliveries,[18] and because the price of Hydro Quebec power will be tied to a fraction of New England's avoided fossil-fuel prices,[19] the Companies expect that NEPOOL could dispatch the 7 billion kWh per year in such a way as to displace oil at least 97.5 percent of the time during the 1990s.[20] Oil usage would drop from 24 percent to 18 percent in 1990/91, and from 38 percent to 33 percent in 1999/2000. EFSC Ex. 117. The Companies estimate that the resultant fuel cost savings will range from $150 million in 1990/91 to $379 million in 1999/2000. EFSC Ex. 47.

In numerous decisions, the Siting Council has encouraged electric utilities to reduce oil usage and to diversify fuel mixes. e.g., In Re Eastern Utilities Associates, 8 DOMSC 192, 236 (1982); In Re Boston Edison Company, 10 DOMSC 203, 247 (1984). Such decisions have recognized oil's position in recent history as the highest-cost fuel for electrical generation and as a fuel susceptible to sudden or unexpected

(Footnote Continued)
1984 NEPOOL Forecast of New England Electric Energy and Peak Load (EFSC Ex. 87), and supply information comes from the 1985 NEPOOL Forecast Report of Capacity, Energy, Loads and Transmission (EFSC Ex. 10).

[18] See Section II.B.1.a(2)(a).

[19] See Section II.B.1.a(2)(a).

[20] This is an average annual figure for the Project's 10-year time frame. The Companies project that coal will be displaced approximately 6.3 percent of the time in 1990/91, with this displacement dropping to less than 1 percent of the time by the late 1990s. EFSC Ex. 42.

price shocks. The Siting Council has justified its oil back-out policies as a way to minimize Massachusetts' utilities' long-run fuel costs, and to reduce consumers' risk of exposure to oil price shocks, if shocks should occur in the future.

Noting the high proportion of regional electric energy expected to be generated from oil in the 1990s, and accepting a fuel price projection that indicates oil prices will exceed coal prices through the next decade, the Siting Council determines that diversification of system fuel mixes and reduced oil usage would be desirable goals for NEPOOL member utilities at the present time.

The Siting Council notes that reduced fuel costs for NEPOOL as a whole benefit Massachusetts consumers directly, due to New England utilities' agreements for pooling their generating resources, for dispatching them in a least cost manner for the pool as a whole, and then for distributing total fuel cost savings to members according to their relative contribution to pool economies. EFSC Ex. 59, Sections 12 and 14.

The Siting Council also notes that the formula proposed for distributing the fuel cost savings associated with Phase 2 purchases, allocates savings to participants according to their 1980 retail sales.[21] This would mean that Massachusetts utilities which participate in Phase 2 would benefit directly from any resultant oil-back out economies.

2. New England's Need for Additional Capacity

In addition, the Companies have proposed the Hydro Quebec Phase 2 Project as a way to meet New England's future capacity needs. In the Companies' view, the provisions of the Phase 2 contract and the characteristics of the 2000 MW interconnection represent at least 900 MW of capacity for New England.[22]

The Companies estimate that in the absence of the Phase 2 Project, New England will need to add new capacity to its electric generating system by 1993/94. Amendment Update, Vol. 1 at 10. This estimate assumes an average annual 2.0 percent increase in peakload demand over the next fifteen years, a constant 20 percent installed required reserve level, and various changes in the NEPOOL supply mix during the next decade.

The Companies presented two NEPOOL studies to indicate the timing and magnitude of New England's need for additional capacity in the

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[21]See Section II.B.1.a(1).

[22]This assumes a total reliability benefit of 1500 MW for the 2000-MW intertie and that 600 MW of this benefit already has been attributed to Phase 1. See discussion in Section II.B.1.b(4).

future. The 1984 NEPOOL Forecast of New England Electric Energy and Peak Load is the basis for the Companies' forecast of peakload demand through the 1990s ("Energy and Load Forecast," or "Forecast"). EFSC Ex. 87. For capacity planning purposes, the Companies used the assumptions in NEPOOL's Forecast Report of Capacity, Energy, Loads and Transmission, 1985-2000 ("CELT Report"). EFSC Ex. 10.

The 1984 NEPOOL Forecast, which projects New England will remain a winter peaking system, estimates that winter peakload demand will grow 2.0 percent a year from 1984 through 1999, with summer peakload rising 2.1 percent annually. EFSC Ex. 87 at 1.

The Companies used this Forecast in both the original Amendment (dated November 1984) and the Amendment Update (dated April 12, 1985), to provide the demand forecast figures required to project region-wide capacity shortfalls in the absence of Hydro Quebec Phase 2. At the time the original Amendment was filed at the Siting Council, only the 1984 NEPOOL Forecast was available. By the time the Amendment Update was filed, NEPOOL had just published its 1985 Forecast. EFSC Ex. 22 (dated April 1985).

The 1985 NEPOOL Energy and Load Forecast projects that winter peakloads will increase at 1.7 percent a year and summer peakloads by 2.1 percent, with NEPOOL becoming a summer peaking system by the summer of 1988. EFSC Ex. 22 at 1; EFSC Ex. 10 at 4. As the basis for these long-run projections, the 1985 Forecast used many of the same assumptions, data and methods that were used in the 1984 Forecast, although there are some important differences.[23] The net effect of the

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[23] In particular, the 1985 Forecast uses actual 1984 peakload and energy data as the base year for projections; 1984 data were higher than had been projected in the 1984 Forecast.

Also, in its forecast of economic activity in the New England region, the 1984 Forecast relies upon macroeconomic data provided by DRI for use as inputs to NEPOOL's own model of the regional economy. The 1985 Forecast uses DRI data for both national and regional economic variables. Also, the 1984 Forecast assumes a 2.0-percent annual increase in personal income in the region; the 1985 Forecast assumes 2.5-percent annual growth.

The two Forecasts use different inputs to their electricity price forecasts, which is one factor which drives consumers' demand for electricity in the NEPOOL forecasting model. In the 1984 Forecast, the electricity price forecast is based upon a number of generation mix assumptions, such as no customer generation as part of the NEPOOL system; availability of Millstone 3, Seabrook 1 and Seabrook 2; energy from Hydro Quebec Phases 1 and 2 purchased at 80 percent of the region's average fossil fuel price in the previous year, from 1986 through 2000; and no capacity value from Hydro Quebec Phase 2. In contrast, the 1985 Forecast assumes a considerable amount of customer generation in the 1990s; Seabrook 2 cancellation; Hydro Quebec energy purchased at 80
(Footnote Continued)

differences is that even though the 1985 Forecast has a lower winter-peak growth rate, it projects winter peakload levels for the 1990s that differ no more than two percent from those estimated in the 1984 Forecast. For summer peak levels, the two Forecasts produced results for any year that differ no more than five percent, with the variations decreasing to one to two percent in the late 1990s.

The Companies decided not to incorporate the new 1985 Forecast results into revised calculations of project need, savings and costs, since the Companies believed that such recalculations were too time-consuming and unnecessary, given the similarity of the results of the 1984 and 1985 Forecasts.[24]

According to the Companies' analysis, then, New England utilities will need to add new capacity to the region's generation mix by 1993/94, in order to meet projected reliability requirements. EFSC Ex. 10 at 3; EFSC Ex. 32; EFSC Ex. 87.[25]

Table 1 indicates how much additional capacity NEPOOL would need each year, starting in 1994, using the Companies' 1984 demand Forecast and 1985 supply mix assumptions. To meet summer load requirements, New England would need to obtain approximately 308 MW in 1994, an additional 864 MW in 1995, an additional 950 MW in 1996, and so forth. (Table 1, line a.)

(Footnote Continued)
percent of average fossil fuel price from 1987-1995, and 95 percent through the year 2000; a lower fuel price forecast; and 1500 MW of capacity credit from the Hydro Quebec projects. These differences result in electricity prices in the 1985 Forecast that are slightly higher than were forecast in the 1984 Forecast. EFSC Exs. 10, 22, 33, 60 and 87.

[24]While the Siting Council agrees that the difference in results of the two Forecasts is relatively small, the Siting Council will review how the different Forecasts of energy requirements would affect estimates of Project need, savings and costs. See discussion in this section and in Section II.B.3.a.

[25]This capacity planning target date does not include capacity from Hydro Quebec Phase 2 and assumes that: NEPOOL will require a 20-percent reserve requirement throughout the 1990s; Millstone 3 and Seabrook 1 are on-line in the late 1980s; Seabrook 2 is cancelled; several New England utilities will receive power from the New York Power Authority or from the Highgate tie to Hydro Quebec; New England utilities will receive approximately 1100 MW of capacity benefits from customer generation by the early 1990s; there will be limited life extensions of generating units now slated for retirement; and Sears Island and Point Lepreau #2 will not be available to provide power to New England in the 1990s. EFSC Ex. 10 at 1, 3, 28, 29.

Table 1

New England Forecast of Electric Power Needs and Requirements
(Summer Peak - MW)

	Summer 1990	Summer 1991	Summer 1992	Summer 1993	Summer 1994	Summer 1995	Summer 1996	Summer 1997
NEPOOL Capacity:* Existing generation	20679	20743	20743	20744	20744	20744	20744	20723
units retrmnts (-)	190	190	374	499	601	819	975	1027
deactvtd units (-)	346	346	346	324	324	324	324	324
net purch & sales	560	602	311	303	295	295	95	95
Millstone 1	1150	1150	1150	1150	1150	1150	1150	1150
Seabrook 1	1150	1150	1150	1150	1150	1150	1150	1150
customer generation	1049	1078	1105	1135	1158	1182	1208	1238
TOTAL Capacity	24052	24187	23739	23659	23572	23378	23048	23005
NEPOOL Peakload Forecast (1984 Forecast)	17986	18446	18962	19377	19900	20458	20975	21292
Excess/Deficient Capacity:								
(a) with 1984 Forecast, 20% reserve	2469	2052	985	407	-308	-1172	-2122	-2545
(b) with 1984 Forecast, 20% reserve, and 600 MW off reserve (Phase 1)	3069	2652	1585	1007	292	-572	-1522	-1945
(c) with 1984 Forecast, 20% reserve, 600 MW off reserve, no Seabrook 1	1919	1502	435	-143	-858	-1722	-2672	-3095
(d) with 1984 Forecast, 24% reserve, 600 MW off reserve	2529	1914	826	231	-504	-1390	-2361	-2797
(e) with 1984 Forecast, 23% reserve, 600 MW off reserve, no Seabrook 1	1379	948	-134	-717	-1455	-2335	-3301	-3734
NEPOOL Peakload Forecast (1985 Forecast)	18700	19214	19678	19926	20417	20829	21171	21519
Excess/Deficient Capacity:								
(f) with 1985 Forecast, 20% reserve	1612	1130	125	-252	-928	-1617	-2357	-2818
(g) with 1985 Forecast, 20% reserve, 600 MW off reserve	2212	1730	725	348	-328	-1017	-1757	-2218
(h) with 1985 Forecast, 20% reserve, 600 MW off reserve, no Seabrook 1	1062	580	-425	-802	-1478	-2167	-2907	-3368
(i) with 1985 Forecast, 24% reserve, 600 MW off reserve	1651	962	-62	-449	-1145	-1850	-2604	-3079
(j) with 1985 Forecast, 23% reserve, 600 MW off reserve, no Seabrook 1	501	4	-1075	-1400	-2091	-2792	-3542	-4013

* Sources: EFSC Exhibits 10, 22, and 87.

The timing and magnitude of necessary capacity additions in the future are extremely sensitive to changes in several important assumptions that the Companies have relied upon in their outlook for New England. For example, there are two adjustments that the Companies agreed were reasonable: (1) the addition of Phase 1's 690-MW interconnection between New England and Canada, a benefit that means that NEPOOL could reduce its region-wide reserve requirements by approximately 600 MW starting in the summer of 1986 when the interconnection is expected to go into service;[26] and (2) an increase to 24 percent in the level of installed reserve capacity that NEPOOL could require in the 1990s, if the Millstone 3 and Seabrook 1 nuclear reactors go into service and if the full 2000 MW intertie to Canada becomes operational in 1990. Tr. 3 at 49-50, 61-64.

As indicated in Table 1, lines b and d, these adjustments on the timing and magnitude of needed additional capacity nullify each other. The 600-MW reduction in reserve requirements would postpone by one year the timing of needed capacity; the combining of that 600-MW adjustment with a 24-percent reserve requirement brings back to 1994 the year of projected capacity shortfalls.

Several other uncertainties also could affect the timing of New England's need for additional capacity. Different assumptions about demand growth rates, or the availability of capacity from various power sources -- such as none from Seabrook 1, more or less from the development of load management, small power producers or cogenerators, or more from aggressive unit life-extension projects -- could alter the date when capacity shortfalls are predicted to occur. Removing Seabrook 1 from the supply mix, for example, would mean that New England would need to add capacity one or two years sooner than expected, holding constant the other assumptions except reserve requirements[27] (Table 1, lines c and d). Using the 1985 Energy and Load Forecast figures, capacity shortfalls could arise a year earlier than predicted using the 1984 Forecast figures (Table 1, lines f through j). The effects of other types of uncertainties are more difficult to predict.

Together, these adjustments place the timing of need for additional capacity between 1991 and 1994. The Siting Council finds that New England will need new capacity in the early 1990s, with the actual timing and magnitude depending upon different scenarios. Still, almost every combination of reasonable contingencies -- such as the 600-MW reduction in reserve requirements, and the increased levels of installed reserve requirements -- would indicate that New England needs at least 1000 MW of additional capacity -- either through demand management, or conventional or non-conventional sources of supply -- no later than 1995.

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[26] See discussion in Section II.B.1.b(4).

[27] If Seabrook 1 is cancelled it would be reasonable to reduce the NEPOOL reserve requirements by 1 percent.

While the Siting Council finds here that New England will need additional capacity in the early 1990s, and accepts for analytic purposes the Companies' capacity-planning date of 1993/94, the Siting Council will review in a later section whether the Hydro Quebec Phase 2 project as proposed offers a way to meet the need for capacity and cheap energy at minimum environmental impact and lowest possible cost. See Section II.B.2.

3. Massachusetts' Need for Low-Cost Energy and Capacity

Although the Companies have proposed the Hydro Quebec Phase 2 project and associated facilities on behalf of New England utilities as a group, the Siting Council must also review whether the proposed project and facilities are needed by the consumers indirectly under the Siting Council's jurisdiction -- that is, by the customers of Massachusetts electric companies.

To review this question, the Siting Council will rely on the long-range forecasts and supplements of electric power needs and requirements filed with the Siting Council by the individual electric companies in the Commonwealth.[28] The information in these documents provides a general overview as to the timing and magnitude of the Commonwealth's needs for capacity and economical oil back out.

The Siting Council's reliance on the individual company forecasts and supplements does not constitute a formal determination as to the adequacy of these individual company forecasts. In fact, the Siting Council has finished its formal review of only two of these filings.[29] Instead, the individual Massachusetts utility forecasts are used in this proceeding for analytic purposes -- in order to explore whether an evaluation of Massachusetts companies' outlooks for long-run demand and supply in the state would change the results of the findings made previously, i.e. that the region needs capacity and relatively inexpensive energy within the next decade. The forecasts and supplements of individual companies are used to establish estimates of the approximate time frame when individual Massachusetts companies need

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[28] The Hearing Officer took official notice of these filings. These forecasts include the most recent filing (date in parentheses) of each of the following companies: Boston Edison Co. (1985); COM/Electric System (1984); Eastern Utilities Associates (1985); Fitchburg Gas and Electric Light Company (1984); Massachusetts Municipal Wholesale Electric Company (1985); New England Electric System (1985); Northeast Utilities (1985); and Taunton Municipal Light Plant (1985).

[29] In Re COM/Electric, 12 DOMSC 39 (1985); In Re Fitchburg Gas and Electric Light Co., 13 DOMSC __ (Docket No. 84-11B, October 31, 1985).

capacity, and when Massachusetts as a whole needs additional power supplies.[30]

Table 2 depicts each Massachusetts company's outlook for its own company's future power supply and for the state's overall situation.[31] All Massachusetts utilities expect growth in energy and peakload demand through the late 1980s and early 1990s.[32] As shown in Table 2, these average annual peakload growth rates range from 0.9 to 2.9 percent for individual companies, and average at 2.3 percent for the state as a whole. Growth in energy demand is expected to range from 1.0 to 2.9 percent for Massachusetts companies, with a statewide average of 2.2 percent.

All Massachusetts utilities expect oil to be the marginal fuel in 1990, although some companies expect to rely upon oil for a larger percentage of their generation than other companies. The most oil-dependent companies include Taunton Municipal Light Plant ("Taunton"), Fitchburg Gas and Electric Light Company ("Fitchburg"), Boston Edison Company, and COM/Electric, all of which expect to burn oil for well over half of their generation. EFSC Ex. 119. Using these utility forecasts to look at the Commonwealth as a whole, Massachusetts could rely on oil for 32 percent of its electric generation in 1990, as compared to 24 percent for New England.[33] EFSC Ex. 119; EFSC Ex. 117.

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[30] Because the forecasts and supplements vary so much in terms of methodology, data and assumptions, and because the assumptions also vary in some instances with those in the NEPOOL Forecast and CELT report (EFSC Exhibits 87 and 10), the Siting Council has made some post-hoc adjustments to the capacity supply figures of several companies, in order to increase the consistency of some key assumptions. In particular, these adjustments include: making the in-service date of Seabrook 1 consistent across company forecasts (i.e., Fall 1987); removing Hydro Quebec Phase 2 capacity from company supply data; imposing similar installed reserve requirements for all companies; and including Hydro Quebec Phase 1 reliability benefits as a reduction in NEPOOL reserve requirements.

[31] Note that the numbers in Tables 2 and 3 include demand and supply figures for holding companies that own subsidiary companies providing retail service in Massachusetts: NEES, NU, and EUA. Therefore, the numbers for Massachusetts as a whole take into account the out-of-state electricity demand and generating resources of these three companies.

[32] 1994 is the final year for which all companies have furnished forecast data, except for COM/Electric, Fitchburg, and Taunton, for which 1993 is the last year for which each Company has provided estimates.

[33] The Massachusetts figure was calculated by summing the estimates of oil-generated MWh for each Massachusetts company, in order to provide weighted percentage of oil-fired generation for the state as a whole.

Table 2

Summary of Massachusetts Electric Utilities' Forecasts

Company	Long-Run Annual Energy Growth Rate (1984-1993)	Long-Run Annual Summer Peakload Growth Rate (1984-1994)	Estimated Percentage of KWH Generation From Oil (1990)	Year of Expected Long-Run Capacity Shortfall
Boston Edison	2.9%	2.5%	75%	1985
COM/Electric	2.3%	2.4%	57%	1991
EUA	2.1%	2.3%	35%	1991
Fitchburg	2.4%	2.0%	81%	1987
MMWEC	2.7%	2.9%	15%	1991
NEES	1.0%	0.9%	18%	beyond 1994
Taunton	2.6%	2.8%	89%	1993
NU	2.6%	2.1%	15%	beyond 1994
Statewide*	2.2%	2.3%	32%	1993

* Weighted average for the state, based on sums of energy and peakload forecasts produced by the individual companies.

Sources: EFSC Ex. 19; Long-Range Forecasts or Supplements of each individual company. See also Table 3, *infra*.

Apparently, then, Massachusetts utilities could benefit from economical oil-back out measures to an even greater extent than could New England as a whole.

Turning to Table 3, which includes annual summer peakload demand and capacity resource data from each of the Massachusetts utilities' long-run forecasts, Massachusetts companies appear to need additional capacity at different times over the next decade. A few companies, such as Boston Edison and Fitchburg, project substantial capacity deficiencies starting in the next few years. Other companies, including COM/Electric, Eastern Utilities Associates, and Massachusetts Municipal Wholesale Electric Company, expect to need additional supplies starting around 1990 or 1991. Northeast Utilities estimates its system will experience capacity shortfalls in 1993. A few Massachusetts companies, including Taunton and the members of NEES system, forecast they will have ample supplies of capacity through the mid-1990s.

Taken as whole, however, the projections of the Massachusetts companies indicate the state will need additional capacity starting in around 1991/92, two years earlier than NEPOOL predicts that New England will need to add capacity.[34] If demand were to increase faster than expected, or if, say, Seabrook 1 were not completed, Massachusetts companies could need more power that year or one or two years earlier.

Even assuming a reasonable margin of error, these estimates indicate timing and magnitude of capacity shortfalls in the state that fall well within the time frame and reliability-benefit levels relevant for Hydro Quebec Phase 2.

The Siting Council determines that Massachusetts companies need additional power supply resources and sources of relatively inexpensive energy in the 1990s. In a later section, the Siting Council reviews whether the Phase 2 project as proposed provides net energy and capacity benefits to the Commonwealth. (See discussion in Section II.B.3.a.)

B. Does the Proposed Project Provide Energy at Minimum Environmental Impact and Lowest Possible Cost?

1. Project Characteristics, Benefits and Costs

The Companies have proposed the Hydro Quebec Phase 2 project not only to meet the need for inexpensive energy and to avoid 900 MW of generation, but also because they believe that the energy and capacity benefits offered by the Phase 2 Project can be obtained at minimum

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[34] These time frames assume: Hydro Quebec 1 is treated as a 600-MW reduction in NEPOOL reserve requirements; Millstone 3 and Seabrook 1 are on-line; Hydro Quebec 2 is not in the capacity mix; 1990s reserve levels are approximately 24 percent for New England, and 23 percent for Massachusetts companies, taking into account the diversity benefits of non-coincident peaks. See notes to Table 3.

Table 3

Massachusetts Electric Utilities' Forecast of Resources and Requirements: 1984-1994

		1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	Growth Rate	(MW)
BECo	Capacity	2979	2979	2971	3044	3059	3086	3136	3124	2928	2938	2938		M3=0
(85)	Peak	2387	2549	2586	2628	2719	2771	2825	2901	2951	2977	3030	2.41	S1=0
	Reserve	2864	3059	3061	3112	3249	3313	3379	3500	3562	3594	3659		HQ1=68
	Exc/Def	115	-80	-90	-68	-190	-227	-243	-376	-634	-656	-721		
NEES	Capacity	4094	4123	4292	4545	4660	4730	4745	4865	4880	4895	4910		M3=140
(85)	Peak	3379	3406	3462	3485	3506	3526	3544	3581	3618	3655	3693	0.89	S1=115
	Reserve	4055	4087	4083	4111	4171	4196	4218	4299	4344	4390	4436		HQ1=106
	Exc/Def	39	36	209	434	489	534	527	566	536	505	474		
MMWEC	Cap(NonFm	950	854	947	996	1117	989	988	982	982	982	982		
(85)	Cap(Firm)	145	147	149	139	136	97	98	102	106	110	114		
	Cap(Total	1095	1001	1096	1135	1253	1086	1086	1084	1088	1092	1096		M3=71
	Peak	818	864	886	906	916	950	983	1008	1037	1062	1090	2.91	S1=121
	Reserve	837	890	902	936	961	1041	1080	1117	1149	1175	1206		HQ1=21
	Exc/Def	258	111	194	199	292	45	6	-33	-61	-83	-110		
COM/Elec	Capacity	833	860	860	860	950	955	960	966	946	952	921		M3=0
(84)	Peak	676	706	726	746	764	783	801	818	832	844	865	2.50	S1=41
	Reserve	811	847	856	881	910	933	955	984	1001	1016	1042		HQ1=22
	Exc/Def	22	13	4	-21	40	22	5	-18	-55	-64	-121		
NU	Capacity	5821	5734	6526	6547	6496	6496	6504	6505	6369	6268	6184		M3=746
(85)	Peak	4105	4415	4489	4616	4746	4897	5024	5152	5277	5438	5565	2.85	S1=47
	Reserve	4926	5298	5300	5453	5658	5842	5997	6205	6359	6557	6713		HQ1=132
	Exc/Def	895	436	1226	1094	838	654	507	300	10	-289	-529		
EUA	Capacity	829	846	867	868	897	933	938	948	978	1043	1043		M3=46
(85)	Peak	716	710	725	726	746	767	781	805	829	850	877	1.73	S1=33
	Reserve	859	852	855	856	888	914	931	968	998	1024	1057		HQ1=22
	Exc/Def	-30	-6	12	12	9	19	7	-20	-20	20	-14		
Fitchbrg	Capacity	94	94	97	62	62	62	62	62	62	62	62		M3=3
(84)	Peak	73	76	77	78	79	81	82	84	85	87	89	1.97	S1=0
	Reserve	88	91	90	91	93	96	97	100	102	104	106		HQ1=3
	Exc/Def	6	3	7	-29	-31	-34	-35	-38	-40	-42	-44		
Taunton	Capacity	76	78	82	118	133	119	119	119	119	119	119		M3=0
(85)	Peak	64	65	66	68	69	71	72	74	75	77	79	2.08	S1=1
	Reserve	77	78	78	80	82	85	86	89	90	93	95		HQ1=2
	Exc/Def	-1	0	4	38	51	34	33	30	29	26	24		
MASS	Capacity	15821	15715	16791	17179	17510	17467	17550	17673	17370	17369	17273		M3=1006
TOTAL*:	Peak	12218	12791	13017	13253	13545	13846	14112	14423	14704	14990	15288	2.27	S1=358
	Reserve	14517	15202	15226	15521	16013	16419	16743	17262	17604	17952	18314		HQ1=376
	Exc/Def	1304	513	1565	1658	1497	1048	807	411	-234	-583	-1041		

Sources and Assumptions:

* Summer peak forecast from each company's latest filing with the Siting Council;
* Reserve requirements = 20% (1984-85), 21% (1986-87), 22%(1988-90), and 23% (1991+), which are 1% less than NEPOOL system reserve req.;
* Each company's reserve requirement reflects company's share of Hydro Quebec Phase 1 reliability benefit (NEPOOL = 600 MW in 1986);
* Millstone 3 in Summer 1986, Seabrook 1 in Fall 1987, Hydro Quebec Phase 1 in Summer 1986, no Hydro Quebec Phase 2;
* Estimates for 1994 were made for COM/Electric, Fitchburg, and Taunton using each company's 1984-1993 growth rate;
* Massachusetts totals include systemwide statistics for Massachusetts companies that are part of an interstate system (NEES, NU, EUA).

environmental impact and at the lowest possible cost. Companies Brief at 106-108.

The Siting Council has identified a number of quantitative and non-quantifiable benefits and costs associated with the Project. These include: reliability impacts; fuel cost savings; payments to Hydro Quebec; energy loss savings; capacity credits; construction costs; and environmental impacts.

Before reviewing and comparing the Companies' estimates of the scope and magnitude of these various positive and negative impacts, the Siting Council provides an overview of project characteristics through a description of the Phase 2 contracts. Thereafter, the Siting Council evaluates the sensitivity of benefit/cost analyses to changes in key assumptions, such as those relating to demand and supply forecasts, fuel price projections, and distribution of savings and costs to Massachusetts consumers.

a) Project Characteristics: Contractual Background

The characteristics of the Phase 2 Project are specified in detail in two sets of contracts: a Firm Energy Contract between Hydro Quebec and the participating NEPOOL utilities; and a series of agreements among the participating NEPOOL utilities which relate to construction, use and support of the facilities necessary to enable the New England bulk power transmission system to interconnect with and take deliveries from the Hydro Quebec system.

(1) NEPOOL Participants' Use and Support Agreements

The New England utilities that elect to participate in the Phase 2 Project will become signatories to three agreements relating to construction and support of the DC and AC facilities ("Support Agreements") and one agreement that governs the use of both Phase 1 and Phase 2 facilities ("Use Agreements").[35]

The Support Agreements designate responsibility for constructing and paying for the facilities needed for the Phase 2 Project. New England Hydro is responsible for the DC facilities in Massachusetts; New England Power is responsible for the AC facilities; and another affiliated company, New England Hydro-Transmission Corporation, is responsible for the DC facilities in New Hampshire. All NEPOOL utilities that elect to participate in Phase 2 will enter into support

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[35]These agreements have been prepared in final form for signing by the participating utilities. As of the time of hearings, the exact set of ultimate participants had not yet been finalized. However, the Companies expect the participants to execute all of these agreements by the end of 1985. Tr. 2 at 61-63.

agreements with each of these three companies to pay the cost of facility construction, and each participant will have the same percentage support obligation under each agreement. Tr. 2 at 31-33, 62-63; EFSC Ex. 36.

The Use Agreement governs the right of each participant to use the Phase 2 facilities for transactions with Hydro Quebec, either as part of the Phase 2 project or independently if the participant negotiates a contract directly with Hydro Quebec. The Use Agreement also establishes the participants' rights to share in savings which result from NEPOOL's transactions under the Firm Energy Contract or under different arrangements which make use of the Phase 2 facilities.[36] A participant's percentage interest under the Use Agreement is identical to its percentage support obligation under the Support Agreements.

The agreements include provisions for allocating 90 percent of the Project's costs and savings on the basis of each participant's percentage share of kWh sold by all of the participants in 1980, and allocating the remaining 10 percent of costs and savings to the "host states" of Vermont and New Hampshire.[37] The agreements also call for the distribution of fuel cost savings that result from Phase 2 transactions through a separate account in the NEPOOL Savings Fund.[38]

(2) NEPOOL-Hydro Quebec Firm Energy Contract

The Firm Energy Contract ("Contract"), obligates Hydro Quebec to make available and NEPOOL to pay for 7 billion kWh of energy a year for a 10-year period starting on September 1, 1990.[39] It also provides for

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[36]Any New England utility that becomes a Phase 2 participant and signs the Use and Support Agreements will have the right later on to enter into separate, alternative arrangements for energy and/or capacity with Hydro Quebec and to use its share of the Phase 2 interconnection capacity for that separate arrangement. A utility that entered into such an arrangement would forfeit its share of the Phase 2 Firm Energy Contract but could keep and continue to support its share of the capacity in the Phase 2 interconnection. Such an arrangement would reduce the total amount of Phase 2 energy scheduled for delivery between Hydro Quebec and NEPOOL by the amount specified in the separate arrangement. EFSC Ex. 4(2), Article 2.2.

[37]Each Host State is entitled to a 5-percent share of total costs and savings. See further discussion in Section II.B.3.b.

[38]This special account, the Quebec Savings Fund, will provide a mechanism for tallying and disbursing Phase 2 savings, after NEPOOL's expenses are subtracted. The savings will be allocated according to the formula based on percentage of 1980 KWh sales. Tr. 3 at 131-132.

[39]During the period of discovery and hearings in this proceeding, (Footnote Continued)

the construction of facilities in Quebec and New England to interconnect the two systems.

These facilities include DC transmission lines and converter terminals to enable a full capability of 2000 MW of energy at any one time. EFSC Ex. 4(2), Article 8.3. Hydro Quebec and NEPOOL have agreed to use their best efforts to make these facilities operable by September 1, 1990. The Contract also contains provisions for the possibility of delays in the in-service date of the facilities.[40]

Other provisions in the Contract govern, inter alia, the purchase, sale, scheduling, and price of energy between Hydro Quebec and NEPOOL participants. The most important features of these provisions are described below.

(a) Project Scheduling

The annual sale and delivery of 7 billion kWh of energy will occur during a "contract year," defined as the period from September 1 to the following August 31. Phase 2 deliveries are expected to run for 10 contract years, ending on August 31, 2000. EFSC Ex. 4(2), Article 1.1.

Hydro Quebec is responsible for establishing the schedule of monthly deliveries of the 7 billion kWh of energy over each contract year. The monthly schedules are governed by minimum and maximum limits, intended to ensure that deliveries are distributed in a relatively even manner throughout the year.[41] The maximums and minimums are highest for winter and summer periods (peak load periods in New England) and lowest in the spring and fall periods (a time of minimum loads and high availability of hydro power in New England). However, during winter months, Hydro Quebec is allowed to schedule monthly quantities that are less than the minimum amounts outlined in the Contract.[42] EFSC Ex.

(Footnote Continued)
the final Firm Energy Contract had not been signed. Only the Final Draft Firm Energy Contract, agreed to by NEPOOL and Hydro Quebec and signed on December 14, 1984, was before the Siting Council for review. EFSC Ex. 4(2). According to the Companies, the provisions of the Final Draft version and the final Firm Energy Contract were anticipated to be the same. Tr. 2 at 16, 63, 64.

[40] If the facilities are not ready for service by September 1, 1993, either party has the right to terminate the contract on two-month's prior notice. EFSC Ex. 4(2), Article 8.5.

[41] The Companies have provided estimates of the expected schedule of deliveries of Phase 2 energy for all project years. EFSC Ex. 8. These estimates have been used in economic studies, described in Section II.B.1.c.

[42] These are the months when Hydro Quebec experiences its peakloads
(Footnote Continued)

4(2), Article 3. If Hydro Quebec schedules monthly quantities that are less than the contract minimums, NEPEX[43] has the right to schedule weekly and hourly deliveries based on the minimums. In such a case, should Hydro Quebec actually fail to deliver such minimums, it would incur a Hydro-Quebec Deficiency, described in Section II.B.1.a.(2)(b).

In general, NEPOOL is entitled to schedule deliveries in any hour up to the 2000 MW capacity of the interconnection. However, Hydro Quebec is not obligated to increase or decrease the rate of deliveries from one hour to the next by more than 500 MW, although the Contract calls for Hydro Quebec to use its best efforts to achieve a higher rate of ramping. EFSC Ex. 4(2), Articles 3.5 and 3.6. NEPOOL currently expects that the scheduling of hourly deliveries by NEPEX will be based on attempts to displace the most expensive fuel on the NEPOOL system during peak usage hours on peak-usage days. EFSC Ex. 8.

Under another provision of the Contract, Hydro Quebec may interrupt energy deliveries to New England during limited periods of time. This provision makes the Phase 2 Project distinct from a completely interruptible energy purchase, such as Phase 1, and from a firm capacity purchase agreement, which guarantees energy deliveries subject only to forced outages and transmission limitations. The Contract permits Hydro Quebec to interrupt or reduce hourly commitments to New England, without penalty, for up to 400 million kWh in each contract year.[44] EFSC Ex. 4(2), Article 5.1. This is equivalent to interruption of deliveries at the full 2000 MW for 200 hours each year.

(b) Deficiencies

The Contract covers in great detail the treatment of different types of deficiencies -- energy not delivered because of construction delays, reductions in hourly commitments, interruptions, or problems on the DC interconnection.

The first type of deficiency, a "Commissioning Deficiency," refers to deliveries that could not occur due to delay of the Phase 2 facilities beyond the target in-service date of September 1, 1990. The

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(Footnote Continued)
and occasionally has icing problems on portions of its system. Tr. 2 at 72, 73.

[43]The New England Power Exchange is the operating arm and central dispatching agency provided for in the NEPOOL agreement. NEPEX will control the dispatch of Phase 1 and Phase 2 energy purchases from Hydro Quebec. EFSC Ex. 8.

[44]Although the Contract does not so require, NEPOOL expects to be provided perhaps as much as two days advance notice of an interruption under this provision, so that alternate generation could be scheduled. Tr. 2 at 103, 104. However, in the event of the loss of generation on the Hydro-Quebec system, notice would be very short. Tr. 2 at 106.

Contract allows for Commissioning Deficiencies of 19 million kWh for each day beyond that target, with a total of 21 billion kWh that may be rescheduled at a later date.[45] Any portion in excess of 21 billion kWh is lost to both parties without penalty. EFSC Ex. 4(2), Articles 1.8 and 2.4.

Deficiencies that occur as a result of outages or other reductions in the transfer capability of the DC interconnection are Transmission Deficiencies and are not attributable to either party. EFSC Ex. 4(2), Article 1.6.

Deficiencies which occur due to the failure of either party to meet scheduled hourly commitments are attributed to the responsible party and are known as either "Hydro-Quebec Deficiencies" or "New England Utilities Deficiencies." EFSC Ex. 4(2), Article 1.6. For example, if Hydro Quebec were unable to deliver energy scheduled for a particular hour due to problems on its system, those missed deliveries would be Hydro-Quebec Deficiencies, with the exception of the 400 million kWh, which the Firm Energy Contract allows Hydro Quebec to interrupt in each contract year.[46]

Deficiencies may be rescheduled within the contract year in which they occur. EFSC Ex. 4(2), Article 4.4. If this is not possible, then all remaining deficiencies are left to be rescheduled in subsequent years, subject to certain limitations. Before the start of each year, Hydro Quebec will establish a schedule of deficiencies carried over from previous contract years. A maximum total of 2 billion kWh of New England Utilities Deficiencies and Hydro-Quebec Deficiencies -- 1 billion kWh each -- are allowed to be rescheduled. Remaining amounts of annual deficiencies over these limits are lost to the parties and a price adjustment is required based on the net deficiency for the prior year.[47]

Those deficiencies that occur as a result of Hydro-Quebec's allowed interruption of deliveries or from restrictions on the DC interconnection are not attributable to either party and no price adjustment results. Tr. 2 at 96; EFSC Ex. 4(2), Articles 1.b and 5.1. Additionally, such deficiencies are not rescheduled until contract years

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[45] This reflects a maximum of three years of construction delays.

[46] Interruptions under this provision are treated as Transmission Deficiencies, which are attributable to neither party and are without penalty. EFSC Ex. 4(2), Article 5.1.

[47] For example, in a previous year, if Hydro Quebec failed to deliver more energy than New England failed to accept, and each of Hydro-Quebec's and New England Utilities' Deficiencies were greater than 1 billion KWh, then Hydro Quebec would incur a penalty and the price paid by New England for the first 5 billion KWh taken in that year would decrease. EFSC Ex. 4(2), Article 4.6.

beginning in 1997. This provision insures that Transmission Deficiency deliveries do not interfere with Phase 1 energy deliveries. Tr. 2 at 88.

The Contract provides a 4-year contract-extension period for the rescheduling of deficiencies. Extension years start in the year 2000 and continue until the year 2004, depending on the amount of energy which remains to be rescheduled and delivered.[48] The Contract limits the quantity of deficiencies which may be rescheduled in extension years to 24 billion kWh. All remaining deficiencies are lost without penalty.

(c) Pricing Provisions

The Contract ties the price of energy imported from Hydro Quebec to the cost of fossil fuel in New England. Specifically, the price in any contract year will be based on NEPOOL's weighted average cost of energy generated from oil, coal, and natural gas in the previous year. In the first 5 years of the contract, the price paid to Hydro Quebec will be 80 percent of the weighted average cost; in the second 5 years, the price will be 94.8 percent of the weighted average cost.[49]

The Companies state that the two-stage pricing formula is the result of extensive arms-length negotiations between NEPOOL and Hydro Quebec. The formula recognizes the cost of production to Hydro Quebec and the value of the delivered energy to NEPOOL. EFSC Ex. 9. In the initial years, the Companies see the Project primarily as a means to reduce fuel costs in New England, while in the second 5 years, it has additional economic value as a way to help Project participants defer capacity additions. Similarly, in the initial years of the Project, the energy Hydro Quebec sells to New England is primarily "surplus energy" in the form of water that might otherwise be spilled at large hydroelectric stations on the LaGrande River in Quebec. In the later years, Hydro Quebec expects to need to construct generating stations in order to fulfill both its internal load and external sales obligations. See discussion, in Section II.B.1.b.(1). EFSC Ex. 9.

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[48] If no Commissioning Deficiencies exist at the end of the 10-year contract period, only one extension year is allowed.

[49] The Contract contains reference prices for use in the price computation. The prior year's weighted average fossil fuel cost is multiplied by the ratio of the reference price to NEPOOL's 1983 weighted average fossil fuel cost. The prices are: $32.25 for the period from project commencement to August 31, 1995; $38.25 from September 1, 1995, through August 31, 2000; and, if necessary for extension years, the price will be $39.00. EFSC Ex. 4(2), Article 6.1.

(d) Dispute Settlement Provisions

In the case of Contract disputes, the parties would submit the issues to arbitration. The Contract provides that the arbitrator cannot be a resident of Quebec or of any of the six New England states; that the proceeding be conducted in Boston, or another place agreed to by the parties; and that the arbitration proceeding be conducted in accordance with the Commercial Arbitration Rules of the American Arbitration Association. EFSC Ex. 4(2), Article 22.

In construing the Contract, the arbitrator shall apply the laws of Quebec. According to the Companies, a standard practice in the utility industry is that contracts between utilities are governed by the law of the seller's jurisdiction. Tr. 2 at 120-121. This arbitration process thus insures that disputes are not settled by a Quebec court under Quebec law.

The Companies are unaware of any treaties that govern the types of commercial transaction covered in the Firm Energy Contract. EFSC Ex. 182.

b) Reliability Impacts

As part of its evaluation of the costs and benefits of the proposed Phase 2 Project, the Siting Council must review the reliability of the power supply expected to be made available to NEPOOL through its DC interconnection with Hydro Quebec and through its Contract with Hydro Quebec. The Companies have provided evidence on the reliability of this power supply. This evidence has three components: information relating to the technical reliability of the facilities and the Firm Energy Contract; information relating to the political reliability of NEPOOL's reliance upon a foreign source of power; and information relating to the reliability/capacity value of the firm energy. Before analyzing this information, the Siting Council will provide background on the Hydro Quebec System.

(1) Hydro Quebec System: Background

Hydro Quebec, the provincial utility of Quebec, is slightly larger than NEPOOL, both in terms of generating capacity and energy sales.[50] In 1983, Hydro Quebec had over 26,500 MW of available generating capacity. EFSC Ex. 20. Hydro Quebec's energy sales amounted to approximately 111.2 billion kWh in 1983, of which 18 percent was sold to export markets. EFSC Ex. 11 at 73.

Much of Hydro Quebec's generating capacity is based on the enormous hydroelectric development complex on the LaGrande River near James Bay,

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[50] In 1984, NEPOOL's summer-rated generating capacity totalled approximately 21,300 MW and its energy generation amounted to 92.2 billion kWh. EFSC Ex. 10 at 3 and 4.

Quebec. Hydro Quebec originally undertook this development in the early 1970s when it was projecting a 6-to-7 percent annual growth rate for its service territory. Amendment Update, Vol. 1 at 6. The first phase of the James Bay construction program includes projects already underway or built, for a total installed capacity of 10,300 MW. Hydro Quebec also has plans for a second phase.

Since planning and construction of the first phase began, Hydro Quebec has experienced slower than expected growth, which leaves the utility with significant amounts of surplus hydroelectric energy. Hydro Quebec either must sell these surpluses or waste them by spilling water at the hydro facilities. Amendment Update, Vol. 1 at 6.

For the future 15-year period, Hydro Quebec has forecast relatively fast growth in firm energy sales from 1986 through 1991 (at 4.1 percent a year), and slower growth in the 1990's (at 2.3 percent a year). EFSC Ex. 15. Under this forecast, firm sales are projected to be approximately 132 billion kWh in 1991 and 155 billion kWh in 2001.[51] EFSC Ex. 11 at 37. Peak loads are expected to grow substantially the same way as firm energy sales.

Hydro Quebec estimates in its 1985 Development Plan that its existing generating capacity should be able to satisfy peakload and energy needs of its internal and external markets until 1990 and 1997 respectively. Accordingly, new peaking capacity will be required by 1991, and new baseload plant by 1998. EFSC Ex. 11 at 37-38. Hydro Quebec currently plans to commission 980 MW of baseload capacity on the LaGrande complex (LG2) in the early 1990s.

Use of the increased capacity at LG2 will require a sixth James Bay transmission line at the time LG2 is placed in service. Hydro Quebec's Development Plan states "among the various alternatives possible to satisfy the requirements related to the [Phase 2] agreement with NEPOOL, the isolation of some generating units at the LG2 powerhouse and the transmission of energy from these units by a direct current line to the American border proves to be the best solution. For this reason, the sixth line will be DC and its commissioning will coincide with the beginning of the NEPOOL contract in 1990." EFSC Ex. 11 at 38.

The Companies state that an unexpectedly rapid increase of Quebec's internal electricity needs can be met by developing hydroelectric sites at a "faster pace than set forth in the expansion plan." EFSC Ex. 18. Hydro Quebec estimates that undeveloped rivers of Quebec represent annual generating capacity in the order of 30,000 MW or 200 billion kWh of energy. EFSC Ex. 11 at 39. Regarding the development of installations required after 1994, the year LG2 is expected to go on line, Hydro Quebec states it does not need to make a decision on

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[51] NEPOOL's 1985 Energy and Load Forecast calls for net energy requirements of 106.8 billion kWh in 1991 and 128.6 billion kWh in 2000. EFSC Ex. 10 at 4.

commissioning of a second phase of construction of facilities until 1988 and that the scope and configuration of the facilities will be determined in part by the future energy and power sales contracts to export markets.

One of Hydro Quebec's primary goals in its development plan is to intensify its efforts to penetrate export markets. Hydro Quebec currently is interconnected to several locations and utilities to which it sells energy.[52] After commissioning of the 690 MW tie with New England in 1986, and increasing that tie to 2000 MW in 1990, Hydro Quebec's total interconnection capacity with outside markets would reach 7000 MW. These interconnections would be able to carry up to 55 billion kWh per year, compared to 19.5 billion kWh in 1983 and would allow Hydro Quebec to sell 95 percent of its energy surpluses projected to be available between 1983 and 1993. EFSC Ex. 11 at 5.

According to the Companies, Hydro Quebec does not depend on surplus energy to meet its obligations under firm energy contracts. All such requirements are added to the needs of Hydro Quebec's firm customers and included in its expansion plan. The Companies also state that Hydro Quebec plans to meet Phase 2 requirements with existing surplus energy until 1998. Thereafter, Hydro Quebec will meet Phase 2 requirements by pre-building generation plants that Hydro Quebec otherwise would not need until after the end of the Phase 2 contract period. The Companies state that studies are underway to implement these projects. EFSC Ex. 11; EFSC Ex. 16.

Hydro Quebec's firm export sales, including those covered by the Phase 2 Firm Energy Contract with NEPOOL, are expected to represent 101.3 billion kWh over the 1985-2001 period. EFSC Ex. 11 at 32. In 1991 these sales would total 8.5 billion kWh, or 5.5 percent of Hydro Quebec's total expected sales. When surplus, non-firm export sales are considered, this figure increases to 30.1 billion kWh, or nearly 20 percent of total sales. EFSC Ex. 11 at 73.

The impact of export sales on Hydro Quebec's financial posture is significant. Estimates for 1984 indicate that firm export sales provided Hydro Quebec with $645 million (Canadian dollars) in operating revenues, or nearly 16 percent of total revenues. This figure is projected to rise to $1,028 million in 1987, or 19 percent of operating revenues. The Companies estimate that NEPOOL's payments alone to Hydro Quebec will total $238 million in 1990/91, and will escalate to $692 million in 1999/2000 (U.S. dollars). EFSC Ex. 43.

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[52]These are: the New York Power Authority ("NYPA") and Niagara Mohawk Power Company in the State of New York; Citizens Utilities Company in the State of Vermont ("the Vermont Group"); New Brunswick Electric Power Commission; Ontario Hydro, Ceders Rapids Transmission Company and St. Lawrence Power Company in the Providence of Ontario; and four neighboring power entities in the Province of Quebec. EFSC Ex. 13.

(2) Technical Reliability

The Companies' witness, Mr. Bigelow, testified that in terms of transmission reliability, Hydro Quebec plans its transmission system to achieve a lower level of reliability than does New England. Tr. 4 at 34. He stated that Hydro Quebec experiences significantly more outages than does NEPOOL, and estimated that Hydro Quebec experiences systemwide shutdowns once every 3 to 5 years. Tr. 2 at 132. The Companies explained that since the Hydro Quebec generating system is almost entirely hydroelectric, it can tolerate system-wide shutdowns much more efficiently than New England can, with New England's largely fossil-fueled and nuclear baseload system. Hydro facilities are better able than nuclear and fossil-fuel plants to return to service quickly after an outage. Additionally, because most of Hydro Quebec's generating is located hundreds of miles away from its load centers, Hydro Quebec does not find it economical to install the kind of redundant transmission capacity that would be required to improve its system reliability to the level planned by NEPOOL. Tr. 2 at 132.

According to the Companies, NEPOOL did not want firm energy deliveries to be subject to Hydro Quebec's lower level of reliability, and NEPOOL negotiators insisted that Hydro Quebec isolate transmission of Phase 2 deliveries from the rest of the Hydro Quebec system. Tr. 2 at 132. Hydro Quebec has agreed to isolate these deliveries through construction of a new DC transmission line dedicated to supplying New England with its contracted energy. As proposed, the new transmission line will connect the LaGrande hydro facilities with the Canadian converter terminal near the U.S. border. The line will enable Hydro Quebec to feed power directly to New England from James Bay without using any of Hydro Quebec's AC bulk power transmission. With this new line, New England will continue to receive power scheduled under the Phase 2 Contract, even if Hydro Quebec experiences a systemwide transmission outage. Tr. 2 at 130-131.

The Companies estimate that by 1990 total interconnection capacity between Hydro Quebec and the northeastern power region, including New York, New England and New Brunswick, would approach 4,000 MW.[53] According to Witness Bigelow, NEPOOL believes this level of reliance on the Hydro Quebec transmission system is too high, especially since those regions of the Northeast are themselves interconnected through interties with NEPOOL. Thus, NEPOOL encouraged Hydro Quebec to devise its plan to build the dedicated DC line to New England, so that if the Hydro Quebec AC system went out of service, at least half of its power supply to the Northeast would continue to flow. Tr. 2 at 134. The DC line from James Bay to New England will isolate 2000 MW from the Hydro Quebec system and direct it to New England, so that the maximum amount that could be lost due to a failure of the Hydro Quebec AC transmission system would be 2000 MW -- an outage which NEPOOL believes the Northeast's systems could handle. Tr. 2 at 134.

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[53] EFSC Ex. 49; Tr. 2 at 133.

Additionally, the Companies' witness Mr. Snow testified that three regional electricity coordinating councils were conducting a study ("MEN" Study), to determine the effects of a sudden loss of the DC interconnection on New England and on regions outside of New England.[54] Tr. 9 at 141-149; EFSC Ex. 205. Specifically, the study is investigating potential overloading problems which could arise in power pools neighboring New England and even in more distant pools, should more than one of the U.S. ties to Hydro Quebec be lost simultaneously. The MEN Study is expected to establish the limits on imports from Hydro Quebec that the Northeast region can tolerate without experiencing such reliability problems or causing neighboring pools to experience similar sorts of contingencies. Tr. 9 at 145. The results of the study were not available at the time of this writing.

Witness Snow stated that should the study reveal the potential for serious problems, the coordinating councils would make recommendations that could include "operating around" the problem, or the construction of additional reinforcement facilities to prevent problems as a result of such contingencies. Tr. 9 at 147.

The willingness of these neighboring coordinating councils to cooperate to anticipate and try to deal with possible region-wide problems, and the contractual commitment of Hydro Quebec to build a transmission line dedicated to delivering power under the Phase 2 contract, give the Siting Council a degree of comfort that New England's system reliability will not be adversely degraded as a result of interconnection with Hydro Quebec.

(3) Political Reliability

By 1991, when the Companies expect Phase 2 to provide 7 billion kWh of energy to New England (i.e., NEPOOL), New England's total energy requirements are projected to amount to 107 billion kWh. EFSC Ex. 10 at 4. This would mean that NEPOOL would rely on the Phase 2 Project for 6.5 percent of New England's energy needs.

Also in 1991, the Companies estimate that NEPOOL will purchase approximately 5.5 billion kWh as a result of other transactions with Hydro Quebec[55] and an additional 2.4 billion kWh from other Canadian sources.[56] EFSC Ex. 160. When combined with the Phase 2 firm energy

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[54]The title of the "MEN Study" is an acronym for the three sponsoring regional coordinating councils: the Mid-Atlantic Area Coordinating Group; the East Central Area Reliability Siting Council; and the Northeast Power Coordinating Siting Council.

[55]These include 4 billion kWh from the Phase 1 contract, and the Vermont Group's purchase of an estimated 1.3 billion kWh.

[56]These include: Bangor Hydro's and Central Maine Power Companies' (Footnote Continued)

supplies, these Canadian energy supplies will represent an estimated 14 percent of NEPOOL's projected energy requirements in 1991, and approximately 7.5 percent of summer peakload requirements. EFSC Ex. 10 at 4. In subsequent years, NEPOOL's reliance on Canadian energy is expected to drop from approximately 12 percent in 1992 to approximately 6 percent in 1999.[57] EFSC Ex. 10 at 4; EFSC Ex. 160.

In contrast, approximately 24 percent of NEPOOL's 1990/91 energy is expected to come from oil-fired generation in the absence of Phase 2 energy. EFSC Ex. 117. With Phase 2, this figure is expected to decline to 18 percent. Therefore, the Phase 2 project could help NEPOOL reduce its reliance on oil at the expense of increasing reliance on imported electricity from Canada and especially on a single supplier, Hydro Quebec.

The Companies state that the United States is presently Canada's most important trade partner. Canada exports more to the U.S. than any other country and imports more from the U.S. than from any other country. EFSC Ex. 17. According to the Companies, both the U.S. and Canada have honored their commercial commitments in the past. EFSC Ex. 17; Tr. 2 at 121-122. The Companies see no reason to believe that Canadian or American attitudes would be different in regard to electricity agreements, which must be authorized by high-level governmental authorities in each country: the Canadian National Energy Board for Canadian exports, and the U.S. Department of Energy for imports. Amendment Update, Vol. 1 at 22.

Further, the Companies state that the Quebec government has worked to strengthen commercial ties with New England over the past decade. In part, the recent electricity sales from Hydro Quebec to New England reflect these efforts. Export sales represented 16 percent of Hydro Quebec's total revenues in 1984, and are expected to increase to 19 percent in 1987 after the Phase 1 interconnection is placed into operation. EFSC Ex. 11 at 75.

The Companies recognize the possibility that Hydro Quebec deliveries could be interrupted as a result of governmental actions. However, they believe the risk is small and no greater than risks faced from any source of supply outside the immediate region, whether foreign or domestic. The Companies are unaware of any contract between Canadian and U.S. utilities where a Canadian political entity interfered with the terms of the contract once it had been signed and approved. Further,

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(Footnote Continued)
power purchases from New Brunswick, totalling 30 MW and 150 MW respectively; the Vermont Group's Southern Canadian power purchase of 0.3 billion kWh and its Ontario 3 capacity purchase of 51 MW; and Boston Edison Companies' 100 MW purchase of Point LePreau 1.

[57] This is expected to result from terminations of some of the aforementioned agreements, and from 2.1-percent annual growth in energy requirements in New England.

they believe that the economic benefits which will flow to Quebec under the Phase 1 and Phase 2 arrangements make it even more unlikely that adverse governmental interference will occur. EFSC Ex. 18.

The Siting Council finds that the incremental dependency of NEPOOL upon Hydro Quebec and the Phase 2 project do not expose New England consumers to unreasonable levels of risk. In particular, the Siting Council views this addition more as a means to greater fuel diversity than a step towards greater reliance upon a single fuel source or power supplier, since the Phase 2 imports from Canada will largely back out NEPOOL's consumption of oil -- all of which comes from outside the New England region. In the year of the Phase 2 Project when NEPOOL is expected to have the highest dependency on Canada, New England will depend on Canada for 14 percent of its energy requirements and nearly half of that from Hydro Quebec Phase 2. Thereafter, NEPOOL's reliance upon Canada is currently projected to decline rapidly, dropping to 7.3 percent when the Phase 1 contract terminates (assumed to occur in 1995). EFSC Ex. 160; EFSC Ex. 10.

The Siting Council recognizes several incentives that could enhance the chance that Hydro Quebec will deliver its energy as planned under the Phase 2 contract. The first incentive is the same significant financial stake that Hydro Quebec has in the Phase 2 sales, not to mention subsequent sales agreements designed to use the DC interconnection built to service the Phase 2 contract at an expected cost to Hydro Quebec of approximately $1,211 million. EFSC Ex. 11 at 42. Secondly, the provisions of the Phase 2 Contract ensure that failure to perform under the Contract results in penalties for the responsible party and that disputes may be mediated in the U.S. In this sense, Hydro Quebec has as much incentive to deliver energy under the contract as NEPOOL has to accept that energy.

(4) Reliability Value

The Companies assert that even though the proposed Phase 2 Project would not involve a purchase of capacity, it nonetheless would have reliability value for the NEPOOL system. The Companies indicated that when NEPOOL determines the level of capacity needed by the entire system to meet its reliability criterion, it considers the effect of transmission interconnections currently in place with neighboring power pools. EFSC Ex. 24 at 3; Tr. 3 at 48. Such interconnections, along with mutual-support and shared-service agreements, allow a power pool to reduce the amount of capacity installed on its system to cover contingencies, including maintenance and scheduled outages. Tr. 3 at 48. The magnitude of these reliability improvements, or intertie benefits, depends primarily upon the relative reliabilities of the interconnected systems and the transmission transfer capability between the two interconnected systems. EFSC Ex. 49.

With respect to Phase 1 non-firm energy transfers across the 690-MW interconnection with Canada, NEPOOL's reliability calculations treated this intertie in the same way NEPOOL treats existing ties with the New York Power Pool and with New Brunswick. Tr. 3 at 48-49. These reliability calculations recognize the benefits to NEPOOL of the ability to call on Hydro Quebec and other neighboring pools for help in emergencies.

The numerical value of this reliability benefit, defined in terms of installed reserve capacity that can be avoided as a result of the interconnection, is determined through a study which models the inherent characteristics of the two systems. EFSC Ex. 37. Factors considered in the two-pool studies are projected loads, projected installed generation, assumed unit availability and forced outage rates, and the projected reliability and transfer capability of the interconnection. Tr. 3 at 49.

The capacity/reliability benefits of inter-pool ties are modeled by assessing the level of peakload that can be carried with existing generation. Peakload levels are raised until the NEPOOL reliability standards are met. The resulting output is the amount of additional peakload which can be met with existing generation and interties to neighboring pools. Tr. 3 at 51-55.

The two-pool study conducted for Phase 1's 690-MW intertie calculated the installed capacity needed to meet NEPOOL's reliability criterion,[58] while taking into account a certain probability that NEPOOL will be able to call on neighboring power pools for assistance. No consideration was given to the expected non-firm energy deliveries under the Phase 1 energy contract. Tr. 3 at 49-50.

Witness Bigelow testified that when the tie is small relative to the size of the two systems, the effective capacity benefit can come close to the transfer value of the tie. Tr. 3 at 49. Such is the case for the Phase 1 project. NEPOOL has calculated the value of the Phase 1 690 MW tie to be 600-MW.[59] The Phase 1 interconnection thus allows NEPOOL to reduce by 600 MW the installed reserve capacity that would otherwise have been required. See EFSC Ex. 49.

The Companies reported that when NEPOOL calculated the value of increasing the interconnection's transfer capability from 690 MW to the 2000 MW planned under the Phase 2 Firm Energy Contract, NEPOOL also considered the effect on reliability benefits of the 7 billion kWh of "firm" (i.e., pre-scheduled but interruptible) energy. Tr. 3 at 51. In order to determine how best to model the Phase 2 agreement, NEPOOL

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[58]This criterion involves a probability that non-interruptible customers will be disconnected one day in every ten years.

[59]Capacity benefits from ties with neighboring pools are expressed as "perfectly reliable generation," an "equivalent generator," or a generator with a perfect record of reliability. In the case of the Phase 1, the 690-MW interconnection with Hydro Quebec provides the equivalent of 525 MW of perfectly reliable generation (i.e., at 100 percent availability), equivalent to 600 MW of actual capacity with an availability of 87.5 percent. See EFSC Ex. 37 and EFSC Ex. 4.

consulted with Hydro Quebec on what assumptions to use regarding the scheduling and interruptibility of the energy. Tr. 4 at 14. Hydro Quebec indicated it would expect to interrupt its allowable quantity of 400 million kWh during December and January. Hydro Quebec expects that excess energy will exist during the remaining months; thus, it would be unlikely that generation-related problems would cause Hydro Quebec to exercise its right to interrupt deliveries at those times. Tr. 3 at 51. On this basis, NEPOOL modeled the Phase 2 contract and interconnection as a 2000-MW unit with an availability rate of 37.5 percent in December and January (the interruptible period) and a 97-percent availability rate in the other 10 months of the year.[60] EFSC Ex. 37.

The two-pool study conducted for the Phase 2 Project involved two generation runs -- i.e., with and without the Phase 2 Contract and facilities in place. The difference between the results of the two runs represents the additional peakload which could be met with the Project and interconnection in place and without violating NEPOOL's reliability criterion. This net load is equivalent to 1250 MW of perfectly reliable generation. Tr. 4 at 21-24, 47. Since real generation facilities are not perfectly reliable, NEPOOL also had to determine the level of less-than-perfect capacity, to be backed up by installed reserve in order to carry 1250 MW of peakload. Tr. 4 at 23.

To do this, the Companies assumed a 20-percent reserve margin. Tr. 4 at 22. They determined that 1250 MW of peakload and reserve could be met with 1500 MW of capacity (1250 times 1.2), or that 1250 of perfectly reliable generation is equivalent to 1500 MW of capacity at an availability rate of 83.33 percent (1250 divided by .8333). EFSC Ex. 48. Therefore, the Companies calculated the actual generation displaced by the Phase 2 interconnection to be 1500 MW.[61]

Therefore, the determination that 500 MW of the 2000 MW intertie would not provide capacity benefits is attributable to two things: the size of the tie and its resultant high reserve requirements; and the interruption provisions of the Contract.

The Siting Council finds that the Companies' methods for determining the inherent reliability value of the Phase 2 interconnection and Contract are acceptable, especially in light of the

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[60] The Companies' witness testified that given the 98.5 percent availability rate assumed for the facilities (EFSC Ex. 20), it appeared that another 1.5 percent unavailability had been added to account for possible outages on the Hydro Quebec system. Tr. 4 at 16.

[61] If the 20-percent reserve requirement used by the Companies for this analysis proves to be lower than the actual level of installed reserves required by NEPOOL in the 1990s, then this estimated 1500-MW capacity value for the Phase 2 interconnection and Contract also could be too low since it would displace generation which requires a greater amount of installed reserve. Tr. 4 at 23 and 24.

fact that the methods are consistent with NEPOOL's treatment of other interties for the purposes of planning for reliability and reserve requirements.

Also, the Siting Council notes that the Companies' analysis took into account the fact that the 2000-MW interconnection (if constructed as proposed and awarded a 1500 MW capacity credit by NEPOOL) would become the single largest power source on the NEPOOL system. The Companies determined that the firm energy delivered through the 2000 MW intertie should be relied upon only to displace 1500 MW of capacity, at least in part because this represented the largest single loss that could be tolerated on the NEPOOL system without adversely degrading NEPOOL's overall reliability. Tr. 3 at 62. Thus, the 500 MW of potential additional capacity credit not awarded to the Project is partially a "penalty" for the interruptibility provisions of the Contract, and also a reflection that the Project was designed at a size larger than the maximum single-unit outage that the NEPOOL system could reasonably tolerate. At the same time, the Siting Council recognizes that this 500 MW "penalty" is imposed against the 2000 MW maximum delivery permitted under the Firm Energy Agreement; thus providing a net reliability benefit of 1500 MW which has economic value to New England.

c) Net Fuel Cost Savings

According to the Companies' own estimates, the most significant long-term economic benefits of the Phase 2 Project will result from net fuel cost savings. NEPOOL's purchase of 7 billion kWh of firm energy from Hydro Quebec for 10 years is expected to enable NEPOOL members to avoid generating electricity from their most expensive fuel sources and obtain the energy at a price lower than NEPOOL's average marginal price for generating electricity.

In this section, the Siting Council reviews the Companies' estimates of the value of displacing expensive marginal energy generation, and the Companies' projections of NEPOOL's payments to Hydro Quebec for energy delivered under the Phase 2 Contract. The difference between these avoided fuel costs and payments to Hydro Quebec represents the net fuel cost savings to New England. The Companies estimate that these net savings will rise from $150 million in power year 1990/91 to $379 million in 1999/2000.[62] EFSC Ex. 47. (See column e of Table 4.)

To construct these estimates, the Companies performed a number of studies that relied on use of the Westinghouse Capacity Model and the Westinghouse Production Cost Model.[63] Through separate runs of these

[62] The estimates discussed in this section are in current dollars.

[63] The Generation Capacity Model determines the capacity required and optimal maintenance schedule needed over a given time frame to meet projected hourly loads and reserve requirements. The model relies on (Footnote Continued)

models, the Companies evaluated the impact of projections of Phase 2 energy purchases and deliveries on the NEPOOL system's annual production costs. Amendment Update, Vol. 1 at 12-13.

In a study the Companies refer to as the User Agreement Pricing Study ("User Study"), the Companies produced annual estimates of generation by type of fuel and total fossil fuel costs, under different scenarios. EFSC Ex. 208. The first scenario assumed no energy from Phase 2 during the 1990s and included both pre-scheduled energy from Phase 1 (i.e., two-thirds of Phase 1's energy) and Phase 1's economy energy. In the second scenario, both pre-scheduled Phase 1 energy and Phase 2's firm energy were dispatched before Phase 1's economy energy. EFSC Ex. 208; EFSC Ex. 123. These two runs held constant a number of assumptions regarding load levels, availability of generating resources, and fuel prices.[64]

For each power year, the separate runs included projections of generation by type of fuel, total fossil fuel costs (based upon projected fuel consumption by fuel type, multiplied by DRI's fuel price forecast by fuel type) and average fossil fuel cost (total fuel cost, divided by total fossil-fired generation). EFSC Ex. 122; EFSC Ex. 208. Payments to Hydro Quebec for Phase 2 firm energy were calculated by multiplying average fossil costs in the preceding year by 7 billion kWh.

The User Study produced estimates of gross fuel cost savings attributable to Phase 2, assuming that Phase 2 is dispatched before Phase 1 economy energy. The User Study also provides estimates of net fuel cost savings, after payments to Hydro Quebec are subtracted from gross fuel cost savings. The final results of the User Study are included in Table 4, columns b and e.

(Footnote Continued)
data inputs and assumptions concerning load levels and shapes, ratings of existing and planned generation capacity, unit retirement schedules, unit maintenance schedules, unit availability factors, and system reliability criteria. EFSC Ex. 55; Amendment Update, Vol. 1 at 12-13. The Production Cost Model determines through an economic dispatch of a system's generating resources an estimate of the system's fuel consumption and variable production costs over a given time frame. It relies on data and assumptions concerning load duration curves, spinning reserve requirements, fuel price projections, and unit heat rates and maintenance schedules. EFSC Ex. 54; Amendment Update, Vol. 1 at 13.

[64] These assumptions are summarized in the Amendment Update, Vol. 1 at 13-20. Load growth assumptions were taken from the 1984 Energy and Load Forecast, EFSC Ex. 87. Information on generating capacity, including new unit in-service dates and unit retirements, was taken from the 1985 CELT Report (EFSC Ex. 10), except that construction beyond 1996/97 was assumed to include: three 100-MW gas turbines in 1997/98; a 600-MW coal unit in 1998/99; and two 100-MW gas turbines in 1999/2000. Amendment Update, Vol. 1 at 13-14. The Companies used forecasts of
(Footnote Continued)

The Companies reestimated these net fuel cost savings under different assumptions in various other studies. One study was known as the Feasibility Pricing Study ("Feasibility Study"). EFSC Ex. 208; EFSC Ex. 209(f). It differed from the User Study in that it based its final estimate of savings associated with Phase 2 relative to a base case in which all of Phase 1 energy (i.e., pre-scheduled and economy) was dispatched. The difference between the results of the two studies reflects the impact on estimates savings of the presence of Phase 1 economy energy.[65]

The results of the Feasibility study, which also are included in Table 4, (columns c and f), indicate somewhat lower estimates of fuel costs savings in the first four years of the Phase 2 project as compared to the estimate produced by the User Study.[66]

While the Siting Council accepts the overall methodology the Companies have used to estimate NEPOOL payments to Hydro Quebec and gross fuel cost savings, the Siting Council finds that use of the results of the Feasibility Study are more appropriate as an indication of the incremental impact of Phase 2 energy on the region's total fuel costs. The Siting Council believes that a study of incremental effects of Phase 2 would include a reasonable base-case generating mix which assumes all 33 billion kWh of Phase 1 energy -- that is, both pre-scheduled and economy purchases over a 11-year contract period -- since Hydro Quebec is under contract to provide and New England is under contract to accept all of that energy. Such a base case is reflected more closely in the results of the Feasibility Study than those of the User Study.[67]

The Siting Council believes that the User Study results reflect the net effects of distributing regionwide total savings associated with Phase 2 firm energy and Phase 1 economy energy among the Phase 2

(Footnote Continued)
fossil fuels prepared by DRI in January 1985 in these analyses. Amendment Update, Vol. 1 at 16-17.

[65] In the User Study, Phase 2's firm energy is assumed to be dispatched before Phase 1's economy energy, so that Phase 2 is responsible for avoiding more expensive fuel than is Phase 1's economy energy. According to the Companies, this is probably the way that the dispatch will actually work. The Feasibility Study assumes that Phase 1's economy energy is dispatched before Phase 2's firm energy. EFSC Ex. 123.

[66] Payments to Hydro Quebec were similar in each of the two studies. See column a of Table 4.

[67] The Companies agree that the results of the User Study do not reflect incremental savings to New England resulting from the Phase 2 Project. EFSC Ex. 123; EFSC Ex. 208.

Table 4

Estimates of Annual Fuel Cost Savings and
Payments to Hydro Quebec Under the Phase 2 Project
(Millions of current dollars)

	(a)	(b)	(c)	(d)	(e)	(f)
	Estimated	Estimated Gross Fuel Savings			Es'd Net Fuel Svgs	
	Payments to Hydro Quebec	User Study	Feasi-bility Study	Difference (c)-(b)	User Study (b)-(a)	Feasi-bility Study (c)-(1)
1990/91	238	388	378	-10	150	140
1991/92	255	443	425	-18	188	170
1992/93	280	498	476	-23	219	196
1993/94	308	572	546	-26	264	238
1994/95	342	633	633	0	291	291
1995/96	461	712	712	0	251	251
1996/97	513	823	823	0	310	310
1997/98	573	907	907	0	334	334
1998/99	641	960	960	0	319	319
1999/00	692	1071	1071	0	379	379

Source: EFSC Ex. 47; EFSC Ex. 209(f).

participants and the Phase 1 participants.[68] In contrast, the Siting Council finds that the Feasibility Study results better portray the net impact of total regional fuel costs of purchases and deliveries of a new project. Therefore, the Siting Council will use the results of the Feasibility Study in this analysis of benefits and costs associated with the Phase 2 Project.

d) Economic Value of Capacity Credits

As discussed previously, the Companies state that Phase 2 offers significant capacity benefits to New England, even though the Firm Energy Contract does not specifically provide for capacity entitlements or payments.

The Companies have determined through reliability studies[69] that the net effect of the 2000-MW Hydro-Quebec/NEPOOL interconnection and Firm Energy Contract is a 1500 MW reduction in New England's need for new generation. This means that with the full interconnection in service when the Phase 2 facilities begin operating, NEPOOL participants will be able to forego construction of 1500 MW of capacity that otherwise would have been required to meet NEPOOL reliability criteria. See Section II.B.1.b(4).

The Companies state that NEPOOL also has determined based on the 690-MW transfer capability and the Phase 1 surplus energy contract, that the Phase 1 interconnection will provide NEPOOL with a 600 MW capacity benefit. Thus, the Companies believe that during the years when Phase 1 is in effect (presumably power years 1986/87 through 1993/94), the Phase 1 interconnection effectively reduces NEPOOL's installed reserve requirements by 600 MW. See Section II.B.1.b(4).

During the years when both the Phase 1 and Phase 2 projects are operative and when the interconnection's transfer capability increases to 2000 MW, the interconnection is given a total of 1500 MW of capacity credits, or an incremental increase of 900-MW. During these years, the allocation between Phase 1 and Phase 2 is 600 MW and 900 MW respectively. Tr. 4 at 9; EFSC Ex. 37.

The Companies have calculated the economic value of Phase 2's 900 MW of capacity benefits. In these calculations, they have assumed that capacity benefits begin to occur when, in the absence of Phase 2, New England would need to obtain additional capacity to meet projected peakloads and a 20-percent installed reserve margin. The Companies have projected that the 1993/94 power year is the first year in which NEPOOL

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[68]The utilities that participate in Phase 2 may or may not be the exact set of utilities that are participating in Phase 1.

[69]These studies are discussed in greater detail infra at Section II.B.1.b(4).

would need to add capacity to meet its reliability criterion. EFSC Ex. 38; Amendment Update, Vol. 1 at 10. See Section II.A.2.

Under this analysis, NEPOOL participants would need to add 300 MW in 1994, another 700 MW in 1995, another 500 MW in 1995/96, and so on.[70] EFSC Ex. 32. The first 600 MW would be provided by Phase 1, so Phase 2's 900 MW of capacity would have economic value starting in 1994 (400 MW) and in 1995 (500 MW). EFSC Ex. 38.

The Companies used a modified peaker methodology to calculate the dollar value of Phase 2 capacity benefits. EFSC Ex. Ex. 32. The modified peaker method estimates the future cost of constructing a peaking unit (including all nonvariable costs) on a per-kW basis in the year it is projected to be needed to meet electricity demand. This cost is then annualized and either left in nominal dollars or discounted to determine its present value. The resulting cost estimates represent a utility's average willingness to pay for capacity to meet reliability objectives.

The Companies assumed that the economic value of Phase 2 capacity would be tied to the costs of gas turbine units since their value to a generating system is one of reliability alone. Amendment Update, Vol. 1 at 10. Based on the cost of $688 per kW of gas-turbine capacity installed as of June 1994 and $740 per kW installed cost in June 1995, the Companies calculated that the levelized annual carrying charges would be $122 million (in current dollars) per year of the Phase 2 project. EFSC Ex. 24 at Exhibit 1; EFSC Ex. 32. This equates to $321 million (1990 $) in cumulative savings associated with these capacity benefits.[71]

The Siting Council finds that the methods used by the Companies to establish the reliability benefits of the Phase 2 interconnection and Firm Energy Contract and to calculate the economic value of those benefits are acceptable.

e) Facility Costs

As proposed by the Companies, the economic benefits of the Phase 2 Project cannot be achieved without the construction of major transmission facilities in New England and Canada to establish an interconnection at the full 2000-MW energy import level provided for in the Firm Energy Contract.

The Companies are already constructing a 2000-MW DC transmission line between Sherbrooke, Canada, and Monroe, New Hampshire. This line

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[70]The Companies' calculations do not assume that Phase 1's 600 MW have already been taken into account.

[71]Using a 10.4 percent discount rate. Amendment Update, Vol. 1 at 59.

will deliver Phase 1 energy starting in July 1, 1986 (Exh. RHS at 5), and was designed in anticipation of a possible second energy agreement between NEPOOL and Hydro Quebec. However, the Phase 1 DC/AC converter terminal at Monroe was designed with a capacity of only 690 MW.[72] Therefore, the Companies believe that additional facilities are required to import the remaining 1310 MW proposed under the Phase 2 Project. See Section III.C.1.

In regard to project-level costs and benefits, the discussion here summarizes information regarding facility construction costs. A detailed evaluation of these costs estimates, and the methodology, data and assumptions used by the Companies used in developing them is in Sections III.B.2.

The Companies prepared study-grade estimates of the capital costs of constructing Phase 2 facilities. These capital cost estimates include initial construction costs, escalation factors, and costs of allowance for funds used during construction. Amendment Update, Vol. 1 at 62. Additionally, the Companies projected annual carrying costs for the facilities over the life of the project. These included financing costs, depreciation, operations and maintenance costs, and local, state and federal taxes. Ex. ROB at 14; Amendment Update, Vol. 1 at 58-62.

The Companies expect the capital costs for their preferred route to total $585 million (in 1990 dollars). Amendment Update, Vol. 1 at 61-62. This translates into annual carrying charges that start at $191 million in 1990/91 and gradually decrease to $128 million in 1999/2000.[73] Ex. ROB at 14-15; Ex. 47. The cumulative present worth of these costs is $911 million.[74]

Finally, the Companies offered estimates of costs that fall within a range of ±25 percent of the expected $585-million cost figure. This range produces a low cost estimate of $440 million and a high of $730 million. This range of cost estimates was used by the Companies in sensitivity analyses. See discussion in Section II.B.3.

The annual carrying costs associated with construction costs at each level are indicated in Table 5 below:

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[72]This is the maximum additional amount of power the Companies believe the northern New England transmission system can handle at that location without alteration. See Section III.B.2.

[73]These are in current dollars.

[74]This assumes the Companies' 10.4-percent discount factor. Amendment Update, Vol. 1 at 59.

Table 5

Annual Carrying Charges of Various Construction Costs Estimates
(current dollars)

	@ $440 M	@ $585 M	@ $730 M
1990/91	143	191	238
1991/92	139	184	230
1992/93	133	176	220
1993/94	127	169	211
1994/95	122	162	203
1995/96	117	156	194
1996/97	112	149	186
1997/98	108	143	179
1998/99	103	137	171
1999/00	96	128	160

Source: EFSC Ex. 47

As discussed later in Sections III.B.2 and 3, the Siting Council finds that the range of cost estimates and the methodology used by the Companies to develop them are acceptable and constitute a reasonable projection method for analyzing the project-level costs and benefits.

f) Energy Loss Impacts

The Companies presented the results of analyses showing that the operation of the Phase 2 facilities and inclusion of Phase 2 firm energy in NEPOOL's generation and transmission system in the 1990s would reduce energy losses in the region as compared to a system without the Phase 2 project. These loss savings are part of Phase 2 impacts. The Siting Council summarizes the results of these studies here. A more detailed review of these studies is in Section III.B.2.

In their analyses of energy losses, the Companies compared the 10-year operation of a generation and transmission system with and without the proposed Phase 2 project. The energy loss studies for each scenario evaluated losses resulting from operation of both DC and AC systems.

The "reference" case in these analyses assumed that the Phase 1 DC facilities were functional for the years 1990 through 1994 and were used to import energy at the 690-MW maximum capacity of the Phase 1 converter terminal at Monroe, New Hampshire. The reference case also assumed an AC transmission system as currently planned by NEPOOL utilities for the 1990s, without the additional AC reinforcement lines proposed as part of the Phase 2 project. Amendment Update, Vol. 1 at 61-66.

The "Phase 2" case assumed that: the proposed DC and AC facilities were operational on the Companies' preferred routes; in any hour, New England would import energy at the full 2000 MW capacity of the DC line, or not at all; and 1800 MW would flow through the Phase 2 converter terminal and the remaining 200 MW through the Phase 1 terminal. Amendment Update, Vol. 1 at 63-65.

In comparison to the reference case, the Phase 2 case produced the following set of energy loss impacts over the 10-year contract period: (1) energy loss costs totalling $12.4 million[75] for the 2000-MW DC line from the Canadian border to the Phase 1 terminal in Comerford; (2) energy loss costs amounting to $24.4 million for the 133.1 mile, 2000 MW DC line between Comerford and the Phase 2 terminal at Sandy Pond, Massachusetts;[76] (3) energy loss costs of $26.5 million associated with the operation of the Phase 1 and Phase 2 converter terminals; and (4) energy loss savings of $102.0 million on the operation of NEPOOL's AC bulk power transmission system. Amendment Update, Vol. 1 at 63-65.

The net effect of these additive energy loss estimates is to reduce New England's system energy losses by $38.7 million over the 1990s. The Companies cite two reasons to explain these estimated savings: transmission of electricity over ± 450 kV DC facilities is more efficient than transmission over 230 and 345 kV AC facilities in terms of line losses and most Phase 1 and Phase 2 imports will be delivered at a location relatively close to load centers in southeastern New England. This will result in more efficient loadings on the existing AC system than would occur if New England did not have the Phase 2 facilities, had to generate electricity from its own oil-fired generators, and had to accept Phase 1 imports only through the Phase 1 converter terminal. Amendment Update, Vol. 1 at 45; Ex. ROB, at 11-12.

The annual savings associated with these energy loss impacts range from $5 million to $10 million a year through the 1990s. EFSC Ex. 47.

The Siting Council finds these estimates are acceptable for use in an evaluation of project-level costs and benefits.

g) Environmental Impacts

The Companies have estimated that certain types of environmental impacts will result from the implementation of the Phase 2 Project as structured under the Firm Energy Contract. These "project" impacts are distinct from those "facility impacts" that relate to the siting, construction and operation of the proposed Phase 2 facilities.[77]

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[75]The figures in this paragraph reflect the 10-year cumulative present worth of revenue requirements associated with energy loss impacts, expressed in 1990 dollars.

[76]Sandy Pond is the Companies' preferred site for the Phase 2 converter terminal. See Sections III.B.1 and 2.

[77]These facility-related environmental impacts are discussed in detail in section III.C.4.

The delivery of energy produced from hydroelectric facilities in northern Canada under Phase 2 is expected to enable NEPOOL to avoid generating 7 billion kWh of energy per year for 10 years that otherwise would have to be produced by other energy sources in New England.

The Companies estimate that nearly all of the total 70 billion kWh displaced by Phase 2 would have been generated at oil-fired powerplants in New England. EFSC Ex. 42; EFSC Ex. 44. Over one third of this oil is expected to have relatively high-sulfur content. EFSC Ex. 42. The avoided local generation represents approximately 120 million barrels of oil, or about 12 million barrels a year for 10 years. EFSC Ex. 67 at VI.B-1. Such reduction in oil consumption is projected to produce several regional environmental impacts, in the area of air quality, acid deposition, water quality and solid waste disposal.

With respect to air quality impacts, the Companies project that the annual avoidance of burning 12 million barrels of oil would result in reduced emissions of air pollutants within New England.[78] These estimated reductions would include an average of 50,000 tons of sulfur dioxides, 1,500 tons of particulates, and 15,000 tons of nitrogen oxides during each year of the project. EFSC Ex. 67 at VI.B-1.

Since emissions of sulfur dioxides and nitrogen oxides are considered to be precursors of acid deposition, the Companies indicate that the reduced use of oil and the avoidance of emitting an estimated 50,000 tons of sulfur dioxides and 15,000 tons of nitrogen oxides annually for 10 years will reduce levels of acid deposition and any resulting adverse impacts on the environment that would have been attributable to the precursors. EFSC Ex. 67 at VI.B.3.

In the area of water quality impacts, the Companies estimate that Phase 2 energy imports will allow New England to avoid approximately 35 trillion British thermal units of waste heat that would have been produced and discharged each year as a by-product of oil-fired electric generation. EFSC Ex. 67 at VI.B-2.

Other avoided waste products identified by the Companies include 2700 tons of oil ash each year. Oil ash produced at oil-fired powerplants normally must be transported from the facility and deposited at properly equipped disposal sites in order to avoid leaching of metals into groundwater systems. The Companies expect that the need for such disposal sites and systems will be reduced by 2700 tons a year if Phase 2 goes into operation as proposed. EFSC Ex. 67 at VI.B-2 and -3.

The Siting Council finds that these project-related environmental impacts are generally beneficial to New England, even though the Siting

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[78]These estimates are relative to the amount the Companies project would have been produced in the 1990s to meet expected energy requirements, as opposed to reductions relative to the levels of air emissions experienced in 1985.

Council has not attempted to build a record of their direct and indirect economic value. The Siting Council also recognizes that these regional environmental benefits can be achieved only through the construction and operation of transmission facilities that are accompanied by other, more localized environmental impacts. These facility-related impacts are described and evaluated in Section III.C.4.

2. Comparison of Project Benefits and Costs

According to the Companies, the Phase 2 project will produce significant and positive net benefits. Amendment Update, Vol. 1 at 77. To reach this conclusion, the Companies compared the expected economic costs and benefits in several ways: on the basis of annual net benefits; in terms of cumulative present worth of benefits and costs over the 10-year contract period; and on the basis of payback period. Amendment Update, Vol. 1 at 73-80.

Using the Companies' estimates of net fuel cost savings,[79] capacity credits, energy loss savings, and construction costs, the annual costs and benefits of the project are summarized in Table 6. These estimates indicate that at the Companies' expected construction cost of $585 million, the project is expected to have net costs for the first two years, with net benefits occurring annually thereafter and rising to $379 million (current dollars) in the final year of the project. The net savings will flow directly to the customers of utilities that participate in Phase 2, and are expected to result in electric bills lower than they would have been without the Phase 2 project. Amendment Update, Vol. 1 at 77.

The estimated cumulative net savings for the 10 years of the project are also shown in Table 6. The cumulative present worth of benefits[80] is expected to be $1,700 million (1990 dollars), as compared to costs of $911 million.[81] These would yield net savings of $789 million over the 10-year contract period. Using these estimates, the project would pay for itself in approximately 5.7 years.

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[79] In this analysis, the Siting Council uses the results of the Companies' "Feasibility Study" for projections of fuel cost savings. See discussion in Section II.B.1.c.

[80] Including net fuel cost savings, capacity credits, and energy loss savings.

[81] These estimates of cumulative present worth of benefits and costs are based on the Siting Council's discounting of the Companies' current-dollar estimates using the 10.4-percent present worth rate proposed by the Companies. Amendment Update, Vol. 1 at 59. These discounted figures differ slightly from the Companies' figures, probably due to rounding error and use of different discounting formulas.

Table 6

HYDRO QUEBEC PHASE 2 PROJECT:
ESTIMATED ECONOMIC BENEFITS AND COSTS
(Millions of dollars)

	Economic Benefits						Economic Costs			
	Net Fuel Cost Savings		Capacity Credits		Energy Loss Savings		Construction Costs @ $585 M		Net Economic Benefits (Costs)	
	Current $	1990 $	Current $	1990 $	Current $	1990 $	Current $	1990 $	Current $	1990 $
1990/91	140	116	0	0	5	4	191	158	(46)	(38)
1991/92	170	128	0	0	6	5	184	138	(8)	(5)
1992/93	196	133	0	0	6	4	176	120	26	17
1993/94	238	147	26	16	7	4	169	104	102	63
1994/95	291	162	87	49	8	4	162	90	224	125
1995/96	251	127	122	62	9	5	156	79	226	115
1996/97	310	142	122	56	10	5	149	68	293	135
1997/98	334	138	122	51	5	2	143	59	318	132
1998/99	319	120	122	46	6	2	137	51	310	117
1999/00	379	129	122	41	6	2	128	44	379	128
10-Yr Cumulative Present worth ($1990)		1342		321		37		911		789

Sources: Current-dollar estimates from EFSC Ex. 47 except net fuel cost savings from "Feasibility Study," EFSC Ex. 208; estimates of constant-dollar savings and costs are based on Siting Council's discounting of current-dollar figures using the Companies' proposed present-worth rate of 10.4 percent (Amendment Update, Vol. 1 at 59).

The Siting Council concurs that the Companies' estimates of expected economic costs and benefits show substantial net savings from the Phase 2 Project. In fact, the Siting Council believes that the Companies might have understated their expected net economic benefits in several ways.

First, the Companies' analysis bases its comparisons of benefits and costs on an internally consistent 10-year time frame, so that for analytic purposes all costs associated with facility construction are presumed to be recovered within the 1990-1999 time frame. Tr. 4 at 127-128. In fact, the Companies expect that these capital costs actually will be recovered from consumers over the 30-year life of the transmission facilities, when additional benefits may flow. Tr. 2 at 150-155. Therefore, during the 1990s, consumers may actually realize greater dollar benefits in their electric bills than indicated by the Companies' analyses.

Secondly, the Companies have not attempted to attach a dollar value to the possibility of energy banking during the 1990s, as provided for in the Phase 2 Contract. Under the energy banking provision, NEPOOL could transmit to Quebec relatively inexpensive energy generated during off-peak hours and receive equivalent amounts during on-peak periods when generating costs are higher. Ex. ROB 1 at 10, 12-13. Additionally, economic benefits could result from actions of individual Phase 2 participants. Participants could elect to negotiate separate agreements directly with Hydro Quebec for purchases of entitlements in Hydro Quebec facilities, and still use their portions of the capacity in the Phase 2 facilities to transmit this power. Ex. ROB at 13-14; Tr. 2 at 65-68. Also, the Companies have not estimated the value of possible short-term or long-term sales of excess energy between Hydro Quebec and NEPOOL, both of which could occur during the 1990s. Ex. ROB at 10, 12-13.

Third, the Companies' use of a 20-percent NEPOOL installed-reserve requirement could understate the present worth of the reliability value associated with the Phase 2 intertie and Firm Energy Contract. If New England were presumed to need additional capacity sooner than 1993/94 (i.e., as would occur with a higher reserve level) then Phase 2 capacity would have reliability value sooner than 1993/94 and would be worth more in today's dollars. Similar effects would occur if the Companies had assumed that capacity were introduced earlier in the power year in which it is needed, or if the Companies had attached some risk to misestimating demand growth or the availability of power from various generating sources that are currently under construction or being planned.

Before concluding, however, that the Phase 2 Project is likely to achieve net benefits to the region, the Siting Council will review the sensitivity of the Companies' estimates to changes in key assumptions. Thereafter, the Siting Council will review whether the Phase 2 Project is the superior means to solve the region's need for energy and capacity at least cost and minimum environmental impact.

3. Sensitivity Analysis

a) Region-Wide Benefits

The Companies' witness Mr. Bigelow stated that Project "benefits are sensitive to fuel price escalation, timing of new generating units and the load growth rate." Ex. ROB at 16. As background for these conclusions, the Companies performed several studies of the sensitivity of estimates of Project benefits to changes in key assumptions. In addition, the Siting Council conducted several other sensitivity analyses using data provided by the Companies. Overall, the results of these analyses give the Siting Council confidence that the Phase 2 Project is likely to produce substantial economic benefits to New England consumers and that the Project risks are reasonable.

Among the sensitivity analyses performed by the Companies, was one provided in the Amendment Update. Between the time the original Amendment was filed with the Siting Council in November 1984, and updated in April 1985, the Companies had changed several assumptions and data input that affected the magnitude of their estimate of project benefits. The principal differences between the assumptions in the two filings were that the Amendment Update assumed lower fossil-fuel prices, slightly lower load growth, a lower discount rate, and various changes in the region's generation mix in the 1990s.[82]

The net effect of these changes was that the Amendment Update produced a 15-percent reduction in cumulative net Project savings relative to the results of the original Amendment. These differences are shown in Table 7 below. The Companies attribute this reduction largely to the lower fossil-fuel cost projections assumed in the Amendment Update.

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[82] In the 1984 Amendment, the following assumptions were used: annual long-term fuel price increases of 9.0 percent oil (#6) and 8.4 percent for coal (medium sulfur); load growth averaging 2.0 percent a year; a discount rate of 12.5 percent; and a 1990s supply mix that would include approximately 600 MW of customer generation; three 600-MW units, and one 100-MW gas turbine. Amendment, Vol. 1 at 13-17, 59. In contrast, the 1985 Amendment Update assumed: annual fuel price increases of 6.4 percent for oil and 7.5 percent for coal; load growth averaging 1.7 percent a year; a discount rate of 10.4 percent; and a 1990s supply mix that includes over 1000 MW of customer generation; one 600-MW coal unit, two 100-MW coal units, and three 100-MW gas turbines. Amendment Update, Vol. 1 at 13-17, 59.

Table 7

Comparison of Cumulative Project Benefit Estimates in the Amendment (11/84) and the Amendment Update (4/85) (millions of 1990 dollars)

	Amendment	Amendment Update
Cumulative Project Benefits	$2,026	$1,749
Cumulative Project Carrying Costs	1,019	897
Cumulative Net Project Benefits	$1,007	$ 852

Source: Amendment, Vol. 1 at 78; Amendment Update, Vol. 1 at 78.

In another set of studies, the Companies analyzed the sensitivity of the November 1984 estimates first with respect to changes in oil costs and then for the cancellation of Seabrook 1. EFSC Ex. 209(d) and (e). The Companies found that lower oil costs reduced consideribly the estimated net benefits, while the cancellation of Seabrook 1 increased project benefits.

The oil price study assumed oil costs were $10 a barrel above equivalent coal costs. Cumulative net fuel cost savings totaled $1,196 million -- a decline of $622 million (1990 dollars) relative to the results in the Amendment -- which represents a 34-percent reduction in these savings. EFSC Ex. 209(d). The study of the impacts of Seabrook 1 cancellation indicated that cumulative net fuel cost savings would amount to $1,976 million, an increase of $158 million, or 9 percent above those projected using the assumptions in the Amendment. EFSC Ex. 209(e).

The Companies also tested the sensitivity of the results of the Amendment Update to changes in coal-price and various generation-mix assumptions. In one analysis, the Companies relied on a fuel-cost forecast prepared by the NEPOOL Generation Task Force ("GTF"), which assumed lower coal prices than were presented in the January 1985 DRI fuel price forecast.[83] EFSC Ex. 121. The results showed only a $40-million or 3-percent increase in savings.[84] The study on various generation mix assumptions indicated NEPOOL would generate more energy

[83] This DRI forecast was used in the Amendment Update.

[84] Cumulative net fuel savings of $1,414 million rather than the Amendment Update's estimate of $1,374 million.

from oil-fired units. EFSC Ex. 121. Here, the cumulative savings decreased by only $28 million, or 2 percent, as compared to the results of the Amendment Update.[85] A study that assumed both the GTF fuel-price forecast and the increased reliance on oil-fired energy resulted in a reduction in cumulative savings of $107 million.[86]

In addition to these sensitivity analyses performed by the Companies, other studies were conducted by the Siting Council.[87] The Siting Council first attempted to reconstruct the Companies' estimate of avoided fuel costs, payments to Hydro Quebec and net fuel cost savings. Using data provided by the Companies on annual generation by fuel type (EFSC Ex. 42), fuel price forecasts (Amendment Update, Vol. 1 at 16-17), and a 10.4 percent discount rate (Amendment Update, Vol. 1 at 59), the

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[85] According to the Siting Council's discounting of the Companies' nominal dollar estimates, the cumulative net fuel cost savings would be $1,233 million rather than $1,374 million in the Amendment Update. This reduction might be explained by several factors: an increase in oil-fired generation would increase fossil-fuel savings, because Hydro Quebec energy would avoid more of NEPOOL's relatively high-priced generation; energy payments to Hydro Quebec would also increase, because average fossil-fuel costs would rise due to the higher percentage of oil in the NEPOOL generation mix; and the relative increase in payments to Hydro Quebec would exceed the relative increase in avoided fuel costs. Thus, projected net fuel cost savings would decrease.

[86] Cumulative net fuel cost savings totalled $1,267 million, as compared to $1,374 million in the Amendment Update.

[87] The Siting Council had to perform somewhat less sophisticated sensitivity measurements than those conducted by the Companies, due to lack of complete information on NEPOOL's annual hourly load curves and unit heat rates that would have been required to replicate fully the Companies' production-cost model results. Also, the Siting Council's analyses do not reflect comprehensive (direct and indirect) impacts of the assumption changes that it has investigated through its analyses. For example, these analyses focus on change in net fuel costs savings, since those are the principal expected economic benefits of the Phase 2 project. They may not always reflect consistent impacts on such things as capacity credits and line losses, since the Siting Council lacked sufficient information to calculate these second-order economic effects of changing the assumptions affecting fuel-cost savings estimates. Therefore, the Siting Council's analyses are useful primarily for identifying and evaluating generally the effect on fuel-cost savings projections of large changes in key variables or assumptions. The Siting Council did request that the Companies perform sensitivity and break-even analyses relating to changes in assumptions of special interest to the Siting Council. However, the Companies could not fulfill these requests due to resource limitations.

Siting Council produced a "base case" set of results that differed little from those in the Amendment Update.[88]

Using its base-case calculations,[89] the Siting Council tested the sensitivity of these results to changes in energy demand, fuel prices, Hydro Quebec Deficiencies, use of the surplus-sales provisions of the Firm Energy Contract, and the discount rate. Cumulative net Project benefits were found to be most sensitive to changes in oil prices, Deficiencies, and the availability of surplus energy to NEPOOL.

Increases or decreases in NEPOOL energy demand were found to produce relatively insignificant changes in overall Project benefits. A 10-billion-kWh increase in NEPOOL energy requirements in each power year -- equivalent to a 7-to-9 percent increase in generation -- would decrease total Project benefits by about 5 percent. In this test, the Siting Council assumed that additional generation would be met by oil-fired facilities.[90] A 10-billion-kWh annual decrease in energy requirements would increase total Project benefits by approximately 5 percent. Here, the Siting Council assumed that 8-billion-kWh of this energy reduction would have been displaced oil-fired generation, and the remaining 2-billion-kWh would be backed-out coal-fired generation.[91]

According to the Siting Council's analyses, non-completion of Seabrook 1 would lead to a 5 percent reduction in total Project benefits. According to the Companies, however, cancellation of Seabrook would increase Project benefits by approximately 10 percent. EFSC Ex. 209(e). The Siting Council believes that the difference in these results can be explained by the Companies' reliance upon the data and assumptions in the Amendment and the User Study, while the Siting

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[88]The differences are largely attributable to rounding error and use of the Feasibility Study estimates rather than the results of the User Study.

[89]These calculations were performed on a spreadsheet that used "LOTUS 1-2-3" software, instead of on a production cost model.

[90]This assumption is generally consistent with the generation data in EFSC Ex. 42, which indicate that Phase 2 energy would displace nearly all oil-fired generation in New England.

[91]These increased Project benefits resulting from reduced energy requirements are quite sensitive to assumptions concerning the generation mix displaced by Hydro Quebec firm energy. For instance, if only oil were backed out by the 10-billion-kWh reduction in energy requirements, then cumulative Project benefits would have increased by 10 percent, rather than 5 percent. The Siting Council believes that its use of a 80-percent/20-percent split between oil and coal backout might exaggerate the amount of coal actually backed out by a 10-billion-kWh reduction in energy demand from the level assumed in the Amendment Update.

Council used the information in the Amendment Update and Feasibility Study. The original Amendment assumed 1000 more megawatts of coal capacity in the 1990s in the generating mix, which would affect its estimate of project benefits. The Siting Council repeated its analyses of Seabrook 1 cancellation under the assumption that half of the replacement energy would come from coal-fired plants (rather than coming totally from oil plants, which was the original assumption). This change produced a 7 percent increase in total Project benefits relative to the Siting Council's base case. However, the Siting Council believes that this assumption is unrealistic, given the lead-time for constructing mid-sized baseload coal plants, and therefore believes that its original analysis of the impacts of Seabrook 1 cancellation could be more reliable, at least with respect to this assumption.

In contrast to these relatively small impacts associated with changes in projected energy requirements, total Project benefits appear quite sensitive to variation in oil price forecasts. The Siting Council's analyses indicate that a 10-percent increase or decrease in oil prices relative to those forecasted by DRI in January 1985 would increase or decrease cumulative Project benefits by 25 percent. A 30-percent change in oil prices would produce a 75-percent change in cumulative benefits. Total Project benefits are much less sensitive to variations in coal prices than to oil prices. A 10-percent change in coal prices relative to those projected by DRI would produce a 10-percent reduction in overall Project benefits.

In each case, there appears to be a positive relationship between the changes in fuel prices and the change in total project benefits: increased fossil-fuel prices increase Project benefits, and decreased fossil-fuel prices reduce benefits. The Siting Council's analyses of the sensitivity of Project benefits to changes in fossil-fuel prices are consistent with those reported by the Companies. The Companies found a substantial, positive relationship between oil-price changes and estimated benefit levels, and a less substantial relationship between changes in coal prices and estimates of Project benefits.

The Siting Council's investigations indicated that total project benefits are relatively sensitive to deficiencies in the delivery of Phase 2 energy, regardless of whether Hydro Quebec or NEPOOL is responsible for the deficiencies. Assuming oil-fired generation is called upon to make up for deficiencies, a New England Utilities Deficiency of 1 billion kWh in each year of the contract would decrease Project benefits by 50 percent.[92] A Hydro Quebec Deficiency of similar magnitude would reduce benefits by 20 percent.

Additionally, the Siting Council's analyses show that if NEPOOL can exercise its options under its interconnection agreements with Hydro

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[92]Net fuel cost savings would decrease by 35 percent and the NEPOOL participants would have to pay a penalty equal to an additional 15-percent reduction in benefits.

Quebec and obtain more than the 7 billion kWh provided for under the Phase 2 Contract, then total project benefits could be increased substantially. An additional annual purchase of 1 billion kWh would increase cumulative project benefits by 35 percent (assuming conservatively that this additional purchase displaced generation that was 80-percent oil-fired and 20-percent coal-fired in each year).

Further, the Siting Council studies indicate that total project benefits are relatively insensitive to changes in the discount rate. If the discount rate increased by one percentage point to 11.4 percent, as compared to the 10.4 percent used in the Siting Council's base case, project benefits would decrease by only about 5 percent. If the discount rate increased to 13.3 percent, benefits would decline by 20 percent. In either case, net project benefits would remain substantial.

Finally, the Siting Council constructed a "break-even scenario"[93] to assess the risk that the Project would produce no benefits at all. For analytic purposes, this break-even scenario assumed that: (1) oil prices were 26.6-percent lower than those in January 1985 DRI forecast; (2) capitalized construction costs were 25-percent higher than the Companies' expected cost of $585 million (i.e., costs at $730 million); (3) a discount rate of 13.31 percent;[94] (4) New England energy requirements 15-percent lower than those projected in the Amendment Update; and (5) the reduced load in assumption (4) would displace only fossil-fired generation.

Regarding the reasonableness of such assumptions, the Siting Council notes Witness Bigelow testified that "a plus or minus 25 percent in the 1990s is probably not an unreasonably wild guess" for a change in forecasted oil prices. Tr. 3 at 117. Also, a plus or minus 25-percent change in construction costs was incorporated in the Companies' own analysis for planning purposes.

The Siting Council believes that some risk exists that both the 25-percent increase in oil prices and the 25-percent increase in capital costs could occur. However, such increases would not necessarily be accompanied by the assumed reductions in demand and the increased discount rate. Therefore, the Siting Council believes that the assumptions in its break-even analyses are extremely conservative.

Further, the Siting Council recognizes that other contingencies could occur that could yield increased economic benefits associated with the Phase 2 contract and the construction of the Phase 2 transmission facilities. Such unquantified benefits could include the possibility of

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[93] The Siting Council asked the Companies to identify the conditions that would cause the project to "break even"; the Companies responded that resource constraints prevented them from fulfilling the request.

[94] This discount rate is the one used by the Companies in the sensitivity analyses reported in EFSC Ex. 121.

energy banking, and additional sales transactions between Hydro Quebec and NEPOOL (or Phase 2 participants) that utilize the Phase 2 facilities during the 1990s or thereafter. See discussion in Section II.B.2.

Therefore, in light of these possible conditions and especially in consideration of the conclusions of the various sensitivity analyses performed by the Companies and the Siting Council, the Siting Council finds that it is highly unlikely that the Project will produce negative benefits to New England consumers. Therefore, the Siting Council determines that the Project is beneficial to New England.

The Siting Council points out, however, that the foregoing benefit/cost analyses rely primarily on comparisons of a 1990s regional resource plan that includes Phase 2 firm energy, against one that relies more heavily upon fossil-fuel powerplants to provide both energy and capacity in the absence of the Phase 2 Project. In both the Companies' and the Siting Council analyses, Phase 2 firm energy is viewed as a replacement predominantly for oil-fired energy generation and for conventional fossil-fuel plant capacity.[95]

The Companies revealed a slightly different planning perspective in the presentation of the results of a busbar-cost analysis which compared the costs of Phase 2 power with power supplied by either a nuclear, coal or gas-turbine unit.[96] In these results, Phase 2 energy fared well, with an estimated busbar cost of 6.8 cents per kWh, as compared to 12.8 cents for a new nuclear facility, 14.8 cents for a new coal plant, and 18.4 cents for a peaking unit. EFSC Ex. 35. Still, even this analysis only compared Phase 2 power to conventional facility- construction options.

In the Siting Council's view, this array of analyses does not represent an evaluation of the full range of transmission and non-transmission alternatives.[97] The Companies confirmed that they did

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[95]The Amendment Update indictates that the Companies' reference case (that is, no Phase 2) includes the addition of gas-turbine peaking units and a mid-sized coal plant. Amendment Update Vol. 1 at 14. Apparently, the Companies project that such facilities would be required in the late 1990s even with the Phase 2 project. Before the late 1990s, Phase 2 is viewed for analytic purposes as displacing consumption of oil at existing powerplants and at peaking units that would otherwise have had to be built for reliability purposes by the mid-1990s.

[96]The comparisons were to new 1150-MW nuclear plant, a 600-MW coal plant, and a 100-MW peaking unit. EFSC Ex. 35.

[97]Siting Council Rule 64.8(3), by reference to Administrative Bulletin 78.2, requires an applicant requesting approval for a transmission line to discuss the "range" of transmission and non-transmission alternatives, and the methodology used by the applicant to identify the range of practical transmission and non-transmission

(Footnote Continued)

not compare the Phase 2 project to non-conventional options, such as demand management, small-power production or cogeneration, or even to a comprehensive resource plan that attempted to optimize investments in and/or purchases from facilities and demand-management strategies. Tr. 4 at 152. The Siting Council believes the Companies' presentation is lacking in this respect.[98] Therefore, while the Siting Council finds that the Phase 2 Project is the least-cost approach among the alternatives evaluated by the Companies, the Siting Council simply cannot determine whether the project is or is not the least-cost, least-environmental-impact solution to New England's long-term energy and reliability needs.

Still, the Siting Council is aware that many demand-management and small-power options are in developmental stages in many parts of New England. The Siting Council recognizes that it could be difficult to bring forth sufficient amounts of economical demand reduction and/or alternative supply additions on the scale and in the time frame being

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(Footnote Continued)
alternatives. Further, the Siting Council regards conservation and load management as a supply source to be evaluated on an equal footing with conventional sources. In Re COM/Electric, 12 DOMSC 39, 72 (1985). The Companies' witness Bigelow testified that Hydro Quebec 2 could be viewed as complementing conservation. Tr. 4 at 185-86. And, the Companies argue that a non-transmission alternative would mean energy would not be imported from Hydro Quebec. Memorandum at 7. Nevertheless, conservation and load management must be considered as sources of supply along with conventional supply sources. Indeed, the Siting Council's statute requires an applicant to include in a forecast or supplement a description of planned action including "other sources of electrical power." Mass. Gen. Laws Ann., Ch. 164, Sec. 69I. Also, the Companies appear to suggest that demand and supply are not linked in the statutory scheme. Specifically the Companies state the Siting Council's Rules requiring conservation policies to be considered in the demand methodology do "not seem particularly pertinent to the question at hand." Memorandum at 7. As stated previously in this Decision, the Siting Council can approve a forecast or supplement if it determines the projected demand for electricity is based on substantially accurate historical information and measurable statistical projection methods. The Companies did not present in the filing an evaluation of conservation either as part of a demand methodology or as a supply source.

[98] The Siting Council is aware that NEPOOL's 1985 CELT report, which provided the basis for supply assumptions used in the Amendment Update, projects that over 1000 MW of "customer generation" will be available to NEPOOL utilities in the 1990s. EFSC Ex. 10 at 28. According to the Companies, this reflects utility purchases of electricity from small-power producers and cogenerators. Additionally, the 1984 NEPOOL Energy and Load Forecast assumes 400-1000 MW of demand-management impacts from utility-sponsored programs in the 1990s, as opposed to price-induced conservation. EFSC Ex. 22.

proposed for the start of the Phase 2 Project, although the record in this proceeding sheds little light on this subject.

Given that the Hydro Quebec Phase 2 Project is proposed for the period beginning in the winter of 1990, and given that this record indicates New England's need for low-cost energy and additional capacity to exceed the quantity to be provided by Phase 2, the Siting Council finds that the Phase 2 project is an acceptable solution to the region's power needs, even though the Companies have not compared it to what the Siting Council would consider a full range of alternatives.

The Siting Council intends that future proposals to construct electric facilities in the region, and the evaluation of supply plans, will be subject to comprehensive reviews of alternative least-cost, minimum-environmental-impact resource plans.

b) Massachusetts Benefits

In this final section on project-level benefits and costs, the Siting Council reviews whether its preceding determination that the Phase 2 Project will produce net benefits to the region, would be consistent with findings based on the distribution of costs and benefits to Massachusetts consumers.

(1) Background: Allocation of Benefits to States

The Phase 2 Use and Support Agreements establish the method for allocating total fuel-cost and energy-loss savings, capital costs, and capacity shares among participating utilities. Capacity credits are treated separately by NEPOOL. A participating utility will benefit economically from its share of the capacity from the Project when, in the absence of Phase 2, that company would have had to obtain alternative capacity.

The Use and Support Agreements call for allocating 90 percent of the benefits and costs according to each participant's percentage share of KWh sold by all the participants in 1980, and apportioning the remaining 10 percent to the "host states" of Vermont and New Hampshire. For this purpose, Massachusetts is not considered a host state.

These allocation methods were the result of negotiation. Tr. 4 at 123-125. During negotiations on the original Phase 1 participant agreements, when the allocators were determined for a possible later Phase 2, the negotiators agreed to a constant allocator for all years of both projects. The underlying principle was that all participants had to bear a certain level of risk in the short run in order to bring the project to fruition, and that benefits ought to be tied to that fixed share of project risk. Tr. 3 at 155-156.

The host states wanted extra shares for several reasons. First, the Phase 1 facilities, designed for both Phase 1 and Phase 2, would be constructed entirely in Vermont and New Hampshire, and would be used exclusively for Hydro Quebec deliveries, rather than for general transmission purposes. Most of the Hydro Quebec power would flow through these states to serve demand in other parts of New England, while the two states shouldered the environmental impacts of facility construction and operation. Tr. 4 at 100-101.

Secondly, for Phase 2, additional facilities would have to be built in New Hampshire to extend the Phase 1 DC facilities southward, and new lines would need to be located in Massachusetts. Phase 2 power still would have to flow through the original DC facilities in Vermont and New Hampshire to reach to southern New England load centers. Representatives from Vermont and New Hampshire required an extra incentive to agree to the Project because those states would be bearing the major environmental burden but receiving only a small portion of project savings. Since approximately 40 percent of the Phase 1 and Phase 2 power would serve demand within Massachusetts, the negotiators decided not to press for a "host state" share for Massachusetts. Further, the negotiators believed that the proposed Phase 2 AC facilities were being constructed mainly to improve the reliability of the southeastern Massachusetts transmission system, while the costs of the AC system additions and upgrades were being paid for by all of New England. Tr. 4 at 100-101.

(2) Massachusetts Share of Project Benefits and Costs.

Even though Massachusetts does not receive a host state share, the Companies believe that Massachusetts consumers will benefit substantially from the Phase 2 Project.

Assuming a $585 million project cost, the Companies estimate that net project benefits to Massachusetts consumers would increase from a net cost of about $14 million in 1990/91 to a net benefit of about $152 million in 1999/00. Amendment Update, Vol. 1 at 80.[99] Assuming the Companies' original estimate of $875 million of cumulative present worth of net benefits for New England as a whole, Massachusetts would expect to receive approximately $350 million in cumulative net benefits (1990 dollars). The Project payback period would be approximately 6-years. Amendment Update, Vol. 1 at 80.

These estimates of net project benefits are based on the receipt by Massachusetts of approximately 40 percent of the total benefits available to New England. Amendment Update, Vol. 1 at 77. The benefits include 40 percent of "direct costs and benefits" (fuel cost savings, energy loss savings, and capital costs) and capacity credits, where the economic benefit of capacity is realized starting in 1993/94, the year New England (rather than Massachusetts) needs capacity.

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[99] These current-dollar estimates are based on the "User Study" results.

Another way to examine potential savings and costs for Massachusetts is to analyze the timing of the need for capacity of Massachusetts electric companies and make available the economic value of their share of Phase 2 capacity credit starting in the appropriate year. Since the Siting Council believes it is likely that Massachusetts companies as a group will need to add capacity sooner than New England, an earlier reliability benefit for Phase 2 firm energy could result in increasing the relative value of the project for Massachusetts consumers.[100]

Table 8 summarizes the Siting Council's estimates of total annual Project benefits by each Massachusetts utility company. To estimate these figures, the Siting Council used: (1) the annual estimates of direct costs and benefits from Table 6; (2) the formula in the Use and Support Agreements for allocating direct costs and Phase 2 benefits; and (3) the information on the individual companies' needs for capacity, as developed in Section II.A.3.

The information in Table 8 indicates that annual Project benefits could be positive for Massachusetts as a whole starting in the first year of the project.[101] This result contrasts with the Companies' estimate that New England as a whole will not receive positive annual net benefits until the third year of the project. See Table 8, columns a and b.

Further, cumulative Project benefits for Massachusetts could total approximately $350 million (1990 dollars), which is nearly 45 percent of total NEPOOL benefits. Thus, even though Massachusetts utilities would have rights to only 38 percent of the Project's direct costs and savings (EFSC Ex. 64), the Siting Council believes that Massachusetts could receive an even higher percentage of total Project benefits when the economic value of capacity benefits is included. While the project payback period is approximately 5.7 years for New England, it could be closer to 4.4 years for Massachusetts.[102]

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[100]The Siting Council recognizes that it has not yet reviewed the most recent long-range forecasts of all Massachusetts electric companies. As described earlier, the Council is utilizing the forecasts and Supplements adjusted for certain assumptions for sensitivity analysis purposes. See Section II.A.3.

[101]Some individual Massachusetts companies could have net costs for the first 2 or 3 years, and positive benefits thereafter. These companies (NEES, NU and Taunton) do not project capacity shortfalls until the mid-1990s or beyond. See Table 3.

[102]Note that this is an estimated state-wide average; some utilities could have shorter or longer payback periods, as indicated in Table 8.

Table 8
Net Project Benefits for NEPOOL, Massachusetts
and Major Massachusetts Companies
(millions of 1990 dollars)

	NEPOOL	MASS.	BECo	COM/Elec	EUA	Fitchburg	MMWEC	NEES	N.U.	Taunton
1990/91	-38.0	4.4	5.0	0.3	1.0	0.1	1.2	-4.4	-1.3	-0.1
1991/92	-5.0	25.8	7.4	2.6	1.5	0.3	2.3	-0.7	-0.2	-0.0
1992/93	17.0	31.3	9.1	3.1	1.8	0.4	2.8	2.0	3.5	0.1
1993/94	63.0	39.0	11.3	3.8	2.2	0.4	3.5	5.4	4.2	0.2
1994/95	125.0	47.0	13.7	4.6	2.7	0.5	4.2	8.8	5.0	0.2
1995/96	115.0	36.8	10.7	3.6	2.1	0.4	3.3	6.1	4.0	0.2
1996/97	135.0	43.9	12.8	4.3	2.5	0.5	3.9	9.1	4.7	0.3
1997/98	132.0	43.3	12.7	4.3	2.5	0.5	3.9	9.4	4.6	0.3
1998/99	117.0	38.2	11.2	3.8	2.2	0.4	3.4	8.2	4.1	0.2
1999/00	128.0	42.7	12.5	4.2	2.5	0.5	3.8	10.1	4.5	0.3
	======	======	======	======	======	======	======	======	======	======
Cumulative Savings (10-year)	789.0	352.4	106.4	34.6	21.0	4.0	32.3	54.0	33.1	1.7
Payback period (# of years)	5.7	4.4	4.3	4.4	4.3	4.4	4.3	6.5	4.9	6.2

Sources: * NEPOOL figures based on data compiled in Table 6 (from EFSC Ex. 47 and "Feasibility Study" estimates of fuel cost savings, from EFSC Ex. 209(f)).

* Massachusetts figures based on 38 percent of NEPOOL annual fuel cost savings, energy loss savings, and construction costs, after 10 percent host-state shares removed from NEPOOL totals. Capacity credits based on 38 percent of 1500 MW (344 MW) awarded when Massachusetts could need capacity (201 MW in 1990/91; 143 MW in 1991/92).

* Massachusetts companies' figures based upon each company's share of 90 percent of NEPOOL's fuel cost savings, energy loss savings, and construction costs, anc capacity credit awarded in year each company estimates it will need capacity (See Table 3).

The Siting Council has utilized the forecasts of Massachusetts companies for the limited purpose of evaluating whether its earlier finding that Phase 2 will be beneficial to New England is consistent with an evaluation of the Phase 2 costs and benefits to Massachusetts.[103] If these long-range forecasts' data are reliable, then the Siting Council believes that Massachusetts consumers are reasonably assured of benefitting from the Phase 2 project, and that it is reasonably likely the Phase 2 project will produce net benefits to Massachusetts.

III. ANALYSIS OF THE PROPOSED FACILITIES

Having found that the proposed Hydro Quebec Phase 2 project is consistent with the Siting Council's mandate, the Siting Council must determine whether construction of the proposed facilities also is consistent with the mandate.

Specifically, the Siting Council examines whether the existing New England transmission system is adequate to import the 2000 MW of power (i.e., whether there is a need for facilities); whether the applicant has identified proposed facilities and a reasonable range of practical alternatives that satisfy any previously identified need (Administrative Bulletin 78.2); and whether the proposed facilities are superior to the alternatives.

A. Scope of Review

Before approving an application to construct facilities under its jurisdiction, the Siting Council must find that the proposed construction is consistent with its mandate to "provide a necessary energy supply for the commonwealth with a minimum impact on the environment at the lowest possible cost." Mass. Gen. Laws Ann. Ch. 164, Sec. 69H. In so doing, the Siting Council determines whether capacities for proposed facilities are "... based on substantially accurate historical information and reasonable statistical projection methods." Mass. Gen. Laws Ann. Ch. 164, Sec. 69J.

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[103] The statute specifically mandates the Siting Council to consider approved forecasts of other companies. In the last two years, the Siting Council has approved the demand projections of several companies, e.g. Boston Edison Co., 10 DOMSC 203 (1983); COM/Electric System, 12 DOMSC 39 (1985); Eastern Utilities Associates, 11 DOMSC 61 (198); Massachusetts Electric, et al, 12 DOMSC 197 (1985); Massachusetts Municipal Wholesale Electric Companies, 11 DOMSC 1 (1984); Northeast Utilities, 11 DOMSC 237 (1984); and Taunton Municipal Lighting Plant, 10 DOMSC 252 (1984). In those proceedings, the Siting Council ruled on the reliability of the forecast demand methodologies. Thus the Siting Council believes the use of the pending forecasts is appropriate for the purpose of sensitivity estimates.

In practice, the Siting Council requires applicants to justify facility construction proposals in three phases.

First, the Siting Council requires the applicant to show that facilities are needed. Specifically, given the demand projections, existing facilities, and supply resources contained in an approved forecast or forecast supplement, the applicant must show that its existing facilities are inadequate to provide a necessary energy supply over the forecast period. For an electric transmission system, the Siting Council has found that the inability of the system to withstand the loss of any single major component is sufficient to justify the need for facilities in order to maintain reliability. In Re Taunton Municipal Light Plant, 8 DOMSC 148, 154 (1982); In Re Com/Electric, 6 DOMSC 33, 44-47 (1981). Alternatively, the Siting Council might base its determination of need on other considerations of reliability, or on trade-offs between environmental impacts and cost.[104]

Next, the Siting Council requires the applicant to present construction plans for facilities that satisfy the previously identified need. Along with the proposed facilities, the Siting Council requires an applicant to identify a reasonable range of practical alternatives, including non-construction alternatives. See Siting Council Administrative Bulletin 78-2, "High Voltage Transmission Facilities," at 8.

Finally, the Siting Council requires the applicant to show that the proposed construction plan is superior to the proposed alternatives. The proposal and the alternatives are compared on the basis of the environmental impact and the cost of maintaining a secure source of power, consistent with the Siting Council's statutory mandate.

B. Are Additional Facilities Needed?

1. Description of the Existing System

Because of its magnitude, the proposal to import 2000 MW of power from Hydro Quebec will affect system operations through much of the New England high-voltage electric transmission system ("the System" or "the New England grid"). The power engineering impacts of the proposed import extend across state lines and across utility service territories. Thus, in reviewing the need for the proposed facilities, the Siting Council considers the operations of the relevant portions of the whole System without limiting its analysis to facilities physically located in Massachusetts or to facilities owned by the lead applicants.

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[104] In one instance, the Siting Council has approved a proposal to construct facilities without explicitly determining that the proposed facility was necessary to provide an energy supply. In that case, the approval was based on economic considerations. The Siting Council found that the balance between cost and environmental impact was favorable
(Footnote Continued)

Figure 2 is a geographic map of the New England transmission grid. The map shows the major AC transmission lines operating at 345 kV, 230 kV, 115 kV and 69 kV, as well as important substations and generating stations. In analyzing the proposed Phase 2 facilities, the Siting Council assumes the New England grid includes both the Phase 1 facilities outside Massachusetts including the Comerford DC/AC converter terminal and the 450 kV DC transmission line between Comerford and the US/Canada border.

2. Adequacy of the Existing System.

The Companies propose to import the power over a DC intertie between the Hydro Quebec and New England transmission systems. The Companies' witness, Mr. Snow, gives several reasons for preferring a DC intertie to an AC intertie. Specifically, he asserts that a DC intertie would better maintain the reliability of the New England system independent of the Hydro Quebec system; and that only a DC intertie would allow the flow of energy between the two systems to be closely controlled. Ex. RHS at 7-11. Moreover, facilities to implement a DC intertie are already under construction in connection with Phase 1, whereas there are no existing or proposed AC interties between Hydro Quebec and any other system. Ex. RHS at 10.

For the intertie, the Companies proposes to use the Phase 1 DC line, which was designed with a transmission capacity of 2000 MW, in anticipation of the line serving as the intertie for imports under both the Phase 1 arrangement, and possible additional purchases of energy from Hydro Quebec. Ex. RHS at 5.

In addition, the Companies propose to construct additional capacity for converting DC power to AC power. The Phase 1 converter terminal was designed with a nominal capacity of 690 MW. Thus, the Companies state construction of at least 1310 MW of additional DC/AC conversion capacity is required to import the full 2000 MW of DC power into New England.

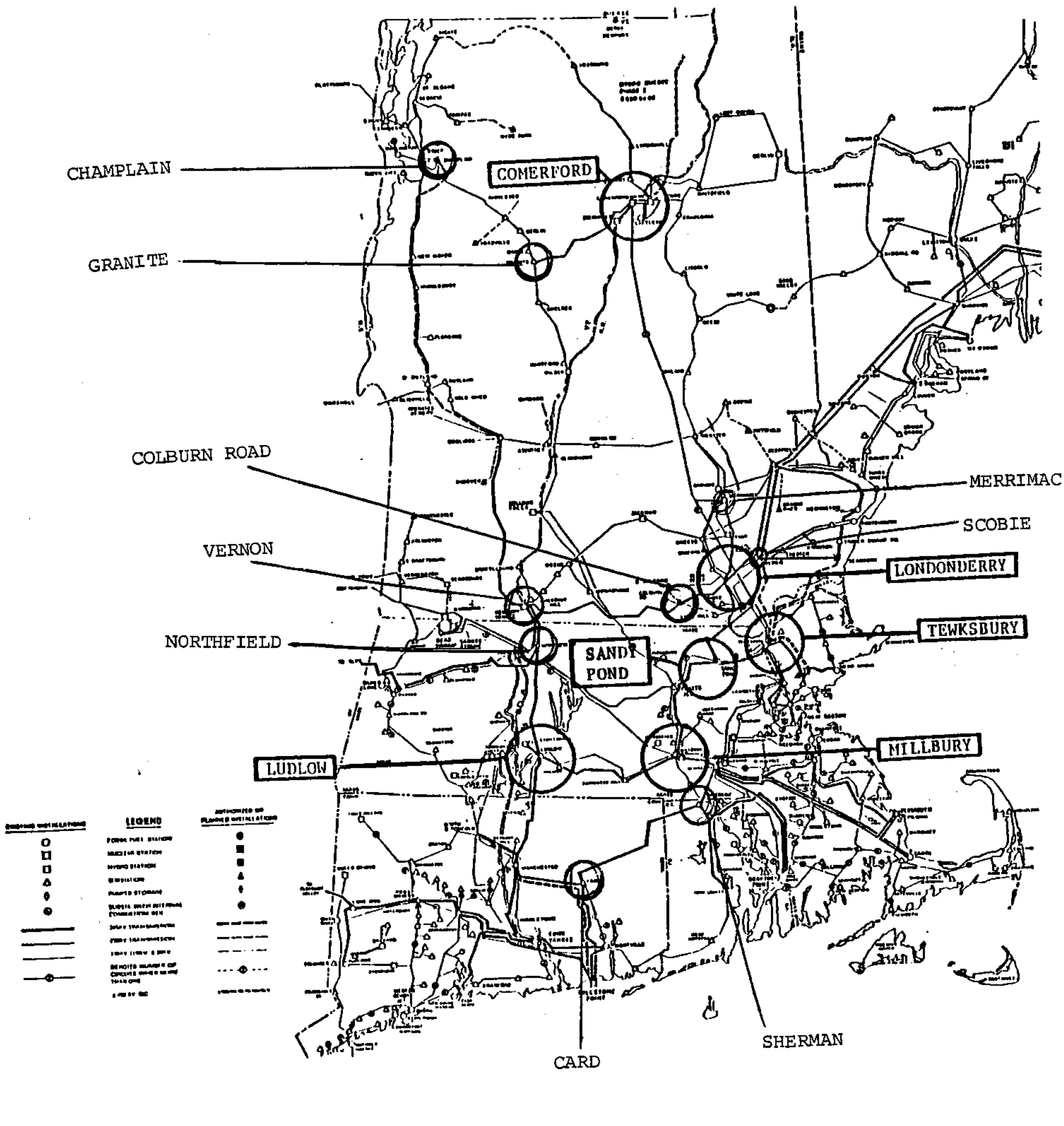
Finally, the Companies propose to construct AC and DC transmission lines to distribute the imported power from the terminus of the Phase 1 DC line to load centers in central New England. The Companies' witness states that the Phase 1 converter terminal was not designed on a firm transmission basis: in certain contingencies,[105] the New England grid is inadequate to accept 690 MW of Phase 1 imported power through the intertie. Ex. RHS at 46-47.

(Footnote Continued)
because the environmental impact was minimal. In Re Boston Gas Co., 11 DOMSC 159, 163 (1984).

[105] Those contingencies include outages on the existing 230 kV AC transmission lines between the following substations: Comerford and Tewksbury, Comerford and Granite (near Barre, Vermont), or Comerford and Merrimack (New Hampshire). Tr. 9 at 89-91.

Figure 2

New England Geographic Transmission Map



Source: Exhibit 10, NEPOOL Forecast Report of Capacity, Energy, Loads and Transmission, 1985-2000 at 50.

The Companies cannot import power from Hydro Quebec without a transmission intertie. The Siting Council concurs that it is desirable to use the Phase 1 DC line as the intertie for Phase 2, inasmuch as there is no need to construct additional facilities north of Comerford.

Also, the Companies cannot import 2000 MW of DC power into the New England AC transmission system without 2000 MW of DC/AC conversion capacity. The existing System includes only 690 MW of DC/AC conversion capacity. Thus, the Siting Council finds that there is a need to construct at least 1310 MW of additional DC/AC conversion capacity to implement the import.

Finally, given the inadequacy of the existing system under certain conditions to accept the Phase 1 import of 690 MW, the Siting Council concludes the existing system is inadequate to accept the Phase 2 import of 2000 MW on a firm basis under the same conditions. Moreover, the Siting Council believes that the New England grid should be designed to accept the full 2000 MW import on a firm basis despite the loss of any single major AC system component.

The basis of the need for transmission facilities is more complicated. The Company states that it "... considered installing the Phase 2 facilities without reinforcing the AC system ..." but found that reliability standards could not be maintained without construction. EFSC Ex. 191.

Indeed, the Companies state that changes in operating procedures cannot substitute for construction because, EFSC Ex. 191:

> It is not feasible to operate the converter terminal at power levels of 1310 MW or above and still maintain system stability unless the AC system is strengthened. In the case of AC system instability, the damage is done, and the system is lost, the moment the initial short circuit occurs. There is no time for DC converter terminal power adjustment to compensate for a weak or underbuilt AC system once the short circuit has occurred.

The issue here is not economics, but operations. Thus, remedies that consider only project economics (e.g., not building any new transmission lines, reducing import levels when outages occur, and preparing to pay the contractual penalties for doing so) do not compensate for the increased level of risk of widespread system damage or loss after an outage.

Therefore, the Siting Council finds there is a need for additional transmission facilities to distribute the Phase 2 power into the New England grid on a firm basis.

C. Are the Proposed Facilities Consistent with the Need to Provide Energy Supplies with a Minimum Impact on the Environment at Lowest Possible Cost?

1. Description of Proposed and Alternative Facilities.

To satisfy the needs identified above, the Companies presented the proposed facilities and 8 alternatives. Each alternative consists of 3 types of facilities: a DC/AC converter terminal with a nominal capacity of at least 1310 MW; a new 450 kV DC transmission line between the terminus of the Phase 1 DC line at Comerford and the site of the converter terminal; and additional 345 kV AC lines ("reinforcement lines"), which the Companies state are required to maintain System reliability and stability. Ex. RHS at 16.

The Companies propose to construct the Phase 2 converter terminal adjacent to the existing Sandy Pond 345 kV AC substation in Groton and Ayer, Massachusetts. For this option ("the Sandy Pond option"), the Phase 2 DC line would be constructed along existing rights-of-way between Comerford and Sandy Pond, a length of 133 miles. In addition, the Sandy Pond option includes the construction of two 345 kV AC reinforcement lines ---- one from the Sandy Pond substation to the existing Millbury 345 kV AC substation in Millbury, Massachusetts ("the proposed Sandy Pond-Millbury line"); the other from the Millbury substation to the existing West Medway 345 kV AC substation in Medway, Massachusetts ("the proposed Millbury-Medway line").

As summarized on Table 9, the Companies identified 5 alternative sites other than Sandy Pond for the Phase 2 converter terminal. Each location requires a different length Phase 2 DC line to interconnect with the terminus of the Phase 1 DC line at Comerford. Additionally, each location requires a set of reinforcement lines.

The Companies identify the same set of reinforcement lines for the proposed construction plan and 3 of the alternatives: the Sandy Pond, Tewksbury, Millbury and Ludlow options, although Ludlow would require only the proposed Millbury-West Medway line.

The Companies indicate that more than one set of AC reinforcement lines is required for 2 of the alternative Phase 2 terminal sites, i.e., at Comerford and Londonderry. All of the Comerford and Londonderry options require at least construction of the proposed Sandy Pond-Millbury and Millbury-Medway lines. Some options also require additional reinforcement lines.

Each of the 3 potential "Comerford" converter terminal sites would require different additional reinforcement lines. The Vermont alternative includes construction of one 345 kV AC line between Comerford and an existing 345 kV AC substation in Coolidge, Vermont, and a second 345 kV AC line between Comerford and an existing 345 kV AC substation in Champlain, Vermont. The New Hampshire alternative calls for construction of a 345 kV AC line between Comerford and Sandy Pond and another between Comerford and an existing 345 kV AC substation in Scobie, New Hampshire. Likewise, the New Hampshire-Vermont alternative

TABLE 9

Summary of the Proposed Facilities
and the Alternatives

Phase 2 converter terminal site[1]	Length of DC line from Comerford to terminal	Required 345 kV AC reinforcement lines
Proposed		
Sandy Pond	133 miles	Sandy Pond-Millbury Millbury-West Medway
Alternatives		
Tewksbury	127 miles	Same as proposed
Millbury	171 miles	Same as proposed
Londonderry (looped)	108 miles	Sandy Pond-Millbury Millbury-West Medway[2]
Londonderry (unlooped)	108 miles	Sandy Pond-Millbury; Millbury-West Medway; Londonderry-Sandy Pond Londonderry-Scobie
Ludlow	220 miles	Millbury-West Medway
Comerford (VT)	0.5 miles	Sandy Pond-Millbury Millbury-West Medway Comerford-Coolidge Comerford-Champlain
Comerford (NH)	0.5 miles	Sandy Pond-Millbury Millbury-West Medway Comerford-Sandy Pond Comerford-Scobie
Comerford (NH/VT)	0.5 miles	Sandy Pond-Millbury Millbury-West Medway Comerford-Coolidge Comerford-Sandy Pond

Source: Ex. RHS at 18-19; Ex. RHS-29; EFSC Ex. 40, Appendices at 30-31; and EFSC Ex. 98.

Notes:

1. The Companies analyzed converter terminal conversion capacities at a later stage.

2. The need for this line depends on the size of the converter terminal.

calls for construction of 345 kV AC lines: one between Comerford and Sandy Pond, and between Comerford and Coolidge, Vermont.

The Companies identified two alternatives for a converter terminal at Londonderry, New Hampshire. Both alternatives would require construction of a 345 kV AC line between Londonderry and Sandy Pond, and another between Londonderry and Scobie. The looped option differs from the unlooped option in that it requires alteration of two existing 345 kV AC lines.

2. Review

a) Identification of a Reasonable Range of Alternatives

To determine whether the Companies have identified a reasonable range of alternatives, the Siting Council reviews the breadth of the options from the perspectives of both power engineering and geography.[106]

Early in the site-selection process, the Companies developed the belief that a site in northeastern Massachusetts would be the best location for the Phase 2 converter terminal due to the site's proximity to southern New England load centers. Further, the Companies preferred to locate the new converter terminal near an existing 345 kV AC transmission line, and to maximize the use of existing rights-of-way for construction of the Phase 2 DC line between the Phase 2 converter terminal and Comerford. Tr. 9 at 15-16.

The Sandy Pond, Tewksbury, and Millbury sites all met the Companies' criteria.

The Companies also identified several alternatives to test alternative power-engineering design strategies. Thus, the Ludlow site was selected because of its proximity to Connecticut load centers. The Ludlow option requires a DC line of greater length and less AC reinforcement than the northeastern Massachusetts sites. The Companies selected the Comerford sites to compare the relative merits of alternatives that utilize AC transmission lines to bring the power south from Comerford. The Companies identified the alternative Londonderry sites as a compromise between these AC and DC transmission strategies. Ex. RHS at 19-20.

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[106] The Siting Council focuses its examination on the breadth of the options for locating the DC/AC converter terminal, because selection of a terminal site practically dictates the choices of routes for the Phase 2 DC line. The options for selecting AC reinforcement lines are reviewed in the next section, where the Siting Council determines whether the examined options are "practical." See section III.C.1.b.

In addition, the Companies' witness stated that the identified alternatives were generally representative of sites in a wide geographic range. Ex. RHS at 19. The Sandy Pond, Tewksbury and Millbury sites are representative of sites throughout eastern and central Massachusetts. The Ludlow site is representative of sites in western Massachusetts. The Comerford and Londonderry sites are representative of sites in northern and southern New Hampshire.

The Siting Council notes that the Companies identified not one, but 3 alternatives that satisfy the Companies' initial criteria for the Phase 2 converter terminal location. Also, the Companies identified three alternative strategies for bringing the power south from Comerford. Moreover, for the two potential converter terminal sites which would require the greatest reliance on 345 kV AC lines to transmit the power south from Comerford (i.e., the Comerford and Londonderry sites), the Companies identified more than one transmission option.

In view of the diversity of these options, the Siting Council finds that the Companies identified a reasonable range of power engineering strategies for bringing the power south from Comerford. Further, the Siting Council notes that the identified alternative sites for the new converter terminal are representative of locations throughout a large part of New England. Thus, the Siting Council finds that the Companies considered a reasonable range of geographic alternatives for the Phase 2 converter terminal site.

Consequently, the Siting Council finds that the Companies identified a reasonable range of alternatives.

b) Identification of Practical Alternatives

(1) Selection Process

To determine whether an alternative is "practical," the Siting Council first reviews the process used by the Companies to identify the proposed facilities and the alternatives.

The Companies identified the options in three phases. First, the Companies identified potential sites for the Phase 2 converter terminal. Then, the Companies selected a route for the Phase 2 DC line and each alternative terminal site that maximized the use of existing rights-of-way. Then, the Companies performed studies to select the reinforcement lines included in each option.

The Siting Council notes that all 9 of the options identified by the Companies assume that the Phase 2 DC line will be constructed solely on existing rights-of-way. The Siting Council stated in an earlier case that

> [I]n many cases the use of an existing right-of-way as the site of new lines is the most appropriate way to achieve the proper statutory balance of the need, environmental, and cost factors... .

In Re Boston Edison Companies, 3 DOMSC 44, 54 (1978). The Siting Council endorses the application of the foregoing policy to the present proceeding. Consequently, the Siting Council finds that the Companies' choices of alternative routes for the Phase 2 DC line were practical for each of the nine options.

Given a reasonable range of alternative terminal sites and a practical Phase 2 DC line matched to each site, the Siting Council must review only the appropriateness of the selection of AC reinforcement lines for each option in order to find that the Companies have identified a range of practical alternatives.

The Companies stated that the AC reinforcement lines were selected " ... to maintain system reliability and stability in connection with each of the alternative converter terminal locations." Ex. RHS at 16. The Companies reached conclusions regarding system reliability using the "Reliability Standards for the New England Power Pool." Ex. RHS-7.

> For transmission systems, these standards provide that all equipment must operate within normal capacity limits when there is no disturbance and must operate within acceptable emergency limits following any reasonably expected contingency. These standards also require that the transmission system be designed so that loss of critical elements of the system will not adversely affect the stability of the New England bulk power supply system.

Ex. RHS at 28-29.

"Normal" and "emergency" limits refer to the maximum amount of power (in MVA) that a transmission line can carry under normal and emergency conditions.[107] A transmission line that is loaded beyond its capacity limits can suffer permanent physical damage, shortened life expectancy and increased probability of failure in service. Ex. EFSC Ex. 133. "Stability" refers to the ability of an AC power system to keep all of its generators at the same constant speed after a disturbance. Ex. RHS at 8. The possible consequences of instability include permanent damage to generators and widespread loss of electrical service to customers for a long period of time. Id. at 40. A "disturbance" or "contingency" might include the loss from service of a major element of the New England grid, such as a major transmission line or generating unit.[108]

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[107] Ex. RHS-8 lists the normal and emergency power transmission limits for major transmission lines in central New England relevant to this proceeding. Other system components not discussed here (such as transformers) also have capacity limits.

[108] Ex. RHS-6 lists the disturbances evaluated at an early stage of the analyses.

The Siting Council concurs that reliable AC transmission systems should have line loadings that are below normal ratings under normal conditions and below emergency ratings after a contingency. In addition, the Siting Council agrees that the New England grid should maintain its stability despite the occurrence of a contingency. Failure of the System to meet these standards reasonably justifies construction of AC reinforcement lines.

Therefore, the Siting Council considers an alternative "practical" if, for a given alternative Phase 2 converter terminal site and associated DC line, AC reinforcement lines were selected which meet the reliability standards identified above at a minimal environmental impact and the lowest possible cost.

The Companies used three types of analysis to determine whether AC reinforcement lines are required. First, the Companies used the Contingency Analysis Program ("the CAP program") to calculate loadings on specific transmission lines and other elements under prespecified conditions. Using the output of the CAP program, the Companies can determine whether any system elements have loadings that exceed normal ratings under normal conditions or emergency ratings after a contingency. Next, the Companies use load-flow analysis to confirm loadings on system elements that the CAP program identified as potentially problematic. The load-flow analysis program is inherently more accurate than the CAP program; it also provides information on maintenance of voltage levels that the CAP program does not provide. Finally, the Companies use transient-stability analysis to determine whether the system's response to specific contingencies is stable or unstable.

These three types of analysis require similar inputs. Each requires a mathematical model of the electrical properties of the New England grid, including line operating voltages and capacities, and the configuration of relevant transmission lines, transformers, and breakers.[109] Each requires assumptions as to the level of System demand and the distribution of demand among various points in the System. Each requires assumptions as to the amount of power being provided by individual generating units in New England, as well as the site of the Phase 2 converter terminal. And, each requires specification of the contingencies which the System should be able to withstand.

As inputs, the Companies used data that conform to NEPOOL's expectations of what the configuration of the System will be in 1990.

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[109]The transient-stability analysis requires additional information about the dynamic properties of system elements.

Thus, the Companies assumed that the Seabrook 1 nuclear plant[110] and the as-yet unbuilt 345 kV AC transmission line between Seabrook and Tewksbury will be in operation. The Companies used the 1990 demand taken from the 1984 CELT report (EFSC Ex. 33), and allocated the demand among various points in the System using historical data from the Northeast Power Coordinating Council data base. EFSC Ex. 40 at 15; Tr. 9 at 67. The generation assumptions include both a base case economic dispatch of generators in New England, taken from the NU-UI scheduling program (EFSC Ex. 40 at 20); and simulation of a set of alternative dispatching assumptions for New England based on "severe but realistic assumptions with regard to the unavailability of existing generators in certain geographic areas" ("the generation bias conditions"). Ex. RHS at 26. The contingencies include the loss of major transmission lines, transformers and generators.

Using these analyses and inputs, the Companies selected AC reinforcement lines for each Phase 2 converter terminal site in 3 stages. First, the Companies analyzed each relevant contingency to determine whether line overloads or instances of instability occur. Next, the Companies proposed the addition of an AC reinforcement line or lines to alleviate the identified problem. Last, the Companies repeated the analysis assuming that the proposed AC reinforcement lines are constructed, thereby testing whether the proposed construction would solve the identified problems. Tr. 9 at 82.

The Siting Council finds that the use of the CAP program, load-flow analysis, and transient stability analysis is reasonable for determining instances of line overloading or system instability.

(2) Sensitivity Analysis

However, the Siting Council is concerned that the Companies' assumptions about the input data might have a substantial affect on the output of these analyses. Specifically, the assumptions regarding the level of system demand and the availability of generation including Seabrook 1, both rely on the Companies' projections of conditions in 1990. Because these projections of future conditions are not based on "actual historical information ...," the Siting Council is required by statute to determine whether the projections constitute "reasonable statistical projection methods." Mass. Gen. Laws Ann. Ch. 164, Sec. 69J.

The Siting Council believes in this case that a reasonable statistical projection method must consider the sensitivity of the outputs to variation in key input variables. Thus, in reviewing the Companies' use of analysis to select AC reinforcement lines for specification of "practical" alternatives, the Siting Council examines both the results of analyses that use the Companies' input assumptions and the results of analyses that vary some of these assumptions.

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[110] The Company originally assumed that Seabrook 2 would be in operation in 1990, but later modified this assumption.

Table 10 summarizes the results of the analyses the Companies used to justify its selection of AC reinforcement lines.

With the Phase 2 converter terminal at Comerford, the Companies state two new lines are needed; one to raise the import capability at Comerford from 690 MW to 2000 MW, the other to insure that the import is firm in the event of an outage on the first line. The Companies present 3 alternatives for meeting this need for two new lines at Comerford, each of which connects Comerford with major north-south lines in the Comerford area.

The Siting Council finds that two new AC transmission lines are needed to insure a firm import of power if the converter terminal is sited at Comerford, subject to the accuracy of the Companies' input assumptions.

Similarly, with the Phase 2 converter terminal at Londonderry, the Companies state that it needs two new lines: one to transmit 2000 MW of power into the System, the second to insure that the import is firm in the event of an outage on the first line.

The Siting Council finds that two new AC transmission lines are needed if the Phase 2 converter terminal is sited at Londonderry, subject to the accuracy of the Companies' input assumptions.

The Companies justify the need for the new Millbury-Medway line on the basis of load flow analysis. Specifically, when 1300 MW of generation are unavailable in southeastern Massachusetts (Ex. RHS at 26), an outage of the Pilgrim nuclear power plant causes loadings on the existing Millbury-Medway line that exceed the line's emergency rating.[111] This occurs when 1310 MW (or more) are being imported from Hydro Quebec for all of the six proposed terminal sites. Construction of a second Millbury-Medway line reduces line loadings to acceptable levels.

The Siting Council finds that a second Millbury-Medway line is needed for all six of the proposed sites for the Phase 2 converter terminal, subject to the accuracy of the Companies' input assumptions.[112]

The Companies justify the need for the Sandy Pond-Millbury line on the basis of load-flow analysis and transient-stability analysis. In particular, with an import of 1310 MW at Comerford, Sandy Pond, Tewksbury, or Londonderry, there are two reliability problems: an outage

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[111] The Companies identify three recent actual occurrences of outages at Pilgrim when 1300 MW of generation in southeast New England were unavailable. EFSC Ex. 127.

[112] The Companies did not attempt to show the need for the Sandy Pond-Millbury line with the converter site at Ludlow.

TABLE 10

Justification of Need for AC Reinforcement Lines

Terminal Site (option)	Reinforcement lines[1]	Justification[1]
Comerford (VT) Comerford (NH) Comerford (NH-VT)	ComCool, ComCh ComSc, ComSP ComCool, ComSP	1 line needed to raise Comerford import capability from 690 to 2000 MW 1 line needed to make import firm during single contingencies
Londonderry	LnSc, LnSP	1 line needed to avoid overloads on ScSP line 1 line needed to make import firm during single contingencies
Sandy Pond, Millbury, Tewksbury, Londonderry, Comerford, Ludlow	MiMe2	Existing MiMe line overloads when Pilgrim 1 is out of service for a southeast generator bias condition
Sandy Pond, Tewksbury, Londonderry	SPMi2	Existing SPMi line overloads when VeNf line is out of service. Outages at Ve or SP cause transient stability problems.
Millbury	SPMi2	Existing SPMi line overloads when ScCR line is out of service.

Sources: Ex. RHS at 6, 31-41; Exhibits RHS-9 through RHS-29; Tr. 9 at 88.

Notes: [1] This column identifies required reinforcement lines by identifying the substations at the ends of each line. The following abbreviations are used:

Ch	Champlain	Me	West Medway
Com	Comerford	Mi	Millbury
Cool	Coolidge	Sc	Scobie
CR	Colburn Road	SP	Sandy Pond
Ln	Londonderry	Ve	Vernon
Nf	Northfield		

A "2" signifies a second line parallel to an existing line and on the same right-of-way.

of the Vernon-Northfield line results in loadings on the existing Sandy Pond-Millbury line that exceed its emergency rating; and an outage at Vernon or Sandy Pond results in System instability. With the import terminal at Millbury, an outage of the Scobie-Colburn Road line causes an overload on the existing Sandy Pond-Millbury line. The Companies state that construction of a second Sandy Pond-Millbury line reduces line loadings to acceptable levels and avoids the instability problems.

The Siting Council finds that a second Sandy Pond-Millbury line is needed for five[113] of the proposed sites for the Phase 2 converter terminal, subject to the accuracy of the Companies' input assumptions.[114]

Therefore, the Siting Council finds that the Companies' alternatives are practical subject to the accuracy of the Companies' input assumptions.

One input assumption of concern to the Siting Council is the impact of non-completion of Seabrook 1 on the need for the AC reinforcement lines. The Companies assume in all of their analyses that Seabrook 1 will be operating by 1990. However, uncertainty exists as to whether Seabrook 1 will be completed. Thus, the Siting Council examines the impact of non-completion of Seabrook 1 on the need for AC reinforcement lines.

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[113] The Siting Council did not examine transmission alternatives to the Millbury-Medway line, because an outage of a large generator forms the basis of its need. However, the Siting Council did examine the amount of replacement generation capacity that would need to be constructed to eliminate the need for the line. Though the exact amount of replacement capacity cannot be determined without knowing the exact location and characteristics of the new generation, the Siting Council believes that the amount of required construction for such generation would be less desirable than construction of a second Millbury-Medway line. See Ex. 129; Tr. 10 at 39-41.

[114] The Siting Council examined two alternatives to construction of the Sandy Pond-Millbury line during the course of this proceeding. Installation of extra primary breakers at Sandy Pond and Vernon would address the transient stability problem, but would not remedy the thermal overload problem. Construction of a second line along the existing right-of-way between Vernon and Northfield might solve the thermal overload problem at less cost and with a shorter line than the Sandy Pond-Millbury plan, but would not address the transient stability problem. Moreover, for the Millbury site (which has no transient stability problems that require construction) the cost advantage for the shorter line does not compensate for the other cost disadvantages of the Millbury site. Finally, construction of the Sandy Pond-Millbury line, which is closer to major New England load centers than the Vernon-Northfield line, would generally do more to strengthen the New

(Footnote Continued)

Table 11 compares the results of load flow analyses that assume that Seabrook 1 is operating with the results of load-flow analyses that assume that Seabrook 1 is not operating. Line loadings on the Sandy Pond-Millbury and Millbury-Medway lines decrease substantially if Seabrook 1 does not operate; however, these lines are still heavily loaded. With the Vernon-Northfield line out of service, the loadings on the Sandy Pond-Millbury line still exceed its emergency rating for terminal locations at either Sandy Pond or Tewksbury. With Pilgrim out of service, the loadings on the Millbury-Medway line are barely less than the line's emergency rating. However, this slight margin should not be relied upon to assure system reliability, because small changes in other assumptions (e.g., increases in the import level from 1310 MW to 1800 MW; increases in demand after 1990) could eliminate the margin quite easily. See EFSC Ex. 129.

Therefore, the Siting Council finds that the need for the AC reinforcement lines in this case does not depend on the status of Seabrook 1.

Other input assumptions of concern to the Siting Council are the level and allocation of demand at various points in the System, and the expectations for the location of generating and transmission facilities in 1990. The Companies' assumptions of demand and system configuration can have a substantial effect on the calculated values of expected loadings for individual transmission lines, and consequently, on the need for individual facilities. See EFSC Ex. 128.

The Siting Council recognizes that forecasts of demand and system configuration are inherently uncertain. However, by using several generation bias conditions to test the strength of the New England grid, the Companies essentially conducted sensitivity analyses that examine the impacts of changes in assumptions for the System's configuration. In view of the long lead times associated with construction of major generating facilities, the Companies' assumptions for the System configuration in 1990 are not likely to change substantially by that date. Moreover, the Companies performed load flow analyses for load levels ranging from 60 percent to 100 percent of the forecasted 1990 peak demand, a range that is wide enough to be reasonably likely to include actual conditions in 1990. Thus, the Siting Council finds that the Companies have used reasonable methods to test the sensitivity of the need for AC reinforcement lines to its input assumptions.

3. Comparison of Proposed Facilities and Alternatives

The Siting Council compares proposed facilities and identified alternatives by reviewing the cost, environmental impact and reliability of each option. In Re Boston Edison Company, 13 DOMSC __ (Docket No.

(Footnote Continued)
England grid than a combination of extra breakers and a new Vernon-Northfield line. EFSC Ex. 126; EFSC Ex. 130; Tr. 9 at 100.

Table 11

Impact of Seabrook 1 Cancellation on Load Flow Analyses.

System Condition	Terminal Site	Critical Line	Rating (MVA) Norm/Emer	Loading w/ Seabrook 1	Loading w/o Seabrook 1
1310 MW import, SE bias, 60% pk, VeNf OOS	Sandy Pond	SPMi	1232/1315	1580	1493
	Tewksbury	SPMi	1232/1315	1741	1432
1310 MW import, SE bias, 60% pk, Pilgrim OOS	Sandy Pond	MiMe	1139/1439	1536	1424
	Tewksbury	MiMe	1139/1439	1517	1405
1310 MW import, SE bias, 60% pk, CdSh OOS, SPMi2 in	Sandy Pond	MiMe	1139/1439	1238	1188
	Tewksbury	MiMe	1139/1439	1225	1178
1310 MW import, SE bias, 60% pk, SPMi2 in	Sandy Pond	MiMe	1139/1439	1192	993
	Tewksbury	MiMe	1139/1439	1166	985

Sources: Exhibits RHS-8 to RHS-29; EFSC Ex. 172.

Notes: OOS is short for "out of service"
The following abbreviations are used:

Cd	Card	Nf	Northfield
Me	West Medway	Sh	Sherman
Mi	Millbury	SP	Sandy Pond

"SE bias" signifies "southeast generation bias conditions,"
See Ex. RHS at 26.

85-12; October 31, 1985, at 13). Also, the Siting Council reviews the Companies' process for comparing the proposed facilities and alternatives including: 1) the judgements and assumptions used by the Companies in the comparison process; 2) the Companies' criteria for screening the alternatives; and finally; 3) the process for selecting the preferred facilities.[115]

The Companies used a multiple-step process to select the proposed facilities from the nine alternatives. Ultimately, the Companies based the selection primarily on a comparison of the cost of each alternative to a base case with no Phase 2 imports.

a) Initial Cost Screening

Initially, the Companies compared the nine alternatives on the basis of preliminary capital cost projections. The Companies developed preliminary cost projections from rough cost estimate factors for various facilities.[116]

The Companies used a contingency analysis procedure (CAP) program to identify the circuit breakers and reinforcement AC transmission lines for each alternative. The Companies based the DC transmission line requirements on the most direct route using existing rights-of-way.

Table 12 presents the initial study estimates from the preliminary cost analysis. The Companies found four alternatives to be superior based on the preliminary cost analysis - Tewksbury, Sandy Pond, Londonderry (non-looped) and Millbury. At this stage, the Companies did not consider the AC system line losses. The remaining alternatives were dropped from further consideration.

As shown in the first column of Table 12, Tewksbury, Sandy Pond, and Londonderry (non-looped) were estimated to be significantly less costly than the other six alternatives.[117] For example, the Comerford options were more expensive than the other alternatives because each

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[115]A petitioner should be able to defend its judgments and assumptions. The Siting Council evaluates whether a company's selection of the proposed facility is sensitive to the utilized assumptions and judgements particularly in instances where there is a wide range of possible assumptions and judgements. The company also should demonstrate a consistent application of the screening criteria.

[116]The Companies used the following rough cost estimate factors: $187 million for the DC terminal; $1.3 million/mile for the DC line; $1.1 million/mile for the AC line; $2.3 million for a 345 kV circuit breaker. EFSC Ex. 75 at 2.

[117]In general, each alternative's estimated cost is directly related to the total length of required AC and DC lines.

Table 12

Initial Screening Cost Comparison
(millions of 1990 dollars)

Plan	Facility Costs	Losses	Total	Difference from least cost plan
Tewksbury	432	23	455	---
Sandy Pond	439	24	463	8
Londonderry (not looped)	438	29	467	12
Londonderry (looped)	451	29	480	25
Millbury	511	31	542	87
Comerford (VT option)	484	62	546	91
Ludlow	530	39	569	114
Comerford (NH/VT Option)	567	74	641	186
Comerford (NH option)	597	73	670	215

Source: Ex. RHS-5

Comerford alternative required two 345 kV AC lines.[118] Thus, the Companies first eliminated the three Comerford alternatives.[119]

In the second phase of the initial cost screening, the Companies distinguished between costs common to all alternatives and costs specific to individual alternatives ("non-common costs"). The Companies performed a series of comparisons. The non-common costs of the least-cost alternative were escalated by 25 percent while the non-common costs of the remaining highest-cost plan were decreased by 25 percent to determine whether the non-common cost differential between these two sites was within the margin of error for study estimates.[120] Then, the Companies compared the adjusted non-common costs. In this analysis, the Ludlow site alternative still was more costly than Tewksbury, the lowest cost alternative.[121] Therefore, Ludlow was dropped from further consideration. Ex. RHS at 23.

At this point, the Companies also dropped the Londonderry looped alternative from consideration because its estimated cost was $13 million higher than the non-looped alternative yet offered no offsetting advantages. EFSC Ex. 40 at 2.

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[118] For an equivalent distance, DC lines would be more expensive in terms of dollars per mile based on the Companies' initial cost estimates of $1.3 million/mile for a 450 kV DC line and $1.1 million/mile for 345 kV AC lines, a difference of approximately 14 percent. However, these cost estimates do not account for the fact that DC lines are able to transmit more power. Thus, in terms of $/kW transmission capability, the DC lines are less expensive. See EFSC Ex. 9.

[119] When system losses are also considered, the Companies state that even the least-expensive Comerford alternative, the Vermont reinforcement option, would be $91 million more expensive than the least-cost alternative; a 20-percent cost differential. See Table 12. Also, this estimate "did not include the costs associated with installing additional static capacitors which would be required to provide reactive support at the Comerford site." Ex. RHS at 22. These additional costs would further increase the cost disadvantage of the Comerford options relative to the six other alternatives.

[120] The Companies estimate the accuracy of their study estimates to be roughly ± 25 percent, EFSC Ex. 75.

[121] Based on their study grade estimate confidence levels, the Companies determined the probability was less than 0.25 percent that Ludlow would cost less than Tewksbury if non-common costs were 25 percent higher for Tewksbury and 25 percent lower for Ludlow.

With one exception, the Siting Council finds that the Companies' initial cost screening process was reasonable in terms of the underlying assumptions and judgements. In particular, the Siting Council finds that the use of rough cost estimates and the escalation or deescalation of non-common costs in the comparison process was reasonable, and that the criteria were consistently applied.

The exception was the Companies' decision to drop the Vermont Comerford option from further consideration even though it was estimated to be four percent less costly (by $23 million) than the Ludlow plan. Also, the Millbury option ($542 million) was retained for more detailed analysis although its estimated cost compared closely to the estimated cost of Vermont Comerford option ($546 million).

The Companies, however, properly justified their decision to eliminate the Vermont Comerford option. Specifically, the Companies pointed out that Ludlow was dropped in the next level of analysis "at about the same point in time." Tr. 10 at 22. Also, the Companies stated that the decision to retain Millbury for more detailed analysis reflected the Company's underlying belief that:

> [t]he Millbury location was much more desirable in terms of placing a Phase 2 Converter than was Comerford.... It was a point adjacent to a strong interconnected location on the 345 kV AC transmission system, and it could be reached principally using existing rights-of-way.

Tr. 10 at 24. The Companies indicated the Vermont Comerford alternative required 135 miles of new right-of-way and hence had a significantly greater environmental impact. EFSC Ex. 98. Further, the Companies indicated that the relative cost advantage of sites near the major load centers were understated by the initial analysis which did not consider AC system line losses. The Companies' reason for diverging from the strict cost criteria of the initial cost screening process was reasonable and justified.

b) The Companies' Detailed Analysis

In the second stage of the comparison process, the Companies compared the estimated costs of the Londonderry (non-looped), Tewksbury, Sandy Pond, and Millbury alternatives in terms of the cumulative present worth of facility revenue requirements ("FRR"). Included in the FRR were the capital construction (including AFUDC), operation and maintenance, and incremental energy loss costs.[122] Ex. ROB-1 at 58.

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[122] Incremental energy loss costs are "those energy loss costs particular to each of the networks when each network is compared against one basic reference case." Ex. ROB-1 at 59.

The capital cost of each component (i.e., the DC line, converter terminal, and AC reinforcements) was based on "study estimates" prepared "using historical information and professional experience and judgement." EFSC Ex. 75. The actual study estimates of facility capital costs were the product of a preliminary engineering analysis identifying the specific facilities, equipment and required construction techniques, and an estimate of the cost of each component.

The cost of line losses consists of AC transmission system losses, and losses on the Phase 2 DC transmission line. For each of the four alternatives, the Companies estimated losses for Phase 2 terminals of three sizes - 1310 MW, 1800 MW, and 2000 MW.

The Companies estimated the AC transmission losses "on an incremental basis from base case load flows which assumed 690 MW of imports at the Phase 1 converter terminal and no Phase 2 imports or facilities." Ex. RHS at 42. The expected number of hours of imports per year was then distributed among three load levels during a 1990 summer peak (100 percent, 70 percent, and 60 percent) based on a projected New England annual load duration curve.[123] Next, incremental MWh losses at each load level for each year were multiplied by the cost per MWh of energy generated by oil in order to estimate the annual incremental energy loss costs on the AC transmission system.[124]

Line losses for the Phase 2 energy on the DC transmission line were based on "the resistance per unit per length of the conductor, the amount of current in the conductor, the length of the conductor, and the amount of time current would be flowing through the line." Ex. RHS at 44. To determine the value of these losses the MWh losses were multiplied by the forecast of oil-generated energy costs.[125]

The AC and DC energy loss costs were combined and discounted to a common present value (1990 dollars). The Companies added the cumulative present value of these losses to the estimated cumulative present value of the revenue requirements of the proposed facilities to yield the cumulative present value of FRR.

Table 13 presents the results of the detailed cost analysis for the Sandy Pond, Tewksbury, Londonderry, and Millbury alternatives for three converter terminal sizes - 1380 MW, 1800 MW, and 2070 MW. As shown, the Sandy Pond alternative was estimated to be the least-expensive

[123] These load levels constitute the range at which the Phase 2 energy would be imported.

[124] The cost of oil-generated electricity is based on DRI's forecast of oil prices for each calendar year of the project.

[125] The loss costs associated with the Phase 1 DC transmission line and the DC-to-AC conversion process were not considered because those costs were common to all alternatives.

Table 13

Cost of Major Facilities Required for the Phase II Terminal Locations
1984 Construction Cost (Millions of Dollars)

	Sandy Pond			Tewksbury			Londonderry			Millbury		
Terminal Rating (MW)	1380	1800	2070	1380	1800	2070	1380	1800	2070	1380	1800	2070
Terminal Import (MW)	1310	1800	2000	1310	1800	2000	1310	1800	2000	1310	1800	2000
DC Requirements												
±450 kV DC converter	120	157	180	130[1]	170[1]	195[1]	120	157	180	120	157	180
Line	113.5	113.5	113.5	102	102	102	86.5	86.5	86.5	142	142	142
345 kV AC Breakers	5.5	5.5	5.5	8.5	8.5	8.5	7	7	7	6	9	9
345 kV AC Lines	--	--	--	--	--	--	25.42	25.42	25.42	--	--	--
Cost	239	276	299	240.5	280.5	305.5	238.92	275.92	298.92	268	308	331.0
Major AC Requirements												
345kV	42.62	42.62	42.62	44.14	44.14	44.14	45.62	56.05[2]	56.05[2]	18.6	106.8[3]	106.8[3]
115kV	29	29	29	37.3	37.3	37.3	29	29	29	29	--	--
Cost	71.62	71.62	71.62	81.44	81.44	81.44	74.62	74.62	74.62	47.6	106.8[3]	106.8[3]
Other Facilities												
M-Wave Comerford												
Improvements, etc.	17	17	17	16.5	16.5	16.5	15	15	15	18.5	18.5	18.5
Total	327.62	364.62	387.62	338.44	378.44	403.44	328.54	375.97	398.97	334.10	433.30	456.30
Revenue Requirements of the Major Facilities[7]												
January 1, 1990 Cumulative Present Worth (Millions of Dollars)												
Total	640	712	755	661	740	788	642	734	777	652	845	888
Cost of Losses												
1990 Cumulative Present Worth[6] (1/1/90)												
(Millions of Dollars)												
DC[4]	16.53	31.22	38.54	15.55	29.37	36.26	13.23	24.97	30.83	20.94	39.54	48.82
AC[4]	7.06	-120	-127.3	-5.98	-133.5	-141.6	37.53	-74.42	-76.32	-17.45	-113	-113
Total[5]	23.59	-88.79	-88.75	9.57	-104.2	-105.3	50.76	-49.45	-45.49	38.39	-73.46	-65
Grand Total	664	623	666	671	636	683	693	685	732	690	772	823

[1] Includes site preparation cost.

[2] Reconductoring of Scobie-Sandy Pond 345 kV line required.

[3] Additional cost included for double circuiting existing 345 kV and 115 kV lines to make room for the DC line.

[4] Based on GTF average annual oil fuel cost for HQ Phase II contract - 1990-2000.

[5] Negative numbers represent the cost savings of reduced losses.

[6] New England Hydro-Transmission Electric Company, Inc. 12.5 percent annual present worth factor assumed.

[7] Based on New England Hydro-Transmission Electric Company, Inc. economics, 20-year life, 10-year revenue requirement.

Source: Ex. RHS-31

alternative ($623 million, $1990),[126] although the Tewksbury alternative was comparable ($636 million, $1990).[127] The Companies' analysis indicated the Londonderry alternative would produce higher line losses than the other alternatives because of its distance from the major southern New England load centers. Also, the capital cost of the additional AC line from Sandy Pond to Millbury which would be required in the Millbury alternative rendered that alternative more expensive.

The Companies selected the Sandy Pond alternative rather than Tewksbury in large part based on strategic and environmental considerations. Ex. RHS at 49; Amendment, Vol. 1 at 29. A converter terminal at Tewksbury would require the location of four "critical" transmission lines on the same New Hampshire State line-Tewksbury corridor, leaving eastern Massachusetts and possibly southern New England vulnerable to a loss of load if this right-of-way were knocked out.[128] However, only two critical lines would be located on the New Hampshire State Line-Sandy Pond right-of-way.[129] The Companies believe "[w]henever possible, it is desirable to avoid siting too many critical transmission lines on a critical right-of-way." Amendment, Vol. 1 at 27. The Companies also justify the selection of Sandy Pond on environmental considerations. A portion of the Tewksbury terminal site is in a wetland and flood plain. EFSC Ex. 75.

Based on their detailed analysis, the Companies also concluded that an 1800 MW terminal would have the lowest cumulative present worth of facility revenue requirements.[130] As shown on the Table 13, a 1310 MW terminal would minimize the capital costs. The Companies' witness, however, indicated that a converter terminal of larger capacity would allow more of the

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[126] The Companies performed a more detailed cost analysis of the two options based on a detailed engineering analysis of the required facilities. See Ex. ROB-1.

[127] The difference in the cumulative present worth of FRR is well within the margin of error of the estimates. See EFSC Ex. 40 at 186.

[128] The Companies' position here assumes the future construction of the Scobie-Tewksbury line.

[129] These two rights-of-way constitute the major "North-South" interface for eastern Massachusetts.

[130] An 1800 MW converter terminal would enable NEPEX to continue importing 2000 MW even if one of the three 230 kV AC lines at Comerford were lost. If a 1310 converter terminal were built and the total Phase 1 and Phase 2 converter terminal capabilities were only 2000 MW, the loss of any one of these three AC lines would force a reduction in the import to ensure that the other lines were not overloaded. Tr. 10 at 73. Under certain circumstances, this could require NEPOOL to pay a penalty to Hydro-Quebec.

> 2000 MW import...to flow directly into the 345 kV AC grid through a new terminal close to load centers in Central New England, rather than through Comerford, [and] system energy losses would be considerably lower. This is true because any power flowing through the Comerford terminal must subsequently flow over lower voltage lines to load centers, incurring higher energy losses.

Amendment Update, Vol. 1 at 45-46.[131] The detailed analysis determined that the optimal terminal size is roughly 1800 MW, at which point the marginal increase in capital costs equals the marginal decrease in line losses.

Again with one exception (see below) the Siting Council finds that the Companies' detailed analysis for comparing alternatives was reasonable in terms of the underlying assumptions and judgements and in terms of the criteria developed and utilized for comparison purposes.[132]

c) Sensitivity Analysis

The one exception is that the Companies did not examine the sensitivity of the detailed cost comparison process to changes in certain underlying assumptions and judgements.[133] The Siting Council, however, has evaluated the Companies' assumptions on the discount rate, the oil-price forecast, and the possibility of additional imports from Hydro-Quebec, and the potential impact of changes in the assumptions on selection of the proposed facilities.

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[131] A lower voltage line requires a higher current to carry the same amount of energy and line losses increase proportionally with the square of the current.

[132] The Companies' FRR analysis did not account for the distribution of costs between New England states.

[133] The Companies adequately addressed the implications of uncertainty in construction costs on the selection process. The estimated costs of the proposed facilities are reviewed in Section III.C.3. Other assumptions, however, were not addressed. For example, discount rates, by definition, are extremely sensitive to market interest rates and the anticipated rate of inflation. This is illustrated by the formula the Companies used to determine the appropriate discount rate:

Discount Rate = Long-Term Inflation Rate
+ (% of debt Financing) (Long-Term Historic Bond Premium Over Inflation)
+ (% of equity Financing) (Long-Term Historic Equity Premium Over Inflation).

During hearings, the Companies justified the discount rate[134] utilized for the detailed analysis. Their witness stated that the historic relationship between inflation and the returns on equity and bonds that was used by the Companies to determine the discount rate, was reflective of the risks associated with bonds and equity issued by utilities. Tr. 4 at 181. Further, the witness testified that the risks of this project were "very comparable" to other utility investments. Tr. 4 at 182.

The Siting Council, however, believes that a more thorough discount rate analysis would consider the additional factor of ratepayers' willingness to trade future costs and benefits with current costs and benefits.

Given the heterogeneity of ratepayers, the Siting Council believes that it is inappropriate to identify a single discount rate for ratepayers as a whole. A more reasonable approach is to develop and analyze a range of discount rates to determine whether the preferred alternative remains preferable under this range.

The Siting Council compared the cumulative present worth of FRR for the preferred and alternate terminal sites at discount rates of 8.0, 10.4, and 25.0 percent. For each of these discount rates, Sandy Pond offered the lowest cumulative present worth of FRR.

Another variable, oil-price projections, is important for sensitivity-analysis purposes, since it directly affects the calculations of the costs of line losses.[135] The Companies, however, did not examine whether deviations in oil-prices from those projected could result in identification of an alternative to Sandy Pond.

The Siting Council determined that the cost advantage of Sandy Pond over the Tewksbury alternative would increase in the event oil prices are lower than projected by DRI. On the other hand, oil prices above the level forecast by DRI would favor the Tewksbury option, which offers higher line loss savings than Sandy Pond.[136]

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[134] In the Amendment Update, the Companies used the term present worth rate rather than discount rate.

[135] The Companies valued line losses (or line loss savings) at NEPOOL's average annual marginal energy cost and according to the DRI fuel forecasts. The marginal fuel is expected to be oil. Therefore, any deviations from the oil price forecast used by the Companies would have a direct impact on line loss savings, and could affect the selection process.

[136] Deviations from the DRI oil price forecast would have no effect on the costs of Londonderry and Millbury relative to the cost of Sandy Pond because both of these alternative terminal sites offer lower line loss savings and higher facility construction costs.

Thus, an eventuality of higher-than-projected oil prices is the only factor that might affect the selected alternative. The Siting Council's analyses show that a 84.4-percent increase in oil prices would be required to make Tewksbury preferable in terms of costs to Sandy Pond. An oil-price increase of this magnitude over the DRI forecast is needed for Tewksbury's comparatively higher line loss savings to offset its higher facility construction costs.

Thus, the Siting Council finds that utilization of an oil-price projection within a reasonable range surrounding DRI's would not impact the facility selection process.

With respect to the impact of additional energy imports from Hydro Quebec, the Companies indicated that there is a significant likelihood that additional contracts could be negotiated with Hydro-Quebec which would make use of the Phase 2 facilities. These additional energy imports could increase the significance of line losses in the selection of the preferred terminal site. For example, Tewksbury's comparatively lower line losses could make the Tewksbury alternative preferable to Sandy Pond. The Companies did not analyze the level of additional imports which might be required to change the selection among facilities.

The Siting Council evaluated the potential impact of additional imports using a rough analysis which based the value of line-loss savings on the escalation rate for line loss savings from the 1990/91 to 1997/98 power year. The Siting Council estimated the highest value of line losses which could be anticipated reasonably with additional imports. The selection of the Sandy Pond option was not affected.

In conclusion, the Siting Council finds that the result of the Companies' selection process would not be affected under a reasonable range of reasonable assumptions and judgements.

4. Facility Construction Costs: Projection Methods

The Siting Council considers the risks associated with a specific proposed facility as part of its review process. In Re Boston Gas Company, 11 DOMSC 159 (1985). When evaluating the proposal, the risks related to cost-estimation errors should be considered, along with all the other potential sources of risk.[137]

Estimates of future costs are inherently uncertain. To the extent that cost-projection errors could cause a project's costs to exceed its

[137] A project's total risk should then be evaluated and a decision must be made whether the expected value of the project's benefits are adequate in light of the project's risk.

benefits, cost-estimation errors are a risk.[138] A review of a project's cost estimates must be tied to a review of the methodology of estimation so as to determine whether cost estimates are reasonable. Indeed, the Siting Council believes it is important to review the cost-estimation methodology and an applicant's past experience with construction cost estimates.

In the Siting Council's view, reliability is the most important criterion when evaluating the risks associated with cost estimates. The Siting Council's standard for reviewing the reliability of demand forecasts is whether the methodologies, data, and judgements inspire confidence that the estimates depict what is most likely to occur. The Siting Council feels an analogous standard is appropriate for construction-cost projections.[139]

The Siting Council evaluates three components of cost-projection methodology to ensure that the methodology is reliable. The first is the scope of analysis, i.e., whether all the major costs have been considered (e.g., line loss differences between transmission networks). The second component is the basis for costs, i.e., what are the bases (e.g., historical information, judgement) for each cost estimate. The third component is the method of analysis, i.e., whether a company used an appropriate method for comparing the costs of different alternatives (e.g., whether the costs of different proposals properly have been discounted to allow a comparison of revenue and cost streams which occur in different years).

a) Scope of Analysis of Facility Costs

The Companies' full calculation of facility costs included capital costs, operation and maintenance ("O&M"), and incremental energy loss costs. Amendment Update, Vol. 1 at 58.

Capital costs include both construction-related expenditures and allowance for funds used during construction of the AC and DC facilities. The total O&M costs are composed of the following elements: 1) microwave charges; 2) transmission line O&M; 3) substation equipment O&M; 4) electronic equipment O&M; and 5) deferred debit account amortization. Incremental energy loss costs are "those energy loss

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[138] In finance, risk is measured in terms of variance, or the dispersion around the expected value. For the purposes of this analysis, the risk associated with this project is that costs will be understated and/or benefits will be overstated so that the discounted value of benefits is less than costs.

[139] Also, the Siting Council examines whether the methodology is appropriate for the project, i.e., suitable given the size of the particular project, and reviewable, i.e., amenable to being evaluated and replicated by another party with similar resources and expertise.

costs particular to each of the networks when each network is compared against one basic reference case." Amendment Update, Vol. 1 at 59.

The level of detail in the Companies' cost analysis is demonstrated by the Companies' worksheets which contain the Companies' study-grade cost estimates for the preferred and alternate networks. EFSC Ex. 75. A highly reviewable, 189-page document presents these estimates and outlines in detail the costs of site-clearing, construction, and required facility equipment. The Siting Council believes that the Companies' detailed evaluation encompassed all relevant costs.[140] EFSC Ex. 75.

However, the Companies did not review the estimated costs of each alternative in the same level of detail as they did for their preferred and alternate networks. The initial cost estimates for alternatives were based on an initial screening of the required facilities. Even so, the range of costs considered was broad enough to enable the Companies to drop high-cost alternatives from early consideration. Therefore, the Siting Council finds that the Companies considered all relevant costs and that the scope of analysis of costs was appropriate and reliable.

b) Basis of Construction Cost Estimates

The Companies prepared cost estimates of each component (i.e., DC line, converter terminal, and AC reinforcements) based on "study estimates" prepared "using historical information and professional experience and judgement." EFSC Ex. 75. The actual study estimates of facility capital costs are the product of a preliminary engineering analysis which identified the specific facilities, equipment and construction techniques, and an estimate of the cost of each component. These study estimates allowed a comparison of the costs of alternatives, and an evaluation of the economic viability of the proposal. EFSC Ex. 75.

Table 14 presents information on the accuracy of cost estimates for all transmission line capital projects performed by NEES's Transmission Engineering Group. These data indicated a high degree of reliability in the Companies' recent cost estimates for such projects. The narrow historical variance between estimated and actual costs raises the Siting Council's confidence in the reliability of Phase 2 cost estimates.[141]

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[140]The Siting Council defines relevant costs as those costs which directly affect the accuracy of the cost estimate and an evaluation of the project's overall economic viability and cost-effectiveness.

[141]As of June 30, 1985, the costs for the construction of Phase 1 facilities were approximately 33-percent below budget. However, this estimate does not account for "change of scope" costs which are usually negotiated at the completion of tasks and are likely to reduce the difference between actual and budgeted costs. EFSC Ex. 145. Therefore,
(Footnote Continued)

Table 14

Data on Companies' Recent Experience in
Estimating the Capital Costs of Transmission Facilities

	Number of Capital Projects	Total Dollars Estimated (Millions)	Total Dollars Spent (Millions)	Percent Variation from Estimates
1979	8	.396	.397	+0.2
1980	17	3.677	3.859	+4.9
1981	14	3.035	2.956	-2.6
1982	12	4.676	4.649	-0.6
1983	15	2.678	2.541	-5.1
5 Year Record	66	14.462	14.402	-0.4

Data for 1984 was not compiled at time of the data request.

Source: EFSC Ex. 136.

Also, the Companies prepared construction cost estimates that differed from the expected cost of $585 million by a factor of ± 25 percent. Thus, the costs were projected to fall within a range of $440 million to $730 million. The Companies estimated further that, given this range, the possibility of under-estimating costs is approximately 2.5 percent.[142] EFSC Ex. 40 at 181.

The Companies' record in projecting the cost of other facilities and their use of confidence intervals in estimating Phase 2 facility costs bolsters the Siting Council's confidence that the Companies' cost estimates for the proposed facilities are reliable and that the risks associated with cost-estimation errors are minimal.

c) Methodology for Comparing Costs of Alternatives

The Companies compared alternatives in terms of the cumulative present worth of facility revenue requirements ("FRR"). The Companies used FRR as the unit of measure because the FRR approach is consistent with the objective of minimizing electricity rates (ceteris paribus). The Companies calculated the present worth of revenue requirements to allow "a consistent means of comparing different streams [of costs and savings] at some reference point." EFSC Ex. 105.

Since the Companies have included a full scope of costs -- capital costs, O & M costs, and incremental line-loss costs -- in their estimates of facility revenue requirements, an economic comparison of alternatives is relatively simple: the preferable alternative is the one with the lowest cumulative present worth or FRR.[143]

With one exception, the Siting Council finds that the Companies' FRR methodology is reliable and appropriate for purposes of comparing alternatives.

The FRR approach cannot fully satisfy the "minimum environmental impact" portion of the Council's mandate because it does not take into account the relative environmental impacts of different proposals, except to the extent that the cost projections include estimates of direct costs associated with mitigating adverse environmental impacts.

(Footnote Continued)
no implications about the probable accuracy of the Phase 2 cost estimates can be drawn from the Companies' experience with Phase 1 costs.

[142]This confidence level reflects the Companies' "assessments based upon past experience and professional judgement and is not statistically based..." EFSC Ex. 159.

[143]In some instances, environmental or strategic concerns (e.g., reluctance to site major transmission lines together) could make an alternative preferable even if it did not have the lowest cumulative present worth of facility revenue requirements.

Therefore, the alternative with the lowest FRR would not necessarily be the Siting Council's preferred alternative under the mandate requiring a balancing of energy, cost, and environmental considerations.

Therefore, the Siting Council can utilize but not exclusively rely upon the results of the Companies' FRR analysis in its determination as to whether the proposed facilities are consistent with the ensurance of a necessary energy supply with minimum environmental impact at lowest possible cost.

In conclusion, the Council finds that these components of the Companies' cost estimation methodology - method of analysis, scope of analysis, and basis for costs - are appropriate and ensure that the cost estimation methodology is reliable.

5. Environmental Impacts

The purpose of the Siting Council's environmental review is to ensure not only that any adverse environmental impacts of facilities are minimized through appropriate siting and mitigation, but also to insure that the overall project represents, on balance, a least-cost and least-environmental-impact approach to meeting an identified energy need. The Siting Council notes that, in addition to the direct environmental impacts of the proposed project facilities discussed in this section, there will be additional environmental impacts associated with the Project expected displacement of fossil fuel generation in Massachusetts and other New England states. See Section II.B.1.g.

The Companies conducted a number of environmental analyses to address the requirements of the Siting Council. The Companies' consultant, C.T. Main, performed an assessment of the environmental resources in the study area. In addition, separate witnesses provided more specialized analyses concerning the significance for public health, safety, and well-being of vegetation-management practices on the rights-of-way, and concerning the electrical environments created by the proposed facilities.

The Siting Council reviews the environmental impacts in two steps. First, the Siting Council presents a categorical review of impacts and associated mitigation measures. Then, the Council reviews the Companies' comparison of the proposed facility network and alternate networks.

a) Environmental Impacts and Mitigation - Preferred Network

The Companies' basic approach to assessing environmental impacts is to inventory categories of potentially impacted resources, consider the likely impacts, and discuss possible and planned mitigation. The categorical assessment is discussed in five sections -- land and water resources, visual resources, vegetation management, electrical environment, and construction period nuisances.

While the analysis is primarily categorical, questions of trade-offs and priorities among issues inevitably arise -- some of which are considered by the Companies. As shown in Figure 3, the Companies developed a hierarchy of constraints for locating transmission structures or towers. As necessary, the Companies' analysis explicitly recognizes design trade-offs affecting two or more environmental impact categories -- for example, the choice between the increased height of double circuit lines and the wider rights-of-way needed to accommodate parallel single-circuit lines. These priorities and trade-offs are noted, as applicable, in the categorical discussion below.

(1) Water and Land Resources

The Companies address both permanent (design) and temporary (construction) impacts (potential and actual) on various natural resources found in or near the transmission line rights-of-way and the converter terminal site. Impacts include the clearing of forests and other vegetation, the filling or disturbing of wetlands, the crossing or affecting of surface waters (in general) or Class A waters (in particular), and the crossing or affecting of contribution zones for water supply recharge or runoff.

The Companies identified and quantitatively assessed actual losses of resource values on the 2400 acres of Project right-of-way area in Massachusetts in only two categories -- forests and wetlands. The Companies' quantifications of impacts on other resource values essentially are limited to tabulations and summary statistics on the instances in which resources are crossed by the rights-of-way. Actual losses of environmental values for the other resource categories were discussed qualitatively in terms of the expected degree, extent, and duration of impacts.

Forest clearing, affecting about half of the length of Project rights-of-way in the state, would extend to 269 acres, including 30 acres at the converter terminal site. EFSC Ex. 67 at IV.C-2. The Companies argue that the expected loss is not regionally significant, citing areawide statistics on forest resources in counties traversed by the preferred right-of-way. Amendment, Vol. 2 at 99; EFSC Ex. 212. With regard to the importance of the loss in forest resources for related environmental resource values, the Companies argue that for one value, wildlife habitat, the impact of conversion to low bushes actually is beneficial. Ex. LPS at 15. The Companies suggest that mitigation measures can be used to minimize any visual impacts. Section III.C.4.a(2).

Wetlands, which cover approximately 10 percent of the right-of-way area, would be permanently altered through forest clearing (24.3 acres of forested wetlands), as well as through filling for an estimated 53 new tower placements (3 to 4 acres filled under practical worst case assumptions as to location and pad requirements) and new access roads (2 to 3 acres filled). EFSC Ex. 67 at IV. A-17 to A-19. Temporary construction impacts would affect up to 50 acres of wetlands, as well as many areas of vegetative screening normally maintained at selective locations along the rights-of-way. EFSC Ex. 67 at A-17 to A-19.

Figure 3

Hierarchy of Constraints for Locating Transmission Structures

Constraints by Level*

High Level

- o Locate structures where the line changes direction
- o Avoid roads and buffer zones next to roads
- o Avoid railroads, pipelines and electric utility lines
- o Avoid bodies of water, rivers and other waterways
- o Limit span lengths to maintain compliance with NESC
- o Leave minimum distance from edge of right-of-way and adjacent transmission lines to maintain compliance with NESC
- o Leave enough distance from edge of right-of-way so that electrical effects off the right-of-way are within acceptable levels
- o Leave enough distance from edge of right-of-way and adjacent transmission lines to allow room to build and maintain line

Medium Level

- o Minimize visual impact on dwellings adjacent to right-of-way
- o Avoid wetlands
- o Avoid locations which can be seen from roads for a long distance
- o When close to a road, locate on the same side of road as existing structure
- o Avoid hill tops
- o Avoid cultivated fields, orchards and hay fields
- o Maintain low, smooth profiles of structure tops to limit distant views of the line

Low Level

- o Locate opposite structures on existing line
- o Avoid ledge out-croppings
- o Use minimum number of structures consistent with medium and high level constraints

* A high-level constraint is one which must be followed. A medium-level constraint should be followed in most cases. It is desirable to follow a low-level constraint, but other factors often will override it.

Source: EFSC Ex. 72

For other natural resource values along the rights-of-way -- principally relating to water quality and water supply -- incremental effects of the new facilities are assumed by the Companies to be minor and essentially limited to the construction period. With respect to Class A waters (used for water supply and certain sport fishing)[144], no new access road construction nor forest clearing (on banks) is planned, although some improvements to existing access roads may be required. EFSC Ex. 67 at IV.A-26. The Companies point out that only short sections of streams intersecting the rights-of-way are subject to temporary or permanent effects (i.e., from removal of forest cover). Amendment Vol. 2 at 103. The proposed ground water withdrawals for cooling purposes at the converter terminal are not expected to affect nearby public wells. EFSC Ex. 215. The Companies assume right-of-way maintenance through use of herbicides, if conducted in accordance with recognized quidelines, is of no significance to water supply or ecological resource values. Section III.C.4.(a)(3).

With regard to the temporary effects of construction, the Companies claim all of the above-noted resource values would be adequately protected through use of good construction practices, including appropriate mitigation relating to erosion, slash disposal, and use of heavy equipment in sensitive areas. EFSC Ex. 67 at IV. A-18 to A-20, A-26, A-29, A-30.

The Siting Council supports the Companies' commitment to responsible construction practices in both wetland and upland areas. Wetland construction practices will be subject to review by local Conservation Commissions under the Commonwealth's Wetlands Protection Act. Mass. Gen. Laws Ann. Ch. 131 Sec. 40. In addition, construction practices in all Project areas potentially will be subject to any mitigation incorporated in the Federal Presidential Permit.[145]

The Companies' environmental assessment also addresses the long-term implications of facility design for natural resource values. Although not finalized, the Companies have articulated design policies and priorities to justify the siting decisions already made, and suggested the criteria for more detailed determinations yet to be made. (See introductory discussion and Figure 3.)

The category of wetlands is included in the Companies' ranking of priorities shown in Figure 3. Keeping towers out of wetlands is

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[144] Class A waters on the rights-of-way include the Charles River, Wachusett Reservoir, and various ponds and streams in the Wachusett Reservoir watershed.

[145] The Department of Energy must issue a Presidential Permit for import of power from Canada for the Phase 2 project. Pursuant to Executive Order No. 10485, an Application was filed on March 4, 1985 (Federal Register, March 21, 1985) to amend the Presidential Permit which was issued for Phase I on April 5, 1984, in Docket PP-76.

assigned a medium priority in tower siting, ranking above, for example, the placement of matching spans on adjacent lines. However, the Companies place other longitudinal constraints, such as the need to have tower locations coincide with changes of direction in the right-of-way, at a higher priority in siting decisions than avoidance of wetlands. More importantly, the Companies acknowledge that, without land acquisitions to widen the rights-of-way, the Companies generally would be unable to make more than slight (25-50 foot) increases in average spans anywhere along the rights-of-way for purposes of avoiding tower placement in wetlands. Tr. 5 at 27-28.

The Council notes that, while final design decisions on proposed tower locations have not been made, those affecting wetlands likely will be subject to review by Conservation Commissions as required under the Wetlands Protection Act. Tr. 5 at 18. By state regulation, Conservation Commissions are precluded from requiring consideration of major siting alternatives (i.e., alternative corridors), as this function is explicitly reserved for the Siting Council. See 310 CMR 10:53(3) (d). However, the Council does not believe that this provision should be construed as precluding in any way the right of Conservation Commissions to require consideration of some variation in transverse as well as longitudinal location of towers within the established right-of-way to minimize any potential adverse impact of the project on wetlands.

Forest resources, although not recognized in the Companies' hierarchy of priorities, are nevertheless an important factor in design trade-offs considered by the Companies. For example, on the proposed DC segment between the state line and Sandy Pond, the Companies considered a double-circuit line, combining the DC line with the existing 345 kV AC line, as an alternative to the separate parallel DC line. Although this alternative essentially would avoid the need for forest clearing, the Companies argue that the adverse visual impact of taller double-circuit towers, as well as cost and reliability considerations, outweigh the loss of forest resources and other environmental impacts associated with widening the cleared portion of the right-of-way.[146] With regard to a similar trade-off in the Sandy Pond-to-Millbury segment, the Companies chose to "double-circuit" two 115 kV lines, rather than widen the right-of-way, thus avoiding forest clearing on most of that segment. Evidently, avoiding the need to acquire additional rights-of-way, which would displace a variety of abutting land uses including forest lands, was the predominant consideration in the Companies' decision to propose placement of the 115 kV lines on a double circuit. Tr. 5 at 53.

The Siting Council believes the Companies have made reasonable decisions on the two options for double circuit lines. The design options did present tradeoffs. The forest clearing in the DC segment has possible long term environmental benefits as well as costs. Some of

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[146] Other impacts include increased use of herbicides and increased visual impacts. See Sections III.C.4.a(2) and (3).

the economic value of the forest resource likely will be realized as utilization of cut timber by landowners or through the marketplace. Other potential long-term adverse impacts of the forest clearing involve visual impact and increased use of herbicides, discussed below.

(2) Visual Resources

Relative to other environmental impacts, the impact of the proposed Project on visual resources is apparent, while the ability to mitigate the visual impacts is limited. The Siting Council is concerned with these impacts, particularly in light of the apparent need for either widened rights-of-way or higher towers, or both, along the entire length of the Companies' preferred network.

As a basis for assessing the visual impact of the proposed transmission line and converter terminal facilities, the Companies investigated and characterized the natural landscapes and manmade features surrounding the existing rights-of-way and the proposed DC converter terminal site.

The Companies utilized the Massachusetts Landscape Inventory, developed in 1982 by the Department of Environmental Management, as a principal source for identifying natural and manmade points of visual interest. The Companies' analysis also recognized population centers, subdivisions, and other features that bring together significant numbers of potential viewers in outdoor settings -- for example, highways and recreational facilities. After listing and characterizing the areas of visual sensitivity, the Companies assessed the likelihood of new or increased visual impacts from the proposed facilities. The Companies' impact assessment for the existing rights-of-way with existing transmission lines focused on those aspects of the new facilities which could result in incremental impact -- higher towers, loss of screening through forest clearing, and clutter or visual discordance associated with multiple lines.

The record indicates that the Companies' analysis was iterative, including at various stages review of maps and other materials, and actual field reconnaissance. Tr. 6 at 76-78. The assessment was largely qualitative -- many of the 259 identified areas were judged as having "no or minimal impact," and were not analyzed further. The remaining areas were systematically rated (five ratings, high to low) for each of the following visual criteria, EFSC Ex. 67 at IV.J-12 to J-13:

1. compatibility of lines to area;
2. landscape quality of area;
3. number of viewers at area; and
4. visibility of line at area.

The Siting Council finds that the Companies have made a systematic effort to identify, array and screen points of visual sensitivity. The approach succeeds in characterizing a range of potential visual impacts and in reasonably screening an inventory of identified areas of potential visual impact to identify the more significant cases of visual impact.

The Companies' methodology (the five-level ratings) is less convincing as a means of assessing the relative importance of areas involving more than minimal visual impact. The relative weights assigned to the four criteria are inevitably subjective, and additional criteria might have been considered. For example, it is uncertain how one should compare a fleeting impact on a large number of viewers, as would occur at a major highway crossing, with a long standing impact on a very limited number of viewers, as would occur at a subdivision.

As methods for mitigating visual impacts, the Companies considered and proposed both transmission line design and vegetation management techniques. As shown in Figure 3, visual impact is an important factor in the tower siting constraints recognized by the Companies. The Companies proposed to select tower styles that minimize visual intrusiveness on surrounding areas. EFSC Ex. 67 at IV.J-21.

The Companies propose to mitigate visual impacts by restoring or planting vegetative screens at road crossings. The Companies also expect to establish new screen plantings in other selected areas along or across rights-of-way, where visual benefits are to be gained.[147] Use of species either indigenous to the area or others compatible with surrounding indigenous plant materials is planned. EFSC Ex. 67 at IV.J-22.

The Siting Council is particularly interested in the use of visual screening, especially in light of the nearly 30 miles of rights-of-way in Massachusetts on which some additional right-of-way clearing would occur. The Siting Council expects the Companies to expeditiously establish or restore effective screening at all road crossings as part of the Companies' mitigation package.

The Siting Council believes the input of abutters and other local interests should be encouraged, to help ensure the effectiveness of screening in addressing visual impact concerns. The Companies should maintain records of concerns raised at street crossing and conservation commission hearings and to the extent raised in written comments by (or solicited from) abutters, local interest groups, or local officials on screening or other means of mitigating visual impacts, and on any resolution of such concerns. Methods of improving local consultation concerning vegetation management are addressed further in Section III.C.4.2(3).

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[147] Locations where rights-of-way cross high or open land at some distance from roadways, but nevertheless visible from roadways, isolated residences, or other visually sensitive areas, could be considered for screening placed along the edge of, or across, the rights-of-way.

In the Companies' analysis, visual impacts constitute one of the major tradeoffs in considering transmission line designs.[148] The Companies can avoid tower placement in wetlands or other sensitive resource areas only at the expense of incorporating staggered tower with existing parallel lines. The Companies appear to be open to public and regulatory input in making such final design choices concerning tower placement.

The choice between establishing double-circuit lines and widening the rights-of-way to accommodate parallel lines involves choices on visual impacts. A double-circuit line (planned on the Sandy Pond-to-Millbury segment), requires towers that are taller than the existing towers. Parallel single circuit lines (as planned on the State Line-to-Sandy Pond and Millbury-to-Medway segments) can result in loss of screening through forest clearing. The Companies appear to have established clear preferences regarding this type of trade-off prior to obtaining public or regulatory input. Cost considerations were evidently an important if not the predominant factor, in the Companies' choices. Parallel lines are cheaper and more reliable where existing rights-of-way can accommodate them. But, the need to acquire new rights-of-way, such as on the Sandy Pond to Millbury segment, shifts the preference toward "double-circuiting".

The Companies considered the design option of underground lines. Underground lines would be particularly effective in avoiding most, but not necessarily all, of the visual impacts associated with above-ground lines. The concerns associated with tower height and aesthetics obviously would be avoided. But the visual impacts associated with right-of-way clearing likely would remain, or even be exacerbated by the need to control more rigorously vegetation over the buried line. Undergrounding also would have more severe impacts on wetlands, surface waters and possibly water supplies. Again, the record suggests that cost and reliability concerns were important if not the predominant considerations in the Companies' preference for above-ground lines. In addition, to the extent that some people may feel that there may be an environmentally-based preference for placing the proposed lines underground, the benefit would be only incremental unless the proposed project was conditioned on placing existing lines underground, as well.

The Siting Council believes the Companies have made reasonable decisions on design and placement of the transmission lines in order to minimize the potential visual impacts as balanced against costs.

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[148] The record in this proceeding contains scant indication of any public preferences concerning transmission line design.

(3) Vegetation Management - Herbicides

The Siting Council is concerned about the proposal to continue use of herbicides as a means of vegetation control, including the process of herbicide application which encompasses the opportunities for consultation.

The Companies currently use herbicides[149] to control vegetation on rights-of-way. The Companies propose to use herbicides, as part of an ongoing vegetation management program, on portions of the rights-of-way in the Commonwealth which would be cleared to accommodate the proposed Project, and to continue the use of herbicides on existing rights-of-way. The vegetation management program, which would continue, includes a variety of methods including mowing and hand cutting as well as herbicide application. However, the Companies prefer the selective use of herbicides to control those species deemed to be undesirable. EFSC Ex. 67 at IV. C-5; Tr. 6 at 102-103.

The Companies believe that their herbicide application program is safe, as it relies on herbicides approved by responsible state and federal agencies, and on herbicide application contractors who are experienced and state-licensed. EFSC Ex. 67 at IV. C-7. The Companies also cite numerous safeguards that are taken to minimize drift of herbicides off the rights-of-way. And the Companies avoid spraying near sensitive areas. EFSC Ex. 67 at IV. C-7 to C-8.

The Companies assess the characteristics, action and break down products for the five herbicides which have been used on the project rights-of-way. In general, the Companies find that their herbicides all show low mobility in soil (at current usage rates), low persistence, low acute toxicity, and low or unclear chronic toxicity. EFSC Ex. 67 at IV. C-8 to C-13.

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[149] Use of herbicides is an environmental issue by virtue of the potential for herbicides to persist and move about in the air, water, and land environment. Herbicides may have unintended toxic effects on ecological values or human health. Although closely related to the discussion of water and land resources, _supra_, application of herbicides on utility rights-of-way is unique in that it involves ongoing maintenance practices (rather than the design or construction impacts of a new line). Also, use of herbicides recently has been the focus of a state-sponsored task force. Massachusetts Department of Food and Agriculture, _Final Generic Environmental Impact Report on Control of Vegetation on Utility and Railroad Rights-of-Way_, prepared by Harrison Biotech, Inc., January 1985. The report, including a section on policy recommendations, was developed in conjunction with the Massachusetts Executive Office of Environmental Affairs, MEPA Unit, Herbicides Task Force. See Final Generic EIR at 122. The Siting Council has taken official notice of this document.

The Siting Council notes that similar assessments of the above-referenced and other herbicides were included in the Generic Environmental Impact Report prepared by the Bureau of Pesticides Control in conjunction with the work of the Herbicides Task Force. While many of the Companies' findings are corroborated by the state-funded analysis, some disagreements are apparent. Most notably, in contrast to the Companies' findings of low mobility, the Generic EIR indicates that two of the herbicides used by the Companies, Picloram and Triclopyr, should be considered mobile, while a third, 2, 4-D, is of unclear mobility. The Generic EIR also indicates that the persistence (half lives) for Picloram and Triclyopyr may range higher than levels cited by the Companies. Tr. 6 at 109-114.[150]

To support their case for the continued use of herbicides, the Companies also present results of groundwater samples taken at four locations along the rights-of-way. The Companies included four herbicide brands used on rights-of-way, and three used at substation sites in the sample analysis. The Companies found no detectable levels of herbicides. In all the sample instances except one, however, the herbicide applications had been made at least five-to-six months prior to the date the samples were taken. The Companies' tests for breakdown products, which were to have been conducted, were not performed due to an unavailability of appropriate standards and analytical protocol. EFSC Ex. 67 at IV. B-4 to B-10; Tr. 6 at 128-129.

The Companies' product research and sampling results suggest that the herbicides can be safely used. While the Siting Council does not disagree at this time with the Companies' findings, the Siting Council believes there are inconsistencies and gaps which should be resolved if the Siting Council and interested citizens of the Commonwealth are to have confidence that there are no public health risks. With respect to the Project area well samples, the time lag between application of the herbicides and sampling, and the failure to test for breakdown products detract severely from the usefulness of the results. The utility-sponsored research conducted by Dr. Karl Deubert, which is the basis for the Companies' divergent findings on mobility and persistence, was only completed in March, 1985. Tr. 6 at 109. Thus, there has not been much opportunity for peer review to date.

As indicated at the outset of this subsection, the Siting Council is concerned about the process of herbicide application. As recognized in the Companies' own safeguards (as well as in the work of the Herbicides Task Force) there is the need to be aware of and take special steps to protect sensitive areas. The Generic EIR lists 14 types of sensitive areas, and recommends establishing buffer zones

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[150] Regarding the divergent findings on mobility and persistence, findings cited by the Companies are based on the utility-funded report: Studies on the Fate of Garlon 3A and Tordon 101 used in Selective Foliar Application in the Maintenance of Utility Rights-of-Way in Eastern Massachusetts, Karl M. Deubert. March 19, 1985. EFSC Ex. 89.

around some or all of the sensitive areas (where general herbicides application would not be permitted). Generic EIR at 116-117. Only two types of areas -- wells and areas tributary to public water supply reservoirs -- are currently recognized in established state guidelines specifying such buffer zones.[151]

The Companies believe they effectively identify and protect most of the types of sensitive areas. The Companies have internal guidelines, for example, that go beyond the existing state guidelines in protecting such areas as residences and surface waters other than reservoirs. Tr. 6 at 132. The Companies assert that they consult topographic and transmission line maps and other information provided by regulatory agencies, as well as using point persons on the herbicides application crews, to provide a systematic approach to identifying sensitive areas. EFSC Ex. 219.

The Companies note, however, that two types of sensitive areas, private wells and private gardens, can be reasonably identified only in the field by point persons on herbicide application crews. EFSC Ex. 67 at IV. C-28; Tr. 6 at 134. Because such methods rely on direct observation, and evidently do not include systematic consultation with abutters, it is possible that some areas may be missed. The Companies' witness, Mr. Van Bossuyt, agreed there is a need for improvement in mechanisms that exist for informing abutters about spray schedules and obtaining input from abutters about locations of sensitive areas. Tr. 6 at 138-139. However, he added that the present process is not grossly deficient, and the Companies overall position is that there is no specific need to expand the process. EFSC Ex. 219.

Beyond the protection of sensitive areas, the Siting Council is concerned with the broader question of using overall maintenance practices that are responsive to the concerns of abutters and nearby communities. The Herbicides Task Force has recognized the need to encourage cooperative agreements between utilities and abutters or municipalities concerning non-chemical alternatives to herbicides. As conceived by the Task Force, local preferences for non-chemical alternatives would be considered as part of an expanded state agency review of utility-prepared vegetation management plans. Generic EIR at 118-119.

The Companies do cite some instances where they have addresed abutter concerns about the use and management of rights-of-way. For example, the Companies have made agreements with interested abutters to convert rights-of-way to useful purposes, such as pasture or gardens.

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[151] Massachusetts Department of Food and Agriculture, Interim Guidelines Relative to the Use of Herbicides to Control Woody Vegetation on Railroad Layouts and Rights-of-Way in Massachusetts. October 15, 1983. The Siting Council has taken official notice of this document.

The Companies have indicated they also expect to do so in the future. It is even apparent that, if faced with abutters opposing the use of herbicides, the Companies will make arrangements with such abutters to allow them to manage the rights-of-way themselves. Tr. 6 at 144.

The extent to which the Companies publicize, and extent to which abutters are aware of these instances is unclear. In response to the comment that methods for consultation with abutters may not be sufficiently systematic, the Companies stated, EFSC Ex. 219:

> Persons who reside along the rights-of-way can obtain information [on spray plans] from the local officials [notified by Company pursuant to M.G.L. c. 132B, Sec. 6B] or, if they request it, directly from the company. Often as the [herbicides application] crew is working in the right-of-way they will have conversations with abutters. Company arborists, foresters, and managers meet with any local officials, landowners or members of the general public when requested to do so. Very few abutters have requested that herbicides not be used. When they do, arrangements are usually worked out.

The Companies' response also identifies related notification procedures and informational mechanisms, and asserts that the overall process constitutes a systematic approach. EFSC Ex. 219. However, the above described process evidently represents the extent of direct contact with abutters. Such a consultation process -- dependent on conversations that "often" occur and arrangements that are "usually" worked out -- conceivably could leave some abutters' concerns unheard or unmet.

The Siting Council finds that the Companies have endeavored to develop a vegetation management program that consistently complies with state and federal regulations and guidelines for protecting the environment and public health. The Companies have been generally supportive of the work of the Herbicides Task Force, and apparently are willing to, and in fact do, go beyond minimum requirements in meeting possible public concerns with spraying. No evidence has been presented that the Companies' current practices are harmful to the environment or public health.

However, the Siting Council sees two particular areas where the Companies could take immediate steps that would contribute to timely advances in the Companies maintenance program.[152] One area of concern

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[152] The Siting Council recognizes that the Herbicides Task Force set some long term policy directions and interagency responsibilities for improving vegetation management practices. The Siting Council does not intend to preempt the coordinated state effort by requiring actions that
(Footnote Continued)

is in the monitoring for ground water contamination along system rights-of-way. The Companies' own monitoring analysis is an example of how limited information can be confusing if not misleading. The other area concerns utility consultation with abutters and other local interests about spray plans.

As discussed previously, the Companies' ground water monitoring analysis was of only partial value because it was not related, by any design, to the timing of herbicides applications. The analysis was performed at the request of the Executive Office of Environmental Affairs, as part of the MEPA process. EFSC Ex. 67, Section I. The analysis would have missed any possible occurrences off the right-of-way of those herbicides which persist only in the short run, or of herbicide break-down products regardless of length in time of persistence. Thus, the Siting Council believes that the Companies should, in conjunction with any planned future herbicides applications near sampling points on the Project rights-of-way, including substations, conduct further ground water monitoring more appropriately timed to capture any effects, but otherwise consistent with the general purposes outlined by MEPA as part of the scope of the EIR.

It is a CONDITION of this Decision that the Companies, within six months of the Decision shall provide to the Siting Council a plan for conducting additional ground water monitoring on the Project rights-of-way. The plan should follow-up on and be generally consistent with the purposes of the ground water monitoring required as part of the MEPA scope for the EIR. The plan should provide for monitoring at times relative to spray schedules that will maximize the likelihood that any ground water contamination off the rights-of-way, including short-term occurrences, will be detected. The plan should include one or more monitoring sites incorporating each of the following features (or, if the Companies believe it is inappropriate to incorporate any feature, explain why):

1. public water supply well adjacent to or near the right-of-way;
2. down gradient observation well on or adjacent to the right-of-way and in an aquifer area used for private wells, but not near public water supplies or other "protected" sensitive areas.
3. down gradient observation well on or adjacent to a segment of project right-of-way where (and on the same side of such right-of-way as where) forest clearing to widen the right-of-way is planned as part of the Project; and
4. down gradient observation well at or adjacent to a substation.

(Footnote Continued)
may later prove inconsistent with the evolving state process. One ongoing state effort of which the Siting Council is aware is that of the Bureau of Pesticides Control to develop proposed regulations for submission and review of vegetation management plans.

The locations and times of sampling should be determined in consultation with interested state agencies.

With regard to abutter consultation, the Siting Council believes that there is a need for improvements in various types of two-way communication between abutters and utility personnel responsible for right-of-way maintenance. The Herbicides Task Force recognized the need for better consultation in identifying sensitive areas, and also highlighted the role of cooperative agreements between utilities and abutters as a means of increasing the use of non-chemical alternatives to herbicides. The Siting Council concludes better consultation methods are needed to ensure protection of sensitive areas, but also to improve public awareness of existing opportunities to sign utility-abutter agreements allowing abutters to maintain rights-of-way or convert right-of-way lands to productive uses.

The Siting Council does not intend to prescribe specific new Company procedures to address concerns with respect to abutter consultation on the Project rights-of-way. Improving such procedures is clearly of statewide concern, relating to many existing as well as new or expanded rights-of-way. The consultation methods are within the central purview of the Herbicides Task Force and the lead state agencies designated in Task Force recommendations.

However, the Siting Council believes that the proposed Project presents an appropriate context and starting point from which to initiate timely research and development of techniques for improving abutter consultation about right-of-way maintenance practices. There is no evidence to indicate that the Companies on their own have considered, or plan to consider, specific options which might significantly upgrade the level or consistency of such abutter consultation.[153]

It is a CONDITION of this Decision that the Companies, 30 days prior to the first application of herbicides to control woody vegetation on any Project rights-of-way after the commencement of any on-site project construction activities, shall provide to the Siting Council an analysis, with recommendations, of alternative consultation and related informational mechanisms capable of improving the Companies' knowledge of sensitive areas along rights-of-way, and enhancing abutter awareness about all opportunities for abutter-utility agreements concerning right-of-way maintenance. The analysis shall be based on experience elsewhere and, as appropriate, on actual demonstration by the Companies of prospective techniques on portions of the project rights-of-way. Pending submission of such analysis, the Companies shall provide annual

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[153] Examples of such options might include: (1) instituting hand delivery of copies of public notice of spray plans to all affected resident abutters (this is currently required in Vermont, pursuant to the Vermont Pesticide Control Act of 1970), and (2) making available printed information on Company policies with respect to abutter - Company agreements to use non-chemical means of vegetation management.

reports, beginning one year after the date of this Decision, on their progress and future plans for meeting this Condition. All efforts to comply with this condition shall be closely coordinated, as appropriate, with any ongoing efforts or programs to implement recommendations of the Herbicides Task Force.

(4) Health and Nuisance Effects of Electrical Environments

The Companies have presented information about expected electromagnetic effects of the proposed transmission facilities. As part of its environmental review, the Siting Council has utilized the information to evaluate the relationship between the proposed transmission facilities and public health.

The Siting Council's ultimate task is to determine whether the proposed facilities constitute the minimal-environmental-impact, least-cost solution (or partial solution) to an identified energy need. In the areas of public health the Siting Council is interested in the effects of the facilities, whether there are impacts, and whether the impact is harmful. Thus, there are three questions of primary concern to the Siting Council: What changes will the facilities produce in the local electrical environments? Will these changes result in impacts on noise levels, radio/TV reception, or biological systems? Will those physical or biological effects result in harm in the form of short or long term ecological damage, health problems, or unacceptable public nuisances?

The proposed Hydro Quebec Phase 2 facilities include both AC and DC transmission lines. Historically, bulk electric power was transported using alternating current. The operation of DC transmission lines is a relatively new phenomenon. The Phase 2 HVDC line would be the first DC transmission facility in Massachusetts. Thus, the Siting Council has given particular attention to the health effects of the proposed DC facilities.

The proposed ±450 kV HVDC transmission line terminating at Sandy Pond will generate DC electric and magnetic fields. According to the Companies, corona activity catalysed by DC transmission of electricity will lead to the production of small air ions in the immediate vicinity of the conductors. Ex. GBJ at 23-24.[154] Elevated levels of small air ions will increase the electrical charge present in the atmosphere of the right-of-way and beyond. (The Siting Council will refer to this electrical charge in the air as "space charge".) The electric charge on the conductors and the space charge will interact to produce the total

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[154] Corona is the "partial electrical breakdown of the air surrounding the conductors." Ex. GBJ at 5. A small air ion is comprised of a cluster of molecules held together by charge due to the gain (negative ion) or loss (positive ion) of an electron. EFSC Ex. 195.

effect of the proposed DC facilities on the electrical environment. Other effects of corona activity include ozone production, radio interference, and noise. Ex. GBJ at 19-30.

AC transmission facilities have a different set of electromagnetic fields and effects. The proposed 345 kV AC transmission lines extending from Sandy Pond to Millbury and Millbury to West Medway will generate 60 Hz AC electric and magnetic fields. Radio interference, noise, and ozone production will result from AC corona activity. Small air ion release is not an issue with AC transmission facilities, since each pole alternates between positive and negative charges effectively neutralizing the vast majority of the ions produced. Ex. GBJ at 9-19.

The Companies presented testimony from three expert witnesses on the potential of health risks associated with expected electromagnetic effects of the proposed transmission facilities. The consensus of the witnesses was that, while effects are present, operation of the facilities will present no unreasonable danger to human, animal, or plant health. Tr. 7 at 11, 15, 19. Further, the witnesses stated it is unlikely the proposed facilities will be found to present such a danger in the future.

The Companies presented estimates of the intensities of the electric and magnetic fields at the edge of the right-of-way, inside the converter complex and at the terminal fence. The intensities at the edges of the rights-of-way represent cumulative levels resulting from existing and proposed lines.[155]

The Companies did not specifically present information on the quantities of aerosols expected to be charged by either the proposed AC or DC facilities. The Siting Council acknowledges the difficulties inherent in producing reliable estimates of charged aerosols. EFSC Exs. 195, 196.

The Companies conclude that no harm or unacceptable nuisance problems will occur from electrical environments associated with the proposed facilities. With respect to air quality, the Companies' findings as to the limited levels of ozone that may be expected to be generated and to move off the right-of-way are indeed compelling, and are not discussed further in this Decision. EFSC Ex. 67 at IV.F-2. The remaining impact areas -- noise, radio/television interference, and health effects -- are discussed in more detail below.

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[155] The Companies elected, generally, not to address the extent to which the proposed facilities are expected to cause incremental changes in those levels relative to those associated with existing AC facilities on the Project rights-of-way. Estimates of such changes were eventually provided with respect to noise impacts.

(a) Noise Effects

The Companies provided separate noise analyses for the converter terminal and the transmission facilities. The Companies developed estimates of the noise impacts of the converter terminal for selected locations on and surrounding the site, and compared estimates for noise levels in perimeter and off-site areas, with existing ambient noise levels at the respective locations. The Companies' estimates of corona-related noise levels at the edge of the transmission line rights-of-way, by segment and side, represent conditions with and without the proposed additional lines under different weather assumptions.

Based on their analyses, the Companies concluded that all noise impacts of the proposed transmission facilities would fall within accepted federal guidelines for public health and welfare. Ex. GBJ at 10, 21. With regard to the converter terminal, the Companies concluded that the continuous noise produced by the transformers and would not be objectionable at nearby residences, and for the most part would not even be perceived. EFSC Ex. 221. An additional noise at the converter terminal, the discharge of a circuit breaker, was characterized as very intermittent, likely to occur as a one-shot sound only about five times annually. Tr. 5 at 88.

The Siting Council finds that the Companies' noise analyses, in general, provide a reliable basis for Siting Council review. The Siting Council accepts the Companies' overall conclusion that, based on recognized criteria, the proposed facilities will not result in an unacceptable level of noise problems at nearby residences, or for the public in general.

However, as part of its mandate to ensure that the Project minimizes any environmental impacts (in addition to meeting all recognized regulatory guidelines), the Siting Council has considered the possibility that there may be noise complaints related to the project's electrical environment.

One area of concern is that the Companies' findings on limited noise impact at the converter terminal apparently depend on the existence of continuous background noise from the nearby New England Milling Company. This facility, along with the existing Sandy Pond Substation, is expected to preclude any chance of incremental noise impacts from the continuous noise sources at the proposed converter terminal. Tr. 5 at 93; Ex. DLH-5; EFSC Ex. 221.

The Siting Council cannot be completely sure that background noise conditions which depend on a single nearby facility will continue unchanged through the start-up date for the proposed project and thereafter. The Siting Council requests that the Companies promptly advise the Siting Council, prior to project energization, of any actual or expected changes in the operations at New England Milling that may significantly affect background noise levels in the area.

The other area of concern from the transmission lines, is that estimates of noise impacts from corona were not actually compared to measured ambient conditions at any points along the rights-of-way. Rather, the Companies provided comparisons with recognized decibel values for common indoor and outdoor noises. Ex. GBJ-4. The Companies initially made no representation that corona-related noise would not be noticeable at times in areas adjacent to the project rights-of-way.

In response to concerns raised by Siting Council Staff about corona-related noise, the Companies provided additional information addressing the estimated increase in such noise that would result from the addition of the proposed lines, above that already produced by the existing lines on the project rights-of-way.[156] As shown in Table 15, the increase would range from zero to 4 dB(A). The Companies noted it is their experience that an increase of 1 or 2 dB(A) is not detectable by most people, while an increase of 3 or 4 dB(A) is detectable but seldom objectionable. EFSC Ex. 220.

TABLE 15

Estimated Maximum Audible Noise at Edge of Rights-of-Way
Before and After Project - dB(A)

	Summer Fair		Wet Conductor		Heavy Rain	
Cross Section	Before	After	Before	After	Before	After
New Hampshire - Sandy Pond	44	45	48	48	55	55
Sandy Pond - Millbury	43	45	46	48	55	56
Millbury - West Medway	38	41	42	45	50	54

Source: EFSC Ex. 220

Using the Companies' criteria, the information in Table 15 suggests that there would be few complaints related to increased corona noise from the Project. If at all, Table 15 suggests complaints might occur on the south side of the Millbury-West Medway segment. Other data provided by the Companies show that there are only 7 residences within 100 feet of the south side of this segment, increasing to 28 residences within 200 feet. EFSC Ex. 67 at IV. D-62. Along the Sandy

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[156] Noise levels measured as decibels on the A-weighted scale of a sound level meter, or dB(A).

Pond-to-Millbury segment, which traverses more densely inhabited areas, the maximum edge-of-right-of-way noise increase would be 2 dB(A), a level just below the Company-suggested threshold of detection for most people. The expected noise increase on the DC line segment would be negligible.

Based on the information provided by the Companies, the Siting Council believes that the chances for a large number of project-related noise complaints reflecting changed electrical environments (complaints linked to a noise increase following energization) are slight. However, the projected increases in the Millbury-to-West Medway segment are acknowledged by the Companies to be detectable. And, the smaller noise increases expected along the Sandy Pond-to-Millbury segment, although not considered as detectable generally, nevertheless do result in the highest off-site post-energization (cumulative) noise impacts projected for any component of the preferred network.

Thus, the Siting Council must recognize the possibility that there might be noise complaints associated with energization of the project transmission lines. At the converter terminal, continuous noise does not appear to present a problem based on currently available information. Also, a higher-than-expected incidence of circuit breaker discharges could result in a level of complaints from abutters that would be of concern to the Siting Council.

Thus, it is a CONDITION of this Decision that the Companies shall maintain records on noise complaints starting six months after the date of this decision until two years after the new facilities are energized, and shall report to the Siting Council on the nature and any resolution of complaints of abutters residing within 800 feet of the converter terminal or within 200 feet of the edge of the transmission line rights-of-way at the end of the first two full years following energization.

As a general rule the Siting Council believes that the Companies should maintain records of noise-related complaints.

The Siting Council also believes that it would be advisable for the Companies to conduct a minimal level of noise monitoring in most-affected areas adjacent to the Project rights-of-way under foul-weather conditions before and after energization, in order to verify the extent of any changes in noise impacts. Accordingly, the Companies should provide the Siting Council by December 30, 1987, with a noise-monitoring plan, or an explanation as to why the Companies believe noise-monitoring is unnecessary.

(b) Radio/Television Interference

Corona-produced interference is generally apparent in the form of broadcast "static." The Companies maintained that any interference associated with the Project would be limited to AM radio reception, which is more easily affected than FM radio and television reception. Ex. GBJ at 11; EFSC Ex. 67 at IV.G-1 to G-2.

The Companies developed estimates of potential radio interference[157], by segment and side of the rights-of-way, to represent cumulative conditions with both the existing and proposed lines in operation. The Companies used 50 dB as the assumed threshold of interference for primary-service-area AM reception.[158] The Companies' analysis showed that there would be no interference problems for primary service AM reception under any weather conditions at a distance of 100 feet or more from the edge of the rights-of-way, or during fair weather at the edge of the rights-of-way. However, as shown in Table 16, interference would be expected at the edge of the right-of-way on the most affected side of all three segments during "wet conductor" conditions, and on both sides of the Sandy Pond-to-Millbury segment during heavy rain.

The Companies did not present data regarding the change in radio interference to be expected as a result of energization of the proposed facilities. The Companies merely asserted that the proposed DC line should not create any radio interference problems (EFSC Ex. 67 at IV.G.3), while making no representation as to the incremental impact of the AC reinforcement lines on radio reception within 100 feet of the edge of the rights-of-way.

The Siting Council accepts the Companies' contention that the DC line will not significantly affect radio/television reception. With regard to the AC reinforcement lines, the Siting Council notes that the data in Table 16 suggest at least some potential for interference along extensive boundary sections of the rights-of-way. However, the expected frequency, duration, and aerial coverage of the potential radio interference, in the adjacent land areas extending up to 100 feet from the edge of the rights-of-way, must be considered before drawing conclusions.

The prospects for radio interference problems seem most pronounced on the east side of the Sandy Pond-to-Millbury segment. There are 35 residences within the 100-foot band on this segment edge. EFSC Ex. 67 at IV. D-62. Radio interference levels under wet conductor conditions are expected to be 60 dB at the edge of the right-of-way and 40 dB at a distance 100 feet from the right-of-way, suggesting that the 50 dB threshold would be exceeded over a significant portion of the 100-foot band. The corresponding interference levels under heavy rain conditions would be 8-9 dB higher, thus exceeding the threshold over nearly all of the 100-foot band. Ex. GBJ at 12 and 13.

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[157] Measured as decibels above one microvolt per meter, hereafter referred to as decibels (dB).

[158] Assuming primary-service-area signal strength of 70 dB or more, and satisfactory reception when radio signal strength is 20 dB or more above the interference level. See Ex. GBJ at 13, 23. This is based on information for 15 AM radio stations. Individual towns along the project rights-of-way each receive primary service from 4-7 stations, depending on location. EFSC Ex. 222.

As in the case of the DC segment, the existing 345 kV line is nearest the side of the right-of-way (e.g., the east side of Sandy Pond-to-Millbury) projected to experience the most intense corona effects. Given the sensitivity of corona-produced radio

TABLE 16

Estimated Radio Interference Levels at Edge of the Rights-of-Way for Existing and Proposed Transmission Lines

Cross Section	Summer Fair	Wet Conductor (dB above 1 uV/m)	Heavy Rain
Sandy Pond - Millbury			
East Side	43	60	68
West Side	30	47	56
Millbury - West Medway			
North Side	22	39	48
South Side	36	53	63

Source: EFSC Ex. 169

interference levels to distance[159] from the source, the Siting Council recognizes that, along the east side of Sandy Pond-to-Millbury segment, the share of interference attributable to the proposed 345 kV line may be small. Tr 7 at 29. However, the Siting Council believes that the cumulative interference levels and the number of exposed residences along this segment warrant careful monitoring of complaint levels before and after energization.

The information presented by the Companies indicates interference impacts elsewhere, including the west side of the Sandy Pond-to-Millbury segment and the south side of the Millbury-to-West Medway segment, would be limited essentially to periods of heavy rain conditions.[160] Although

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[159]Interference decreases at an approximate rate of 12 dB per doubling of distance from the conductors up to a distance of about 150 feet, and at an approximate rate of 6 dB at greater distances. Ex. GBJ at 12.

[160]There would be interference at the south edge of the Millbury-to-West Medway segment under wet conductor conditions. But, (Footnote Continued)

heavy rain may be an infrequent occurrence, the incremental component of any such problems associated with the Project may be greater, given that the proposed and relocated lines in both areas are situated nearer the edges of the rights-of-way than the existing 345 kV lines. Thus, the Siting Council again believes careful monitoring of complaint levels before and after energization is warranted.

In summary, the Siting Council finds that the Companies did not address the incremental impacts of the AC reinforcement lines on radio interference. They did not establish that impacts on radio will not occur or will be minimal. Based on its consideration of the overall information provided by the Companies, the Siting Council concludes that there is unlikely to be a large increase, following energization, in the number of complaints about radio interference.

It is a CONDITION of the Decision that the Companies shall maintain records on TV and radio reception complaints received six months after the date of this decision until one year after the new facilities are energized, and shall report to the Siting Council on the nature and any resolution of complaints of abutters within 100 feet of the edge of the AC reinforcement transmission line rights-of-way at the end of the first full year following energization.

As a general rule the Siting Council believes the Companies should maintain records of T.V. and radio reception complaints.

(c) DC Line Health Effects

Witness Banks presented information specifically about epidemiological studies on the effect on health of DC transmission facilities. These studies investigated the effects of exposure to DC electric and magnetic fields as well as exposure to elevated levels of small air ions. Of the six relevant epidemiological projects reported to date, five projects studied human populations and one studied dairy cows. Ex. RSB at 7. Mr. Banks presented the results of his detailed examination of these studies, which indicated serious shortcomings in the research design of each human study.[161] The Siting Council believes

(Footnote Continued)
because the interference level there is only 53 dB or 3 dB above the 50 dB threshold, it appears interference would extend only a short distance beyond the right-of-way edge. "Wet conductor conditions" are intended to be representative of normal rainfall or heavy fog, while "heavy rain conditions" represent only the most intense periods of rainfall. The Companies note, that impact levels calculated for heavy rain conditions occur 5 percent or less of the time during which rain in general is occurring. Ex. GBJ at 10.

[161] Mr. Banks made the following comments on each study:

(Footnote Continued)

that such methodological flaws undermine the value of these studies for indicating either the presence or absence of health effects.

Apart from these specific methodological problems, the Siting Council believes other issues are pertinent to its evaluation of the reported results. None of the studies cited by Mr. Banks involved the examination of the exposed population by qualified medical personnel, Tr. 8 at 182. Nor were any of the studies designed to be able to detect the possible existence or nonexistence of health problems that have long latency periods, such as various cancers, given that they studied

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(Footnote Continued)

a) The Minnesota Landowner Health Perceptions Study suffers from an inadequate questionnaire design, respondents' recall bias, and an inadequate response rate. Ex. RSB at 18.

b) The UPA Sick Leave Study has small a sample size and looks at only one index, i.e., sick leave; no examination is made for systematic sources of bias; and does not measure exposure to electric or magnetic fields for the subpopulations compared. Tr. 8 at 200-201.

c) The North Dakota Landowner Survey studied the extent to which opinions and attitudes about the CU DC line in Minnesota, particularly in relation to health effects, were shared by landowners in North Dakota. The study did not investigate whether physical evidence of effects did or did not exist. Exh. RSB at 23.

d) The Utility Health Agency Complaint Survey monitored the existence of direct health complaints filed at a health agency by residents living near a DC line. Such a survey might not detect subtle increases in already common problems and would not elicit information on the health of individuals who do not report complaints to public health agencies. Tr. 8 at 224-225.

e) The Pacific Intertie Health Perceptions Study has a low respondent rate. Tr. 8 at 223. Further, there could be methodological problems associated with the levels of exposure to DC electrical environments and the validity of the criteria used to define the Pacific Intertie control group, given the effect of atmospheric conditions. EFSC Ex. 194. Apparently, the electrical environment of DC transmission facilities is highly sensitive to wind conditions. EFSC Ex. 194, 196. In the Pacific Intertie study, the prevailing winds throughout the study period were from the west. Tr. 8 at 214-215. EFSC Ex. 171. In that study, conditions of population exposure were not measured for either the control group or population studied. Given the orientation of the transmission line and the geographical distribution of the study population, there is a reasonable doubt as to whether a large portion of the study population received significant exposure to the DC electrical environment during the study period. Additionally, the control group in the Pacific Intertie Study may have received exposure since it was located 0.65 to 0.85 miles from the line. Therefore, the appropriateness as a control is open to question, Tr. 8 at 212.

exposure to DC electrical environments from exposure to DC transmission facilities that had not been in operation for long periods of time.[162]

The Siting Council finds that these human epidemiological studies cannot be considered as strong evidence of either the safety or the harm of the proposed DC transmission facilities. Individually, each study suffers from serious flaws. Collectively, the Siting Council believes that at most the studies indicate that humans do not perceive health effects related to exposure to elevated electromagnetic fields or small air ion levels.

The epidemiological report on the health effects of DC transmission facilities that involved a non-human population, the Minnesota Dairy Cow Performance Study, did not attempt to quantify actual exposures to small air ions or DC electric and magnetic fields. Nevertheless, its methodology has several advantages over the human DC epidemiological studies. The Dairy Cow Study found no ill effects on dairy cows from exposure to DC transmission facilities.

The Companies submit that together the epidemiological studies indicate that no harm to humans is likely to occur from exposure to DC transmission facilities. Tr. 7 at 19. The Siting Council finds instead that no determination of the safety or lack of safety associated with exposure to the DC electromagnetic environment can be drawn from the presented body of relevant epidemiological work.

The record, however, does provide an accessible and organized overview of the findings of more extensive laboratory research on the health effects of small air ions and of DC electric and magnetic fields. Witness Charry evaluated this body of research in terms of whether individual studies do or do not meet minimal scientific criteria. Tr. 8 at 9, 23. In the overall analysis and conclusions, the witness gave more weight to studies that meet such criteria. Ex. JMC at 9-10.

The Siting Council agrees with the Companies that the literature on experiments on both small air ion and DC field health effects is uneven in quality and difficult to interpret. Ex. JMC at 9. However, the research is sufficiently informative for the Siting Council to find that it is unlikely that exposure to DC electric and magnetic fields has serious acute effects on the health of humans or animals. The Siting Council expresses more caution with regards to the short term effects of small air ions. Additional research seems warranted here. Also, the short operating history of existing DC facilities precludes a full evaluation of long term health effects of both DC fields and small air ions. Until appropriate epidemiological studies can be conducted, findings on long term safety based solely on laboratory studies cannot be treated as final. Still, the Siting Council must rely on the information available today. Therefore, the Siting Council finds based

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[162] The first DC transmission line, the Pacific Intertie line, was brought into service in 1970.

on the evidence from presently available laboratory research, that no health problems should be expected to result from the electromagnetic environment of the proposed DC transmission lines.

(d) AC Line Health Effects

The Companies also presented testimony on the health effects associated with exposure to AC transmission facilities. Witness Carstensen summarized his review of the large body of literature on these AC health effects. The witness concluded that the evidence indicates only a few large or clear effects: electric shock; changed honeybee activity within hives; and disturbances in the performance of certain heart pacemakers. Ex. ELC at 22.

According to the Companies, the greatest risk is associated with electric shock to individuals, in or near the right-of-way, who may come into contact with a large conducting object insulated from ground. Proper operation and maintenance of the proposed facilities, as well as grounding of large metallic objects in the vicinity of the right-of-way, should prevent the occurrence of shock. Tr. 8 at 22-23. Corona produced by the facilities may damage the foliage of plants with sharp pointed leaves if they are allowed to grow up under the transmission line. Periodic clearing of vegetation in the right-of-way ought to prevent such harm from occurring. In any case, corona damage has not been found to result in economic loss to forestry or farming operation. Tr. 8 at 8. Honeybee hives placed directly under AC transmission lines may experience lower-than-normal vitality and honey production. Grounding or shielding of hives will eliminate this problem. Tr. 8 at 25. The operation of one type of heart pacemaker may be disturbed in the electrical environment of the proposed AC lines. However, the available data indicate that no harm to human health is likely to result, assuming that proper precautions are taken. Tr. 8 at 113.

The Siting Council finds that the Companies presented adequate evidence that the known health effects of transmission facilities need not present serious risk of harm if proper precautions are taken.

The Companies also presented evidence that it is unlikely that additional harmful effects will be found to exist. For the four reasons discussed below, the Siting Council finds the Companies' evidence on this issue is not credible.[163]

In reviewing this evidence, the Siting Council is unable to conclude whether the data on AC health effects summarized in Exhibits ELC-3 ELC-4 and ELC-5 support or do not support the witness' conclusions. The sources of the problem are twofold. The body of

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[163] While the Siting Council recognizes that science cannot prove a harmful effect does not exist, the Siting Council believes that scientific research can shed light on the possibility that an unknown effect may occur. This statement applies to AC and DC health effects.

research is voluminous, and highly varied in terms of its quality. Further, the witness has not helped the Siting Council to distinguish good from bad research.

The witness' supporting exhibits list the laboratory and published epidemiological studies on AC electromagnetic field effects. Exs. ELC-3, ELC-4, ELC-5. Such presentation of results from such a large number of studies without providing an indication of the quality of individual studies undermines the usefulness of the information to the Siting Council. The Siting Council believes that the quality of a study affects the weight to be attributed to the study in the Siting Council's decision-making process.[164]

The Companies also apparently recognize the importance of the quality of research, since Dr. Charry, their witness on the issue of DC health effects, did attempt to assess the quality of the various studies he considered. The Siting Council finds that Dr. Carstensen's unexplained use of a different methodology in evaluating the AC studies seriously detracts from the credibility of his testimony.

Second, in Exhibits ELC, ELC-3, ELC-4 and ELC-5, Dr. Carstensen attempted to interpret the relative importance of effects reported by various researchers by indicating the magnitude of each effect through a data transformation.[165] The Siting Council finds the results of this analysis unpersuasive in the absence of other information on individual studies, such as statistical significance or sample sizes.

Third, Dr. Carstensen submits that unless recorded effects are "large" or "clear," as opposed to "innocuous" or "subtle," no concern about health need arise. Ex. ELC at 14, 20. Yet without information regarding the statistical significance of scientific results it is difficult to evaluate which effects are in fact "clear" or "large." It is conceivable to the Siting Council that a subtle but consistent effect might place a population at significantly greater risk of harm than large but infrequent effects. Also, studies that result in slight but statistically significant changes in a level or a parameter could serve as a useful guidepost for further research. Thus, the Siting Council questions the witness' interpretation of the AC transmission line electric and magnetic field epidemiological data.

Finally, Dr. Carstensen indicated during cross-examination that only animal studies involving AC electric fields of less than 10 kV/m are relevant to an evaluation of the proposed transmission facilities'

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[164] Evidence on the quality of any studies presented to support an application to construct facilities (whether scientific, economic, engineering, or environmental) is crucial to the agency's review.

[165] Magnitudes were calculated by dividing the difference in values between control and experimental populations by the standard deviation of the value for the control population.

effects on humans. Elsewhere, however, the Companies also explained that, EFSC Ex. 193:

> The internal ac fields in animals which are induced by exposure to external electric fields in air depend upon the shape of the organism, its orientation with respect to the direction of the electric field, the conductivity of the tissues of the animal and to a limited extent upon the distribution of the materials of different conductivities within the animal. In a human being, the induced ac electric fields may range in magnitude over a factor greater than 30 from one part of the body to another. ... However, the induced fields would not be different by orders of magnitude.

These two statements are difficult to interpret for two reasons. First, the foregoing quotation seems internally inconsistent, since the Siting Council believes that effects that differ by a factor of 30 constitute an "order of magnitude" difference. Secondly, the quoted statement conflicts with Dr. Carstensen's conclusion, since the quotation implies that exposing different types of animals, including humans, to electric fields of equivalent strength could generate significantly different axial current densities and surface electric fields. Therefore, the Siting Council finds that these statements make it impossible for the agency to draw conclusions in this area.

For the foregoing reasons, the overall record in this proceeding on health effects associated with exposure to AC transmission lines is complex, difficult to review and difficult to interpret. This being the case, the Siting Council is unable to give credence to much of the evidence adduced in this area. In keeping with the administrative agency's obligation to assess the credibility of testimony presented before it, and the rather wide discretion agencies are afforded in doing so,[166] the Siting Council finds that the Companies have not proven that no additional health-related research on AC lines is needed.

At the same time, the Siting Council has before it no affirmative evidence that the proposed AC facilities <u>will</u> produce harmful health effects.

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[166] General Dynamics Corp. v. Occupational Safety & Health Review Comm., 599 F.2d 453 (1st Cir. 1979) (review commission improperly overturned ALJ's judgement that witnesses lacked credibility); Town of Sudbury v. Dept. of Public Utilities, 351 Mass. 214, 218 N.E.2d 415 (Mass. 1966) (department properly admitted testimony concerning adverse effects of proposed transmission line "for whatever value the department might place upon it"); Number Three Lounge v. Alcoholic Beverages Control Comm., 7 Mass. App. 301, 387 N.E.2d 181 (Mass. App. 1979) (court refused to reverse agency finding that witness lacked credibility).

(e) Health Effects: Conclusions

The Companies presented sufficient evidence on known health effects for the Siting Council to find it likely based on the evidence presented and the literature published to date, that the proposed transmission lines will not adversely affect the health of Massachusetts residents, provided precautions are taken to minimize the known health effects.

The Siting Council reaches this finding despite the following: Specifically, the poor methodology of the epidemiological studies on exposure to DC facilities allows no conclusions to be drawn, except that more research could be warranted. The results of laboratory studies conducted to date on DC electrical environments support the position that no harm is likely to occur. The available evidence on AC electromagnetic effects, while complex and difficult for the Siting Council to review, reveals only a narrow set of effects on human health -- effects that the Siting Council believes can be managed properly so that lines can be safely sited and operated from the standpoint of human health.

However, the Siting Council specifically rejects as not credible the assertion that no further study of biological effects of the AC electromagnetic environment is needed. To the contrary, the record indicates to the Siting Council that additional research would be useful for answering scientific questions that have not been fully explored to date.[167] Additional research could attempt to clear up problems that exist in the scientific literature in this area - i.e., lack of study on long-term exposure to electromagnetic fields, lack of study on dose-response rates, and lack of carefully designed and implemented epidemiological studies. Such additional studies would advance the state of the research and would attempt to answer questions that, in the Siting Council's view, have not been addressed adequately to date by the scientific community.

In spite of these shortcomings in the information currently available on health-related effects of DC and AC transmission lines similar to the ones proposed, the Siting Council is quite confident that the proposed facilities are consistent with ensuring a necessary energy supply with minimum environmental impact at lowest possible cost. Still, the Siting Council attaches a health-related CONDITION to the APPROVAL.

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[167] In sum, in the cases of both potential AC and DC health effects, while the universe of known human effects is limited, the Siting Council does not equate the absence of current evidence of additional health effects with the non-existence of such postulated effects. The degree of uncertainty surrounding this problem is such that definitive answers are not possible at this time. The Siting Council's attitude is reflected in its belief that additional research into these questions is needed.

Specifically, the Companies shall develop and present alternate proposals for monitoring both the levels of AC and DC electric and magnetic fields and small air ion emissions to which a population near the proposed facilities would be exposed. The plan should identify the populations to be studied, the effects to be monitored, and the impacts to be evaluated. The Companies' proposals shall consider and address the concerns on data and methodology raised herein regarding studies published to date. The Companies shall identify the monitoring program(s) they might prefer to implement. The Companies shall evaluate the cost and operational characteristics of monitoring the electrical environment, and, if appropriate, present reasons why a monitoring program would be uneconomical or otherwise unnecessary at this time. Also, the Companies shall evaluate the cost and operational characteristics of alternative health monitoring programs and, if deemed appropriate by the Companies, present reasons why the Companies believe the program(s) would be uneconomical or otherwise not feasible at this time. The Companies shall present this information to the Siting Council by December 30, 1987.

Submission of this information in a complete manner shall constitute compliance with this portion of the Condition. Also, the Companies shall maintain records on health-related complaints associated with the approved AC and DC facilities after they are energized, and shall report annually to the Siting Council, for a period of five years, on the nature and any resolution of such complaints.

As a general rule the Siting Council believes that the Companies should maintain records of health-related complaints.

(5) Construction Period Nuisances

The Companies estimate that construction of the proposed transmission facilities would take approximately 3 years. The DC line construction would require 28 months. The construction of related AC line reinforcement would take 33 months to complete in the Sandy Pond-to-Millbury segment (including the 115 kV and 69 kV line relocations) and 12 months in the Millbury-to-Medway segment. Ex. FSS at 66.

Construction staging areas would be located on or near the rights-of-way at sites not finally determined, but typically occurring approximately at 5-mile intervals along a Project right-of-way. Actual work at any particular location along the route itself is expected to last for approximately 5 months. Ex. FSS at 65-66.

In their environmental assessment, the Companies focus on siting and operating factors related to the construction staging areas. The active life of staging areas is expected to be 12 months or longer on the Sandy Pond-to-Millbury segment, but 6 to 9 months on the remainder of the Project rights-of-way in Massachusetts. EFSC Ex. 67 at IV.I-5. While construction nuisances can occur at any point along the rights-of-way, construction activity will be more prevalent and of longer duration in the vicinity of staging yards.

The Companies developed a list of 23 potential staging area sites for the Project based on preliminary field review. Approximately 13 of these sites will be chosen during the final design phase based on the following criteria:

- o Land owned in fee or held in easement by New England Power Company;
- o Previous use in line construction;
- o Relatively level terrain;
- o Preferably open (i.e., not heavily wooded);
- o Adjacent vegetation screening present;
- o Safe accessibility to a paved road with low traffic volume;
- o Low residential density; and
- o Availability of telephone and electric service.

The Siting Council notes the Companies' recognition of the importance of low residential density and adjacent vegetation screening. The Companies are encouraged to select and design staging yards with the objective of avoiding abutter construction-related complaints to the maximum extent possible. Adequate records of abutter complaints and any resolution should be kept by the Companies throughout the construction period.

b) Comparison of Preferred and Alternate Networks

The Companies compared the anticipated environmental impacts of the proposed facility network (Sandy Pond) and the "best" alternative network (Tewksbury). Differences in the two networks are limited to the 20.7-mile segment of the preferred network (12.2 miles in Massachusetts) terminating at the preferred converter terminal site in Groton, and the 14.7-mile segment of the alternate network (6.5 miles in Massachusetts) terminating at the alternate converter terminal site in Tewksbury.[168]

In terms of the potential impacts on the environmental resources of each network, the Companies submit there are four substantial areas of difference; Amendment, Vol. 2 at 202:

1. the amount of construction work (i.e., circuit miles of lines);
2. the amount of forest clearing;
3. the number of and extent of impact on wetlands affected and surface waters crossed; and
4. the extent of potential visual impacts (visual sensitivity).

The Companies' analyzed these factors, including prospective mitigation measures, and concluded the principal negative environmental

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[168] The two networks are identical in most respects including those portions of DC transmission line construction in New Hampshire north of Sandy Pond Junction, and the AC transmission line reinforcement in Massachusetts south of the Sandy Pond substation.

factors to be recognized and weighed are forest-clearing impact (greater for the proposed network), wetlands impact (greater for the alternate network), and visual impact (greater for the alternate network). The Companies concluded that, on balance, the proposed network involves the least environmental impact. Amendment, Vol. 2 at 203.

In terms of the required construction, the Companies argued that overcrowding of transmission lines on the Tewksbury network right-of-way would require more circuit miles of construction work even though that network is substantially shorter. Although the preferred network requires 5.7 more miles of DC line installation, the alternate route requires 6.2 miles of relocated AC lines installation. If required removals of existing AC line also are considered, the total circuit miles of construction on the Tewksbury route would be nearly double those on the preferred route.[169]

The significance of the estimates of total construction miles on environmental impacts depends upon the impact being considered. Total line installation (rather than just DC line installation) is an appropriate indicator for certain permanent impacts such as the impact of tower placements on wetlands and surface waters. With respect to short term construction impacts, total line installation and removal may be the appropriate indicator, as relates for example to the duration of construction-related noise and dust impact on rights-of-way and staging areas. However, with respect to still other measures of environmental impact, the line relocations are not necessarily important at all, as in number of abutters and the potential exposure to effects of herbicides or electro-magnetic effects.

The loss of forests and other vegetation is the one impact which appears to detract from the proposed Sandy Pond network. The estimated permanent loss is 90 acres for additional vegetation clearing on the existing right-of-way, plus 30 acres for clearing the converter terminal site. EFSC Ex. 67 at IV.C-1. For the alternate Tewksbury network, the estimated permanent loss is only 11 acres at the converter terminal site itself.[170]

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[169] The Council notes a qualification with respect to and involving the expected need to relocate high voltage AC lines on the alternate right-of-way. One of the AC lines to be relocated (a 345 kV line) is in fact a planned line. Although approved by the Siting Council (2 DOMSC at 5-6), it is possible that the 345 kV line may not be constructed as planned (or when planned), and thus may not need to be relocated to allow installation of the DC line. The Companies' assessment of visual impacts, in particular, appears to depend substantially on the need to construct a double circuit 230 kV/345 kV line to replace two other lines -- one of which is the planned 345 kV line.

[170] For the Tewksbury network, an additional 7 acres nearby would be temporarily cleared to allow excavation and regrading for compensatory
(Footnote Continued)

The Companies believe for several reasons that the greater loss of forest resources with the proposed network is not a severe drawback. First, they argue that the expected loss is not regionally significant, citing areawide statistics on forest resources in counties traversed by the preferred right-of-way. In fact, the Companies state the loss of forest resources is actually beneficial in terms of impact on wildlife habitat. They contend any adverse impact on water quality and temperature is minimized by the narrowness of the forest strip to be cleared. What's more, the Companies suggest that mitigation measures can be used to protect water quality, as well as to minimize any visual impacts.

The Siting Council generally concurs with the Companies about the minimal environmental significance of the forest resources that would be lost. However, the Siting Council is more concerned with the environmental significance of the widening of the cleared right-of-way, an impact distinct from the reduction of the local or regional forest resource. First, the expanded right-of-way area would require increased herbicide applications, presumably in proportion to the width of the area to be cleared. Secondly, limitations on the ability of current screening practices to mitigate effectively the increased visibility of facilities in the widened rights-of-way must be recognized. Thus, the Siting Council must consider the forest clearing associated with the proposed network to be a potentially adverse environmental impact -- even with the proposed mitigation.

In the area of impacts on wetlands and surface waters, the dominant consideration in comparing the two networks is the loss of wetland resources which would be associated with construction of the alternate converter terminal site. Approximately 8 acres of flood plain, including 6 acres of vegetated wetland, would be filled adjacent to upland areas currently occupied by a substation and utility buildings. (The latter facilities would need to be relocated within the existing site boundaries to provide still additional space for the converter terminal.) The Companies note that, under state regulation, compensatory flood storage would have to be created in the same contiguous flood plain, and additional compensatory wetland area might be required as well. EFSC Ex. 67 at VI.A-5 to VI.A-7.

Although there also are expected permanent wetland losses associated with the transmission lines, these losses are highly dispersed and the differences between the two networks are small. The proposed network would require one more DC tower placement in wetlands than the alternate network. But the proposed network also would avoid four new tower placements required for AC line relocations on the alternate network. Thus, even the slight difference in permanent wetland losses along the rights-of-way also favors the proposed route.

(Footnote Continued)
flood storage because the converter terminal site would be in a flood plain.

In the area of visual impact, NEH contends that the proposed network again has the advantage over the alternate network. Amendment, Vol. 2 at 214. The Companies acknowledge that the increase in visibility through forest clearing on the preferred right-of-way is one disadvantage for the preferred network. EFSC Ex. 67 at VI.A-3. However, the Companies argue that other factors offset this one disadvantage.

First, the alternate network would affect one more area of visual sensitivity than the preferred network. A recreation/conservation area and Route I-495 are among areas of visual sensitivity affected by the alternate network but not by the preferred network.

Second, as a result of its cross-sectional scale and constraints, the alternate network would be more intrusive than the preferred network. The relocated AC lines would involve structures approximately 25 to 40 feet taller than the tallest structures which would be used on the preferred network. And, as a wider right-of-way with up to six different sets of structures, the alternate network would be more visually discordant.

The Siting Council agrees with the Companies that the identified drawbacks of the alternate network with respect to the impacts on wetlands and visual compatibility are significant. While creation of compensatory wetland resources would mitigate partially the impact on wetlands, the mitigation results at a cost in land resources elsewhere, and is of uncertain effectiveness. The Companies' assessment of the visual intrusiveness of towers on the alternate network also appears to be reasonable, and mitigation measures do not appear to be available to counter this disadvantage significantly.

IV. CONCLUSION AND ORDER

The Siting Council enthusiastically supports the Hydro Quebec Phase 2 Project.

In this Decision, the Siting Council has made a number of findings based on the record in the proceeding:

* that the record is substantially accurate and complete and has provided the Siting Council with adequate grounds on which to base its determinations;
* that New England and Massachusetts need low-cost sources of energy that reduce the region's reliance upon oil;
* that New England and Massachusetts will need to add economic sources of supply for reliability purposes during the next decade;
* that the Companies developed reasonable and reliable estimates of the economic, environmental and reliability impacts of the Project under different assumptions regarding uncertain events in the future;

* that the Phase 2 Project will provide New England and Massachusetts with needed energy and capacity at a substantial savings over alternatives;
* that additional transmission facilities are needed to implement the Project and fully realize its potential economic, environmental, and reliability benefits;
* that in determining what facilities are needed, the Companies identified and evaluated a reasonable range of practical alternatives;
* that the Companies developed reliable cost estimates for the proposed facilities;
* that the proposed facilities are superior to alternatives in terms of cost and environmental impacts; and
* that the Companies' plans for expansion and construction of the proposed facilities are consistent with the current health, environmental protection and resource use and development policies of the Commonwealth.

The Siting Council notes the detailed and thorough level of planning demonstrated by the Companies and comprehensive information and analyses they provided to the Siting Council in this proceeding. The Siting Council appreciates the cooperation the Companies exhibited in its review of the proposed Project facilities.

The Siting Council believes that the Companies have presented a petition that is thoroughly reviewable, appropriate and reliable and one that sets a standard for facility reviews in the future.

The Siting Council has imposed a number of conditions on its approval of the facilities. None of the conditions is designed to detract from the Siting Council's support for the Project; rather they are designed to allow the Siting Council to monitor areas of environmental impact of concern to the Siting Council.

The Siting Council hereby APPROVES the Amendment to Supplement 2C to the Second Long-Range Forecast of Electric Requirements and Resources of the Massachusetts Electric Company, New England Power Company, Yankee Atomic Electric Company and New England Hydro-Transmission Electric Company, subject to the following CONDITIONS:

(1) the CONDITION set forth in Section III.C.4.a(3) concerning monitoring of ground water in conjunction with herbicides applications along the rights-of-way;
(2) the CONDITION set forth in Section III.C.4.a(3) concerning an analysis of ways to improve the Companies' knowledge of sensitive areas along the rights-of-way and to improve abutters' awareness of the Companies' policies on rights-of-way maintenance;
(3) the CONDITION set forth in Section III.C.4.a(4)(a) concerning monitoring of abutters' complaints about noise along the rights-of-way;
(4) the CONDITION set forth in Section III.C.4.a(4)(b) concerning monitoring of abutters' complaints about TV and radio interference along the rights-of-way; and

(5) the CONDITION set forth in Section III.C.4.a(4)(e) concerning development of a plan for monitoring the electrical environment to which populations near the rights-of-way would be exposed.

James G. White, Jr.

James G. White, Jr.
Carolyn E. Ramm
Hearing Officers

November 21, 1985

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of November 21, 1985, by the members and designees present and voting: Chairperson Sharon M. Pollard (Secretary of Energy Resources); Sarah Wald (for Paula W. Gold, Secretary of Consumer Affairs); Joellen D'Esti (for Evelyn F. Murphy, Secretary of Economic Affairs); Stephen Roop (for James S. Hoyte, Secretary of Environmental Affairs); Madeline Varitimos (Public Environmental Member); Patricia Deese (Public Engineering Member). Inelegible to vote: Dennis LaCroix (Public Gas Member); Elliot Roseman (Public Oil Member).

10 December 1985
Date

Sharon M. Pollard

Sharon M. Pollard
Chairperson