Decision and Orders

Massachusetts Energy Facilities Siting Council

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COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of the Braintree Electric Light Department for Approval of its 1989 Long-Range Forecast of Electric Requirements and Resources	EFSC 89-32

FINAL DECISION

Robert P. Rasmussen
Hearing Officer
January 24, 1992

On the Decision:

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The Energy Facilities Siting Council hereby APPROVES the 1989 demand forecast and REJECTS the 1989 supply plan of the Braintree Electric Light Department.

I. INTRODUCTION

A. Background

Braintree Electric Light Department ("BELD" or "Light Department") is a municipally-owned utility supplying electricity to residential, commercial, and industrial customers in the Town of Braintree ("Town" or "Braintree"). The Light Department serves approximately 13,000 customers (Exh. HO-1, p. 6). In 1988, the Light Department sold approximately 340,000 megawatt-hours ("MWh") of electricity and experienced a summer system peak of about 77 megawatts ("MW") and a winter system peak of about 65 MW (id., pp. 6, 14, 24, 32, 41, 49).[1]

BELD owns two oil-fired 2 MW peaking units and the combined-cycle Potter II unit, all of which are located in Braintree (id., p. 8).[2] The Potter II station has a summer rating of 71 MW and a winter rating of 87 MW (id., p. 102).[3] BELD also owns the 13 MW oil-fired Potter I unit which currently is not in service (id., p. 87). BELD purchases base load, intermediate, and peaking power from various sources

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1/ BELD's annual electricity sales for 1989 were approximately 346,100 MWh (Exh. HO-G-2).

2/ While BELD's filing indicates that BELD owns two peaking units, the Siting Council notes that BELD only includes one of these units in its supply plan, indicating that the second unit ("Diesel 2") may, in fact, be retired.

3/ During the course of this proceeding, the Light Department stated that it had performed maintenance to the Potter II unit which had increased the unit's capability to 76 MW in summer and 96 MW in winter and that it had been converted to burn natural gas in addition to oil (Tr., pp. 123-124). For a further discussion of the status of Potter II, see n.30, below.

throughout New England, New York, and Canada (id., pp. 8, 102).

BELD's filing in the present proceeding contains the Light Department's second independent supply plan and its first independent demand forecast to be reviewed by the Energy Facilities Siting Council ("Siting Council"). BELD previously had been a member of the Massachusetts Municipal Wholesale Electric Company ("MMWEC").

On April 14, 1987, BELD filed with the Siting Council a proposal to construct two 115 kilovolt transmission lines and a substation, both in Braintree. The Siting Council docketed that proposal as EFSC 87-32. On July 28, 1987, in a separate proceeding decided during the course of EFSC 87-32, the Siting Council approved the 1985 demand forecast and rejected the 1985 supply plan of MMWEC. Massachusetts Municipal Wholesale Electric Company, 16 DOMSC 95 (1987) ("1987 MMWEC Decision").

Although BELD had been a member of MMWEC at the time of the MMWEC filing,[4] BELD withdrew from MMWEC effective March 24, 1987, prior to its filing of EFSC 87-32. The Siting Council, therefore, before reviewing BELD's facility proposal, required the Light Department to file a demand forecast and supply plan, in accordance with G.L. c. 164, sec. 69I, which mandates that a "company shall not commence construction of a facility[5] at a site unless the facility is consistent with the most recently approved long-range forecast or supplement thereto." Braintree Electric Light Department, 18 DOMSC 1, 6 (1988) ("1988 BELD Decision"). BELD filed its first independent demand forecast and supply plan on December 22, 1987. Id. The Siting Council subsequently determined that the 1987 MMWEC

4/ MMWEC filed its 1985 demand forecast on August 1, 1985 and its 1985 supply plan on August 17, 1985.

5/ The transmission lines and substation proposed by BELD in EFSC 87-32 were jurisdictional facilities within the meaning of the Siting Council's enabling legislation. G.L. c. 164, sec. 69G.

Decision applied to BELD, and, therefore, held that it was unnecessary to review BELD's demand forecast. However, due to the rejection of MMWEC's supply plan, the Siting Council determined that it was necessary for the Siting Council to review the supply plan submitted by BELD prior to making a determination regarding the proposed facilities. Id. at 9, 10.

B. Procedural History

On October 6, 1989, BELD filed its 1989 Demand Forecast and Supply Plan with the Siting Council. On December 4, 1989, the Hearing Officer issued a Notice of Adjudication and directed BELD to publish and post the notice in accordance with 980 CMR 1.03(2). BELD subsequently submitted confirmation of publication. Michael J. Lang, a resident of Braintree, was granted interested person status for purposes of the proceeding.

On December 5, 1990, the Siting Council received a letter from BELD listing seven significant events which had occurred since the October 6 filing and which would have an effect on BELD's supply planning decisions (Exh. HO-2).[6]

An evidentiary hearing was held on December 11, 1990. BELD presented three witnesses: Mayhew Seavey of PLM, Inc., who testified regarding BELD's econometric modeling and supply planning methodology; and Walter McGrath, general manager for BELD, and Robert Keenan, energy services manager for BELD, who both testified regarding BELD's use of the forecasting and planning models and BELD operations in general. At this hearing, the Siting Council issued 13 record requests, responses

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6/ This letter noted that these events "have changed certain facts and assumptions underlying the forecast" (Exh. HO-2, p. 2). Nevertheless, BELD asserted that the demand forecast and supply plan before the Siting Council was accurate and in compliance with Siting Council requirements when it was filed. Here the Siting Council notes that it is not unusual for events to change subsequent to submitting a demand forecast and supply plan which may affect underlying facts and assumptions. It is, therefore, incumbent on any party that has filed information in an ongoing proceeding before the Siting Council to update such information when such changes occur.

to which were provided by BELD on December 21, 1990.[7]

The Hearing Officer entered 95 exhibits into the record, including BELD's filing in this case and BELD's responses to information and record requests.

BELD filed its brief on January 15, 1991.

7/ In light of the fact that, at the time of the hearing, more than one year had elapsed since BELD filed their demand forecast and supply plan and BELD had indicated that significant events had occurred since the original filing which would affect BELD's supply planning decisions (see previous note), the hearing officer provided an opportunity for BELD to supplement the record to update the filing (Tr., p. 179). In addition, an optional fourteenth record request was made by the hearing officer to allow BELD to update its demand forecast and supply plan (id., pp. 179-181).

On December 21, 1990, BELD responded to the first 13 record requests and indicated that a full response to the fourteenth record request would be provided when BELD filed its brief.

On January 15, 1991, BELD filed its brief and did not respond to the fourteenth record request.

II. ANALYSIS OF THE DEMAND FORECAST

A. Standard of Review

As part of its statutory mandate "to provide a necessary energy supply for the commonwealth with a minimum impact on the environment at the lowest possible cost," the Siting Council determines whether "projections of the demand for electric power...are based on substantially accurate historical information and reasonable statistical projection methods." G.L. c. 164, secs. 69H, 69J. To ensure that the foregoing standard is met, the Siting Council applies three criteria to demand forecasts: reviewability, appropriateness, and reliability.

A demand forecast is reviewable if it contains enough information to allow full understanding of the forecasting methodology. A forecast is appropriate if the methodology used to produce the forecast is technically suitable to the size and nature of the utility that produced it. A forecast is reliable if the methodology provides a measure of confidence that its data, assumptions, and judgments produce a forecast of what is most likely to occur. Nantucket Electric Company, 21 DOMSC 208, 214 (1991) ("1991 Nantucket Decision"); Massachusetts Municipal Wholesale Electric Company, 20 DOMSC 1, 10 (1990) ("1990 MMWEC Decision"); 1989 MECo/NEPCo Decision, 18 DOMSC at 302 ; Boston Edison Company, 18 DOMSC 201, 208 (1989) ("1989 BECo Decision"); Eastern Utilities Associates, 18 DOMSC 73, 79 (1988) ("1988 EUA Decision"); 1987 MMWEC Decision, 16 DOMSC at 99; Boston Edison Company, 15 DOMSC 287, 294 (1987) ("1987 BECo Decision").

1. The Appropriateness Standard

The second of these three criteria; i.e., the appropriateness of the forecast, or the concept that the methodology used by an electric company to prepare its demand forecast should be suitable to the size and nature of the utility that produced it, traces its origin to the Siting Council's enabling legislation and early rules of practice. The Siting Council's enabling legislation requires electric companies to use "reasonable statistical projection methods" when projecting demand forecasts. G.L. c. 164, sec. 69J. Siting Council regulation 980 CMR 7.02(9)(b)2, which serves to effectuate this statutory mandate, states that such reasonable statistical projection methods "may depend upon the size of the company, the state of the art of forecasting, and the extent to which the requirements of 980 CMR 7.00 are met." 980 CMR 7.02(9)(b)2. See, e.g., Rowley Municipal Lighting Plant, 3 DOMSC 183, 184 (1980) ("1980 Rowley Decision"); Taunton Municipal Lighting Plant, 3 DOMSC 127, 136-137 (1980) ("1980 Taunton Decision"). This standard is analyzed and applied on a case-by-case basis. 1980 Rowley Decision, 3 DOMSC at 184. In addition, Siting Council regulations state "[t]he Council does not prescribe a particular methodology that must be used by all electric companies in forecasting future demand" (emphasis added). 980 CMR 7.03(5). Thus, the size of an electric utility is considered by the Siting Council when determining whether the statistical projection methods used by that utility are appropriate.

The current use of the specific term "appropriate" as used in this context can be traced to the decision in Northeast Utilities Companies, 8 DOMSC 62, 76 (1982). In that decision, the standard of review used by the Siting Council for the evaluation of electric company demand forecasts, which had evolved in the Siting Council's prior decisions, was formalized. This standard was explained to include the three criteria of reviewability, appropriateness, and reliability. "Appropriateness" was further explained to mean "technically suitable for the utility at hand." Id.

2. BELD's Argument

BELD states in its brief that, as set forth "by a long line of EFSC precedent, a forecast is appropriate if the chosen methodology is technically suitable to the size and nature of the particular utility" (Brief, p. 11). BELD maintains that, as a relatively small utility, its decision to employ an econometric forecast, a forecast methodology which the Siting Council has accepted for systems of BELD's size, is appropriate (id., pp. 11-13). BELD further states that the 1980 Taunton Decision sets forth the premise that "less stringent forecasting standards should be applied to smaller systems" (id., p. 3). BELD maintains that both the Massachusetts Department of Public Utilities ("MDPU") and the Siting Council "recently recognized and confirmed this concept in their Integrated Resource Management ("IRM") Regulations" (id.). BELD states that these regulations recognize "that smaller electric utilities do not have the resources to efficiently and effectively undertake certain obligations" (id.).

3. Analysis and Conclusion

The Siting Council notes that BELD has correctly interpreted the 1989 MECo/NEPCo Decision as regards the appropriateness criterion. As noted above, this criterion has evolved over a number of Siting Council decisions and now includes specific language that indicates that the size of an electric company is relevant to the analysis of the appropriateness of a demand forecast. Additionally, BELD is correct in noting that the Siting Council has found econometric methodologies to be appropriate for the demand forecasts of electric utilities of a similar size to BELD.

The Siting Council, however, has serious concerns about BELD's interpretation of the 1980 Taunton Decision as it relates to the issue of the size of an electric utility and its relation to the Siting Council's review of the appropriateness of a demand forecast. In the 1980 Taunton Decision, the Siting Council made reference to the size of the Taunton Municipal Light Department in two instances: first, with reference to what constitutes a reasonable statistical projection method, and second, with reference to the adequacy of the forecast (3 DOMSC at 136-137, 142-143). In this latter instance, the Siting Council stated that "what is expected of [the Taunton Municipal

Light Plant] is relative to its size in keeping with a long-standing Council policy." Id. at 143.

Neither this statement nor any other part of the 1980 Taunton Decision provides support for the proposition that "less stringent forecasting standards should be applied to smaller systems" as BELD has argued. Rather, the 1980 Taunton Decision indicates the Siting Council's awareness of the fact that different-sized electric companies may find the use of different statistical models better suited to their forecast needs and utility resources.

It is reasonable for BELD to expect that the Siting Council would not require BELD to use demand forecast methodologies that would be an unnecessary burden on BELD's resources. It is also reasonable, however, for the Siting Council to use the same stringent standards in its review of the demand forecast methodology chosen by BELD that the Siting Council would use in the review of the demand forecast methodology chosen by a larger electric utility with greater resources.

In addition, BELD's assertion that both the Siting Council and the MDPU "recognized and confirmed this concept, i.e., less stringent treatment for smaller systems, in their Integrated Resource Management ("IRM") Regulations" is also misplaced. Fitchburg Gas and Electric Company ("FG&E") is an electric company whose peak load, a common determinant of utility size, is comparable to that of BELD. FG&E is subject to the IRM rules, and the MDPU has stated that it would not expect to grant an exception for any major component of the IRM process to FG&E, although the MDPU would consider exceptions from specific requirements that may be onerous. 980 CMR 12.01(2)(b)5; D.P.U. 89-239, p. 50 n.18 (Aug. 31, 1990). Further, in the Siting Council Final Order On IRM Rulemaking we noted that, even though municipal electric systems are sometimes limited in resources, we would not rule out the possibility that IRM-type regulations would be imposed on municipal electric companies in the future (21 DOMSC 91, 104 (1991)).

The Siting Council remains sensitive to the resource limitations of small electric utilities. This sensitivity is reflected in the Siting Council's appropriateness criterion. The Siting Council does not require all electric utilities to produce their demand forecasts through the use of the same method(s). The Siting Council also readily recognizes its acceptance of the use of econometric methodologies in previous demand forecast reviews. However, the Siting Council does expect all utilities, regardless of their size, to produce demand forecasts to the same exacting and stringent standards; i.e., they must be reviewable, appropriate, and reliable. As such, the Siting Council sees no need to alter its long-standing approach to the review of whether a demand forecast is appropriate, and specifically rejects BELD's argument that "less stringent forecasting standards should be applied to smaller systems."

B. Previous Demand Forecast Review

As noted above, this is BELD's first independent demand forecast reviewed by the Siting Council. The 1987 MMWEC Decision, which included BELD's demand forecast, contained no conditions specifically related to BELD (16 DOMSC at 140).

C. Energy Forecast

BELD stated that it forecasted annual energy requirements by first developing electricity price and other economic and demographic forecasts and then applying these forecasts in multiple linear regression econometric models (Exh. HO-1, pp. 6-9). BELD explained that it used these models to forecast electricity demand for its residential, commercial, industrial, and streetlighting customers (id.). BELD developed its own forecasts of electricity price (see Section II.C.1, below), and number of customers, while utilizing data projections for Norfolk County income and employment from Data Resources, Inc. ("DRI") (Exh. HO-1, p. 22). In addition, BELD utilized Heating Degree Day ("HDD") and Cooling Degree Day ("CDD") data obtained from the Blue Hills Observatory, located near Braintree (id., p. 4).

The forecast submitted for review by BELD covers the period from 1989 through 1998. BELD's forecast projects annual energy demand to grow at an average rate of approximately 2.0 percent (id., p. 7). At the end of the forecast period, annual system demand is forecasted to be 455 MWh (id., p. 63).

1. Electricity Price Forecast

a. Description

BELD stated that it forecasted electricity price as the sum of its power supply costs and non-power supply costs (id., p. 8). The Light Department stated that it forecasted the power supply costs, which include power production costs and purchased power supply costs, for its base case supply plan using its production costing model and revenue requirements model (id., pp. 80-82).

BELD stated that it forecasted non-power supply costs as the average of estimated non-power supply costs for 1979 to 1989 (id., p. 9). BELD explained that it estimated the non-power supply costs for each of these years by calculating the average power supply costs for the entire period, allocating these costs to the customer classes based on BELD's current rate structure and cost of service, and then subtracting these allocated power supply costs from the total electricity price for each customer class in each year (id., pp. 8-9, Exh. HO-G-1). BELD stated that it then adjusted the resulting non-power supply component for each year "to reflect a uniform four percent rate of return" (Exh. HO-1, p. 9). BELD used the eleven-year average value of these estimated historic non-power supply costs as its forecast of non-power supply costs, assuming that these costs will remain constant for the forecast period (id.).

b. Analysis

The Siting Council notes that the basic structure of BELD's electricity price forecast -- disaggregating costs into power supply and non-power supply costs, and calculating power supply costs from production costing models -- is an appropriate methodology for a company the size of BELD. However, the Siting Council is concerned with two significant weaknesses in BELD's electricity price forecast. First, BELD has not supported its use of average power supply costs as the basis for average non-power supply costs, nor has it supported its four percent rate of return adjustment to non-power supply costs. The use of such approximations, in the absence of supporting analysis, could adversely affect its electricity price forecast. Second, BELD has provided no analysis assessing the validity of its assumption that non-power supply costs will remain constant throughout the forecast period. BELD's forecast of electricity price would have been strengthened by an analysis of these factors. The Siting Council has often criticized companies for approximating major components related to their forecasts. Commonwealth Electric Company and Cambridge Electric Company, EFSC 90-4, pp. 25-26 (1991) ("1991 CECo/CELCo Decision"); 1991 Nantucket Decision, 21 DOMSC at 251-252; 1990 MMWEC Decision, 20 DOMSC at 12-14; 1989 MECo/NEPCo Decision, 18 DOMSC at 313-315.

Nevertheless, for the purposes of this review, the Siting Council finds that BELD's methodology for forecasting electricity prices is acceptable. In order for the Siting Council to approve BELD's electricity price forecast in its next filing, BELD must either (1) provide and use actual annual historic costs for power supply and non-power supply costs as the basis for future costs, or (2) provide an analysis justifying BELD's current methodology, which uses historic averages, a four percent rate of return adjustment, and assumed constant non-power supply costs.

2. Residential Energy Forecast

a. Description

BELD stated that it forecasted aggregate residential electricity demand using a regression equation methodology

(Exh. HO-1, p. 10). BELD's residential regression equation incorporated income, number of customers, electricity price, and CDDs as independent, explanatory variables (id.).[8] BELD stated that income is the principal determinant of residential electricity demand (Exh. HO-D-5). BELD used DRI's 1989 forecast of per capita income for Norfolk county as its income forecast (Exh. HO-1, p. 12). BELD forecasted the number of residential customers with a regression equation that uses the historic number of residential customers as the independent variable (id., pp. 11-12). BELD stated that in 1988 it had 11,500 residential customers with total consumption of 88,385,000 kilowatthours ("kWh") (id., p. 14), representing about 26 percent of its total system requirement in that year (id., p. 63). BELD projected the average annual growth rate for the aggregate residential class over the forecast period to be 1.3 percent (Exh. HO-D-4). BELD obtained CDD data from the Blue Hills Observatory (Exh. HO-1, p. 2).

BELD stated that it currently subdivides its residential sector into three customer classes: residential base; residential with uncontrolled water heaters; and residential with controlled water heaters (Exh. HO-D-7). BELD stated that it is appropriate to disaggregate its forecast by rate class because customers in different rate classes have different characteristics (Exh. HO-G-4; Tr., p. 15). BELD stated that it intends to provide a disaggregated forecast of electricity usage by residential customers with controlled water heaters in future

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8/ BELD noted that it examined HDDs as an independent variable, but chose not to use it due to its statistical weaknesses (Exhs. HO-G-4, HO-RR-3). BELD stated that it also evaluated real income and population as explanatory variables, but rejected the models using these variables due to "the inferior power" of the population variable (Exh. HO-1, p. 19). The Siting Council notes that both population and real income were significant at the 99.5 percent level in the one model which included both variables, and that this model had an R-squared value of .958, while the model which BELD utilized had an R-squared value of only .922 (id.).

filings (Exh. HO-D-2).[9]

BELD also stated that it was unable to produce a disaggregated residential electric heat forecast at this time, because BELD does not have a separate rate class for electric heating customers (Exh. HO-D-2; Tr., p. 13).[10] BELD argued that the lack of any statistically significant results from the use of HDDs in the regression analysis demonstrated that disaggregation of electric heat customers would not improve its residential forecast (Tr., p. 50; see also n.8, above). Further, BELD indicated that it does not keep records identifying electric heating customers, and that it has no plans to use surveys or other methods to determine heating usage (Exh. HO-D-7). BELD stated that: (1) it assumed that an electric heating usage determination would be extremely costly and time-consuming; (2) it would require surveying every active residential customer; and (3) "it would still be five years before BELD would have the five years of historic usage data

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9/ BELD explained that it does not expect differing total levels of consumption for customers with the residential base rate and customers with the controlled water heater rate (Tr. pp. 16, 19). BELD stated that both rates are offered to customers with water heaters as a result of recent BELD actions to phase out the uncontrolled water heater rate (id., pp. 16, 19, 21). While BELD stated that it expects the time of energy use to differ for the two remaining residential rate classes due to the water heater controls, the Light Department's billing methods "are not set up to determine that" (id., pp. 16, 21).

10/ In BELD's previous supply plan and demand forecast filing, BELD indicated that, in order to comply with Siting Council standards, it would provide a disaggregated analysis of demand by residential customers with electric heating (Exh. HO-D-2). In the instant proceeding, BELD indicated that the statement expressing this intention was "incorrect" (id.).

required by the [Siting Council]" (Exh. HO-D-23).[11]

b. Analysis

The Siting Council has previously accepted BELD's forecast of electricity price (see Section II.C.1.b, above). Here, the Siting Council also accepts BELD's methodology for forecasting numbers of customers and income. Further, the Siting Council accepts BELD's use of weather data from the Blue Hills Observatory as appropriate and reliable.

The Siting Council notes that BELD's overall methodology for the forecast of residential customer demand -- a regression equation incorporating independent explanatory variables -- is generally acceptable. However, the Siting Council notes with concern the absence of any adjustments to BELD's econometric equation to account for conservation and load management ("C&LM") that may occur either naturally[12] or as a result of BELD's efforts.[13]

11/ BELD stated that it is currently conducting a survey of electric water heating customers (Exh. HO-S-20). BELD stated that no attempts were made to collect information about electric heating with this survey because BELD assumed that the survey would be more costly or less successful if additional questions were asked (Tr., pp. 170-171). BELD's witness, Mr. Seavey, also testified that, although it would be difficult to do so, an electric heat forecast could be obtained through analysis of customer records (Tr., pp. 43, 46).

12/ Natural conservation is defined as conservation and load management that will occur without the intervention of the electric company. Examples of natural C&LM are: (1) C&LM programs sponsored or mandated by federal, state and local governments, such as building code standards and appliance efficiency standards; (2) market-induced C&LM and self-generation; and (3) fuel switching. The Siting Council notes that Siting Council regulations require companies to address these issues when forecasting demand. See, e.g., 980 CMR 7.09(2)(d).

13/ See Section II.C.3.b, below, for a discussion of BELD's incorporation of conservation in its econometric modeling.

The Siting Council also has significant concerns with respect to the appropriateness and reliability both of BELD's aggregate forecast, and of its plans for future disaggregation. The aggregate forecast submitted in this filing is clearly inconsistent with Siting Council regulations, which specifically require separate forecasts for residential customers with and without electric heating. See 980 CMR 7.03(7)(a). This requirement recognizes that heating and non-heating customers have substantially different electric use patterns, and that treating such customers as homogeneous may well undermine the accuracy of the forecast.

BELD's stated intention to disaggregate future demand forecasts by rate class will result in a forecast that is similarly inconsistent will Siting Council regulations. BELD's approach does not allow for disaggregation beyond the existing rate classifications either in the residential sector or in other sectors where further disaggregation may be warranted.[14] BELD has argued that its approach to disaggregation is justified by the different characteristics of the customers in each class. The Siting Council notes that BELD's approach will lead to disaggregation of residential customers solely on the basis of controlled water heater ownership. However, the Light Department has reported that no difference in total consumption levels between the controlled and uncontrolled water heater rate classes is expected, and that it has no way to measure any expected difference in time-of-energy use. Thus, BELD's proposed disaggregation by rate class does not reflect any customer characteristic which might affect the forecast.

BELD's argument, based on its analysis of the HDD variable, that separate forecasts of residential electric heating and non-heating customers are unnecessary is similarly unfounded. The Siting Council notes that the statistical

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14/ BELD's reliance on rate classes for forecast disaggregation is discussed further in the review of the industrial energy forecast (see Section II.C.4, below).

analysis of aggregate residential demand presumes that all residential customers, on average, will be equally affected by each variable. This is clearly not the case with the HDD variable, which has a major effect on electric heating use. BELD included all residential customers in its analysis of HDD, regardless of their status with respect to electric heating, thus diluting the potential effect of HDDs on electrical heating users and the statistical significance of the HDD variable as a predictor of residential demand. Therefore, the Siting Council finds that BELD's failure to determine the number and usage of residential electric heating customers before testing the explanatory value of HDD is inappropriate.

Further, BELD's lack of the data needed to identify and disaggregate its electric heating customers does not relieve BELD of its responsibility to acquire or estimate such data.[15] The Siting Council notes that BELD is currently implementing a customer survey which could have included questions relative to electric heating usage (Exh. HO-S-20; see also n.11, above). While the Siting Council recognizes that inclusion of additional survey items may add to costs, the acquisition of fundamental data leading to a better understanding of customer characteristics is an essential component of forecasting. The Siting Council has frequently instructed companies to acquire the data needed to improve their forecasts. 1991 CECo/CELCo Decision, EFSC 90-4 at 16, 20, 28-29; 1991 Nantucket Decision, 21 DOMSC at 241, 253; 1990 MMWEC Decision, 20 DOMSC at 17-18, 30-32; 1989 MECo/NEPCo Decision, 18 DOMSC at 319-320; 1988 EUA Decision, 18 DOMSC at 87-88.

BELD has also argued that a disaggregation of electric heating customers would require either a separate electric heating rate class, or a survey of customers. The Siting Council notes that electric heating usage could be estimated

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15/ The Siting Council's regulations provide that when accurate historical data cannot be provided, the data shall be estimated. See 980 CMR 7.01(5)(e).

through alternative means, such as an analysis of billing data. Mr. Seavey has testified that such alternative means are available to BELD. BELD's argument for not disaggregating residential heating and non-heating customers is, therefore, unpersuasive.

The Siting Council has criticized another electric company for its failure to comply with Siting Council regulations which require the disaggregating of residential heating and non-heating customers. 1991 Nantucket Decision, 21 DOMSC at 231. Here, BELD has similarly failed to disaggregate heating and non-heating customers. In order for the Siting Council to approve BELD's residential energy forecast in its next filing, BELD must initiate and complete a study of the heating usage of residential electric heating customers, which will assist the Light Department in developing a comprehensive understanding of electric heating usage in its service territory, and commence a process designed to identify BELD's residential customers with electric heat in compliance with Siting Council regulations. The Siting Council notes that such a study should assist the Light Department in the preparation of more appropriate and reliable residential forecasts.

Accordingly, the Siting Council finds that BELD has failed to establish that its forecast of residential energy requirements is appropriate and reliable.

3. Commercial Energy Forecast

a. Description

BELD stated that it disaggregates commercial electricity demand into three categories which correspond to the three rates available to BELD commercial customers (Exh. HO-1, pp. 20, 28, 38). These three categories and their contribution to total commercial energy consumption in 1988 are: Small Commercial (31 percent), Large Commercial (56 percent), and Commercial Heating and Cooling (13 percent) (Exh. HO-1, p. 63). The Light Department separates its customers into each category based on the rate for which they qualify (Tr., pp. 13-14). The commercial sector accounted for 53 percent of

BELD's total energy requirements in 1988 (Exh. HO-1, p. 63).

BELD indicated that it uses separate regression equations to forecast these three categories of commercial customers (id.). BELD indicated that all three equations utilize HDD as an explanatory variable, and that individual equations also incorporate a number of the following independent variables: employment, income, electricity price, number of customers, and CDD (id.).[16] BELD obtained forecasts of employment and per capita income from DRI (id., p. 22). BELD forecasted the number of customers in each rate class with a regression equation using employment in Norfolk County as the independent variable (id., p. 30).[17]

BELD made no adjustments to any of the regression equations or results despite several references to C&LM activities in the commercial sector (id., p. 96, Exhs. HO-S-16,

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16/ BELD provided a series of statistical analyses in support of each of its commercial forecast equations (Exh. HO-1, pp. 27, 37, 44). These analyses show that in each instance, BELD's equation has the strongest statistical significance of the equations evaluated.

BELD's equation forecasting small commercial energy requirements uses price, income, employment, and HDD as independent variables (id., p. 27). BELD stated that it also evaluated real income, real price, and CDD as explanatory variables, but found these to be statistically weak (id., p. 23). The R-squared statistic for BELD's equation is .993 (id., p. 27).

BELD's equation forecasting large commercial energy requirements uses number of customers, income, and HDD as independent variables (id., p. 37). BELD stated that it also evaluated employment and CDD as explanatory variables, but found these to be statistically weak (id., p. 31). The R-squared statistic for BELD's equation is .993 (id., p. 37).

BELD's equation forecasting commercial heating and cooling energy requirements uses employment, HDD, and CDD as independent variables (id., p. 44). BELD stated that it also evaluated the number of customers, price, and Consumer Price Index as explanatory variables, but found these to be statistically weak (id., p. 40). The R-squared statistic for BELD's equation is .917 (id., p. 44).

17/ BELD projected average annual growth rates for subsets of the commercial class as follows small commercial (3.7 percent), large commercial (2.8 percent), and commercial heating and cooling (0.3 percent) (Exh. HO-1, pp. 21, 30, 39).

HO-S-18, HO-S-38). Mr. Seavey explained that adjustments for conservation are unnecessary because econometric models inherently identify conservation that occurs during the years used as a database for the analysis, and project its effect into the forecast (Tr., p. 120).

b. Analysis

The Siting Council has previously found BELD's forecast of electricity price to be acceptable. For the purposes of this review of the commercial forecast, the Siting Council accepts BELD's forecast of employment and income. Further, the Siting Council accepts BELD's use of HDD and CDD data from the Blue Hills Observatory as appropriate and reliable. Finally, the Siting Council accepts BELD's methodology of projecting commercial customer numbers.

BELD's disaggregation of the commercial forecast into small commercial, large commercial, and commercial heating and cooling classes is a reasonable forecasting approach. The Siting Council notes, however, that BELD's econometric methodology limits its ability to capture important changes in the energy usage patterns of its commercial customers. Regression equations based on historical data do not reflect trends in the patterns of consumption, such as increasing natural conservation, until such trends are well-established. Similarly, regression equations cannot reflect predictable future trends, such as changes in electricity consumption due to new federal efficiency standards.

Despite the limitations of its methodology, the Light Department has not analyzed emerging trends which would warrant adjustments of the forecast methodology and its results. For example, Mr. Seavey asserted that efficiency improvements will be taken into account as the historic data reflects them. While this statement is an accurate one, the Siting Council notes that in the meantime, BELD may be overlooking variations in consumption which could affect BELD's forecast. The Siting Council has frequently stressed the importance of adjusting forecasts to incorporate the impact of factors, such as efficiency improvements, which are not reflected in the forecast methodology. 1991 CECo/CELCo Decision, EFSC 90-4, pp. 28-29; 1991 Nantucket Decision, 21 DOMSC at 242-243; 1989 MECo/NEPCo Decision, 18 DOMSC at 333-334. The Siting Council notes that the forecast of BELD's commercial class is particularly important due to its magnitude -- about 53 percent of system consumption overall.

Nevertheless, for the purposes of this review, the Siting Council finds that BELD's forecast of commercial energy demand is reviewable, appropriate, and reliable. The Siting Council expects BELD to continue to explore ways to improve the reliability of its commercial forecast as new data sources become available and new explanatory variables are found to be relevant.

4. Industrial Energy Forecast

a. Description

BELD stated that its industrial class was composed of 15 customers with a total demand of 51,493,192 kWh in 1988 (Exh. HO-1, p. 51). BELD stated that this usage accounted for approximately 15 percent of BELD's total electricity sales (id., p. 63). BELD reported that the 1989 industrial class consumption was 50,860,010 kWh (Exh. HO-G-2). BELD indicated that consumption for the industrial class is projected to decline at an average annual rate of 0.1 percent over the forecast period (Exh. HO-1, p. 47).

BELD stated that it forecasted industrial class electricity consumption using a separate econometric forecast which incorporated number of customers, electricity price, and employment as independent variables (<u>id.</u>, p. 52).[18] BELD stated that employment data were taken from the 1989 DRI forecast of employment for Norfolk County (<u>id.</u>, p. 47), while the number of customers was assumed to remain constant at the 1988 level. BELD also indicated that it holds annual meetings with industrial customers to discuss their plans for changes in activity and energy consumption (Exh. HO-D-22). However, BELD's industrial forecast methodology does not incorporate this information (<u>see</u> <u>id.</u>, Exh. HO-1, pp. 45-52).

BELD stated that, in order for a customer to qualify for the industrial rate, it requires that: (1) electricity must be used for industrial or manufacturing purposes; (2) total electricity demand must be 300 kilovolt-amperes ("kva") or more; and (3) energy consumption must be in excess of 100,000 kWh per month (Exhs. HO-1, p. 45, HO-RR-2; Tr., p. 31). BELD's witness, Mr. McGrath, identified two industrial customers which did not meet these requirements (Tr., pp. 33, 37). The first of these customers met the first two requirements but not the third. Mr. McGrath indicated that an exception was made for that customer because the requirements for inclusion in this rate class had recently changed, and the Light Department "would not penalize an existing industrial customer" by removing them from the rate class (<u>id.</u>, pp. 36-37).

The second customer identified by Mr. McGrath was the Massachusetts Bay Transit Authority's ("MBTA") railroad operation. Mr. McGrath indicated that the MBTA is very sensitive to BELD's price of electricity, and, unlike other industrial customers, has the ability to shift its purchases to a neighboring electric company when more economical power is

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<u>18</u>/ BELD provided a series of statistical analyses in support of its industrial equation (Exh. HO-1, p. 52). These analyses show that BELD's equation has the strongest statistical significance of the equations evaluated. BELD stated that it also evaluated real price and HDD as explanatory variables, but found these to be statistically weak. The R-squared statistic for BELD's equation is .906 (<u>id.</u>).

available from that source (id., pp. 34-35). In addition, Mr. Seavey indicated that economic conditions would probably affect MBTA usage of electricity differently than other industrial customers (id., p. 34). However, Mr. Seavey stated that "no effort [was] made to determine whether it would be beneficial to further disaggregate any of the classes that were forecasted" (id.). When asked about BELD's ability to perform a separate forecast of railroad usage, Mr. Seavey described the difficulty of using an econometric forecast for that purpose: "[t]he statistical validity of a forecast involving a single customer would be extremely poor. In a class with a single customer, it's difficult, if not impossible, to forecast reliably" (id., p. 166).

b. Analysis

The Siting Council accepts BELD's econometric equation methodology for forecasting industrial demand. However, the Siting Council notes its concerns about three specific aspects of the industrial forecast presented by BELD.

First, BELD makes no adjustments to its forecast to reflect information gathered during its annual meetings with industrial customers. Here, BELD's omission of information that could potentially improve its forecast is a lost opportunity that BELD should reexamine.

Second, BELD has published criteria for customers' inclusion in the industrial rate class, but has waived these criteria for certain customers. The Siting Council does not take issue with BELD's business decision to offer industrial rates to certain customers which do not meet its published criteria. However, the Siting Council is concerned that, as a consequence, the industrial rate class may contain customers whose consumption patterns better suit them for inclusion in the commercial forecast.[19] BELD should define its industrial

19/ It is also possible that the commercial rate class contains customers which do not meet BELD's criteria for the industrial rate class, but whose consumption patterns are well suited for inclusion in the industrial forecast.

class, for forecasting purposes, so that all customers with industrial class usage patterns, and only such customers, regardless of their rate, will be included in the industrial forecast.

Third, BELD has included the MBTA[20] in the industrial forecast although BELD admitted that the MBTA does not share the characteristics of the remaining industrial customers (Tr., p. 34). It is precisely for this reason that Siting Council regulations require a separate forecast for railroad usage. See 980 CMR 7.03(7). BELD has argued that an econometric forecast of a class with a single customer may be open to question; however, this does not relieve the Light Department of its obligation to develop an appropriate and reliable methodology for forecasting MBTA usage.

Nevertheless, for the purposes of this review, the Siting Council accepts BELD's forecast of industrial energy requirements. In order for the Siting Council to approve BELD's industrial energy forecast in its next filing, BELD must: (1) examine alternate methodologies for forecasting MBTA usage; (2) develop a schedule for implementation based on that examination; and (3) develop a reasonable set of criteria for identifying those customers whose patterns of energy consumption suit them for inclusion in the industrial forecast, and include all those customers, and only those customers, in future industrial class forecasts.

5. Other Energy Forecasts

BELD projected energy consumption for two additional classes -- streetlighting, and losses and internal use.[21]

20/ The MBTA's consumption represented nine percent of the industrial class consumption in 1989 (Exh. HO-D-2).

21/ BELD reported no sales for resale throughout the historical and forecast periods (Exh. HO-1, p. 63).

a. Streetlighting Forecast

BELD's streetlighting consumption in 1988 was 5,190,000 kWh, accounting for 1.4 percent of its total energy requirements (Exh. HO-1, p. 63). BELD stated that future consumption was predicted with an econometric forecast, using residential energy usage as the independent variable (Exh. HO-D-2). BELD explained that it assumed that, since new street lights are only installed on public roads, which are primarily residential, increases in streetlighting usage should correlate with residential usage resulting from new customers (Exh. HO-D-2). BELD indicated that it did not attempt to use the number of streetlights as a variable in the forecast, although that data was available (Tr., pp. 39-40). BELD noted, however, that "[s]treetlighting usage is largely a function of the number of streetlights in operation" (Exh. HO-D-2).

BELD's streetlighting forecast predicts an average annual growth rate of 1.7 percent (id.). However, Mr. McGrath stated that BELD had undertaken a streetlighting "conversion program" since the current filing, and that streetlighting requirements are "declining, not increasing" (Tr., p. 40). In fact, streetlighting usage declined by approximately 17 percent in 1989 relative to 1988 (Exh. HO-G-2).

BELD's methodology for forecasting streetlighting energy use raises several concerns. BELD recognized that the number of streetlights in operation would affect a forecast of streetlight usage. BELD also noted that increased streetlighting usage would be correlated to the demand from new residential customers. Yet, BELD omitted both these predictors in its streetlighting equation. Instead, BELD's forecast was based entirely on total residential energy sales. BELD used that variable without analyzing the alternatives, including the two which BELD had identified as applicable. In addition, the actual decline in streetlighting energy requirements clearly demonstrates the need for a forecast model which can adapt to changes in energy use, such as BELD's streetlighting conversion program.

BELD has failed to support its selection of total residential energy sales as the major explanatory variable in its regression equation for streetlighting usage. In addition, BELD's own recognition of downward trends in streetlighting usage have cast serious doubt on the reliability of the forecast. Accordingly, the Siting Council finds that BELD has failed to establish that its forecast of streetlighting energy requirements is either appropriate or reliable. In order for the Siting Council to approve BELD's streetlighting forecast in its next filing, BELD must identify and analyze the key variables that affect streetlighting usage, and incorporate the results of that identification and analysis into its streetlighting forecast methodology.

b. Losses and Internal Use Forecast

BELD indicated that its losses and internal use projections represent eight percent of the Light Department's total energy requirements for each year of the forecast (Exh. HO-1, p. 63).

The Siting Council has criticized utility filings which do not properly document forecasting methodologies for losses and for internal use, and has noted that a company's filing must be supported by sufficient documentation. 1990 MMWEC Decision, 20 DOMSC at 36-37; 1989 MECo/NEPCo Decision, 18 DOMSC at 327-328; Eastern Utilities Associates, 11 DOMSC 61,65 (1984). Here, BELD has provided no documentation of its forecast methodology for losses and internal use.[22] Consequently, for the purposes of this review, the Siting Council makes no finding on the forecast of losses and internal use. In order for the Siting Council to approve BELD's losses and internal uses forecast in its next filing, BELD must provide a description and analysis of its forecasting methodology for energy requirements due to losses and internal use.[23]

22/ The Siting Council notes that the only reference in the filing to the losses and internal use forecast is a column in Table E-8 (Exh. HO-1, p. 63).

23/ The Siting Council notes that such documentation is required by Siting Council regulation. 980 CMR 7.03(7)(a)9.

6. Conclusions on the Energy Forecast

The Siting Council has found that BELD has failed to establish that (1) its forecast of residential energy requirements is appropriate and reliable, and (2) its forecast of energy requirements for the streetlighting sector is appropriate and reliable.

Further, the Siting Council has found that BELD has established that its forecast of commercial energy demand is reviewable, appropriate, and reliable. The Siting Council has also accepted BELD's methodology for forecasting electricity prices and its forecast of energy requirements for the industrial sector. Finally, the Siting Council has made no finding regarding the Light Department's forecast of losses and internal use.

The Siting Council finds that, on balance, BELD has established that its forecast of energy requirements is reviewable, appropriate, and reliable.

D. Peak-Load Forecast

BELD forecasted its peak load to grow at an average annual rate of approximately two percent over the forecast period (Exh. HO-1, p. 7). BELD forecasted summer peak demand at the end of the forecast period to be 94 MW (id., p. 64).

BELD stated that it derived its forecast of summer peak loads[24] from the energy forecast by analyzing load factors for the years 1978 through 1988 (id., p. 53). BELD calculated summer peak load as the average hourly energy consumption during a year divided by the expected load factor (id.. HO-1, p. 53; Tr., pp. 54-55). BELD defined the expected load factor as the average of the past eleven years' annual system load factors (Exh. HO-1, p. 53). The Light Department stated that it assumed that the load factor would remain constant over the forecast period (Tr., pp. 54-55).

24/ BELD is a summer peaking system (Exh. HO-1, p. 53).

In the past, the Siting Council has approved methodologies similar to BELD's peak load forecasting methodology. See 1990 MMWEC Decision, 20 DOMSC at 34-35; 1988 EUA Decision, 18 DOMSC at 96-97. Therefore, for the purposes of this review, the Siting Council finds that BELD's forecast of peak load requirements is reviewable, appropriate, and reliable.

However, the Siting Council notes that this methodology has significant limitations because of its failure to capture any of the underlying factors that cause peak load. For instance, BELD's peak-load forecast was not disaggregated into customer classes, and did not account for important peak-load determinants such as weather effects and varying consumption patterns during different months, days, and hours. The Siting Council has criticized other utilities' peak load forecasts based on similar deficiencies. 1991 Nantucket Decision, 21 DOMSC at 251-253; 1990 MMWEC Decision, 20 DOMSC at 37-39; 1989 MECo/NEPCo Decision, 18 DOMSC at 329-335; 1989 BECo Decision, 18 DOMSC at 222-223; Northeast Utilities, 17 DOMSC 1, 17 (1988) ("1988 NU Decision").

As the Siting Council noted in 1982, considerable advances in peak-load forecasting methodologies have been made. Northeast Utilities Companies, 8 DOMSC 62, 108-109 (1982) ("1982 NU Decision"). Despite these advances, BELD's methodology remains aggregated and fails to take into consideration major factors which affect peak load. In order for the Siting Council to approve BELD's peak load forecast in its next filing, BELD must develop and present an analysis of alternative peak load forecasting methodologies, which should at least include a summary of: (1) a comparison of the strengths and weaknesses of BELD's present methodology and alternative methodologies; (2) a comparison of the level of disaggregation achieved by each alternative methodology; and (3) a comparison of the manner in which each alternative methodology incorporates the major factors which affect peak load. This analysis should assist the Light Department in selecting a forecasting methodology that may result in a more appropriate and reliable peak load forecast.

E. Conclusions on the Demand Forecast

The Siting Council has found that (1) BELD has established that its forecast of energy requirements is reviewable, appropriate, and reliable, and (2) BELD's forecast of peak-load requirements is reviewable, appropriate, and reliable. Accordingly, on balance, the Siting Council hereby APPROVES BELD's 1989 demand forecast.

In approving this forecast, the Siting Council recognizes the fact that this is BELD's first independent demand forecast presented to the Siting Council. In the future, we expect BELD to improve its forecasting methodologies and techniques, to be prepared to justify its selection of forecasting methodologies, and to submit a filing in conformance with Siting Council regulations. In addition, the Siting Council must raise two significant and fundamental concerns regarding the current filing.

First, BELD indicated in its previous filing that its forecast of residential energy demand would be disaggregated into electric heating and non-heating demand (Exh. HO-D-2). Such disaggregation is clearly required by Siting Council regulations and supported by numerous examples of case precedent. The Siting Council is concerned that BELD has delayed making this basic yet essential improvement to its forecast.

Second, BELD provided no analyses of the sensitivity of its forecast to major underlying assumptions and parameters.[25] In particular, BELD provided no indication of whether, or how, changes in assumptions and parameters such as

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25/ The Siting Council's regulations require forecasting methodologies to be designed so as to accommodate sensitivity testing of major assumptions and parameters. See 980 CMR 7.09(2)(a).

the economic, demographic, or electricity price forecasts would result in significant changes in the demand forecast. The Siting Council has implemented standards for reviewing utility forecasts which explicitly recognize the risks associated with projections of demand and supply as well as the necessity for utilities to plan resources in a creative and dynamic manner. Commonwealth Electric Company, 15 DOMSC 125, 134-135 (1986) ("1986 CELCo Decision"). Given the uncertainties inherent in energy and peak-load forecasts and their role as key inputs in the supply planning process, utilities must provide a quantitative basis for analyzing the effects of forecast uncertainties on supply planning.

BELD's response to the specific recommendations and criticisms contained in our analysis of the various elements of BELD's forecast should address the first of these concerns. In regard to the second concern, the Siting Council notes that electric companies routinely test the sensitivity of their demand forecast to a range of outcomes based on modifications to key variables. 1991 Nantucket Decision, 21 DOMSC at 219; 1989 MECo/NEPCo Decision, 18 DOMSC at 328; 1989 BECo Decision, 18 DOMSC at 222-223. In order for the Siting Council to approve BELD's demand forecast in its next filing, BELD must provide tests of the sensitivity of its energy and peak-load forecasts to one or more major underlying assumption(s) or parameter(s) of each of those forecasts.

III. ANALYSIS OF THE SUPPLY PLAN

A. Standard of Review

In keeping with its mandate in G.L. c. 164, sec. 69H, to "provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost," the Siting Council reviews two dimensions of an electric utility's supply plan: adequacy and cost.[26]

The adequacy of supply is a utility's ability to provide sufficient capacity to meet its peak loads and reserve requirements throughout the forecast period. Cambridge Electric Light Company, 12 DOMSC 39, 72 (1985); Boston Edison Company, 10 DOMSC 203, 245 (1984). The Siting Council has determined that different standards of review are appropriate and necessary to establish supply adequacy in the short run and the long run. 1986 CELCo Decision, 15 DOMSC at 134. To establish adequacy in the short run, a company must demonstrate that it has an identified, secure, and reliable set of energy and power supplies. In essence, the company must own or have under contract sufficient resources to meet its capability responsibility under a reasonable range of contingencies. If a company cannot establish that it has adequate supplies in the short run, that company must then demonstrate that it operates pursuant to a specific action plan guiding it in being able to rely upon alternative supplies in the event of certain contingencies. 1987 BECo Decision, 15 DOMSC at 309-322; 1986 CELCo Decision, 15 DOMSC at 134-135, 144-150, 165-166.[27]

To establish adequacy in the long run, a company must

26/ Diversity, which in past Siting Council decisions has been discussed separately, now is treated within the discussion of least cost (see Section III.E.2.b, below).

27/ The short run is defined as the four year period measured from the time in a proceeding that (1) the final discovery or record response is submitted, or (2) the final hearing is held, whichever is later. 1989 MECo/NEPCo Decision, 18 DOMSC at 343; 1989 BECo Decision, 18 DOMSC at 225 n.10, 245.

demonstrate that its planning processes can identify and fully evaluate a reasonable range of resource options on a continuing basis while allowing sufficient time for the company to make appropriate supply decisions to ensure adequate, cost-effective energy and power resources over all forecast years. Generally, a supply plan that meets the least-cost standards set forth below is deemed adequate in the long run.

The Siting Council next determines whether a supply plan minimizes the cost of power (that is, whether it ensures least-cost supply) subject to trade-offs with adequacy, diversity, and the environmental impacts of construction and operation of facilities. Nantucket Electric Company, 15 DOMSC 363, 384-390 (1987) ("1987 Nantucket Decision"). Recognizing that supply planning is a dynamic process carried out under circumstances which make it difficult for a company to identify with exactitude all the power resources it plans to rely upon in the latter years of its long-range forecast (1987 Nantucket Decision, 15 DOMSC at 378-379, 384, 390-391; 1987 BECo Decision, 15 DOMSC at 301, 322-323, 339-348; 1986 CELCo Decision, 15 DOMSC at 133-135; Fitchburg Gas and Electric Light Company, 13 DOMSC 85, 102 (1985)), the Siting Council's review of the long-run cost of the supply plan generally focuses on a company's supply planning methodology. 1987 BECo Decision, 15 DOMSC at 339-349; 1986 CELCo Decision, 15 DOMSC at 136-138.

The Siting Council reviews the company's processes of identifying and evaluating a variety of supply options. In reviewing a company's resource identification process, the Siting Council analyzes whether that company identified a reasonable range of resource options by (1) compiling a comprehensive array of available resource options, and (2) developing and applying appropriate criteria for screening its array of available resource options. In reviewing a company's resource evaluation process, the Siting Council determines whether that company (1) developed a resource evaluation process which fully evaluates all resource options, including the treatment of all resource options on an equal footing, and (2) applied its resource evaluation process to all of its identified resource options. 1991 Nantucket Decision, 21 DOMSC at 261-262; 1990 MMWEC Decision, 20 DOMSC at 43; 1989 MECo/NEPCo Decision, 18 DOMSC at 343; 1989 BECo Decision, 18 DOMSC at 250-280; 1988 EUA Decision, 18 DOMSC at 111-130.

B. Previous Supply Plan Review

In the 1988 BELD Decision, the Siting Council approved BELD's supply plan without conditions. The Siting Council noted, however, that the supply plan reviewed in that decision was the first independent supply plan of BELD to be reviewed by the Siting Council and considered that fact along with BELD's stated intention "to increase its analytic and evaluative capabilities, and to apply them to its supply planning process" in reaching its decision. 1988 BELD Decision, 18 DOMSC at 22.

Even in cases where approvals without conditions were made, the EFSC reviews issues raised in previous cases to determine the utility's response to the previous decision. 1989 BECo Decision, 18 DOMSC at 208, 210; 1989 MECo/NEPCo Decision, 18 DOMSC at 302, 313. Specifically, the Siting Council noted in the 1988 BELD Decision, that BELD had failed to demonstrate that it fully evaluated the resource options that it had identified (18 DOMSC at 16). Additionally, the Siting Council found that BELD's analysis of resource combinations failed to ensure a least-cost resource mix and placed an inordinate emphasis on adequacy at the expense of cost considerations. Id. at 18, 20. The Siting Council also noted that BELD had failed to demonstrate that all resource options were analyzed on an equal footing. Id. at 21. The Siting Council considers BELD's response to these concerns in this review of BELD's supply plan.

C. Supply Planning Process

BELD stated that: (1) least-cost supply planning is the goal of the Light Department (Exh. HO-1, p. 8); (2) least-cost planning is the basis for its decisions about adequacy (Tr., pp. 143-144); and (3) it plans its new supplies to minimize revenue requirements (Exh. HO-1, pp. 84-85). BELD stated that its supply planning objectives are: (1) reduced oil dependency; (2) improved diversity; and (3) rate stability (id., p. 8).

BELD asserted that its supply planning process emphasizes the evaluation of future supply and demand-side options (id., p. 73). BELD stated that if its projections of committed supply resources are insufficient to meet load requirements projected by BELD's load forecasting model, an optimum mix of generic coal-fired capacity and gas-fired combustion turbines is assumed for capacity additions (id., p. 84). BELD stated that these generic capacity additions are combined with the committed supply resources and an optimum mix of capacity is then determined through use of BELD's supply screening model (id.). BELD indicated that new resource options are then individually compared to this assumed mix of optimum resources (id.).

To identify least-cost supply additions, BELD stated that the cost and performance characteristics of each new resource option identified by BELD are inserted into the supply screening model (id., p. 81). BELD indicated that this model optimizes the existing resource mix with the new option and produces an estimate of total system production costs (id.). According to BELD, after using the supply screening model to approximate its least-cost supply plan, BELD combined the selected options in a production costing model, utilizing more specific performance data, e.g., ramp rates, to generate detailed production cost data (id., p. 85, Exh. HO-S-31). BELD stated that it then applied the data from the production costing model and BELD's load forecasting model to its revenue requirements model to project revenue needs and electricity prices for the option or options which produced the lowest total power supply cost in the supply screening model (Exh. HO-S-31). BELD compared total system costs, as estimated by the supply screening model, of various supply plans with different new resources to select the least-cost incremental resource (Tr., pp. 70-72).

BELD stated that it used its supply screening model to analyze more than thirty resource options, including non-utility generation proposals, modifications to its own units, and a load management option (Exhs. HO-1, pp. 86-89, HO-S-18, HO-S-28). BELD reviewed offers of capacity and found that the characteristics and contract terms of two non-utility generation projects, the MASSPOWER Project[28] for base and intermediate capacity, and the Sterling Project combustion turbine[29] for peaking capacity, produced a least-cost mix over the long-term planning horizon (Exh. HO-1, pp. 86, 88-90; Tr., p. 73). BELD used these two non-utility projects throughout the forecast period to meet projected capacity needs (Exh. HO-1, pp. 88-95). BELD stated that it used the MASSPOWER and Sterling units as "prox[ies] for all the resources that might be available" (Tr., p. 182). The Light Department explained that it assumes projects very similar to these, with their specific costs escalated for the appropriate year of construction, would be available (id., p. 73). BELD stated that it relied upon that assumption for its supply plan (id.). According to BELD, it can evaluate additional new resource options relative to these units by comparing the system costs when the new option is included in the system, with the system costs when the MASSPOWER and Sterling proxy units are included in the system (id., pp. 71-74). BELD stated that if inclusion of the new option provides lower costs, the supply plan is amended to include the new option (id.).

D. Adequacy of the Supply Plan

1. Adequacy of the Supply Plan in the Short Run

a. Definition of the Short Run

As noted in Section III.A., above, the Siting Council has defined the short run for all electric companies as four years

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28/ The MASSPOWER project is a 220 MW gas-fired cogeneration plant under development in Springfield, Massachusetts (Exh. HO-1, p. 88).

29/ The Sterling Project is a 75 MW oil-fired independent power project proposed for development in Sterling, Massachusetts (Exh. HO-RR-5).

from the date of the final hearing or from the date of the response to the final record request, whichever is later. BELD's hearing was held on December 11, 1990 and the final record request response was dated December 21, 1990. Consistent with previous Siting Council decisions, the short run in this proceeding extends from the winter of 1990-1991 through the summer of 1994.

b. Base Case Supply Plan

The data shown in Table 1 compare BELD's projected system resource capability to its peak load capability responsibility over the short-run forecast period.[30] These data indicate that BELD is projecting a short-run capability surplus of from 0.4 percent to 8.1 percent during summer peak periods.

30/ In the projected system resource capability contained in its forecast filing, BELD included Potter II at a summer capacity rating of 71 MW and a winter capacity rating of 87 MW. BELD asserted in the hearing that repairs had been made to the Potter II hot gas path, allowing the plant to operate at full capacity for the first time in over a decade (Tr., pp. 123-125). Mr. Keenan testified that the summer and winter ratings of the plant had been 71 MW and 87 MW respectively, prior to the repairs and are presently 76 MW in the summer and 96 MW in the winter (id.). In regard to BELD's assertions as to the increased capacity of Potter II, the Siting Council notes that, despite repeated inquiries on the part of Siting Council staff, the Light Department failed to provide any detailed information or documentation in support thereof. BELD has failed to provide the Siting Council with any documentation regarding: (1) the extent of the maintenance activities performed; (2) the impact of the maintenance activities on the type of service provided or limitations to that service; or (3) the impact of the maintenance activities on the future performance, availability, and reliability of the unit. In light of this lack of documentation, BELD has not established in this proceeding that it can rely upon any incremental capacity increase at Potter II through the forecast period. Therefore, the Siting Council reviews the adequacy of the supply plan as it was filed, with the summer capacity of Potter II at 71 MW and the winter capacity at 87 MW..

The Siting Council also is concerned with the manner in which the Light Department integrated its decision regarding the Potter II unit into its supply planning process. The Siting Council reviews this issue in Section III.E.2.a, below.

Accordingly, the Siting Council finds that BELD has established that its base case supply plan is adequate to meet requirements in the short run.

c. Short-Run Contingency Analysis

In order to establish adequacy in the short run, a company must establish that it can meet its forecasted needs under a reasonable range of contingencies. BELD originally identified three contingencies which could impact short-run adequacy: (1) the failure of the Seabrook Nuclear Generating Station ("Seabrook") to commence operation;[31] (2) the failure of the Newbay Cogeneration Project ("Newbay Project") to operate;[32] and (3) the double contingency of both of these occurring. During the course of this proceeding, BELD provided documentation that Seabrook is currently on-line and providing power at full capacity (Exh. HO-RR-13). BELD, therefore, asserted that it no longer needed to plan for the contingency of Seabrook failing to provide the purchased power. The Siting Council agrees with this position. However, the Siting Council notes that although BELD assumed that a power purchase contract for 2.55 MW with the New York Power Authority ("NYPA") would be continued beyond its June 30, 1994 termination date, BELD provided no documentation to support the validity of this assumption (Tr., p. 145). In fact, BELD's forecast clearly provides that the NYPA purchase terminates on that date (Exh. HO-1, p. 112). Therefore, in order to evaluate the adequacy of BELD's short-run supply plan, the Siting Council analyzes the following three contingencies: (1) the failure of the Newbay Project to operate; (2) the termination of the NYPA power

31/ BELD has purchased 7.06 MW from Seabrook, a nuclear generating station located in Seabrook, New Hampshire (Exh. HO-1, p. 104).

32/ BELD has purchased 6 MW from the 72.5 MW Newbay Project, a qualifying facility ("QF") proposed to be built in East Providence, Rhode Island (Exh. HO-1, p. 104).

purchase contract on June 30, 1994; and (3) the double contingency of the cancellation of the Newbay Project and the termination of the NYPA supplies.

i. Cancellation of Newbay Contingency

If the Newbay Project failed to come on line as planned, BELD would be unable to receive 6 MW for which it contracted, beginning in the summer of 1991. In this case, BELD would incur a resource deficiency in the summer of 1993 of 0.6 MW (0.7 percent) and a deficiency in the summer of 1994 of 6 MW (7.3 percent) (see Table 2) (id., p. 106). BELD stated that its action plan for this scenario is (1) to rely on NEPOOL for capacity in the summers of 1993 and 1994 and pay NEPOOL deficiency charges, and (2) to move the planned reactivation of Potter I forward one year, from the summer of 1996 to the summer of 1995 (id.). However, BELD stated that within 15 months Potter I can be modified and brought on line with the capability both to burn gas and oil, and the capability to generate an additional two MW of capacity (id., p. 87).[33] BELD suggested that Potter I, as a short-lead-time resource, can provide flexibility for meeting various contingencies (Tr., p. 186).

The Siting Council notes that under this contingency BELD would have inadequate resources in the summers of 1993 and 1994. As stated above, the Siting Council's standard in the event that a company fails to establish that it has adequate supplies in the short run requires that the company demonstrate that it operates pursuant to a specific action plan guiding it in being able to rely upon alternative supplies. BELD, by

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33/ BELD provided analyses of the relative costs of NEPOOL deficiency charges and the earlier reactivation of Potter II, and stated that the NEPOOL charges were the least-cost option (Exh. HO-1, p. 91). The Siting Council emphasizes that an electric utility has the obligation to demonstrate that it has identified a secure and reliable source(s) of energy and power supplies to meet its short-run requirements.

amending its action plan to include the reactivation of Potter I within 15 months if needed, would have sufficient resources to meet its requirements in 1993 an 1994 under this contingency.

However, BELD's intention to rely on NEPOOL in its action plan raises serious concerns. While the Siting Council recognizes the benefits of Massachusetts utilities' participation in NEPOOL in the areas of economical energy and reliability, these benefits in no way eliminate the responsibility of BELD or any other utility to provide adequate supplies to its customers. The Siting Council's concern with the use of NEPOOL deficiency charges as a planning tool should be obvious if one considers the likely results on a peak demand day if multiple NEPOOL members relied on this approach. Reliance on NEPOOL for capacity supplies should occur only for unplanned capacity shortages. Reliance on NEPOOL deficiency charges for planning purposes shifts BELD's responsibility for providing an adequate energy supply to NEPOOL and is clearly not acceptable.

Nevertheless, if all other resources in the base case supply plan remain available to the Light Department, an action plan involving the accelerated reactivation of Potter I would meet the resource deficiency in the summers of 1993 and 1994 in the event of the cancellation of the Newbay Project. Accordingly, for the purposes of this review, the Siting Council finds that BELD can meet the resource deficiencies in 1993 and 1994 and has adequate resources to meet its system capability responsibility in the short run in the event of the cancellation of the Newbay Project.

ii. <u>Termination of NYPA Contract Contingency</u>

Under the scenario of the termination of the NYPA power purchase agreement, BELD's purchase of 2.55 MW would cease beginning in the summer of 1994. In this case, BELD would incur a resource deficiency in the summer of 1994 of 2.5 MW (3 percent of peak) (see Table 2) (Exh. HO-1, p. 104). BELD did not identify an action plan for this specific contingency, but the Siting Council assumes that BELD would rely on the reactivation of Potter I in this scenario as well.

Therefore, for the purposes of this review, the Siting Council finds that BELD can meet the resource deficiency in the summer of 1994 and has adequate resources to meet its system capability responsibility in the short run in the event of the termination of the NYPA contract.

iii. Double Contingency of Cancellation of Newbay and Termination of NYPA Contract

A possible combination of short-run contingencies would be the termination of the NYPA contract and the cancellation of the Newbay Project. If all other resources in its base case supply plan remain available to BELD, this double contingency would produce short-run resource deficiencies of 0.6 MW (0.7 percent) in the summer of 1993 and 8.5 MW (10.4 percent) in the summer of 1994 (see Table 2) (Exh. HO-1, p. 106). While BELD did not identify an action plan for this specific contingency, it did provide an action plan for deficiencies resulting from the contingency of Seabrook's failure to operate that are similar to the above deficiencies. This action plan consists of: (1) purchases from a generic non-utility generation project for which BELD uses MASSPOWER as a proxy; (2) reliance on NEPOOL deficiency charges; and (3) the advancement of the reactivation of Potter I to 1995 (id., pp. 92, 94-95). As previously noted, with the capacity from an earlier reactivation of Potter I, BELD would have sufficient resources to meet its requirements in the event of this double contingency.

However, the Light Department's action plan, which contains the assumption that it will make purchases from a generic non-utility generator, raises concerns. With its reliance on a generic proxy unit in this action plan, BELD has failed to identify any specific non-utility generator which would be available to BELD in the event of a capacity deficiency. In addition, BELD has failed to describe how it would acquire such resources. BELD has simply assumed that capacity or energy will be available in the event of a reasonable contingency. This clearly does not meet the Siting Council standard of operating pursuant to a specific action plan which will guide the Light Department to alternative supplies in the event that this, or another, contingency occurs.[34] The reliance on assumed future availability of capacity without any assurances regarding such availability or any defined plan for acquiring such capacity, would leave BELD vulnerable to significant supply inadequacies in the event of a future capacity shortage.[35]

Nonetheless, for the purposes of this review, the Siting Council finds that BELD can meet the resource deficiencies in the summers of 1993 and 1994 and has adequate resources to meet its system capability responsibility in the short run in the event of the cancellation of the Newbay Project and the termination of the NYPA contract.

iv. Conclusions on the Short-Run Contingency Analysis

The Siting Council has found that BELD: (1) can meet the

34/ The Siting Council notes that BELD has identified numerous non-utility supply options as part of its least-cost supply planning process (Exhs. HO-S-28, HO-S-35). Additionally, the Siting Council notes BELD's participation in the Public Power Resource Development Group ("PPRDG") which provides assistance in the identification of resource options (Exhs. HO-S-17, HO-S-33, HO-S-34, HO-S-35). While BELD may be able to rely upon such information as a means of identifying specific resources which may be available at the time possible contingencies result in a resource need, the Siting Council requires an electric company to clearly establish that it operates pursuant to a specific plan that will enable it to actually acquire the necessary capacity.

35/ The Siting Council set forth its concerns with an action plan consisting of BELD's reliance on NEPOOL deficiency charges in Section III.D.1.c.i, above.

resource deficiencies in 1993 and 1994 and has adequate resources to meet its system capability responsibility in the short run in the event of the cancellation of the Newbay Project; (2) can meet the resource deficiency in the summer of 1994 and has adequate resources to meet its system capability responsibility in the short run in the event of the termination of the NYPA contract; and (3) can meet the resource deficiencies in the summers of 1993 and 1994 and has adequate resources to meet its system capability responsibility in the short run in the event of the cancellation of the Newbay Project and the termination of the NYPA contract.

Accordingly, the Siting Council finds that BELD's supply plan is adequate to meet its system capability responsibility in the short run under a reasonable range of contingencies.

2. Adequacy of the Supply Plan in the Long Run

BELD's long-run planning period is the remaining forecast horizon beyond the short run; this extends from the winter of 1994-95 through the summer of 1998. BELD's base case supply plan as presented in the petition does not satisfy its long-run capability responsibility.

As previously discussed in Section III.A, above, the Siting Council requires an electric company to establish adequacy in the long run by demonstrating that its planning process can identify and fully evaluate a reasonable range of resource options. The ability of BELD's supply planning process to identify and fully evaluate a reasonable range of resource options is fully discussed from the perspective of least-cost supply planning in Section III.E, below.

As indicated in Section III.E, below, BELD has failed to establish that it identified and fully evaluated a reasonable range of resource options. Accordingly, the Siting Council finds that BELD has failed to establish that its supply planning process ensures adequate resources to meet requirements in the long run.

3. Conclusions on Adequacy of the Supply Plan

The Siting Council has found that BELD has established that (1) its base case supply plan is adequate to meet requirements in the short run, and (2) its supply plan is adequate to meet its system capability responsibility in the short run under a reasonable range of contingencies. The Siting Council also has found that BELD has failed to establish that its supply planning process ensures adequate resources to meet requirements in the long run. However, the Siting Council notes that BELD's base case supply plan would satisfy capability responsibility throughout the long-run planning period with the exception of the summer of 1995 (Exh. HO-1, p. 104).

Accordingly, the Siting Council finds that, on balance, BELD has established that it has adequate resources to meet its projected requirements throughout the forecast period.

E. Least Cost Supply

In this section, the Siting Council reviews BELD's processes for identifying and evaluating resource options.

1. Identification of Resource Options

BELD identified generation and load management options for evaluation. The Siting Council focuses its review on whether BELD identified a reasonable range of resource options by (1) compiling a comprehensive array of available resource options, and (2) developing and applying appropriate criteria for screening its array of resource options.

a. Available Resource Options

In order to determine whether BELD compiled a comprehensive array of available resource options, the Siting Council must determine whether BELD compiled adequate sets of available resource options for each type of resource identified during this proceeding.

i. Types of Resource Sets

In the course of this proceeding, BELD identified four types of resource sets for consideration in its supply planning process: (1) purchases from non-utility cogeneration and small power developers; (2) peaking capacity from combustion turbines; (3) load management options; and (4) refurbishment and modifications to BELD-owned units (Exhs. HO-1, pp. 86-89, 96, HO-S-31).[36]

BELD stated that it had not identified long-term purchases from other utilities because they knew of no such offerings (Tr., p. 67). BELD explained that no utility had contacted it offering long-term power sales (id.). BELD did not indicate whether it sought to locate such purchases, or why it failed to identify any (id.). The Siting Council notes that, in the past, BELD has been successful in arranging purchases from other utilities (Exh. HO-1, p. 112). Given the size of BELD's system and the fact that it is interconnected with the New England power grid, purchases of supplies from other utilities should constitute an important resource set that BELD should not fail to identify and analyze.

With respect to conservation, BELD stated that "BELD is gathering data to analyze the economics of commercial lighting efficiency programs..." and that "each of these options will be analyzed using the integrated planning process" (id., p. 96). However, BELD did not indicate during the course of this proceeding whether these options were currently being evaluated in BELD's supply planning process. Mr. McGrath testified that the Light Department was "in the process of retrofitting all

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36/ The Siting Council notes that BELD, in its filing, analyzed the refurbishment of its Potter I unit as a part of its least-cost planning methodology (Exh. HO-1, p. 86) and included the unit in its base case supply plan in the summer of 1996 (id., Table E-17). BELD also indicated that it was gathering data to analyze the economics of the refurbishment of BELD's Diesel 2 unit and modifications to its Potter II unit to increase their output and efficiency (id., p. 96).

lighting in town buildings" (Tr., p. 83). Mr. McGrath also testified that another commercial customer, the Flatley Corporation, had approached the Light Department with a lighting retrofit proposal and had been granted a rebate for work in five buildings (id., pp. 90-91). BELD further stated that these two programs have not been offered to other commercial customers, and were not included as resources in the resource plan (id., pp. 90-91, 119).

Despite BELD's recent evaluation of these two specific conservation programs for these two specific customers, the Siting Council notes that BELD has not actually (1) identified conservation as a resource set, or (2) evaluated conservation programs as part of its integrated planning process.[37] The Siting Council also notes that G.L. c. 164, sec. 69J sets forth that an electric company's long-range forecast must include an adequate consideration of conservation.

Accordingly, based on the foregoing, the Siting Council finds that BELD has failed to identify a reasonable range of resource sets. Nevertheless, the Siting Council proceeds with its analysis of the compilation of resource sets which BELD has identified and evaluated.

37/ BELD indicated that it has implemented limited conservation measures, but that none of these are considered resource options (Tr. pp. 119-120). Two examples illustrate BELD's approach to conservation. First, BELD provides audits to residential customers who request them (id.; Exh. HO-S-16). These audits include a limited installation of conservation measures but no attempt to calculate the energy and capacity savings from this program is made by BELD (id.). Second, BELD described a program to distribute to each residence in Braintree 67-watt incandescent light bulbs to replace 75-watt bulbs (Tr., pp. 83-89). BELD provided no indication that this distribution had been evaluated as a resource option. When asked about efforts by BELD to monitor this program and determine its cost-effectiveness, BELD indicated that it did not have any estimates of customers' use of the bulbs and that "it would not be cost-effective to try to find out if they did [install them]" (Tr., p. 86).

ii. Compilation of Resource Sets

With respect to purchases from non-utility cogeneration and small power producers, BELD stated that it had compiled information regarding approximately 30 non-utility cogeneration or renewable small power projects (Exh. HO-S-28). BELD indicated that it has joined the PPRDG, an association of nine public power electric utilities that provides data gathering and screening assistance on supply options and, recently, on demand-side options (Exhs. HO-1, p. 76, HO-S-32; Tr., pp. 67-69). BELD stated that it relies on the PPRDG to maintain contact with non-utility developers, and to provide a matrix of data and initial evaluations of non-utility projects (Exh. HO-RR-5; Tr., pp. 64-65). BELD indicated that, following the 1988 BELD Decision, this new process replaced the informal process used in the past to compile non-utility purchase options (Tr., p. 65). BELD identified projects under development that are to be fueled by natural gas, wood, coal, and landfill gas (Exh. HO-S-28).

BELD's participation in the PPRDG is clearly an improvement over the informal process BELD formerly relied upon to identify non-utility resource options. Based on the foregoing, the Siting Council finds that BELD has compiled an adequate resource set of purchases from cogeneration and small power projects.

With respect to combustion turbines for peaking power, BELD stated that it compiled information on combustion turbines from non-utility developers of peaking power projects (Exh. HO-1, pp. 88-89). BELD identified such projects through direct contacts and through the PPRDG (Exhs. HO-S-28, HO-RR-5).

The Siting Council notes two weaknesses in BELD's process for compiling the peaking capacity from combustion turbine resource set. First, by limiting itself to one technology for generating peaking power, i.e., combustion turbines, and one category of sources for peaking power, i.e., projects under development by non-utility developers, BELD failed to investigate potentially less costly options such as purchasing existing peaking capacity from other utilities or constructing a new, BELD-owned generator. Second, by limiting its information on such projects to that provided by project developers, BELD loses the ability to compare the competitiveness of the developers' offerings with alternative estimates of the costs associated with similar units. Clearly, BELD should evaluate other technologies for peaking power as well as company-owned peaking options in its compilation of this resource set.[38] Because it failed to consider these other types of technologies and units, the Siting Council finds that BELD has failed to compile an adequate set of peaking capacity resources.

With respect to load management, BELD stated that it compiled data on load management technologies which provide direct control of customer load (Exh. HO-1, p. 86). Although the record is unclear as to how BELD compiled and analyzed information on these direct-control technologies, Mr. McGrath stated that "cost-data studies" and "economic runs" were evaluated (Tr., p. 81). However, BELD did not demonstrate that they identified more than one technology or method for load management (id.).[39] Finally, Mr. McGrath stated that BELD did not have time to choose among load management systems (id.).

38/ In the past, the Siting Council has found that an adequate set of company-owned generation resources included a wide range of capacity factors, size increments, fuel types and technologies. 1990 MMWEC Decision, 20 DOMSC at 64; 1989 BECo Decision, 18 DOMSC at 257-258.

39/ BELD stated that it intended to utilize this technology to control residential and commercial hot water heaters and commercial air conditioners (Exh. HO-1, p. 87). After installing the load control equipment at BELD distribution locations, however, BELD discovered that the equipment that had been purchased was unable to transmit its signal to commercial air conditioners that operate at 480 volts (Tr., p. 115). BELD indicated that the air conditioner market they had targeted, therefore, could not be reached with their load control technology as currently designed (id.).

The weaknesses of BELD's process in the compilation of load management options are apparent. From the outset, BELD limited itself to options which provide direct control of loads. Such a decision narrows BELD's options substantially. For example, electric companies have pursued other load management options such as interruptible contracts and the installation of thermal storage equipment. 1989 MECo/NEPCo Decision, 18 DOMSC at 350, 1989 BECo Decision, 18 DOMSC at 234; 1988 EUA Decision, 18 DOMSC at 119. Therefore, BELD has failed to identify and evaluate numerous load management options routinely pursued by electric utilities.

Pursuant to G.L. c. 164, sec. 69J, electric utilities are directed to provide an adequate consideration of load management in their supply plans. The Siting Council's standard of review for a supply plan requires that a utility identify and document a comprehensive range of resource options. Here, BELD has failed to comply with such requirements. Accordingly, the Siting Council finds that BELD has failed to compile an adequate set of load management resources.

Finally, in regard to the Light Department's selection of BELD-owned generating units as candidates for refurbishment or modification, BELD did not specifically indicate how these generating units were selected as candidates for refurbishment or modification. BELD stated, however, that its own units, which had been identified for refurbishment or modification, included the retired Potter I unit, the retired Diesel 2 unit, and "modifications to the Potter II unit" (Exh. HO-1, pp. 87, 96). Considering that BELD's set of generating units available for refurbishment or modification includes all but one of the units that BELD owns, the Siting Council finds that BELD has compiled an adequate set of resources from the refurbishment and modification of BELD-owned units.

iii. Conclusions on Available Resource Options

The Siting Council has found that BELD has failed to identify a reasonable range of resource sets. The Siting Council also has found that BELD has compiled an adequate resource set (1) of purchases from cogeneration and small power projects, and (2) from the refurbishment and modification of BELD-owned units. Further, the Siting Council has found that BELD has failed to compile (1) an adequate set of peaking capacity resources, and (2) an adequate set of load management resources.

BELD's failure to identify conservation activities as available resource options and to compile an adequate set of load management resources represents a serious flaw in BELD's supply planning process. The Siting Council's statute sets forth that electric companies are to include an adequate consideration of conservation and load management in their supply plan. Clearly, conservation and load management options represent significant least-cost supply resources that may be available to a utility within its own service territory.

Accordingly, the Siting Council finds that, on balance, BELD has failed to demonstrate that it has compiled a comprehensive array of available resource options. Therefore, in order for the Siting Council to approve BELD's next supply plan, BELD must (1) identify, and fully document, a comprehensive range of conservation and load management technologies and programs, and (2) demonstrate how BELD evaluates the implementation of those technologies and programs in its array of available resource options which potentially could contribute to a least-cost supply plan.

b. Development and Application of Screening Criteria

To determine whether BELD developed and applied appropriate criteria for screening its array of available resource options, the Siting Council reviews the criteria developed and applied to each of BELD's resource sets. The Siting Council has found that BELD compiled an adequate resource set of purchases from cogeneration and small power projects, and an adequate set of resources from the refurbishment and modification of BELD-owned units. Therefore, the Siting Council reviews BELD's development and application of screening criteria for these sets. Although the Siting Council found that BELD failed to compile an adequate set of peaking capacity resources in Section III.E.1.a.ii, above, the Siting Council reviews BELD's development and application of screening criteria for this resource set, as BELD includes a peaking capacity combustion turbine in its supply plan.

During the course of the proceeding, BELD stated that it plans its new supplies to minimize revenue requirements (Exh. HO-1, pp. 84-85). BELD also referred to a list of non-cost criteria that "were applied to all resources on an equal basis" (Exh. HO-S-28). In this list, BELD included the following criteria: diversity, level of development and viability, need for transmission service, dispatchability and technology, environmental controls, amount of capacity available, and fuel price methodology (id.). BELD, however, provided no description of how these criteria are applied in its evaluation of individual resource options, nor did BELD provide any evidence that it has a methodology which can incorporate these criteria (id., Exh. HO-1, pp. 84-85).

For the purposes of screening its non-utility cogeneration and small power resource options, and peaking capacity combustion turbine resource options, BELD stated that it receives a matrix of information from the PPRDG (Tr., pp. 64-65). In addition to cost data, the PPRDG matrix includes a "probability of success" score and a "judgment factor" score (Exh. HO-RR-5). BELD stated that it uses the cost data from PPRDG in its supply screening model to determine the present worth of the total system production costs with the addition of each option (Exh. HO-1, p. 81; Tr., pp. 70-71). BELD stated that this "figure of merit" is used to compare the cost impacts of each option (Tr., p. 71).

The comparison of cost data through the use of the supply screening model is an acceptable methodology. BELD, however, did not indicate how it uses the non-price information provided by PPRDG. BELD's use of cost as its sole criterion for screening non-utility purchases is clearly insufficient. Use of such limited criteria may well mean that BELD selects resource options that are less likely to progress to operation, and may lead BELD to eliminate options which could provide significant benefits in areas such as diversity or environmental impact. The Siting Council has consistently held that companies must consider both price and non-price factors in order to fully evaluate resource options. 1989 MECo/NEPCo Decision, 18 DOMSC at 337-338; 1989 BECo Decision, 18 DOMSC at 225-226; 1988 EUA Decision, 18 DOMSC at 102-103; 1987 Nantucket Decision, 15 DOMSC at 384-390.

Accordingly, the Siting Council finds that BELD has failed to develop and apply appropriate criteria for screening its set of non-utility cogeneration and small power purchases and its set of peaking capacity combustion turbine options.

In regard to the set of BELD-owned units which were considered for refurbishment and modification, BELD asserted that it applied both cost and non-price criteria (Exh. HO-1, p. 80). Despite this assertion that it applied both cost and non-price criteria to the three units identified in this resource set, BELD has failed to demonstrate that it consistently used any specific screening criteria for this set of resource options. For example, the Light Department stated that it relied upon an engineering study of the cost of reactivation of Potter I (Exh. HO-S-5). The Siting Council notes, however, that the study, which was prepared in 1987, does not address BELD's present plans to increase the output of the unit and provide dual fuel capability (Exhs. HO-1, p. 87, HO-RR-10). In addition, BELD was not able to provide an estimate of the total scope of work contemplated for Potter II, or provide an estimate of the costs.[40] Further, BELD did not provide any analysis of the Diesel 2 unit, or why it excluded the Light Department's other diesel generator from this set of resource options. Finally, the Light Department made no reference to its non-price criteria in regards to this resource set.

Accordingly, the Siting Council finds that BELD has failed to demonstrate that it developed and applied appropriate criteria for screening its resource set of refurbishment and modifications of BELD-owned units.

The Siting Council has found that BELD has failed to develop and apply appropriate criteria for screening: (1) its set of non-utility cogeneration and small power purchases; (2) its set of peaking capacity combustion turbine options, and (3) its resource set of refurbishment and modifications of BELD-owned units. Therefore, the Siting Council finds that BELD has failed to demonstrate that it developed and applied appropriate criteria for screening its array of resource options.

c. <u>Conclusions on Identification of Resource Options</u>

The Siting Council has found that BELD has failed to demonstrate that it has compiled a comprehensive array of available resource options. The Siting Council also has found that BELD has failed to demonstrate that it developed and applied appropriate criteria for screening its array of resource options.

Accordingly, the Siting Council finds that BELD has failed to establish that it has identified a reasonable range of resource options.

40/ Additionally, since the petition was filed, BELD has implemented the Potter II modifications, and yet has failed to document the use of any screening criteria in its decision to proceed.

2. Evaluation of Resource Options

BELD identified its supply planning objectives as (1) improving unit and fuel diversity, and (2) maintaining stable rates while achieving least-cost planning (Exh. HO-1, p. 8).[41] BELD has stated that its objectives are applied to all resource options on an equal basis and that its model is able to analyze demand and supply options in the same, neutral manner (id., p. 82, Exh. HO-S-28).

Here, the Siting Council reviews BELD's resource evaluation process to determine whether BELD (1) has developed a resource evaluation process which fully evaluates all resource options and treats all resource options on an equal footing, and (2) has applied its resource evaluation process to all of the resource options identified in Section III.E.1, above.

In order to make this determination, the Siting Council reviews a company's resource evaluation process in terms of its ability to reflect an adequate consideration of appropriate cost, diversity, and risk minimization objectives. 1991 Nantucket Decision, 21 DOMSC at 304; 1990 MMWEC Decision, 20 DOMSC at 83; 1989 MECo/NEPCo Decision, 18 DOMSC at 362-363; 1989 BECo Decision, 18 DOMSC at 238, 270. In addition, the Siting Council also has an obligation to balance economic considerations with environmental impacts in ensuring that the Commonwealth has a necessary supply of energy. G.L. c. 164, sec. 69H. Thus, in this section, the Siting Council analyzes the extent to which BELD incorporates cost, diversity, risk minimization, and environmental impacts in its supply planning process.

41/ BELD also identified reducing dependency on oil as a supply planning objective (Exh. HO-1, p. 8). The Siting Council considers this objective along with BELD's objective of improving unit and fuel diversity.

a. Cost

BELD's overall supply planning objective is "to have least-cost planning" (Exh. HO-1, p. 8). As noted in Section III.C, above, BELD's planning process selects supply options on the basis of cost by evaluating each option using the Light Department's supply screening model. The Siting Council first reviews BELD's incorporation of cost in its evaluation of the following resource options.

i. Non-utility Cogeneration and Small Power Projects and Combustion Turbines

As described in Section III.C, above, BELD analyzed its sets of non-utility cogeneration and small power projects and combustion turbine projects through repeated iterations of BELD's supply screening model. BELD stated that it used this process to identify those projects which are the least cost of their type, and then used the identified projects as proxies for future resource additions (Tr., pp. 71, 182). BELD stated that it identified the MASSPOWER cogeneration project for baseload and the Sterling project for peaking power as the most cost-effective options in their respective resource sets (Exh. HO-1, pp. 88-89). BELD then combined these options with the options selected from its other resource sets, and developed its supply plan (id., p. 89).

BELD included 2 MW of capacity from combustion turbines in 1998 in its base case plan on the basis of the cost and performance of the Sterling project (id., p. 90). Similarly, BELD stated that it relied on differing amounts of capacity from the MASSPOWER project in its contingency cases (see Section III.D.1.c, above) (id., pp. 90-94). BELD stated that it had not contracted for resources from the Sterling or MASSPOWER projects, but rather, it used these units as generic proxies for future resource additions which are assumed to be available throughout the planning period (id., pp. 88-89, Exhs. HO-S-12, HO-S-31). BELD stated that it views MASSPOWER and Sterling as "fairly typical" projects (Tr., p. 73). BELD also stated that these projects were unique in their respective sets on the basis of cost (Exh. HO-1, pp. 88-89). Further, when questioned regarding how the Light Department would proceed once resources were in fact needed, Mr. Seavey stated only that "presumably ... Braintree [Electric Light Department] would perform another iteration of the least-cost planning methodology" (id., p. 157).

The Siting Council is concerned whenever a utility uses proxy units to make decisions regarding resource acquisitions planned during the forecast period (see, e.g., 1988 BELD Decision, 18 DOMSC at 18). BELD is unable to ensure that it will be able to acquire resources with the same cost characteristics as its proxy units at the time such resources are in fact needed. Given that BELD forecasts the first need for resources from this set in 1998, the Siting Council expects that BELD will correct this weakness prior to the actual need to acquire these additional resources. Further, the Siting Council expects that BELD will not rely on proxy units when the actual decision is made to acquire such additional resources.

Nevertheless, for the purposes of this review, the Siting Council finds that BELD's evaluation of its resource sets from non-utility cogenerators and small power producers and combustion turbines adequately considered BELD's least-cost planning objective.

ii. Refurbishment and Modification of BELD-owned Units

BELD's decisions regarding the refurbishment and modification of BELD-owned units raise serious issues. The Siting Council reviews BELD's decisions regarding its Potter II and Potter I units.

BELD's Potter II generating facility was originally brought on-line in 1977 with a winter design rating of 96 MW and a summer design rating of 76 MW (Exhs. HO-S-3, HO-S-40; Tr. p. 123). Material problems with the hot gas U-duct in 1980 resulted in repairs and an upgrading to the "best available material" at that time for those components (Tr., p. 126). Despite such repair, BELD decided to operate the unit at a lower temperature, thereby prolonging the life of the hot gas path components, but resulting in a derating of the unit to a winter rating of 87 MW and a summer rating of 71 MW (id., pp. 124, 126; Exh. HO-S-40).

During the initial stages of discovery in the present proceeding, the Siting Council sought information on the status of a proposed overhaul of the Potter II unit which BELD had asserted in its previous filing would return the unit to its original design rating (Exh. HO-S-3).[42, 43] In response, the Light Department indicated: (1) the overhaul had not taken place; (2) an overhaul was then being conducted as a part of the gas conversion of Potter II; and (3) BELD had chosen not to conduct the specific overhaul needed to return Potter II to its design capacity "at the time that it is converting Potter II to gas use" due to a projected increase in emissions of oxides of nitrogen (id.).

In response to a later discovery request from the Siting Council, BELD indicated that the modifications were actually normal maintenance practices, and as a result of doing this normal maintenance at the same time as the conversion to gas, the Light Department was able to save additional costs in

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42/ BELD stated "[B]y summer of 1989 Potter II will have been through a major overhaul. During the overhaul we plan to do the necessary modifications to bring the unit back to its original design of 96 MW" (Exh. HO-S-3). BELD also stated that it was "gathering data to analyze the economics of ... modifications to the Potter II unit to increase its output and efficiency" (Exh. HO-1, p. 96).

43/ In the 1988 BELD Decision, the Siting Council noted that BELD projected supply capacity, commencing in Summer 1989 and continuing through the forecast period, which included the full 96 MW original design capacity output from Potter II. 1988 BELD Decision, 18 DOMSC at 57.

labor, materials and services (Exh. HO-S-40).[44] At the time of the response to this later discovery request, BELD indicated that the maintenance and gas conversion of Potter II was in the process of being performed as well as the addition of steam injection to control nitrogen oxides (id.). The Light Department indicated that the modifications should "in theory" allow the return of the Potter II unit to its original design capacity, however, it was "not 100% sure" that this would be achieved (id.).

At the outset, we note that the Siting Council usually does not review decisions of utilities to undertake procedures to maintain its units in reliable working condition.[45] Thus, BELD's decision to make necessary repairs to the Potter II unit is not at issue here.

Nonetheless, the Siting Council has concerns with BELD's statement that there had been no need to address the Potter II upgrade as a supply side option because the work had been limited to necessary maintenance (Exh. HO-RR-8). As noted above, BELD made this argument despite its initial indications that it was evaluating the upgrade of Potter II as a supply resource. In addition, the Light Department provided no evidence that it had conducted any planning relative to the potential increase in output that resulted from the

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44/ The Light Department reiterated the need for this maintenance in response to a Hearing Officer record request (Exh. HO-RR-8). BELD responded:

> [t]he replacement of the U-duct at the Potter II plant was nothing more than a maintenance repair. However, it was a very large maintenance repair. ... The decision to replace the U-duct had absolutely nothing whatsoever to do with economics, new ratings of the machine or any other supply side or demand side option. It was strictly a maintenance procedure that had to be done regardless of its cost in order to continue operation [id.].

45/ The Siting Council notes, however, that in some situations maintenance procedures may not be cost-justified.

modifications to the Potter II unit. Further, BELD failed to provide any cost information on the completed work to the Potter II unit despite repeated requests from Siting Council staff throughout the proceeding, thereby preventing the staff from independently reviewing this supply planning decision (Exhs. HO-S-40, HO-RR-8; Tr., p. 129).

In addition, the Siting Council takes issue with BELD's planning surrounding Potter II as it relates to BELD's overall supply plan. BELD's decision to operate Potter II at a lower temperature, arguably justifiable at that time, resulted in the loss of 9 MW of winter capacity and 5 MW of summer capacity. A decision to accept a reduction in capacity is clearly a supply planning decision. From the point in time when an upgrade to Potter II was feasible, outside capacity purchases should have been made only if less costly than the repairs which could provide the additional capacity to Potter II.[46] Proper supply planning requires that a utility first determine the cost or benefit of each supply-side resource, regardless of whether it is a purchase, repair, conservation, or load-management, before making commitments to purchase new supplies.

The Siting Council notes that, to the extent that repairs to Potter II affected BELD's supply plan, as noted above, BELD failed to demonstrate that it applied its evaluation process to the modifications performed on Potter II. As the record is unclear as to when BELD would have been able to plan for the additional Potter II capacity, the Siting

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46/ The record indicates that BELD replaced the Potter II combustor liner in 1987 and ordered a replacement U-duct that year, both made of materials which could withstand the original firing temperature of the unit (Exh. HO-RR-8). Thus, the record indicates that BELD had the ability to upgrade its Potter II unit at least as early as 1987, to return it to its original design capacity. The record does not indicate how long before 1987 the materials necessary for the upgrade were available.

Council expects that, to the extent that Potter II provides additional capacity to the Light Department, BELD would apply its evaluation process to a review of its options under existing contracts, as well as to its future decisions to obtain capacity. Such reviews would be consistent with BELD's least cost planning objectives.

The Siting Council also has concerns regarding BELD's decision to reactivate Potter I. In its petition, BELD indicated that it had evaluated the reactivation of its Potter I unit as a supply option (Exh HO-1, p. 90). BELD provided documentation of its analysis of the Potter I reactivation using its supply planning methodology (id., Exh. HO-S-47B). However, the Siting Council notes significant problems with the information BELD provided. As noted in Section III.E.1.b., above, BELD has included the reactivation of Potter I in its supply plan as a least-cost resource without accounting for the costs of the proposed gas conversion, modifications to raise the capacity to 15 MW, or possible additional emissions control equipment similar to what was installed in the Potter II unit to reduce oxides of nitrogen. While the Light Department did apply its evaluation process to the reactivation of Potter I, the lack of complete cost data renders the results of BELD's analysis unreliable. Thus, the record shows that BELD failed to properly apply their supply planning methodology to the reactivation of Potter I.

Accordingly, based on the above, the Siting Council finds that BELD's evaluation of the refurbishment and modification of BELD-owned units did not adequately consider BELD's least-cost planning objective.

iii. Load Management

In Section III.E.a.ii, above, the Siting Council found that BELD failed to compile an adequate set of load management resources. In addition, in Section III.E.a.i, above, the Siting Council noted that BELD had not identified conservation as a resource set and accordingly found that BELD failed to identify a reasonable range of resource sets. In previous decisions, a company's failure to adequately consider conservation and load management in its supply plan has been cause for rejection of the supply plan. 1990 MMWEC Decision, 20 DOMSC at 84, 92; 1988 EUA Decision, 18 DOMSC at 116, 123, 129-131; Commonwealth Gas Company, 17 DOMSC 71, 125, 139, 142-143 (1988); Boston Gas Company, 16 DOMSC 173, 252-253, 270 (1987); Massachusetts Municipal Wholesale Electric Company, 16 DOMSC 95, 136, 138 (1987).

Accordingly, the Siting Council finds that BELD's evaluation of conservation and load management did not adequately consider BELD's least-cost planning objective.

iv. Conclusions on Cost

The Siting Council has found that BELD's evaluation of its resource sets from non-utility cogenerators and small power producers and combustion turbines adequately considers BELD's least-cost planning objective. The Siting Council also has found that BELD's evaluation of the refurbishment and modification of BELD-owned units did not adequately consider BELD's least-cost planning objective. Further, the Siting Council has found that BELD's evaluation of conservation and load management did not adequately consider BELD's least-cost planning objective. Based on the foregoing, the Siting Council finds that, on balance, BELD has failed to establish that its supply planning process adequately considers BELD's least-cost planning objective. In addition, due to its failure to identify conservation as a resource set and its failure to compile an adequate set of load management resources, the Siting Council finds that BELD's resource evaluation process fails to evaluate all resource options or treat all resource options on an equal footing.

b. Diversity

BELD asserted that its diversity objective is to improve unit and fuel diversity and reduce dependency on oil (Exh. HO-1, p. 8). However, no information was provided by the

Light Department to describe its relative dependence on its existing fuel types.[47] The Siting Council can not evaluate BELD's efforts to achieve diversity without descriptions of existing fuel use and proposed fuel use detailing the variables in fuel use as planned for a utility's supply units. For example, conversion of a supply unit to dual fuel capability may provide no diversity benefits if the utility relies solely on the new fuel to power the unit, thereby decreasing dependence on the first fuel but equally increasing dependence on the new fuel. In addition, reliance on a new mix of the fuels may increase diversity in fuel types but at the expense of a least-cost supply. Thus, BELD needs to identify its diversity objectives relative to its existing resource options.

BELD also defined its diversity objectives in terms of economic benefits (Tr., p. 63). Mr. Seavey testified, "[t]o the extent that diversity produces an economic benefit, ... that economic value of diversity will be an output of the various production costing models that are used" (id.). Although such an approach may be capable of providing information relevant to achieving its diversity objectives, BELD has provided no evidence that its approach to incorporating diversity in supply planning was actually addressed by its supply decisions. In fact, in order for BELD's costing models to be used to adequately address the potential economic benefits of the diversity characteristics associated with the various resource options, BELD would have to evaluate its supply options under a variety of scenarios for fuel prices and other basic cost factors. This is a procedure BELD has not performed.

While BELD's evaluation of one supply option relative to another using its costing models can provide some insight as to

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47/ The Siting Council notes that Siting Council regulations require electric utilities to provide estimates of the input of primary fuel for the first two years of their forecast. See 980 CMR 7.04(4)b.

the relative economic benefits of one fuel or technology based on current fuel and cost projections, the continued validity of such results is directly dependent on the future stability of those price projections. With the historic instability of fuel prices, BELD's use of such a simplifying assumption as a single fuel price projection effectively prohibits BELD from evaluating the future economic benefits of diverse fuel supply options to achieve its diversity objectives.

The Siting Council notes that BELD's supply planning process could enable it to identify a diverse range of suitable resource options -- a significant step in achieving a diverse supply mix. Nevertheless, BELD's failure to directly identify diversity objectives, e.g., what level of diversity it should achieve with respect to fuels or technologies, and to consider the relative merits of its diverse supply options relative to these objectives in its evaluation of those resource options, effectively nullifies this progress.

Accordingly, the Siting Council finds that BELD has failed to establish that its supply planning process adequately considers BELD's diversity objectives.[48]

c. Risk Minimization

As set forth in Section III.C, above, BELD's supply planning methodology evaluates the cost of resource options through the use of its production costing models. The Siting Council recognizes that this methodology can provide an effective means of evaluating the impacts of various resource options on rate stability and can, therefore, enable a company

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48/ In the 1988 BELD Decision, the Siting Council noted that BELD had projected a decreasing dependence on oil and nuclear resources and an increasing presence of coal and gas-fired resources over the forecast period (18 DOMSC at 22). In that decision, BELD was accordingly found to have demonstrated that its supply plan was adequately diversified. Id.

to minimize the financial risk to its ratepayers associated with various supply options. However, as discussed in Section III.E.2.a, above, BELD has failed to establish that it has applied its supply planning process consistently, i.e., on an equal footing, across all its identified resource options. In order for BELD's supply plan to minimize the risk of rate instability, the Light Department must apply that process consistently in making all of its supply decisions, and must incorporate a comprehensive assessment of the total costs and benefits of each supply option in its evaluation of that option.

As noted above, BELD has failed to establish that it applied its supply planning process in increasing the MW output of Potter II. Further, BELD failed to consider a wide variety of significant costs in its evaluation of the reactivation of Potter I. See Section III.E.2.a, above. The Siting Council expects utilities to take adequate steps to determine in advance the costs which will result from supply planning decisions. Clearly, a supply plan which fails to do so cannot produce reliable cost estimates.

Accordingly, based on the above, the Siting Council finds that BELD has failed to establish that its supply planning process adequately considers BELD's rate stability objective, and, therefore, fails to minimize risk to its ratepayers.

d. Environmental Impacts

In previous decisions, the Siting Council has considered whether an electric company has attributed environmental impacts or benefits to different resource options. 1991 Nantucket Decision, 21 DOMSC at 307-308; 1990 MMWEC Decision, 20 DOMSC at 93-95; 1989 MECo/NEPCo Decision, 18 DOMSC at 368-369; 1989 BECo Decision, 18 DOMSC at 270. The Siting Council's standard of review for supply plans explicitly requires utilities to evaluate new supply options in a manner that ensures an adequate supply of least-cost, least-environmental impact energy. See Section III.A, above.

In this proceeding, BELD has not demonstrated that it attributes environmental impacts or benefits to any of the resource options that the Light Department reviewed.

Accordingly, the Siting Council finds that BELD has failed to establish that its supply planning process adequately considers environmental impacts. In order for the Siting Council to approve BELD's next supply plan, BELD must develop and implement a resource evaluation process for resource options which includes an adequate consideration of their environmental impacts.

e. Conclusions on the Resource Evaluation Process

The Siting Council has found that BELD has failed to establish that: (1) its supply planning process adequately considers BELD's least-cost planning objective; (2) its supply planning process adequately considers BELD's diversity objectives; (3) its supply planning process adequately considers BELD's rate stability objective, and, therefore, fails to minimize risk to its ratepayers; and (4) its supply planning process adequately considers environmental impacts.

Based on the foregoing, the Siting Council finds that BELD has failed to establish that it has (1) developed a resource evaluation process which fully evaluates all resource options, including treatment of all resource options on an equal footing, or (2) applied its resource evaluation process to all resource options. Accordingly, the Siting Council finds that BELD has failed to establish that it has evaluated a reasonable range of resource options.

3. Conclusions on Least-Cost Supply

The Siting Council has found that BELD has failed to establish that it has identified a reasonable range of resource options. The Siting Council also has found that BELD has failed to establish that it has evaluated a reasonable range of resource options. Accordingly, the Siting Council finds that BELD has failed to establish that its supply plan ensures a least-cost energy supply.

F. Conclusions on the Supply Plan

The Siting Council has found that, on balance, BELD has establish that it has adequate resources to meet projected requirements throughout the forecast period. The Siting Council also has found that BELD has failed to establish that its supply plan ensures a least-cost energy supply.

BELD argues that its present supply plan should be approved as it "better meets the EFSC's ... stated criteria than did the predecessor plan which was approved" (Brief, p. 21). The Siting Council acknowledges that BELD has demonstrated improvement in some areas of its supply planning process. However, BELD's limited improvement is insufficient in light of the significance of the problems described herein. In particular, BELD's failure to identify and evaluate a full range of conservation and load management options through its supply planning process represents a serious flaw in this process. Such an unbalanced approach to supply planning makes it impossible for BELD to ensure least-cost planning.

As noted in Section III.B, above, in its review of BELD's previous supply plan, the Siting Council considered the fact that the supply plan was the first independently developed BELD plan to be reviewed by the Siting Council. While the Siting Council was willing in that case to view the supply plan in that context, BELD has a clear obligation in this proceeding, and all future proceedings, to meet applicable Siting Council standards. For example, the Siting Council notes that BELD does not incorporate evaluations of the sensitivity of the results to variations in major underlying assumptions of the supply plan and the demand forecast as well. The Siting Council regulations require that all forecasting methodologies be designed to accommodate sensitivity testing of major assumptions and parameters. See 980 CMR 7.09(2)(a).

The Siting Council fully expects that BELD's next filing will not only comprehensively address the criticisms contained within this decision, but also will address any modifications to Siting Council standards as reflected in Siting Council decisions rendered in the interim.

Accordingly, the Siting Council hereby REJECTS BELD's 1989 supply plan.

IV. DECISION

The Siting Council hereby APPROVES the 1988 demand forecast and REJECTS the 1988 supply plan of the Braintree Electric Light Department.

In so deciding, the Siting Council has detailed specific information that the Light Department must provide in its next filing in order for the Siting Council to approve BELD's next demand forecast and supply plan. This specific information is necessary for the Siting Council to fulfill its statutory mandate including its need to determine whether: (1) all information relating to current activities, environmental impact, facilities agreements and energy policies as adopted by the Commonwealth is substantially accurate and complete; (2) the 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 and include an adequate consideration of conservation and load management; and (3) the long-range forecast are consistent with the policy of providing a necessary, least-cost, minimum environmental impact power supply for the Commonwealth.

Therefore, in order for the Siting Council to approve BELD's next filing, BELD must:

(1) either (a) provide and use actual annual historic costs for power supply and non-power supply costs as the basis for future costs, or (b) provide an analysis justifying BELD's current methodology, which uses historic averages, a four percent rate of return adjustment, and assumed constant non-power supply costs when forecasting electricity price;

(2) initiate and complete a study of the heating usage of residential electric heating customers, which will assist the Light Department in developing a comprehensive understanding of electric heating usage in its service territory, and commence a process designed to identify BELD's residential customers with electric heat in compliance with Siting Council regulations;

(3) (a) examine alternate methodologies for forecasting MBTA usage; (b) develop a schedule for implementation based on that examination; and (c) develop a reasonable set of criteria for identifying those customers whose patterns of energy consumption suit them for inclusion in the industrial forecast, and include all those customers, and only those customers, in future industrial class forecasts;

(4) identify and analyze the key variables that affect streetlighting usage, and incorporate the results of that identification and analysis into its streetlighting forecast methodology;

(5) provide a description and analysis of its forecasting methodology for energy requirements due to losses and internal use;

(6) develop and present an analysis of alternative peak load forecasting methodologies, which should at least include a summary of: (a) a comparison of the strengths and weaknesses of BELD's present methodology and alternative methodologies; (b) a comparison of the level of disaggregation achieved by each alternative methodology; and (c) a comparison of the manner in which each alternative methodology incorporates the major factors which affect peak load;

(7) provide tests of the sensitivity of its energy and peak-load forecasts to one or more major underlying assumption(s) or parameter(s) of each of those forecasts;

(8) (a) identify, and fully document, a comprehensive range of conservation technologies and programs, and
(b) demonstrate how BELD evaluates the implementation of those technologies in its array of available resource options which potentially could contribute to a least-cost supply plan.

(9) develop and implement a resource evaluation process for resource options which includes an adequate consideration of their environmental impacts.

The Siting Council further directs the Braintree Electric Light Department to file its next demand forecast and supply plan on February 1, 1993.

Robert P. Rasmussen

Robert P. Rasmussen
Hearing Officer

Dated this 24th day of January, 1992

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of January 24, 1992 by the members and designees present and voting. Voting for approval of the Tentative Decision as amended: Gloria C. Larson (Secretary of Consumer Affairs and Business Regulation); Joseph Donovan (for Stephen Tocco, Secretary of Economic Affairs); Susan F. Tierney (Secretary of Environmental Affairs); Paul W. Gromer (Commissioner of Energy Resources); Kenneth Astill (Public Engineering Member); Mindy Lubber (Public Environmental Member); Joseph Faherty (Public Labor Member); and Michael Ruane (Public Electricity Member).

Gloria C. Larson

Gloria C. Larson
Chairperson

Dated this 24th day of January, 1992

Table 1

BRAINTREE ELECTRIC LIGHT DEPARTMENT

Base Case Supply Adequacy

Year	Capability[a] Responsibility (MW)	Total Capacity (MW)	Base Case Surpl/(Def)	Contingency Surpl/(Def)[b] (MW)
Summer 1991	91.34	98.71	8.1%	7.36
Winter 1991	91.58	115.18	25.8%	23.61
Summer 1992	91.58	98.58	7.6%	7.00
Winter 92-93	92.98	115.15	23.8%	22.17
Summer 1993	92.98	98.34	5.8%	5.36
Winter 93-94	94.77	111.65	17.8%	16.89
Summer 1994	94.77	94.80	0.4%	0.04

Notes:

a. Adjusted for BELD's load management program. BELD indicated that, to determine capability responsibility for supply planning purposes, it subtracted the savings from its direct control load management program from its peak load forecast (Tr., p. 119).

b. BELD reported its winter capability responsibility as identical to that of each following summer. BELD's winter peak load is, in fact, lower than its summer peak load and its winter surplus is larger than reported here.

Source: Exh. HO-1, pp. 104-107

TABLE 2

BRAINTREE ELECTRIC LIGHT DEPARTMENT

Short-Run Contingency Analyses

Newbay Cancellation Contingency

Year	Capability[a] Responsibility (MW)	Total Capacity (MW)	Contingency Surpl/(Def)	Contingency Surpl/(Def) (MW)
Summer 1991	91.34	92.71	1.5%	1.36
Summer 1992	91.58	92.58	1.1%	1.00
Summer 1993	92.98	92.34	(0.7)%	(0.64)
Summer 1994	94.77	88.80	(7.3)%	(5.96)

NYPA Termination Contingency

Year	Capability[a] Responsibility (MW)	Total Capacity (MW)	Contingency Surpl/(Def)	Contingency Surpl/(Def) (MW)
Summer 1991	91.34	98.71	8.1%	7.36
Summer 1992	91.58	98.58	7.6%	7.00
Summer 1993	92.98	98.34	5.8%	5.36
Summer 1994	94.77	92.25	(2.7)%	(2.52)

NYPA Termination and Newbay Cancellation Contingency

Year	Capability[a] Responsibility (MW)	Total Capacity (MW)	Contingency Surpl/(Def)	Contingency Surpl/(Def) (MW)
Summer 1991	91.34	92.71	1.5%	1.36
Summer 1992	91.58	92.58	1.1%	1.00
Summer 1993	92.98	92.34	(0.7)%	(0.64)
Summer 1994	94.77	86.25	(9.0)%	(8.52)

Note:

a. Adjusted for BELD's load management program. BELD indicated that, to determine capability responsibility for supply planning purposes, it subtracted the savings from its direct control load management program from its peak load forecast (Tr., p. 119).

Source: Exh. HO-1, pp. 104-107, 112

Appeal as to matters of law from any final decision, order or ruling of the Siting Council may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the order of the Siting Council be modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Siting Council within twenty days after the date of service of the decision, order or ruling of the Siting Council, or within such further time as the Siting Council may allow upon request filed prior to the expiration of the twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the clerk of said court. (Massachusetts General Laws, Chapter 25, Sec. 5; Chapter 164, Sec. 69P).

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Northeast Utilities for Approval of its 1990 Long Range Forecast of Electric Requirements and Resources	)	EFSC 90-17

FINAL DECISION

Jolette A. Westbrook
Hearing Officer
March 5, 1992

On the Decision:

Michael B. Jacobs
John G. Howat

TABLE OF CONTENTS

The Energy Facilities Siting Council hereby APPROVES the 1990 demand forecast of Northeast Utilities System.

I. INTRODUCTION

A. Background

Northeast Utilities System ("NU" or "Company") is a public holding company comprised of the Connecticut Light and Power Company ("CL&P"), Western Massachusetts Electric Company ("WMECo"), Holyoke Water and Power Company ("HWP"), Holyoke Power and Electric Company ("HP&E"), and Northeast Nuclear Energy Company. Its Massachusetts subsidiaries, WMECo, HWP and HP&E,[1] are subject to Siting Council jurisdiction. NU is the largest electric utility system in New England and had total sales of approximately 24,892 gigawatthours ("GWH") of electricity in 1989 (Exh. HO-1B, p. 7), with a peak demand of 4,779 megawatts ("MW") (Exh. HO-2B, p. 8).

WMECo's service area covers 59 municipalities, in whole or in part, and serves a total of approximately 449,000 customers (Exh. HO-1C, p. II-4). WMECo sold 3,819 GWH at retail and 11 GWH at wholesale in 1989 (Exh. HO-1B, p. 92), and had a peak system load of 822 MW (Exh. HO-2B, p. 109). In 1989, WMECo sold 37.3 percent of its energy to residential customers, 33.6 percent to commercial customers, 27.9 percent to industrial customers, 0.8 percent to the streetlighting class, and 0.3 percent wholesale for resale (Exh. HO-1B, p. 92).

HWP has two customer classes: industrial and wholesale for resale. HWP sells wholesale power to its subsidiary HP&E, the City of Chicopee Electric Department and Westfield Gas and

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1/ HP&E is a subsidiary of HWP, and provides transmission services for owners of power entitlement in the Mt. Tom power plant including WMECo, HWP, and the New England Power Company (Exh. HO-1C, p. II-5).

Electric Department (Exh. HO-1C, p. II-5).[2] In 1989, HWP had retail sales of 119 GWH, total sales of 277 GWH (Exh. HO-1C, p. II-11), and a peak load of 49 MW (Exh. HO-2C, p. II-12).

In its most recent review of NU's demand forecast, the Energy Facilities Siting Council ("Siting Council" or "EFSC") approved the Company's demand forecast. Northeast Utilities, 17 DOMSC 1, 6-18 (1988) ("1988 NU Decision").[3]

B. Procedural History

Northeast Utilities filed its 1990 demand forecast and supply plan with the Siting Council on April 1, 1990 (Exhs. HO-1A, HO-1B, HO-1C).[4] On July 16, 1990, the Hearing Officer issued a Notice of Adjudication and directed NU to publish and post the Notice in accordance with 980 CMR 1.03(2). The Company subsequently submitted confirmation of publication and posting. The Siting Council received no petitions to intervene in the proceeding.

The Siting Council held evidentiary hearings on May 31, June 18, and June 19, 1991. NU presented five witnesses: Bruce Blakey, manager of economic and load forecasting; Derek Howell,

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2/ HWP began selling wholesale power to Westfield Gas and Electric Department in May 1990 (Exh. HO-1C, p. II-5).

3/ In its most recent review of the supply plan of NU, the Siting Council approved the supply plan. 1988 NU Decision, 17 DOMSC at 19-69.

4/ During the course of this proceeding, NU provided its 1991 demand forecast and supply plan to the Siting Council (Exhs. HO-2A, HO-2B, HO-2C). While not the subject of review in this proceeding, the 1991 demand forecast and supply plan were admitted into evidence. Therefore, the Siting Council uses the 1991 demand forecast to assist in evaluating the Company's 1990 demand forecast. The Siting Council notes that the Company's 1991 demand forecast is based on substantially the same methodology as the 1990 demand forecast, except that the 1991 demand forecast uses a new methodology for the industrial class forecast. See Section II.C.6, below, for a discussion of the industrial forecast.

senior economic and load forecasting analyst; Terry Ranger, director of corporate strategy and business planning; Michael Delphia, supervisor of generation planning studies; and Michael Townsley, manager of demand program planning and analysis.

The Hearing Officer entered 220 exhibits into the record, primarily composed of the Company's responses to information and record requests. Pursuant to a briefing schedule established by the Hearing Officer, NU filed its brief on July 12, 1991. Thereafter, the Company filed a supplemental brief on August 22, 1991.

C. Scope of Review

In this decision, the Siting Council reviews only the 1990 demand forecast of NU. The demand forecast and supply plan of NU next will be reviewed in the integrated resource management ("IRM") process jointly developed by the Siting Council and the Massachusetts Department of Public Utilities ("MDPU" or "Department"). This comprehensive IRM process (by which additional resources are to be planned, solicited, and procured to meet an investor-owned electric company's obligation to provide reliable electric service to ratepayers in a least-cost, least environmental impact manner), requires coordinated regulatory review of electric companies' IRM practices by both the Siting Council and the MDPU in the exercise of each agency's statutory authority. On November 30, 1990, the Siting Council issued an Order and final regulations regarding the IRM procedures. Final Decision of the Siting Council on IRM Rulemaking, 21 DOMSC 91 (1990) ("1990 Final IRM Decision"); 980 CMR 12.00. On August 31, 1990, the MDPU issued an Order and final regulations for its portion of the IRM regulatory framework. Order of the Department on IRM Rulemaking, D.P.U. 89-239 (1990); 220 CMR`10.00.

In the 1990 Final IRM Decision, the Siting Council set forth a schedule requiring NU to file its first IRM submission on April

1, 1992 (21 DOMSC at 153). In light of this filing date, the Siting Council has decided not to review NU's supply plan in this decision and reviews only the demand forecast of NU.

II. ANALYSIS OF THE DEMAND FORECAST

A. Standard of Review

As part of its statutory mandate "to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost" (G.L. c. 164, sec. 69H), the Siting Council determines whether "projections of the demand for electric power ... are based on substantially accurate historical information and reasonable statistical projection methods." G.L. c. 164, sec. 69J. To ensure that the foregoing standard is met, the Siting Council applies three criteria to demand forecasts: reviewability, appropriateness, and reliability.

A demand forecast is reviewable if it contains enough information to allow a full understanding of the forecasting methodology. A forecast is appropriate if the methodology used to produce that forecast is technically suitable to the size and nature of the utility that produced it. A forecast is reliable if the methodology provides a measure of confidence that its data, assumptions, and judgments produce a forecast of what is most likely to occur. Nantucket Electric Company, 21 DOMSC 208, 214 (1991) ("1991 Nantucket Decision"); Massachusetts Municipal Wholesale Electric Company, 20 DOMSC 1, 14 (1990) ("1990 MMWEC Decision"); Massachusetts Electric Company/New England Power Company, 18 DOMSC 295, 302 (1989) ("1989 MECo/NEPCo Decision"); Boston Edison Company, 18 DOMSC 201, 208 (1989) ("1989 BECo Decision"); Eastern Edison Company/Montaup Electric Company, 18 DOMSC 73, 79 (1988) ("1988 EECo/Montaup Decision"); 1988 NU Decision, 17 DOMSC at 6; Boston Edison Company, 15 DOMSC 287, 294 (1987); Commonwealth Electric Company/Cambridge Electric Light Company, 12 DOMSC 39 (1985).

B. Previous Demand Forecast Review

In the 1988 NU Decision, the Siting Council approved NU's demand forecast with the following Orders:

1. to present an analysis of each of the economic factors which may have an impact upon commercial floorspace growth;[5] and
2. to file supporting documentation describing (a) each of the variables used in the industrial class econometric model, and (b) the theoretical basis for using non-linear estimation in the industrial class model (17 DOMSC at 42).

In response to Order Two, NU provided descriptions of each of the variables used in the 1990 industrial class econometric forecast model (Exhs. HO-1B, pp. 71-72, HO-B-7). NU also explained the theoretical basis for using non-linear estimation in the model as a means to subtract the past levels of industrial production from the factors predicting current production and current sales (id.). The Company also stated that it had not been satisfied with the available data and exogenous variable forecasts required by its industrial class model (Exh. HO-B-7). The Company stated that, therefore, it had developed a new methodology for the industrial class forecast in an effort to address its concerns (Exhs. HO-B-1, HO-2B, pp. 60-73). The new methodology employed in the 1991 forecast does not rely on non-linear estimation. See Section II.C.6.b, below, for a discussion of the Company's new industrial class model.

Based on the above, the Siting Council finds the Company has complied with Order Two.

5/ The Siting Council addresses the Company's response to Order One in Section II.C.5.a, below.

C. Energy Forecast

NU forecasted annual energy requirements by first preparing economic and demographic forecasts and an electric price forecast, and then applying those forecasts in econometric and detailed end-use models (Exh. HO-1B, pp. 4-6).[6] WMECo, CL&P, and HWP energy requirements were forecasted separately (Exh. HO-1A, p. II-2).[7] The Company combined each of these forecasts into a single forecast of energy requirements (Exh. HO-1B, p. 4). The first year of the Company's energy forecast was projected with a short-run methodology (Exh. HO-1B, p. 24). See Section II.C.3, below. The remaining years were forecast using the Company's long-run models, which were adjusted based on the results of the short-run forecast (id.).

The Company stated that 38.5 percent of its total energy sales were to its residential sector, 35.2 percent to its commercial sector, 22.3 percent to its industrial sector, 0.6 percent to its streetlighting sector, 0.5 percent to its railroad sector, and 2.8 percent to its wholesale for resale customers (id., p. 94).[8] The 1991 demand forecast did not significantly change the customer sector percentage shares for the forecast period (Exh. HO-2B, p. 95).

In its 1990 demand forecast, NU projected annual energy sales to increase from 24,892 MWH in 1989 to 28,708 MWH in 1999, representing a compound annual growth rate of 1.4 percent (Exh. HO-1B, p. 7). In NU's 1991 demand forecast, energy sales were forecasted to rise from 24,899 MWH in 1990 to 27,296 MWH in 2000, representing a compound annual growth rate of 0.9 percent

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6/ NU used the same demand forecast methodologies for WMECo and CL&P (Exh. HO-1B, pp. 25-26, 47, 59, 70-72).

7/ NU forecasted HWP sales to industrial customers based on latest actual sales and changes in the usage of specific customers (Exh. HO-D-9).

8/ The percentage of total sales shown is based on 1989 actual sales (Exh. HO-1B, p. 94).

(Exh. HO-2B, p. 7).[9] The results of NU's 1990 energy forecast are presented in Table 1, below.

1. Economic and Demographic Forecasts

The Company stated that its economic and demographic forecasts were principle drivers of its energy forecast (Exh. HO-1B, p. 12). NU stated that it purchased economic and demographic data for its service territories from Data Resources, Inc. ("DRI") (id.). NU also stated that the economic and demographic forecasts for the WMECo and HWP service territories were based on data supplied by DRI for the Springfield, Massachusetts Metropolitan Statistical Area ("MSA") (id., pp. 12, 14).[10] The Company indicated that it used Summer, 1989 DRI Regional data for its economic and demographic forecast (Exh. HO-D-2, Forecast Addendum, pp. 9-10).

Essentially, the Company used DRI data on employment growth rates, housing permits, personal income, and population as inputs to its forecasting models (id.). The Company stated that employment was the primary indicator of economic activity in DRI's models (Exh. HO-1B, p. 14). The Company indicated that DRI used a system of quarterly models to forecast change in over 50 demographic and economic factors (id.).

To forecast employment in the WMECo service territory, the Company stated that it first collected historical employment data

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9/ The forecasted growth in peak for the NU summer system peak was 2.1 percent in the 1990 forecast and 1.5 percent in the 1991 forecast (Exhs. HO-1B, p. 8, HO-2B, p. 8).

10/ The Company indicated that the Springfield MSA is comprised of 23 cities and towns, and that the entire WMECo and HWP service territories are comprised of 62 cities and towns (Exh. HO-D-6). The Company acknowledged that the Springfield MSA covers only about one-fourth of the area of the WMECo and HWP service territories, but asserted that the DRI data was more detailed than alternate data sets that were examined (id.).

for the towns in the service territory from the Massachusetts Department of Employment Security (id., p. 15),[11] and then used DRI's employment growth rates from the Springfield MSA[12] (id., p. 16). The Company stated that it used DRI's projections of housing permits in the Springfield MSA to forecast the number of residential customers for WMECo (id., and Exh. HO-1, p. 23).

The Siting Council notes that the Company's economic and demographic forecasting methodology remains essentially the same as that reviewed in the 1988 NU Decision. 1988 NU Decision, 17 DOMSC at 8. In that decision, the Siting Council found the Company's economic and demographic forecasts, which were based on data supplied by DRI, to be reviewable, appropriate and reliable. Id. In addition, the Siting Council has accepted the use of DRI data in other forecasts. (See Commonwealth Electric Company/Cambridge Electric Light Company) ("1991 CECo/CELCo Decision"), EFSC 90-4, p. 6; 1990 MMWEC Decision, 20 DOMSC at 14; 1988 EECo/Montaup Decision, 18 DOMSC at 82.

Accordingly, the Siting Council finds that the Company's economic and demographic forecasts are acceptable.

Although the scope of this review is limited to the Company's 1990 demand forecast, the Siting Council notes that the Company's inclusion of Pittsfield MSA data in its 1991 demand forecast enhances the Company's economic and demographic forecasts. The inclusion of the Pittsfield MSA data is likely to strengthen the Company's economic and demographic forecasts by making them more representative of WMECo's service territory.

11/ The Company stated that it collected Massachusetts Department of Employment Security historical employment data from the years 1972 through 1988 (Exh. HO-D2, pp. 9-10).

12/ The Company stated that, for its 1991 economic and demographic forecasts, it used DRI data from both the Springfield and Pittsfield MSAs (Exh. HO-2B, p. 16).

2. Electricity Price Forecast

The Company indicated that NU's electricity price forecast is used as an input to its energy forecast and peak load forecast models (Exh. HO-RR-6, p. 1).

The Company indicated that the forecast of electricity prices was based on a production cost simulation and a financial simulation (id., p. 2). The production cost simulation accounted for various inputs and factors, including preliminary energy and peak load forecasts,[13] the Company's resource plan,[14] and fuel price projections[15] (id.). The Company stated that the financial simulation took into account the results of the production cost simulation, as well as existing system data, capitalization and financing expenses, taxes, capital expenditures, and other expenses (id.).[16]

13/ The Company stated that the preliminary energy and peak load forecasts used for the electricity price forecast here were the same forecasts used in NU's 1989 Demand Forecast, minus the effects of conservation and load management and self-generation (Exh. HO-RR-6, p. 1). The electricity price forecast then became an input to the revised energy and peak load forecasts used by the Company to model the effects of conservation and load management and self-generation (id.).

14/ The Company stated that the resource plan included the costs associated with committed resources (e.g., private power production, Seabrook and Hydro-Quebec, and demand-side management programs), and financing charges associated with the construction of assumed future supply additions (Exh. HO-RR-6, p. 1).

15/ The Company stated that fuel price projections from Summer, 1990 and Winter, 1991 DRI oil and coal forecasts were used in developing the electricity price forecast (Exh. HO-RR-6, pp. 3, 6). The Company indicated that nuclear fuel and natural gas price projections were developed using internally-generated data (id.).

16/ The Company stated that (1) existing system data included the original cost of existing NU electric plants; (2) capitalization and financing data included all outstanding debt and projections of future financing costs; (3) current taxes included state and federal income and gross earning taxes, plus

The Company further described that its simulations produced a forecast of annual electricity price change for each customer class, and that the rates of change were applied to historic prices to obtain a forecast of future electricity prices (Tr. 2, p. 69).

The Siting Council approved the Company's previous electricity price forecast, which was similar to the electricity price forecast currently under review. 1988 NU Decision, 17 DOMSC at 9. Here, the Siting Council notes that the Company's electricity price forecast includes the use of current DRI fuel price data, and the application of electricity price growth rates to individual customer classes.

Accordingly, the Siting Council finds that the Company's electricity price forecast is acceptable.

3. Short-Run Energy Forecast

NU defined its short-run forecast period as one year, the first year of the Company's ten-year forecast period (Exh. HO-1B, p. 24). NU developed a short range forecast model to project energy requirements and hourly load in each class for this year (id.). The Company explained that it performs this short-run forecast primarily for budgeting purposes (id.).

The Company stated that it estimated energy consumption in the first year by using an econometric model (id.). The inputs to NU's econometric model included quarterly projections of numbers of customers, electricity price, income, and employment (Tr. 1, p. 30; Exh. HO-RR-1, p. 9). NU stated that it used its hourly load model to estimate 1990 peak loads and monthly energy

local and municipal property taxes; (4) capital expenditures included expenditures associated with future resource additions; and (5) other expenses included fuel, O&M, purchased power, transmission and other fixed expense items (Exh. HO-RR-6, p. 4).

output by company and by customer class (id.).[17] The Company also stated that it adjusts the short-run forecast for each customer class for the loss of sales due to self-generation and conservation (Exh. HO-RR-1, p. 13). Finally, the Company stated that it checked the industrial short-run forecast for reasonableness by monitoring the consumption of 20 of the largest industrial customers, whose usage accounts for approximately one-third of NU's industrial consumption (id.).

The Company performed several statistical analyses of its short-run forecast (Tr. 1, pp. 30-31; Exh. HO-RR-1, pp. 28-39). The Company stated that these analyses illustrate the relative statistical strength of its econometric model (id.).[18] The Company also prepared an analysis of the forecast accuracy of its previous short-run forecast (Exh. HO-RR-1, pp. 10-13). In this analysis, the Company identified various sources of uncertainty, the largest being the uncertainty regarding regional economic performance (id.). Finally, the Company compared its short-run forecast to (1) forecasts NU made with time-series and end-use methodologies, and (2) to forecasts of electric sales made by DRI and other regional utilities (id.). NU's 1990 short-run forecast was within the range of forecasts with which it was compared

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17/ The Company explained its short-run forecast produced monthly projections of energy requirements (Tr. 1, p. 28). The Company indicated that it used monthly data whenever available, and quarterly data when monthly data was not available (id., pp. 26-28).

18/ The Company reported the following R-squared values for its WMECo short-run forecasts: residential, .96; commercial, .85; industrial, .52 (Exh. HO-RR-1, pp. 33, 36, 39). R-squared is a measure of the amount of variation in the dependent variable which is explained by the variation in the independent variables. R-squared values range between 0.00 and 1.00, where 0.00 indicates no variation explained by the independent variables and where 1.00 indicates complete explanation by the independent variables.

(id., p. 11).[19]

NU used the results of its short-run energy forecasts to calibrate its long-run forecasts (Exh. HO-1B, p. 24). The Company stated that it needed to have consistent short-run and long-run forecasts for financial, supply and C&LM planning (Exh. HO-D-10). The Company stated the long-run forecasts were calibrated to the short-run forecasts with factors ranging from .995 in the WMECo industrial class to 1.02 in the WMECo commercial class, with this latter factor being the only one above one percent (id.).[20]

The Siting Council does not take issue with the Company's use of the short-run forecast to adjust its long-run forecast. In most instances, the level of adjustment was slight, with only one adjustment made exceeding one percent. Furthermore, the Siting Council notes the Company's short-run model exhibited statistical strengths and that the Company compared its short-run forecast with several alternative and independent short-run forecasts.

Accordingly, based on the above, the Siting Council finds that NU has established that its short run forecast is acceptable for use in developing its long-run forecast.

19/ The range of forecasts of total electricity sales ranged from 0.5 percent change forecasted by NU with a short-run end-use model to 1.2 percent change forecasted by DRI for New England (Exh. HO-RR-1, p. 11). The NU short-run forecast projected a 1.0 percent change (id.).

Forecasts of total retail electricity sales ranged from -1.0 percent change forecasted by "other regional utilities - low" to 2.3 percent change forecasted by "other regional utilities - high" (id.). The NU short-run forecast projected 0.8 percent change (id.).

20/ The Company stated that it adjusted the residential long-run forecast for WMECo by a factor of 1.001 (Exh. HO-D-10). In the CL&P forecasts, the Company used the following adjustments: 1.002 in the residential class and commercial class, and 1.003 in the industrial class (id.).

4. Residential Energy Forecast

NU forecasted total residential electricity consumption with econometric and end-use models (Exh. HO-1B, p. 25). These models incorporated the results of the Company's economic, demographic, and electricity price forecasts. NU's residential energy forecast estimated usage as the product of (1) the number of residential customers; (2) the number of appliances per customer; and (3) the average use per appliance (id., pp. 26, 33). Generally, NU used historical data and econometric methods to predict the number of WMECo residential customers (Exh. HO-D-14). NU used survey and industry data to estimate the number of appliances per customer and the average use per appliance (Exhs. HO-1B, pp. 25-26, HO-D-15). The Company also stated that it adjusted its end-use results to reflect the effect of price and income elasticities (Exh. HO-1B, p. 25).[21] The Company's final forecast adjustment was to subtract the savings resulting from Company-sponsored C&LM programs (id., p. 3). However, the Company also assumed that, over time, residential consumption patterns would be affected by broad-based conservation activities (id., p. 27).

NU based its residential energy forecast on the assumption that total class consumption is the sum of usage represented by 16 residential appliance types[22] and a miscellaneous category (id., pp. 25-26). The Company explained that the key driving

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21/ The Company stated that it applied price and income elasticities to total residential sales forecasts (Exh. HO-D-49; Tr. 1, pp. 61-62, 164-165).

22/ NU disaggregated its residential forecast into the following types of appliances: electric space heating, electric heat pump, electric-assisted renewable resource space heating, electric water heating, electric-assisted renewable resource water heating, fossil fuel heating auxiliaries, central air conditioning, room air conditioning, electric range, electric dryer, manual defrosting refrigerator, automatic-defrosting refrigerator, freezer, color television, lighting, and electric car (Exh. HO-1B, pp. 25-26).

variable in the model is growth in the number of residential customers (id., p. 26).

The residential forecast methodology contained in the 1990 demand forecast is essentially the same as the one reviewed by the Siting Council in the 1988 NU Decision, 17 DOMSC at 10-12.

a. Number of Residential Customers

NU stated that it forecasted the number of residential customers using Company records to establish the number of existing customers, and DRI data to project the number of new customers (Exh. HO-1B, pp. 39, 47). The Company stated that new WMECo residential customers were forecast using a regression equation (id., p. 47; Tr. 1, pp. 37-38). A primary input to that equation was housing permits, lagged one-quarter of the year, as forecasted by DRI for the Springfield MSA (id.). The Company explained that it used the one-quarter of a year lag to approximate the construction period of a new residence (Exh. HO-1B, p. 39). The forecasting equation related the growth in new WMECo residential customers to the growth in Springfield housing permits.

The Company stated that alternative methods for forecasting the number of residential customers had been considered in the past (Tr. 1, pp. 26, 28, 54-59). The Company noted that using the number of households and a demographic forecast model had been considered (id.). However, the Company explained that household information is collected on an annual basis, and is not available promptly enough to be used by the Company in its short-run forecasts (id., pp. 26, 28). The Company also explained that its demographic forecasting model was deficient because it was time-consuming and it proved to be less accurate than the housing-data approach (id., pp. 54-59).[23]

23/ The Company also stated that it is exploring an alternative demographic forecasting model known as "REMI" that could be used to project long-run trends in the future (id., The Company's method for forecasting the number of residential customers relies on two appropriate sources of data -- Company records and DRI forecasts. In the past, the Siting Council has recognized the importance of territory-specific data (1991 CECo/CELCo Decision, EFSC 90-4, at 19-21; 1991 Nantucket Decision, 21 DOMSC at 230). In addition, the Siting Council has also found that the use of DRI data is appropriate for use in forecasting (1991 CECo/CELCo Decision, EFSC 90-4, at 6; 1990 MMWEC Decision, 20 DOMSC at 14; 1988 EECo/Montaup Decision, 18 DOMSC at 82). Further, the Company has made a reasonable assumption that housing permits do not lead to occupied residences until the following quarter of the year. Accordingly, based on the foregoing, the Siting Council finds that NU's forecast of the number of residential customers is acceptable.

b. Number of Appliances

For the years 1990 to 1999, NU forecasted the number of appliances in each of the 16 appliance types and the miscellaneous category in its service territory (Exh. HO-1B, pp. 25-26).[24] The Company stated that the 16 appliance types were chosen because they are the major users of electricity in NU's service area households and because they "represent those loads that are most likely to be affected ... by programs for C&LM" (Exh. HO-D-16; Tr. 1, pp. 117-118). The Company further explained that if C&LM programs focussed on an appliance type not explicitly included in its current forecast, the Company would be likely to add it to its residential end use forecast as an additional appliance type or as a substitute for an appliance already included in its residential forecast (id., p. 118).

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p. 58).

24/ The number of appliances must be tracked for each year even though energy requirements for the first year of the forecast were projected with the short-run forecast.

The Company stated that its residential miscellaneous category consisted of the remaining appliances not included in the 16 appliance types, and that the remaining appliances are individually small contributors to residential use (Exh. HO-D-16). The Company collected information on some of the appliance types that are included in the miscellaneous category in its residential appliance survey (Exh. HO-S-24A, p. 16).[25] The Company stated that the miscellaneous category is forecast to account for 20.4 percent of 1990 residential sales, making it the largest end-use category in its residential forecast (Exh. HO-1B, pp. 42-43).

In its forecast of the number of appliances, NU estimated (1) the current number of appliances, and (2) the future number of appliances in each end use (id., p. 34). The current number of most appliances used in the 1990 forecast was estimated from a 1987 NU appliance saturation survey, which established ownership percentages of appliances by type of dwelling (id.). However, NU noted that electric heating appliance ownership was based on Company records of customers that rely on electric heat for a significant percentage of their space heat (id., pp. 26, 35). NU separated electric heating appliances into three categories -- electric resistance heating, heat pump, and renewable resource space heating with electric backup[26] -- using a 1987 saturation survey of electric heating customers (id., pp. 35-36). NU reported that it further divided electric heating appliances into single-family and multi-family categories based on census and

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25/ All of the Company's end-use surveys were conducted across the NU service territory (Exhs. HO-S-24A, HO-S-24B, HO-D-25). NU's 1989 New Home Survey categorized responses by region, including Western Massachusetts (Exh. HO-S-24A).

26/ NU did not include portable electric heaters in its definition of electric heating appliances in this forecast, even though it had data on saturation and usage patterns of portable electric heaters from its 1987 and 1983 surveys (Exhs. HO-1B, p. 40, HO-S-24A, pp. 19, 68).

building permit data (id.).

For each year of the forecast, NU determined the future number of new residential appliances in its service territory by applying penetration rates for each appliance type to new housing, the replacement market, and the existing market categories[27] (Exh. HO-1B, pp. 26, 35). For the new housing market, NU reported that it developed market penetration rates for each appliance type from its 1988 New Home Survey (id.). NU stated that it prepared penetration rates for the existing market and replacement market categories from the trend of all NU saturation surveys since 1978 and a 1988 survey of Connecticut appliance distributors (id.).

The Company stated that it plans to update its appliance saturation information and New Home survey by conducting a survey every year, covering each of the topics in alternating years (Tr. 1, pp. 63-64). The Company's witness, Mr. Howell, indicated that a 1990 appliance saturation survey was in progress (id., p. 63). However, the Company's 1991 forecast indicated that only the survey of Connecticut appliance distributors has been updated (Exh. HO-2B, pp. 34, 36).

The Company's methodology for forecasting the number of appliances is essentially the same as that approved by the Siting Council in its previous review. 1988 NU Decision, 17 DOMSC at 10-12. The Company's periodic surveys continue to provide a reasonable basis for estimating the number of appliances in its service territory. The Siting Council encourages the Company to conduct regular data collection efforts to ensure the reliability of its end use forecasts. In addition, the Siting Council encourages the Company to consider desegregating other

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27/ The Company defined the replacement market as the number of units of a specific appliance retired in a particular year, and the existing market as the number of customers from the previous year which have not yet purchased a certain appliance (Exh. HO-1B, p. 36).

residential appliances such as clothes washers, dishwashers, portable space heaters and microwave ovens as a means of further supporting its end use methodology. Finally, the Siting Council notes that further disaggregation is entirely consistent with the Company's stated objectives regarding C&LM planning.

Accordingly, based on the foregoing, the Siting Council finds that NU's forecast of number of appliances is acceptable.

c. Average Use per Appliance

The Company stated that in its 1990 forecast it determined the average use per appliance using a variety of techniques (Exh. HO-1B, pp. 26, 35; HO-RR-16). NU stated that its base year average use per appliance values were obtained from (1) the Joint Utility Monitoring Project ("JUMP"); (2) national data; (3) engineering models; (4) a survey of other regional utilities; and (5) the Company's "conditional demand analysis" of its 1987 appliance saturation survey (id.). The Company adjusted its forecast of appliance usage for conservation trends and elasticity responses (Exh. HO-1B, pp. 38, 46-47; Tr. 1, pp. 103-105).

The Company stated that its participation in the JUMP study provided it with detailed appliance usage data from the direct measurement of a sample of electric ranges, dryers, refrigerators, and water heaters in WMECo's service territory and elsewhere in Massachusetts (Exh. HO-1B, p. 26). The Company also stated that it obtained appliance usage data for color televisions and lighting from national data, particularly the Association of Edison Illuminating Companies (Exh. HO-RR-16). In addition, the Company stated that it developed the remaining residential appliance usage values from engineering and modeling information (id.; Tr. 1, pp. 101-103). The Company further stated that it compared the results of the engineering models and the national data with a "conditional demand analysis" which estimated electricity consumption by end use from appliance saturation data and samples of customer billing data (Exhs. HO-1B, pp. 26, 35, HO-D-17). The Company did not provide the vintage of any of its appliance usage data (Exh. HO-RR-16).[28]

The Company stated that it adjusted its average appliance usage estimates for significant conservation resulting from a combination of several external forces (Exh. HO-1B, p. 36).[29] The Company anticipated increasing market-induced residential conservation due to "a combination of mandatory and voluntary standards adopted by the construction and appliance manufacturing industries, increasing fuel costs for all forms of energy, the use of space and water heating systems employing alternative or renewable resources, the efforts of NU and others which lead to increasing consumer knowledge of cost-effective conservation measures, the long-run effects of price, and economic incentives to conserve" (Exh. HO-1B, p. 36).

For example, in its 1990 demand forecast the Company estimated that the average new home usage for electric space heating would decline six percent over the forecast period (Exh. HO-1B, p. 37). The Company also estimated that more than half of the residential appliances would have lower use values in the future (id.). Nonetheless, due to the anticipated increase in number of appliances, the Company projected total average use per residential customer in 1999 to be 2.3 percent greater than the total average use per residential customer was in 1989 (id.,

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28/ However, the Siting Council is aware of the vintage of the JUMP study -- the data was collected from December 1986 through December 1987. See 1988 EUA Decision, 18 DOMSC at 80.

29/ In addition, in both the 1990 and the 1991 demand forecasts, the Company reduced its energy forecast to reflect its conservation programs (Exhs. HO-1B, p. 4, HO-2B, p. 5).

p. 27; Exh. HO-2B, p. 39; Tr. 1, pp. 97-98, 102).[30] Essentially, the Company stated that it expects a "transformation" of the market, particularly for new homes and appliances, to be facilitated by its programs of incentives and technical support (Exh. HO-S-22).

The Company also adjusted its average use per appliance estimates with the results of price and income elasticity analyses (Exh. HO-1B, pp. 38, 46-47; Tr. 1, pp. 103-105). The Company developed elasticity factors to represent changes in residential electricity usage due to changes in electricity price and changes in personal income (Tr. 1, pp. 103-105). In the equations used to isolate the income and price responses, the Company used WMECo residential use per person data to incorporate the effects of declining household size on household electricity usage (id., Exh. HO-1B, pp. 38, 46-47).[31] The Company then used the income and price elasticity factors to adjust the average use per appliance (id., Exh. HO-RR-12). This adjustment was uniform across all end-uses (Tr. 1, pp. 103-104).

The Company's methods for estimating average use per appliance raise several issues. First, the Company used base

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30/ In terms of natural conservation, the Company projected much greater savings from improvements in building shell and appliance efficiency standards in the 1991 demand forecast than were forecast in 1990 (Exh. HO-2B, p. 39). To illustrate, in the 1991 forecast the Company estimated the average new home usage for electric space heating to decline 41 percent over the forecast period (id.). The combined effects of conservation anticipated in the 1991 demand forecast led the Company to estimate that total usage per residential customer in 2000 would be 2.7 percent less than total usage per residential customer in 1989 (id., p. 29).

31/ The Company applied persons-per-household data provided by DRI at the state level in the 1991 demand forecast (Exh. HO-2B, p. 48; Tr. 1, p. 109). The 1990 demand forecast used a database of WMECo persons-per-household (Exh. HO-1B, p. 46). Although the two databases differed in the years 1980-1989, both sets of data reported steady declines (Exhs. HO-1B, p. 46, HO-2B, p. 48).

year average values from varied sources with unidentified vintages. The Siting Council regulations require electric companies to report the vintage of data inputs. 980 CMR 7.03(5)a.2.

Second, as noted above, the Company's equations for calculating elasticities relied on "residential electricity use per person", a departure from "residential electricity use per household" used throughout the forecast. The Company explained that the number of persons per household has an impact on use per appliance. However, the Company's residential forecast does not reflect the effects of this variable. The Siting Council notes that another electric company has incorporated the effect of the number of persons per household in forecasts of use per appliance. See 1991 CECo/CELCo Decision, EFSC 90-4 at 18.

The Siting Council is also concerned with the Company's prediction of a market transformation in end-use efficiency. In the 1990 demand forecast, the Company projected efficiency improvements in many end uses, and raised those projections in the 1991 demand forecast. However, supporting documentation for those projections was limited. In past reviews of demand forecasts, the Siting Council has required electric companies to provide sufficient documentation in support of their assumptions. 1991 CECo/CELCo Decision, EFSC 90-4 at 27; 1989 MECo/NEPCo Decision, 18 DOMSC at 335; 1988 NU Decision, 17 DOMSC at 11.

Nonetheless, for the purposes of this review, the Siting Council finds that NU's forecast of average use per appliance is minimally acceptable. In order for the Siting Council to approve the Company's next forecast of average use per appliance, the Company must furnish information supporting its adjustments of average use per appliance.

d. Conclusion on Residential Energy Forecast

The Siting Council has found that NU has demonstrated that its forecasts of residential customers and number of appliances are acceptable. The Siting Council also has found that the Company's forecast of average use per appliance is minimally acceptable.

Accordingly, the Siting Council finds that NU has established that its residential energy forecast is reviewable, appropriate, and reliable.

5. Commercial Energy Forecast

a. Compliance with Order One

In the 1988 NU Decision, the Siting Council found that NU did not establish that its commercial energy forecast was appropriate or reliable (17 DOMSC at 15-16). The Siting Council's concerns focussed on the forecast's use of employment growth as a proxy for growth in commercial floor space (Id.). Therefore, the Siting Council ordered NU to present an analysis of each of the economic factors which may have an impact upon commercial floorspace growth (Id.).

In addressing Order One, NU described three approaches to forecasting floor space stock (Exhs. HO-RR-7, HO-RR-9, p. 2-10). The Company stated that three approaches are "stock demand," "investment demand," and "floor space-per-employee" (id.). The Company explained that it selected the floor space-per-employee approach, which assumes a direct relationship between employment and commercial floor space footage, because of the approach's use of data inputs that are dependable and routinely forecasted by independent, professional forecasters (Exh. HO-RR-7A). Specifically, the Company stated that employment forecasts disaggregated by one-digit SIC code are available and widely viewed as reliable (id.). The Company acknowledged that the cyclical nature of employment is a source of inaccuracy in forecasting commercial floor space stock (Exh. HO-RR-9, pp. 2-11, 2-12). However, the Company emphasized its belief that occupied commercial floor space is best predicted by using employment

(Exhs. HO-1B, p. 57, HO-RR-7). Further, the Company argued that occupied commercial floor space is the best predictor of commercial electricity usage (id.).

The Company also stated that both the stock demand and investment demand models rely on the reporting of construction activity, which is not considered to be comprehensive by either the entity collecting the construction activity, or by the Company (Exhs. HO-RR-7, HO-RR-9, pp. 2-10, 2-11). The Company asserted that this is a fundamental weakness in the use of both the stock demand and the investment demand approach to forecasting floor space (id.). Finally, the Company provided an analysis showing that substantial cycles in construction investment and the varying delay in the use of new buildings makes the investment demand approach a poor predictor of commercial electricity sales (Exh. HO-1B, p. 56).

Based on the above, the Siting Council finds the Company has complied with Order One.

b. Description

NU's 1990 commercial energy forecast methodology projects electricity usage in terms of three end uses and a miscellaneous category for each of ten building types (Exh. HO-1B, p. 53). The Company stated that its commercial forecast methodology is an adaptation of the Electric Power Research Institute ("EPRI") Commercial End-use Model ("Commend") (id., p. 47). The Company stated that the critical assumptions in its commercial forecast are "the key relationship ... that new buildings use more electricity than existing buildings" and that employment drives its forecast (id., p. 57). Therefore, the Company's forecast was disaggregated into new building usage and existing building usage, and employment was a major input in the forecast model (id., p. 63). The Company also adjusted usage to account for appliance efficiency changes (Tr. 1, pp. 159-160). Finally, NU adjusted the forecast results for the predicted impacts of its

C&LM programs (Exh. HO-1B, p. 10).

NU stated that Commend relies on three factors: (1) base year energy usage, (2) future usage due to economic activity, and (3) the quantity of energy-consuming equipment and occupied commercial floorspace (Exh. HO-RR-9, p. 1-1). NU's model projected occupied commercial floorspace with an econometric equation that related growth in commercial floorspace to growth in employment (Exh. HO-1B, pp. 55, 68).[32] The Company disaggregated energy usage with survey information on end-use and building energy requirements (id., pp. 53-55). The Company forecasted future usage starting from its own sales data and increasing sales with econometric equations and elasticities (id., pp. 47, 53-55).

In determining two of the above factors -- base year energy use and the future usage due to economic activity -- the Company used a combination of econometric and end use forecasting techniques. The Company stated that it used its own electricity sales data by Standard Industrial Classification ("SIC") for the past 20 years to provide the database for base year energy usage for its econometric equations (Exh. HO-1B, pp. 54, 67-68). With respect to forecasting future usage, the Company stated that it projected consumption by commercial equipment with an econometric equation that used elasticity responses to fuel price change for the short run and econometric equations using efficiency and fuel choice elasticities for the long run (Exhs. HO-1B, pp. 55, 57, 59, HO-RR-9, pp. 2-1 to 2-5).[33] These elasticities are estimated for the commercial class on a Company-wide basis,

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32/ NU forecasted occupied commercial floorspace in part using a floorspace-per-employee relationship (Exh. HO-1B, pp. 53-55). See Section II.C.5.a, above.

33/ Additional econometric equations were used by NU to develop these sensitivity factors from cost and engineering information collected from a sample of customers (Exhs. HO-1B, pp. 55, 57, 59, HO-RR-9, pp. 2-1 to 2-5).

without disaggregation by end use (Exh. HO-D-24).

NU developed the input information for these equations with surveys of ten building types conducted in 1986 and 1987 (Exh. HO-1B, pp. 54-55, 57).[34] These same surveys provided information on energy requirements and fuel shares by end use applied by NU to its four end-use categories: space heating, cooling, lighting, and miscellaneous (id., pp. 54-55, 58). The Company stated that the EPRI Commend model is designed to forecast usage in seven end uses and a miscellaneous category (Exh. HO-RR-9, pp. 1-1, 2-3).[35] In addition, the Company indicated that its detailed surveys of commercial buildings collected information for the seven end-use categories used in the EPRI Commend model (Exh. HO-D-25). Finally, NU stated that it checked the end use and building type data with its commercial and industrial conservation audit database and a 1983 U.S. Department of Energy ("DOE") survey (Exh. HO-1B, p. 55).

The Company stated that, among its end-use categories, the miscellaneous category is "viewed as the base part of the forecast not subject to considerations of weather or time of year" (Exh. HO-D-23). The Company explained that the several end uses included in the miscellaneous category "individually do not constitute a large share of sales" (id.). For example, the Company stated that electronic office equipment may be noticeable in only two or three building types (id.). The Company also contended that "little data are available on their energy

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34/ The 10 building types used by NU in the end use and econometric models are office, restaurant, retail, food store, warehouse, school, college, health care, hotel, and miscellaneous (Exhs. HO-1B, pp. 53, 58, HO-D-25). The Company also models each building type for both existing and new buildings (id.).

35/ The seven end uses are: space heating, air conditioning, ventilation, water heating, cooking, refrigeration, lighting, and miscellaneous (Exh. HO-RR-9, p. 1-1). The Company also stated that the EPRI model is able to simulate non-weather sensitive end uses separately from the weather sensitive end uses (id., p. 2-6).

requirements or market penetrations" and "only as data become available" could the Company explore further disaggregation of the miscellaneous category (id.). However, the Company indicated that the end uses in the miscellaneous category collectively constituted 47 percent of commercial sales in 1989 (Exh. HO-1B, p. 65).

The final step NU took in its commercial forecast methodology was to adjust the results of its forecast with the predicted impacts of its C&LM programs (id., p. 10). The Company's forecast of C&LM used an assumption in the commercial sector that for "commercial new construction programs the code construction would eventually reach the [Company's] program standards; thus through the process of "market transformation" in the long-run, one hundred percent of customers were assumed to adopt the technologies included in the [Company] program" (Exh. HO-S-23). The Company stated that its assumption that its program goals will be completely adopted is based on the influence of "strong support by the Company" and the Company's experience with changes in building codes in the past (id.).

c. Analysis and Findings

In forecasting commercial energy requirements, NU employs a sophisticated end-use methodology that analyses usage across ten building types. In addition, NU has completed an extensive survey of commercial customers in its service territory and uses such territory-specific data in its commercial forecast. Finally in complying with Order One, the Company has demonstrated that employment is a valid predictor of commercial floorspace.

However, the Siting Council notes some weaknesses in the Company's commercial forecast methodology. First, the Company has not pursued the disaggregation of commercial end-use consumption beyond four appliance types. While the Company has shown that the two bases for the its forecast -- the EPRI Commend model and its own survey data -- are designed to forecast consumption in seven appliance types, the Company has yet to expand its disaggregation of commercial end uses to the extent permitted by these forecasting resources. The Siting Council notes that another electric company has successfully implemented commercial forecasts based on the full capabilities of the EPRI Commend model. See, 1989 MECo/NEPCo Decision, 18 DOMSC at 310-322. A greater degree of disaggregation would provide the forecast with greater detail and a more comprehensive examination of the determinants of commercial demand.

The Siting Council also notes the Company's assumption concerning conservation in the commercial forecast. The Company has assumed, without fully documenting this assumption, that a "market transformation" will occur for efficient technologies. Essentially, the Company forecasted that the goals of its current conservation programs would be met in the future by market changes. While the effects of specific programs sponsored by the Company are small, the effects of a "market transformation" are potentially significant. The Siting Council has required electric companies to provide sufficient documentation in support of their assumptions. 1991 CECo/CELCo Decision, EFSC 90-4 at 27; 1989 MECo/NEPCo Decision, 18 DOMSC at 335; 1988 NU Decision, 17 DOMSC at 11. The Siting Council also encourages the Company to continue to monitor market-induced conservation to better assess the overall effect that a market transformation could have on a forecast of energy sales.

Nevertheless, based on the foregoing, the Siting Council finds that NU has established that its 1990 commercial energy forecast is reviewable, appropriate, and reliable.

6. Industrial Energy Forecast

a. 1990 Industrial Methodology

The Company's 1990 industrial energy forecast is based on an econometric model that predicts sales as a function of: (1) the previous year's sales; (2) the price of electricity; and (3) a weighted production index (Exh. HO-1B, pp. 59, 70-71).[36]

NU stated that it separately prepared forecasts of Company C&LM program and customer self-generation impacts in the industrial sector (Exh. HO-1B, p. 3). The Company stated that it used its C&LM and self-generation estimates directly to reduce the forecast of industrial energy demand (id., pp. 3, 10, 55).

NU further stated that it did not adjust its 1990 industrial forecast for technological change because the use of the previous year's sales in its equation "incorporates embedded technological change" (id., p. 71). NU explained that it did not believe additional adjustments to sales to represent non-price-induced technological change were necessary because NU's prediction of electric sales per unit of industrial production shows a significantly greater decline than DRI's prediction of industrial electric sales per unit of industrial output (id., p. 72).

The Company's 1990 industrial forecast is largely the same as the one approved by the Siting Council in 1988. 1988 NU Decision, 17 DOMSC at 16. The 1990 methodology adequately incorporates electricity price in the forecast, and provides disaggregation of sales into two-digit SICs. However, the Siting Council notes that the Company could have strengthened its industrial forecast by more fully analyzing the relationship between the previous year's sales and technological change. For example, previous year's sales that are influenced by swings in the business cycle or the entry and exit of industrial manufacturers in the service territory could mask emerging trends in technological change.

For the purposes of this review, the Siting Council finds that NU has established that its industrial forecast is

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36/ NU used a weighted production index for selected SICs to subdivide its 1990 forecast of sales into two-digit SICs (Exh. HO-1B, pp. 59, 70-71). The SICs were electrical machinery, non-electrical machinery, fabricated metal, rubber and plastics, paper and products, food and products, and all other SICs (id., p. 76).

reviewable, appropriate, and reliable.

b. 1991 Industrial Methodology

(1) Description

NU stated that its 1991 industrial energy forecast used a new approach as part of the Company's effort to produce an end-use forecast methodology for its industrial sector (Exh. HO-2B, pp. 60-73). NU stated that the 1991 industrial energy forecast methodology is "an econometric model which is used to estimate end-uses" that was developed because NU sought a two-digit SIC-specific industrial end-use model (Tr. 2, pp. 64-65). NU stated that its 1991 industrial energy forecast distributed total industrial energy demand over two-digit SICs and forecasted the market share of energy demand served by electricity (id., pp. 73-82). NU stated that it divided the electricity demand of each SIC across four end-uses (id., pp. 83-84).[37] Finally, NU stated that the Company's industrial C&LM plans "require a better sense of the amount of load that industrial customers will use for motor drive, process heat and lighting" (Exh. HO-2B, p. 60).

NU developed its 1991 industrial forecast using forecasts of: (1) total industrial energy demand in Massachusetts;[38] (2) the market share of electricity in the industrial sector; and (3) national trend data on shares of electrical load by end use (id., pp. 72, 80-83). The Company also made adjustments to its forecast results for C&LM and self-generation (id., pp. 2-3). Finally, after completing its forecast, the Company stated that

37/ The Company used motor drive, heat process, lighting and other as aggregate end uses in its forecast (Exh. HO-2B, p. 85).

38/ Because the Company's historic data on total energy demand ended in 1988, the Company developed its own estimates of total industrial energy demand beginning in 1989 (Exh. HO-2B, pp. 74, 76-77, 79). Therefore, the Company's 1991 industrial energy forecast used the Company's forecast of total industrial energy demand data (id.).

it compared the results of its 1991 forecast with the results of its 1990 forecast methodology using 1991 inputs and assumptions (id., p. 81).

The Company stated that the first major component of its industrial forecast -- total industrial energy demand -- was developed using an econometric equation to represent the historical relationships between industrial production and real price per British thermal unit of energy ("Btu") (id., p. 73).[39]

The Company stated that the predominant driving variable in the calculation of total industrial energy demand was industrial production (Exh. HO-D-63). NU stated that it developed indices of industrial production for two-digit SICs (id.; Tr. 2, pp. 73-74). NU stated that it adjusted national two-digit SIC production indices of industrial production to the state level by applying the ratios of Massachusetts' employment to national employment in each SIC (id.).

In establishing inputs of total industrial energy demand, the Company relied on a historic database that ended with 1988 data (Exh. HO-2B, p. 73). To develop a historical record of total industrial energy demand for the period 1975 to 1988 in Massachusetts, the Company made use of the DOE State Energy Data Report database for industrial consumption of distillate and residual oil, natural gas, and electricity for the years 1960 to 1988 (id.). To forecast future industrial energy demand, NU stated that it used forecasts of state industrial production and industrial employment from DRI's Summer 1990 publications (id.). To forecast future energy prices, the Company used DRI's Fall

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39/ NU used a regression equation that made the result of total industrial Btu consumption divided by the weighted industrial production index the dependent variable (Exh. HO-2B, p. 73). NU stated that the independent variables were real price per Btu of energy and the ratio of Btu consumption to industrial production lagged one year (id., pp. 73, 76-77). NU stated its model produced an R-squared value of .75 for Massachusetts and .93 for Connecticut (id., pp. 76-77).

1990 fossil fuel price forecast and NU's own 1990 electricity price forecast (id., pp. 73, 78).

The second major component of NU's industrial forecast was market share of electricity. The Company forecasted market share of electricity based on a saturation curve methodology (id., p. 75). NU developed its saturation curve for electricity based on a statistical function of time and the ratio of the real price of electricity to the real price of all fuels used in industry (id.).[40] NU explained that while "time is the most dominant variable" in this function, time is included in the function as "a proxy which incorporates the effects of a changing industrial structure and technology" (Exh. HO-D-61; Tr. 2, p. 91). The Company, attempting to explain that the market share for electricity would tend to follow "a typical saturation situation," indicated that, "[i]ndustrial electricity use, after the necessary level of output is decided, is dependent upon relative energy prices and the rate at which electric-using technology is adopted" (Tr. 2, pp. 60, 73). However, the Company also stated "because electricity is such a small share of the value of shipments or value added, electric prices, gas prices, oil prices are not what drive industrial customers to select or reject equipment" (id., p. 91-93).

The final major component of NU's industrial forecast was national trend data on shares of electrical load, NU stated that it relied on EPRI's Industrial Marketing Information System ("IMIS") database for the load share of 43 end uses by four-digit SICs (Exh. HO-2B, p. 83). The Company used these estimates to distribute the forecasted electricity energy demand to the four end uses in each of the two-digit SICs (id., pp. 83-84).

As a final step, the Company made adjustments to its industrial energy forecast for self-generation and C&LM (Exh. HO-

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40/ NU approximated the R-squared value of its non-linear saturation curve regression as .98 (Exh. HO-RR-21).

2B, pp. 2-3). NU stated that it separately prepared forecasts of self-generation by its customers and C&LM and subtracted these from the forecasts of energy and peak load for each customer sector (id.). NU's forecast of peak load served by customer self-generation in the year 2000 is 51 MW (id.).[41] The Company's forecast of the combined effect of C&LM and self-generation on the industrial class system-wide projects a reduction in the growth rate of industrial energy sales from an average 2.7 per cent per year to 0.5 percent per year (id., p. 10). However, the growth in MW impacts from Company industrial sector C&LM programs is forecasted to slow in 1999 and C&LM program impacts are projected to decline following that year (Exh. HO-2A, pp. III-23 to III-24).

After the forecast was prepared, the Company made a comparison of its forecast with a forecast produced using its 1990 methodology (Exh. HO-2B, p. 81). NU stated that it developed forecasts of industrial energy demand using the methodology employed in its 1990 industrial forecast (id.).[42] Industrial sales forecasted with the 1990 methodology, using 1991 data inputs and assumptions, predicted compound annual growth rates over the forecast period of -2.0 percent for CL&P and -0.4 percent for WMECo (id.). NU stated that it compared these results with the results of the industrial forecast made with the 1991 methodology, which were 0.4 percent compound annual growth rate for CL&P and 1.0 percent compound annual growth rate for WMECo (id.). The Company attributed the higher growth rates forecasted by the 1991 methodology to the forecast of increasing saturation of electricity in the industrial fuel mix (id.).

41/ In the 1990 demand forecast, NU predicted a reduction of 75 MW from customer self-generation in 1999 (Exh. HO-1B, p. 2).

42/ The Company stated that it will continue to use the 1990 methodology for comparison purposes until the new industrial methodology is refined (Tr. 2, pp. 105-107).

Further, NU developed forecast accuracy tables for WMECo and the NU system industrial energy forecasts based on the 1990 methodology (Exh. HO-RR-25).[43] The tables show that NU's and WMECo's industrial forecasts are more often (16 of 22) higher than actual industrial sales in the first year following the forecast (id.).

Finally, the Company indicated that it is committed to enhancing and refining the industrial end-use model and has already planned improvements for the next two forecasts (Tr. 2, pp. 65, 106).

(2) Analysis

While the 1991 demand forecast is not the subject of review in this decision, the Company's new industrial forecast methodology presented in its 1991 demand forecast is reviewed here to provide guidance for future forecast filings. At the outset, the Siting Council notes that the Company's modifications to its industrial model relative to the model employed in its 1990 forecast represent an important advance toward a more comprehensive end-use methodology for the industrial sector. Generally, the Siting Council encourages companies to develop new forecast methodologies when the limits of existing forecast techniques become apparent.

While generally this forecast methodology incorporated more a comprehensive analysis of the variables contributing to

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43/ Forecast accuracy tables provide a comparison of a company's past forecasts with actual demand. The Siting Council requires gas companies to use such tables as a means to review their forecasting performance and to make changes to their methodologies when appropriate. See Colonial Gas Company, EFSC 89-61, pp. 5-6 (1991); Evaluation of Standards and Procedures for Reviewing Sendout Forecasts and Supply Plans of Natural Gas Utilities, 14 DOMSC 95 (1986). The Siting Council notes that use of forecast accuracy tables can provide similar guidance to electric companies in making modifications to forecasting methodologies.

industrial demand, we note three areas of concern with the new methodology. First, the Company obtained historical total industrial energy demand through 1988, requiring the Company to forecast total industrial energy demand for 1989 and 1990. The Siting Council is concerned that the use of estimates of historical data may introduce uncertainty in the forecast. Therefore, the Company should make an effort to gather more current data from users and suppliers.

Second, in regard to its estimate of market shares, the Company was unable to give a consistent, reasoned explanation of its saturation equation. Essentially, the Company made conflicting statements about the importance of fuel price as a determinant of technological change represented by its saturation equation. NU described the other variable, time, as a proxy of "a changing industrial structure," a structure which may be sensitive to economic conditions or limits not well captured by the historical data. Furthermore, the Company described a trend of declining electric sales per unit of industrial production in its 1990 forecast, which is directly contradicted by the Company's saturation equation. As the Company's 1991 forecast largely depends upon the saturation equation, a clear explanation of the equation and its relation to observed trends would allow the Siting Council to evaluate the methodology's reliability.

Finally, the Company's comparison of the results of the 1991 and 1990 forecast methodologies raises questions about the reliability of the 1991 industrial forecast. The Company compared the results of the 1991 methodology with the results of the 1990 forecast methodology using the inputs from the 1991 forecast. This comparison showed the 1990 forecast methodology forecasts significantly lower consumption of electricity than the 1991 forecast methodology. The Company did not comment on this comparison. Further, the Company's forecast accuracy data showed that the methodology used in the 1990 forecast over-forecasted industrial demand in roughly three-quarters of past Company forecasts. The Company must address the differences in the results of its methodologies, especially in light of potential over-forecasting by its 1990 model. The Siting Council expects that the Company will describe the accuracy of the new forecast methodology in its next forecast filing and will continue to compare the results of the two methodologies to remedy any apparent over-forecasting tendencies.

Nonetheless, the new approach represents an important advance which incorporates major industrial end-uses and which is consistent with the Company's C&LM planning. The Siting Council anticipates that the Company will continue to enhance its model in future forecast filings.

7. Other Energy Forecasts

In addition to selling electricity at retail to residential, commercial, and industrial customers within its service territory, the Company indicated that WMECo sells electricity at wholesale for resale to certain other utility companies (Exh. HO-1B, pp. 85-86). The Company also forecasted streetlighting use throughout its service territory (id., p. 86).[44]

a. Wholesale Sales for Resale

The Company indicated that WMECo sells electricity at wholesale for resale to R. H. Fletcher Company, Massachusetts Electric Company, and New York State Electric and Gas Corporation; and HWP sells electricity at wholesale for resale to Chicopee Electric Light Department, and Westfield Gas and Electric Department (HO-1B, p. 85). The Company stated that

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44/ The Company projected a portion of its output to be subject to losses and internal use (Exh. HO-1C, pp. 45-46). The Company's tables indicated that losses and internal use accounted for 10.1 percent of total WMECo energy requirements in 1989 (Exh. HO-1C, pp. 45-46).

wholesale sales for resale accounted for about 0.3 percent of WMECo's total sales in 1989, and 57 percent of HWP's total sales (id., p. 93).[45] The Company indicated that its forecast of wholesale sales for resale was based on customers' predictions of their loads (id., and Exh. HO-D-36).

The Company stated that it expected WMECo's wholesale for resale sales to grow from 9,845 MWH in 1990 to 10,759 MWH in 1999, and HWP's wholesale for resale sales to grow from 164,810 MWH in 1990 to 222,900 MWH in 1999 (Exh. HO-1B, p. 87). The Company added that the rapid projected growth in HWP wholesale for resale sales is due to the addition of Westfield Gas and Electric Department as a customer (Exh. HO-D-36).

For the purposes of this review, the Siting Council finds that NU has established that its forecast of wholesale sales for resale is reviewable, appropriate, and reliable.

b. Steetlighting Sales

The Company stated that sales to the streetlighting class accounted for approximately 0.8 percent of total 1989 WMECo sales (Exh. HO-1B, p. 92). The Company indicated that it forecasted streetlighting sales by multiplying (1) the forecast number of residential customers, and (2) a streetlighting-sales-per-customer factor (id., p. 86). The Company stated that its streetlighting-sales-per-customer factor is derived from a time trend model used in the Company's short-run forecast (id.). See Section II.C.3, above. The Company stated that streetlighting sales were projected to decrease slightly in the WMECo service territory due to anticipated conversion from incandescent and mercury vapor lamps to more energy-efficient high pressure sodium vapor lamps (id.).

The Siting Council notes that the Company used a reasonable

45/ HWP sells electricity at wholesale for resale and at retail to industrial customers only (Exh. HO-1B, p. 93).

methodology to forecast streetlighting sales. In particular the Company accounted for both customer growth and the effects of relamping programs in the design of its streetlighting forecast.

Based on the above, the Siting Council finds that NU has established that its forecast of streetlighting sales is reviewable, appropriate, and reliable.

8. Conclusions on the Energy Forecast

The Siting Council has found that the Company's economic and demographic forecasts and price forecast are acceptable. The Siting Council also has found that NU has established that its short run forecast is acceptable for use in its long-run forecast. In addition, the Siting Council has found that NU has established that its residential, commercial, industrial, wholesale for resale, and streetlighting sales energy forecasts are reviewable, appropriate and reliable. Accordingly, the Siting Council finds that the Company's methodology for forecasting overall energy requirements is reviewable, appropriate and reliable.

D. Peak Load Forecast

1. Description

The Company stated that WMECo was a winter peaking system between the years 1969 and 1989 and that it expects to remain so throughout the forecast period (Exh. HO-1B, p. 108). The Company forecasted WMECo's winter peak to grow from 762 MW in 1990 to 833 MW in 1999 (id.), and its summer peak to grow from 682 MW in 1990 to 813 MW in 1999 (id.). The Company stated that it expected WMECo's winter peak to grow at a compound annual rate of 0.1 percent from 1990 to 1999 (id.).[46] The results of NU's 1990

46/ The Company stated that HWP experienced both summer and winter peaks between the years 1969 and 1989 (Exh. HO-1B, p. 109). The Company indicated that HWP expected a winter peak in 1990 and summer peaks throughout the remainder of peak load forecast are presented in Table 2, below.

In developing its peak load forecast, NU stated that it employed an hourly load model to forecast hourly loads for each of its operating companies (id., p. 95; Tr. 2, p. 24). The Company indicated that its hourly load model was based on annual energy sales by end use, monthly and daily "shares" or consumption patterns associated with each end use, different types of day, and minutes of darkness per year (Exh. HO-1B, pp. 95-99).[47] In addition, the Company incorporated the effects of weather by differentiating between weather-sensitive and non-weather-sensitive end uses (id.; Tr. 2, pp. 27-31). The Company stated that weather-sensitive end uses were modeled differently than all others (Tr. 2, p. 28). The Company added that WMECo's peak load forecast reflected the impacts of load management programs, particularly its radio-controlled water heater and time-of-use rates programs (Exh. HO-1B, p. 99).[48]

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the forecast period (id.). The Company further stated that HWP expected its winter peak to decline from 56 MW in 1990 to 44 MW in 1999 (id.), and that it expected HWP's summer peak to decline from 55 MW in 1990 to 45 MW in 1999 (id.). The Company stated that it expected HWP's winter peak to grow at a compound annual rate of -0.4 percent from 1990 to 1999 (id.), and its summer peak to grow at a compound annual rate of -0.2 from 1990 to 1999 (id.).

47/ The Company stated that the residential load forecast was an aggregate of the projected loads of 16 appliance end uses plus a miscellaneous appliance category (Exh. HO-1B, p. 95), that the commercial load forecast was the aggregate of the loads of heating, cooling, lighting and miscellaneous end uses in 10 building types (id.), and that the industrial load forecast was the aggregate of the loads of 14 SIC's (id.).

48/ The Company indicated that it assumed 56 percent of the residential water heaters in the WMECo service territory would be radio-controlled by the year 1999 (Exh. HO-1B, p. 99). The Company further indicated that it anticipated time-of-use rates would account for the shifting of 3.2 percent of WMECo's commercial load and 1.8 percent of WMECo's industrial load from peak to off-peak by the year 1999 (id.).

The Company noted that annual energy sales by end use were obtained from its energy forecast (Exh. HO-1B, p. 95). The Company indicated that, in order to determine hourly loads for each end use, it first subdivided annual usage into monthly usage and daily usage (Exh. HO-1B, p. 97). The Company stated that monthly and daily shares reflect the ratio of average daily sales for a given month and day type to average daily sales for the year (id.). The Company added that monthly and daily shares and the resulting load shapes were estimated based on day types, load research data and internal engineering studies, minutes of darkness and temperature data (Tr. 2, p. 28).

The Company assumed that daily usage could be represented by three day types: (1) weekdays, (2) Saturdays and minor holidays, and (3) Sundays and major holidays (Exh. HO-1B, p. 98). The Company stated that the three day types were used in its peak load model (id.).

The Company stated that minutes of darkness was used as a determinant of hourly residential lighting and streetlighting loads (Exh. HO-1B, pp. 95-97; Tr. 2, p. 28). In establishing minutes of darkness, the Company indicated that it used a database consisting of daily sunrise and sunset times for each year throughout the forecast period (Exh. HO-1B, p. 95). The Company stated that annual residential lighting and streetlighting sales were spread over each hour based on a ratio of minutes of darkness in a specific hour to the total minutes of darkness in the year (Exh. HO-1B, p. 97).

The Company stated that hourly loads for the portions of the residential and commercial sectors which are temperature-sensitive were estimated using temperature data consisting of an hourly temperature input file (id., p. 98; Tr. 2, p. 28). The Company indicated that an hourly temperature input file of 8760 temperatures per year was required to estimate hourly temperature-sensitive loads (Exh. HO-1B, p. 98). The Company stated that the weather year used for the hourly temperature input file was designed to have normal mean temperatures for the year and for each month (id.). The Company indicated that it used 30 years of weather data collected from the National Oceanic and Atmospheric Administration data center at Bradley Field -- located roughly 25 miles from Springfield, Massachusetts -- to construct its normal weather year (id.,; Tr. 2, p. 40).

The Company indicated that hourly loads for industrial end uses, commercial lighting and miscellaneous end uses, and non-lighting residential end uses which are not temperature-sensitive were estimated on the basis of current load research data and internal engineering studies (Tr. 2, pp. 27, 28).

To forecast peak loads, the Company stated that it inserted historically-based peak weather conditions into the months of January and July in the temperature input file described above (Exh. HO-1B, p. 99).

The Company indicated that it conducted regression analyses to determine the relationship between winter and summer peaks and weather (Exh. HO-1B, p. 106). The Company added that it normalized historical weather data based on the results of the regression analyses, but that the normalization had no effect on the levels of forecasted peak loads (id., p. 115).

Finally, the Company stated that its peak load forecast accounted for the effects of load management programs (Exh. HO-1B, p. 99).

2. Analysis

NU has demonstrated that it has developed and implemented a peak load forecast methodology that accounts for the variables which most significantly affect peak load. The Company has demonstrated that its peak demand model captures the effects of weather, type of day, consumption patterns, and load management programs on the loads of various end uses in each of the customer classes. In addition, the Company has differentiated between weather-sensitive and non-weather-sensitive end uses.

Previously, the Siting Council approved the Company's previous peak load forecast methodology, which was similar to the peak load forecast methodology currently under review, (1988 NU Decision, 18 DOMSC at 14), and has accepted peak demand forecast methodologies similar to that employed by the Company in the instant case. 1991 CECo/CELCo Decision, EFSC 90-4 at 36; 1989 MECo/NEPCo Decision, 18 DOMSC at 329.

Accordingly, based on the foregoing, the Siting Council finds that the Company has established that its methodology for forecasting peak load requirements is reviewable, appropriate and reliable.

E. Conclusions on the Demand Forecast

The Siting Council has found that the Company's methodology for forecasting energy requirements is reviewable, appropriate, and reliable. The Siting Council also has found that the Company's methodology for forecasting peak load requirement is reviewable, appropriate, and reliable.

Accordingly, the Siting Council hereby APPROVES NU's 1990 demand forecast of the Northeast Utilities System.

III. DECISION

The Siting Council hereby APPROVES the 1990 demand forecast of the Company.

In so deciding, the Siting Council has detailed specific information that the Company must provide in its next filing in order for the Siting Council to approve NU's next demand forecast. This specific information is necessary for the Siting Council to fulfill its statutory mandate, including its need to determine whether the 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 and include an adequate consideration of conservation and load management.

Therefore, in order for the Siting Council to approve the Company's next forecast of average use per appliance, the Company must furnish information supporting its adjustments of average use per appliance.

The Siting Council notes that the Company's next demand forecast and supply plan will be its first IRM filing which is scheduled to be submitted on April 1, 1992.

Jolette A. Westbrook
Hearing Officer

Dated this 5th day of March, 1992

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of March 5, 1992 by the members and designees present and voting. Voting for approval of the Tentative Decision as amended: Gloria Larson, Secretary of Consumer Affairs and Business Regulation; David Sheehan (for Stephen Tocco, Secretary of Economic Affairs); Chris Donodeo-Cashman (for Paul W. Gromer, Commissioner of Energy Resources); Andrew Greene (for Susan Tierney, Secretary of Environmental Affairs); Kenneth Astill (Public Engineering Member); Joseph Faherty (Public Labor Member); Mindy Lubber (Public Environmental Member); and Michael Ruane (Public Electricity Member).

Gloria C. Larson

Gloria C. Larson
Chairperson

Dated this 5th day of March, 1992

TABLE 1

1990 FORECAST RESULTS
WMECo and HWP Base Case Forecast of Energy Sales
(Gigawatthours)

YEAR	RESI-DENTIAL	COMM-ERCIAL	INDUS-TRIAL	STREET-LIGHTING	WHOLE-SALE	HWP SALES
1990	1456	1298	1049	30	10	271
1991	1485	1307	1069	29	10	295
1992	1503	1312	1065	29	10	296
1993	1510	1294	1053	28	10	316
1994	1524	1277	1049	27	10	318
1995	1533	1262	1048	26	10	325
1996	1550	1281	1061	27	11	327
1997	1566	1309	1078	27	11	329
1998	1588	1340	1102	28	11	330
1999	1606	1375	1117	28	11	331

Source: Exh. HO-1B, pp. 92, 93.

TABLE 2

1990 FORECAST RESULTS
WMECo Base Case Forecast of Peak Loads

YEAR	NET ENERGY (GWH)	SUMMER PEAK (MW)	WINTER PEAK (MW)
1990	4166	682	762
1991	4221	744	764
1992	4232	745	764
1993	4216	750	765
1994	4214	753	766
1995	4205	754	772
1996	4264	763	788
1997	4327	780	806
1998	4410	794	818
1999	4484	813	833

Source: Exh. HO-1B, p. 108.

Appeal as to matters of law from any final decision, order or ruling of the Siting Council may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the order of the Siting Council be modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Siting Council within twenty days after the date of service of the decision, order or ruling of the Siting Council, or within such further time as the Siting Council may allow upon request filed prior to the expiration of the twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the clerk of said court. (Massachusetts General Laws, Chapter 25, Sec. 5; Chapter 164, Sec. 69P).

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petitions of Boston Edison Company for Approval of Its 1990 Long Range Forecast of Electric Requirements and Resources and for Approval to Construct a Bulk Generating Facility and Ancillary Facilities	EFSC 90-12/90-12A (PHASE I)

FINAL DECISION

Frank P. Pozniak
Michael D. Ernst
Robert D. Shapiro
Hearing Officers
April 10, 1992

On the Decision:

Robert J. Harrold
Brian J. Abbanat

John Howat
Michael Jacobs
Marla Simon

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TABLES

The Energy Facilities Siting Council hereby APPROVES the 1990 demand forecast of the Boston Edison Company at the time of the reforecast.

I. INTRODUCTION

A. Background

Boston Edison Company ("Boston Edison," "BECo," or "the Company") is an investor-owned utility engaged in the generation, purchase, transmission, distribution, bulk power sale, and retail sale of electrical energy. In 1991, Boston Edison provided retail service to 40 cities and towns in the greater Boston metropolitan area (Exh. BE-2, p. 1), sold approximately 12,812,000 megawatt-hours ("MWh") of electricity (Exh. HO-D-111), and experienced a peak demand of 2,652 megawatts ("MW") (id.). In the same year, residential customers received approximately 26 percent of the Company's total annual energy sales; commercial customers received 55 percent; industrial customers received 13 percent; and the Massachusetts Bay Transportation Authority ("MBTA"), Massachusetts Water Resources Authority ("MWRA"), street lighting, and municipal sales combined received 6 percent (id.). Losses and internal use accounted for an addition of 8.8 percent of sales to energy requirements (id.). Boston Edison is a summer peaking system (Exh. BE-2, p. 145).

In its review of Boston Edison's previous filing, the Siting Council approved the Company's demand forecast without orders or conditions. Boston Edison Company, 18 DOMSC 201, 208-223 (1989) ("1989 BECo Decision"). In that decision, the Siting Council also approved BECo's supply plan but ordered the Company to: (1) include as part of its supply planning process a comprehensive analysis of the Pilgrim power plant, including sensitivity analyses for certain operating and cost variables; (2) consider for inclusion in its array of available resource options a wider range of the generation technologies which could contribute to a least-cost supply plan; (3) implement a methodology which includes an adequate consideration of the environmental impacts of alternative resource options; and

(4) diversify the sources consulted inside and outside of the Company for the purposes of developing the probabilities assigned to each variable forecast in the company's risk management process. 1989 BECo Decision, 18 DOMSC at 224-282.

B. Procedural History

On May 1, 1990, the Company filed with the Siting Council its 1990 long-range demand forecast, supply plan and a proposal to build a 306 MW gas-fired electric generating facility in the Town of Weymouth, Massachusetts ("Weymouth"), with an alternative site in the Town of Uxbridge, Massachusetts ("Uxbridge") (Exhs. BE-1, BE-2, BE-3, BE-6).

On June 22, 1990, the Siting Council and Department of Public Utilities ("Department" or "DPU") issued a joint notice of adjudication and public hearing concerning this proceeding (EFSC 90-12/12A) and three petitions filed with the DPU by BECo as follows: (1) a petition for a zoning exemption to site the proposed generating facility, the Edgar Energy Park Project ("Edgar") (D.P.U. 90-106); (2) a petition for approval of investments in a new subsidiary to construct and operate Edgar (D.P.U. 90-117); and (3) a petition for preapproval of the Edgar construction costs and the Edgar power purchase agreement[1] (D.P.U. 90-118). On July 27, 1990, the Siting Council and DPU signed a joint memorandum of understanding ("MOU") which set forth the procedure and a tentative schedule for these interrelated proceedings.[2]

1/ See 220 C.M.R. 9.00 et seq.

2/ The MOU was designed to coordinate the review by the Siting Council and the DPU of the various Edgar-related proceedings. The MOU was designed to eliminate unnecessary overlap in the two agencies' proceedings while preserving the rights of all parties to the proceedings. The MOU proposed a schedule for joint publication and notice, time periods for intervention, initial joint public hearings, a joint procedural conference, pre-filed testimony, discovery and the start of evidentiary hearings.

The Siting Council held public hearings in Uxbridge, Massachusetts, on July 23, 1990, and in Weymouth, Massachusetts, on July 24, 1990. BECo provided notice of the public hearings and adjudication as directed by the Hearing Officer.

A notice of intervention was filed by the Office of the Attorney General of the Commonwealth ("Attorney General") on July 6, 1990. Motions to intervene subsequently were filed by the Conservation Law Foundation ("CLF"), Distrigas of Massachusetts Corporation ("DOMAC"), the Energy Consortium ("TEC"), Massachusetts Public Interest Research Group ("MASSPIRG"), Nancy Zerfoss, Weymouth, the Weymouth Board of Public Health, the Weymouth Department of Public Works, Richard and Suzanne Dauphin, East Braintree Civic Association, Blackstone River and Canal Commission, Blackstone River Valley National Heritage Corridor Commission, Uxbridge, the Uxbridge Planning Board, Uxbridge Parents for Clean Air and Water, Daniel Richardson, and South Uxbridge Community Association. Motions to participate as interested persons were filed by Richard and Jacquelyn Aloise, Robert and Leslie Sahagian, Boston Gas Company, Cogen Technologies, Save the Bay, Inc., and New England Cogeneration Association ("NECA").

On August 16, 1990, NECA filed a motion to substitute its petition to participate as an interested person with a petition to intervene. On August 30, 1990, Nancy Zerfoss submitted a letter clarifying her motion to intervene. Ms. Zerfoss stated that the intent of her original motion was to request intervenor status on behalf of the citizen group, Weymouth Against The Edgar Revitalization ("WATER"). On September 14, 1990, DOMAC requested that its motion to intervene be considered instead as a motion to participate as an interested person. At a prehearing conference on September 14, 1990, all motions for intervention and all motions for interested person status were granted (September 14, 1990 Prehearing Conference, Tr. pp. 6-19).

On November 28, 1990, MASSPIRG filed a Motion to Compel Boston Edison to respond to an information request which asked the Company to recalculate its forecast of energy and peak load requirements utilizing updated inputs. At a technical session on December 20, 1990, Boston Edison agreed to provide revised base case and low case energy and peak load forecasts. On February 6, 1991, the Company filed a reforecast using August, 1990 Data Resources, Inc. ("DRI") data.

The Siting Council held 49 evidentiary hearings beginning on February 22, 1991, and ending on June 21, 1991. During the course of the hearings, BECo presented 12 witnesses: Robert J. Cuomo, manager of forecasting and market analysis at BECo, who testified regarding energy and peak demand forecasts; Gregory R. Sullivan, manager of the distribution and planning section of the electrical engineering and station operations department at BECo, who testified concerning the need for transmission and distribution facilities; Johannes H. Baumhuaer, principal engineer at BECo, who testified regarding the Performance Management Study; William P. Killgoar, manager of energy resource planning and forecasting at BECo, who testified concerning BECo's long-range integrated resource plan ("BECo Resource Plan"); Paul D. Vaitkus, head of supply planning at BECo, who testified regarding the supply-side planning portion of the BECo Resource Plan; Richard S. Hahn, vice-president of marketing at BECo, who testified concerning the BECo Resource Plan and Pilgrim Analysis; Kathleen A. Kelly, manager of demand-side planning, monitoring, and evaluation at BECo, who testified regarding demand-side planning; John F. Carlin, manager of fossil fuel planning, procurement, regulation and performance at BECo, who testified concerning fuel supply; Cameron H. Daley, senior vice-president for power supply at BECo, who testified regarding project approach and least cost analysis; John J. Reed, president of Reed Consulting Group, who testified concerning the power purchase agreement between BECo and Edgar Electric Energy Corporation ("EEEC"); Douglas C. Schmidt, project manager for engineering and licensing for Edgar, who testified regarding project design and costs, water supply and alternative sites; and Lillian N. Morgenstern, principal environmental planner at BECo, who testified concerning potential environmental impacts of Edgar and alternative sites.

Weymouth presented the testimony of 13 witnesses: John F. Buckley, water and sewer superintendent for Weymouth, who testified regarding water supply; James J. Pescatore, engineer for Camp, Dresser & McKee, who testified concerning water supply; William C. Woodward, conservation administrator for Weymouth, who presented testimony regarding water quality; Jeffrey R. Coates, inspector of buildings for Weymouth, who presented testimony concerning zoning issues; Robert S. Knorr, deputy director of the Division of Environmental Health Assessment at the Massachusetts Department of Public Health, who testified regarding health-related issues; Jane Gallahue, commissioner of public health in the City of Quincy, who testified concerning health issues; Mary McAdams, chairperson of the Weymouth Board of Health, who testified regarding health issues; Karen M. Durgin, chemicals management and surveillance officer for the Weymouth Board of Health, who testified concerning hazardous conditions at the primary site; Maura Kelly, member of the Weymouth Board of Health, who presented testimony regarding elevated cancer rates in the area around the primary site; Robert Hedlund, State Senator for Weymouth, who testified concerning health problems; Robert A. Cerasoli, State Representative for Weymouth and Quincy, who presented testimony regarding health problems; David Jenkins, a former member of the Weymouth Local Assessment Committee, who testified regarding existing health problems in Weymouth; and Brian J. McDonald, vice chairman of the Weymouth Board of Selectmen, who presented testimony concerning health issues.

The Attorney General presented one witness: Susan Geller, an economist for the Attorney General, who testified regarding the BECo Resource Plan.

CLF presented two witnesses: Paul L. Chernick, president of Resource Insight, Inc., who testified concerning demand-side analysis and the BECo Resource Plan; and Susan E. Coakley, technical coordinator for CLF, who testified regarding demand-side analysis.

Uxbridge presented five witnesses: Russell Cohen, Blackstone River coordinator for the Massachusetts Department of Fisheries, Wildlife and Environmental Law Enforcement, who testified concerning water supply and water quality issues at the alternative site; Noelle F. Lewis, water quality specialist for Save the Bay, Inc., who testified regarding water quality issues at the alternative site; and James Cormier, former chairman of the Growth Study Committee for Uxbridge, who testified concerning land use issues; James Pepper, executive director of the Blackstone River Valley National Heritage Corridor Commission ("Corridor Commission"), and Douglas M. Reynolds, historian for the Corridor Commission, who both testified on issues related to the alternative site in Uxbridge.

The Hearing Officers entered 569 exhibits into the record, primarily consisting of responses to information requests and record requests. The Attorney General entered 161 exhibits into the record. BECo entered 125 exhibits into the record. CLF entered five exhibits into the record. MASSPIRG entered 73 exhibits into the record. NECA entered 40 exhibits into the record. TEC entered one exhibit into the record. Uxbridge entered 101 exhibits into the record. WATER entered 52 exhibits into the record. Weymouth entered 26 exhibits into the record.

The initial briefs of the Attorney General, CLF, MASSPIRG, NECA, Uxbridge, WATER, Weymouth and of the New England Council, the Associated Industries of Massachusetts and the Greater Boston Chamber of Commerce ("Business Associations")[3] were filed on July 26, 1991. BECo's initial brief was filed on August 16, 1991. The reply briefs of the Attorney General, MASSPIRG, NECA and WATER were filed on September 3, 1991. BECo's reply brief was filed on September 13, 1991.

At a procedural conference on October 16, 1991, the Hearing Officers denied two motions by WATER to reopen the record

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3/ On June 17, 1991, the Business Associations filed a motion, subsequently granted, to participate as an interested person for the sole purpose of filing a brief.

and a third such motion, in part, but reminded all parties of their ongoing obligation to update existing exhibits and testimony to ensure that the decision is based upon an accurate record (Procedural Conference, October 16, 1991, Tr. pp. 4-52).[4] The Hearing Officers also granted motions by Boston Edison to include new peak load data in the record and by MASSPIRG to supplement the record with new DRI data on the economy (id., pp. 52-69).

On January 13, 1992, the Siting Council staff issued a Tentative Decision for the first phase of this proceeding ("Phase I").[5] After reviewing the comments from parties on the Tentative Decision, the Siting Council staff presented a memorandum to the Siting Council on January 24, 1992, withdrawing the Tentative Decision for further review and consideration. On January 31, 1992, the Siting Council staff issued its Fifth Set of Information Requests to the Company, including a request for BECo to recalculate its load forecast using updated inputs. The Company prepared this reforecast using August, 1991 DRI data and filed it on February 28, 1992.[6] MASSPIRG and the Attorney

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4/ All three WATER motions were entitled "W.A.T.E.R. Motion to Compel Correction of the Record," filed with the Siting Council on July 25, July 26, and September 26, 1991, respectively. The Hearing Officers, however, considered these motions as motions to reopen the record, because each contained an attachment which WATER asked to be included in the record.

5/ For a discussion of the division of this Decision into Phase I and Phase II, see Section I.C, below.

6/ This reforecast and related information filed on February 28, 1992 have been marked for identification as "Exhibit HO-D-111" and entered into the record. Subsequent references in this Decision to "reforecast" shall mean this February, 1992 forecast.

General submitted comments on the reforecast on March 12 and March 13, 1992, respectively.[7]

By letters dated January 31 and February 14, 1992, Boston Edison also notified the Siting Council that it was revising its projected in-service date for Edgar from January 1, 1994 to January 1, 1996. At a procedural conference on March 2, 1992, the Siting Council directed the Company to update the record on four Phase I issues after consultation with the other parties (March 2, 1992 Procedural Conference, Tr. pp. 56, 77, 79-80).[8] On March 12, 1992, the Company filed an update to the record on those four Phase I issues plus additional information, including a new plan to reduce its load management programs ("March 1992 Record Update").[9] The March 1992 Record Update included a two-page cover letter with comments on the update. On March 16, 1992, the Attorney General and MASSPIRG filed comments on the March 1992 Record Update.

7/ Although the Company did not submit comments on the reforecast, we assume, where appropriate, that the Company's comments on the first reforecast filed in February, 1991 also apply to the reforecast, because both reforecasts used the same methodology (see Section II.B.2, below).

8/ The Company was directed to update the record on four specific issues: (1) the status of the Massachusetts Yankee nuclear power plant in Rowe, Massachusetts ("Yankee Rowe"), (2) the status and projected attrition rates for planned capacity additions from BECo's second request for proposals ("RFP") for capacity additions from non-Company sources (RFP #2), (3) the status and projected attrition rates for planned capacity additions from BECo's RFP #3, and (4) the projection of savings from BECo's conservation and load management ("C&LM") programs, specifically from BECo's commercial and industrial ("C&I") conservation programs (March 2, 1992 Procedural Conference, Tr. pp. 26-30, 56-57, 67-74, 77, 79-80). The parties were expressly asked whether any other issues needed updating in order to determine BECo's resource need for 1996 and 1997, and none were specified by any parties (March 2, 1992 Procedural Conference, Tr. pp. 77-79).

9/ On March 9 and March 13, 1992, the Attorney General issued information requests to the Company. On March 18 and March 19, 1992, the Company filed its response to each of these information requests.

C. Outstanding Motions Relating to Phase I

In its comments submitted on March 12, 1992, MASSPIRG included a Motion to Compel, requesting that the Company recalculate its residential load forecast using an updated projection or the actual figures, if currently available, for the number of BECo residential customers.

In its comments submitted on March 16, 1992, MASSPIRG included a motion to defer consideration of "Edgar cost-effectiveness and other supply options such as the Company's load management curtailment proposal," to the upcoming BECo Integrated Resource Management ("IRM") review[10] or to Phase II, or, in the alternative, to allow discovery, additional hearings and cross-examination on the updated information in Phase I. MASSPIRG argued, inter alia, that the proposed new plan to reduce load management programs was not a status update but a new proposal which required a cost-benefit analysis in the context of the Phase II evaluation to determine the least-cost resources available to the Company to meet its future resource needs.

In his comments filed on March 16, 1992, the Attorney General also moved that the Siting Council defer consideration of the Company's March 1992 Record Update to the IRM proceeding, or, in the alternative, allow discovery, cross-examination of Company witnesses and additional briefing in Phase I. In his motion, the Attorney General asserted that the Company's conservation projections were substantially understated, the new load management cuts were unsubstantiated, the residential demand was probably overstated, the Company's reserve requirement was

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10/ The IRM process was developed jointly by the Siting Council and the Department to review the demand forecasts and supply plans of investor-owned utilities within the Commonwealth, except for the Nantucket Electric Company. Final Order of the Siting Council on IRM Rulemaking, 21 DOMSC 91 (1990) ("1990 Final IRM Order"); 980 C.M.R. 12.00 et seq.; Final Order of the Department on IRM Rulemaking, D.P.U. 89-239 (1990); 220 C.M.R. 10.00 et seq.

overstated, and the availability of BECo's own resources was understated.[11]

At a procedural conference on March 19, 1992, MASSPIRG and the Attorney General reiterated their positions contained in their comments.[12] BECo asserted that it had updated the record as requested and provided sufficient supporting documentation, but also acknowledged that the determination of which resource options are optimal for the Company is a Phase II issue[13] (March 19, 1992 Procedural Conference, Tr. pp. 18-43).

The Siting Council hereby grants MASSPIRG's March 16 motion pertaining to deferral of the consideration of BECo's new load management plans to Phase II of this proceeding. In its filing, BECo presented projections for its conservation and load management programs, existing facilities and planned capacity additions as required by the General Laws, Chapter 164, Section 69I. The replacement of any existing or planned supply resources, such as BECo's RFP #2 resources, must be justified based on a comprehensive least-cost, comparative analysis with other resource options. Similarly, the replacement of existing or planned conservation or load management programs must be supported with the same justification. That analysis has not been presented by the Company as yet, and is appropriately within

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11/ We hereby take administrative notice of the fact that the owners of Yankee Rowe have announced its retirement, and further note that no parties have contested the corresponding adjustment proposed by the Company in the March 1992 Record Update. Therefore, the Siting Council relies upon the updated information on Yankee Rowe in its determination of resource need (see Section III.D, below).

12/ The Attorney General noted that the Company had not consulted with him prior to submission of its updates as requested by the Siting Council on March 2, 1992 and as the Company had agreed (March 19, 1992 Procedural Conference, Tr. pp. 4-18, 32-43, 74, 84).

13/ The Company also noted that "(m)any of the concerns that the Attorney General and MASSPIRG are raising are indeed Phase II concerns and should be addressed there and not attempted to be resolved in this need portion in the next few weeks" (March 19, 1992 Procedural Conference, Tr. p. 32).

the scope of Phase II of this proceeding. Therefore, we do not consider the new load management data further in Phase I, but instead consider it in Phase II.[14]

For reasons set forth in Sections III.D.3 and III.D.4, below, the Siting Council denies all other portions of MASSPIRG's March 16 motions and all other motions discussed above.[15]

D. Scope of Review

This is the first case in which the Siting Council has reviewed a utility's demand forecast and supply plan together with a proposal by that utility to construct a generating facility. Due to the unique nature of this combined docket as well as the extensive record compiled in this docket, the Siting Council determined that the decision should be separated into two phases.[16]

This decision, Phase I, will address issues associated with the Company's demand forecast and resource need. More specifically, the Phase I decision will include: (1) an analysis of the Company's demand forecast, an examination of its projections of existing and planned resources, and the

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14/ Full opportunity for discovery and comment on the new load management proposal, including more than 200 pages of supporting documentation (but not including a cost-benefit analysis), will be afforded in Phase II (Exhs. BE-121, AG-91, AG-92, AG-98 to AG-102). We further note that this additional information included key documents dated as early as June 1990 and November 1991, which had not been filed with the Siting Council previously (Exh. AG-98, AG-100).

15/ The information submitted in the March 1992 Record Update, except for the two-page cover letter with comments on the update, is marked for identification as "Exhibit BE-121" and entered into the record. The Company responses to the information requests submitted by the Attorney General on March 9 and March 13, 1992, and filed by the Company on March 18 and March 19, 1992, are marked for identification as "Exhibit AG-87" to "Exhibit AG-103" in numerical order and entered into the record.

16/ The two phases of this decision generally correspond to the phases of the IRM process.

integration of those factors to achieve various levels of system reliability; (2) a determination of the level of resource need; and (3) a determination of the adequacy of the Company's supply plan in the short run.

The Phase II decision will address (1) the adequacy of the Company's supply plan in the long run, (2) the least-cost nature of the Company's supply plan, including consideration of the Edgar project and other resource options available to serve the resource need identified in Phase I, (3) the Company's site selection process, and (4) the Edgar project, including the cost, environmental and reliability impacts of the proposed facility at both the primary and alternative sites.

II. ANALYSIS OF THE DEMAND FORECAST

A. Standard of Review

As part of its statutory mandate "to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost" (G.L. c. 164, sec. 69H), the Siting Council determines whether "projections of the demand for electric power...are based on substantially accurate historical information and reasonable statistical projection methods." G.L. c. 164, sec. 69J. To ensure that the foregoing standard is met, the Siting Council applies three criteria to demand forecasts: reviewability, appropriateness, and reliability.

A demand forecast is reviewable if it contains enough information to allow a full understanding of the forecasting methodology. A forecast is appropriate if the methodology used to produce that forecast is technically suitable to the size and nature of the utility that produced it. A forecast is reliable if the methodology provides a measure of confidence that its data, assumptions, and judgments produce a forecast of what is most likely to occur. Commonwealth Electric Company and Cambridge Electric Light Company, EFSC 90-4, pp. 4-5, (1991) ("1991 CECo/CELCo Decision"); Nantucket Electric Company, 21 DOMSC 208, 214 (1991) ("1991 Nantucket Decision"); Massachusetts Municipal Wholesale Electric Company, 20 DOMSC 1, 14 (1990) ("1990 MMWEC Decision"); Massachusetts Electric Company/New England Power Company, 18 DOMSC 295, 302 (1989) ("1989 MECo/NEPCo Decision"); 1989 BECo Decision, 18 DOMSC at 208; Eastern Edison Company/Montaup Electric Company, 18 DOMSC 73, 79 (1988) ("1988 EECo/Montaup Decision"); Northeast Utilities, 17 DOMSC 1, 6 (1988) ("1988 NU Decision"); Boston Edison Company, 15 DOMSC 287, 294 (1987).

B. Overview of Demand Forecast Process

BECo stated that its forecast filing covered a 25 year time period, from 1990 to 2014 (Exh. BE-2, p. 2). In its forecast of energy requirements, BECo indicated that the forecast period was divided into short-run and long-run segments, with each segment utilizing a different forecasting methodology (id., p. 2). BECo indicated that its short-run forecast methodology generally covered three years, from 1990 to 1992, while its long-run forecast covered the remaining years of the forecast period (id., pp. 1-3, 128). BECo stated that its short-run forecast was designed to measure the month-to-month response of energy sales to changing conditions (id., p. 128). The Company noted that its overall energy requirements were based on a blending of its short-run and long-run forecast results (id., p. 2).[17] The Company stated that forecasts of electricity price, demographics, and employment were prepared for use as primary inputs to both its short-run and long-run forecast methodologies (id., pp. 2-7, 128). The Company also stated that customer usage characteristics and energy forecast results were included in its peak load forecast (id., p. 7).

In addition to its initial forecast filing of energy and peak load requirements, the Company prepared a reforecast of energy and peak load requirements during the course of the proceeding (Exhs. BE-9, HO-D-111).

The following sections contain a brief description of BECo's initial forecast and its reforecast. Table 1, below, contains the base case initial forecast of annual sales and peak load. Table 2, below, contains the base case reforecast of annual sales and peak load as presented in the Company's reforecast.

17/ BECo's forecast of energy requirements was divided by customer class as follows: residential, commercial, industrial, streetlighting, MBTA, MWRA, municipal sales, and losses and company use (Exh. BE-2, p. 1).

1. BECo's Initial Forecast

a. BECo's Short-Run Methodology

BECo stated that it developed econometric equations for use in forecasting the short-run energy requirements of the residential, commercial, and industrial classes (Exh. BE-2, p. 128). In each instance, the Company stated that its equations were predicated on selected economic and weather variables (id., pp. 128-138). The Company stated that its econometric equations were used to project sales for the foregoing customer classes on a monthly basis (id., p. 128).[18] In addition, the Company stated that it forecasted short-run energy requirements for the streetlighting class by utilizing adjusted historical data; for municipal sales by utilizing regression equations; for the MBTA by utilizing assumed growth rates; and for the MWRA by utilizing rainfall variables (id., pp. 140-143).[19] The Company did not indicate whether losses and company use were included in its forecasts of short-run energy requirements. For a discussion of the Company's short-run forecasts of energy sales, see Sections II.C.4.a.i, II.C.5.a.i, and II.C.6.a.i, below.

b. BECo's Long-Run Methodology

BECo stated that end-use models were used to project long-run energy requirements for its residential, commercial, and industrial classes (id., pp. 48-57, 69-88, 103-110). BECo stated that residential energy requirements were driven primarily by changes in personal income, while commercial and industrial

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18/ The Company stated that its short-run forecast is also used for capacity planning, demand-side management planning, revenue projections, budgeting, reliability studies, and fuel procurement (Exh. BE-2, p. 128).

19/ BECo indicated that the short-run and long-run forecast methodologies for streetlighting, municipal sales, MBTA, and MWRA classes were essentially identical (Exh. BE-2, pp. 121-123, 140-143). However, for its 1990-1992 short-run period, the Company disaggregated forecasted energy requirements for the foregoing classes into monthly quantities (id., pp. 140-143).

requirements were driven primarily by changes in employment (id., pp. 48, 70, 104; Exh. MP-1, pp. 2-3). In addition, BECo indicated that its forecast for losses and company use was based on a loss factor calculated by its load research department (Exh. BE-2, pp. 122-123). For a discussion of the Company's long-run forecasts of energy sales, see Sections II.C.4.a.ii, II.C.5.a.ii, and II.C.6.a.ii, below.

c. BECo's Peak Load Forecast Methodology

BECo stated that it developed its peak load forecast based on end-use and load shape characteristics associated with each of its major customer classes (id., pp. 145-146). In addition, BECo claimed that its peak load forecast accounted for varying consumption patterns reflective of hours of the day, days of the week, and seasons of the year (id.). For a discussion of the Company's peak load forecast, see Section II.D, below.

2. BECo's Reforecast Methodology

BECo stated that its reforecast utilized August, 1991 DRI economic data while January, 1989 DRI data was used in the Company's initial forecast filing (id.; Exh. BE-9).[20] BECo also stated that the basic load forecasting methodology used in its reforecast remained the same as that used in its initial forecast filing (id.).

To allow for a comprehensive evaluation of BECo's energy and peak load forecast, the Siting Council reviews both the Company's initial forecast and its reforecast.

20/ BECo indicated that at the time its most recent reforecast was prepared and filed -- February, 1992 -- actual sales data was available for 1991 (Exh. HO-D-111).

C. Energy Forecast

1. Employment Forecast

a. Description

i. Initial Forecast

Boston Edison indicated that it developed its forecast of employment with an econometric model based on territory-specific employment data from the years 1967 through 1987 (Exh. BE-2, p. 36), and on statewide employment projections supplied by DRI (id.). The Company stated that it first disaggregated total employment into the commercial and industrial sectors (id.). BECo stated that it next separated commercial sector employment into 12 building types, and industrial sector employment into 19 two-digit Standard Industrial Classification ("SIC") categories (id.). The Company stated that its initial employment forecast was based on data inputs from DRI's January, 1989 base case forecast of Massachusetts employment (Tr. 4, p. 138).

The Company stated that its econometric equations were subjected to statistical tests[21] and were backcast[22] against the performance of previous forecasts (id., pp. 71-72). The Company noted that it used the results of its employment forecast as inputs to both its commercial and industrial energy sales forecasts (Exh. BE-2, p. 36).

21/ Boston Edison stated that it applies R-squared, T-statistic, and Durbin-Watson tests to the equations of its employment forecast model to gauge statistical significance (Tr. 4, pp. 71-72).

22/ Backcasting is the practice of testing the accuracy of a model by comparing the results of the model with actual historical data.

BECo stated that, to forecast employment in the commercial sector, the Company used DRI data[23] as inputs to econometric equations designed to project employment in 12 building types[24] (Exh. BE-2, pp. 36-37, 44-45; Tr. 3, pp. 95-99). The Company stated that it then tested each of the equations used to derive the commercial sector employment forecast for statistical significance (Exh. BE-2, pp. 43-45).[25]

23/ Major data inputs to the commercial sector employment equations include: Massachusetts employment growth in respective employment categories; U.S. employment in the services, transportation, communication and utilities sectors; federal grants to state and local governments; population in Massachusetts; population in the U.S.; personal income in Massachusetts; and per capita income in Boston and New England (Exh. BE-2, pp. 43-45).

24/ The 12 building types are: (1) offices, (2) restaurants, (3) grocery stores, (4) other retail trade, (5) warehouses, (6) colleges, (7) primary and secondary schools, (8) hospitals, (9) other health services, (10) non-office government, (11) hotels, and (12) miscellaneous (Exh BE-2, pp. 43-45). In the cases of offices, warehouses, colleges, schools, hospitals, other health services and miscellaneous, the Company broke down the broad building type categories into sub-categories (id.). The Company used separate econometric equations to calculate employment within the sub-categories (id.).

25/ R-squared is a measure of the amount of variation in the dependent variable which is explained by the variation in the independent variables. R-squared values range between 0.00 and 1.00, where 0.00 indicates no variation explained by the independent variables and where 1.00 indicates complete explanation by the independent variables. The equation used to project employment in the sub-category of private schools produced an R-squared of 0.39 (Exh. BE-2, p. 44). The equation used to project employment in the grocery stores category produced an R-squared of 0.56 (id., p. 43). The equation used for the sub-category of transportation, communication and utility warehouses produced an R-squared of 0.62 (id.). All other building types produced an R-squared of 0.75 or higher (id., pp. 43-45).

To forecast employment in the industrial sector, Boston Edison stated that it used DRI data[26] as inputs to econometric equations designed to project employment in each of 19 two-digit SIC categories[27] (id., pp. 36-37, 46-47; Tr. 3, pp. 95-99). Boston Edison then applied tests of statistical significance to determine the strength of each industrial sector employment equation (Exh. BE-2, pp. 46-47).[28]

BECo noted that non-manufacturing employment was one of the "key drivers of commercial energy sales and total energy sales in general in the Boston Edison service territory..." (Exh. MP-1, p. 3). The Company also acknowledged that it was aware at the time it filed its initial forecast that "(t)he Massachusetts economy continued to deteriorate rapidly during the first quarter of 1990..." (id., p. 2). The Company indicated that the January, 1989 DRI Massachusetts employment forecast projects employment levels to range between 3.2 million jobs and 3.5 million jobs for the years of 1990 through 2000 (Exh. MP-11, p. 3). The Company also acknowledged that more recent DRI employment data "differ(ed) significantly" from the January, 1989 DRI data, and that "(t)his difference will impact the BECo energy forecast" (id., p. 3).

26/ Major data inputs to the industrial sector employment equations include: Massachusetts employment growth in respective SIC categories, and U.S. industrial production index in respective SIC categories (Exh. BE-2, pp. 36-37, 46-47; Tr. 3, pp. 95-99).

27/ The SIC categories are: (1) food and kindred, (2) textile mills, (3) apparel products, (4) lumber and wood, (5) furniture and fixtures, (6) pulp and paper, (7) printing and publishing, (8) chemicals, (9) petroleum products, (10) rubber and plastics, (11) leather products, (12) stone, clay and glass, (13) primary metals, (14) fabricated metals, (15) machinery, except electrical, (16) electrical and electronic machinery, (17) transportation equipment, (18) instruments, and (19) miscellaneous (Exh. BE-2, pp. 36-37, 46-47; Tr. 3, pp. 95-99).

28/ The equation for stone, clay and glass produced an R-squared of 0.60; the lumber and wood equation produced an R-squared of 0.62 (Exh. BE-2, pp. 46-47). All other equations produced an R-squared of 0.73 or above (id.).

ii. Reforecast

As part of its reforecast, the Company filed a reforecast of employment (Exh. HO-D-111, Base Case Attachment, p. 12). The Company stated that, although new values for employment, income, population, industrial production and government grants were used in the employment reforecast, the methodology used in the employment reforecast was the same methodology used in the initial employment forecast (id.). The Company stated that its employment reforecast was based on data from DRI's August, 1991 forecast (id.).[29] The Company indicated that the August, 1991 DRI Massachusetts employment forecast projects employment levels to range between 2.8 million jobs and 3.1 million jobs for the years of 1990 through 2000 (Exh. BE-119, p. 2).

b. Positions of Parties

i. MASSPIRG

MASSPIRG argued that Boston Edison's initial employment forecast was developed using obsolete economic inputs from DRI, resulting in (1) an overestimation of employment, and (2) ultimately, an unrealistically high long-run load forecast (MASSPIRG Initial Brief, p. 2). MASSPIRG contended that since DRI issued its January, 1989 base case forecast of Massachusetts employment, the state of the Massachusetts economy had deteriorated considerably (id., pp. 7-8). MASSPIRG asserted that subsequent DRI forecasts from 1990 and 1991 project five-year to eight-year lags in reaching the employment levels predicted in DRI's January, 1989 forecast (id.).

ii. Company

The Company argued that its current employment forecasting methodology was basically the same as the methodology approved by

29/ During the course of this proceeding, the Company also provided DRI employment data from February, 1991 (Exh. MP-RR-10).

the Siting Council in its previous filing and that therefore, the initial forecast should be approved (BECo Brief, pp. 41-42). Boston Edison also contended that the January, 1989 DRI employment projections used in its initial forecast were the most current available at the time its resource plan was being developed (BECo Brief, p. 44).

With respect to DRI's August, 1991 forecast, Boston Edison contended that the new data "should not significantly affect the Siting Council's review of (its) long-range forecast..." (Exh. BE-119, p. 1). To support this position, the Company argued: (1) that the initial forecast was designed to address uncertainty in forecast variables; and (2) that there needs to be some closure to consideration of new information in a forecast review (Exh. BE-119, pp. 1-2).

c. Analysis and Findings

i. Initial Forecast

In the 1989 BECo Decision, the Siting Council approved the Company's employment forecasting methodology. 1989 BECo Decision, 18 DOMSC at 216. In that decision, the Siting Council approved the Company's use of a widely accepted forecasting firm to supply inputs to its employment forecast. Id. at 215. The Siting Council also approved the Company's use of econometric techniques to obtain projections of territory-specific employment levels. Id. at 216. Here, the Siting Council finds the initial employment forecast to be reviewable and appropriate.

With respect to reliability, the record indicates that Boston Edison's initial employment forecast is based on January, 1989 DRI data. Those data indicate that Massachusetts employment will range between 3.2 million jobs and 3.5 million jobs during the period of 1990 and 2000. These data were 16 months old at the time the Company filed its initial forecast in May, 1990. In addition, the Company was aware at the time of this filing that (1) the Massachusetts economy was deteriorating rapidly, (2) more current DRI employment data which reflected the economic decline were available, (3) the more recent data differed significantly from the January, 1989 data, and (4) the difference in the new data would affect the Company's energy forecasts. In fact, the August, 1990 DRI forecast projects an average of nearly 202,000 fewer jobs statewide each year between 1991 and 2000 than the number of jobs projected in the January, 1989 DRI forecast. Even when a forecast methodology is sound, a forecast cannot be reliable if the data inputs used to develop the forecast are obsolete. In the past, the Siting Council has rejected a Company's forecast that used outdated inputs. 1991 CECo/CELCo Decision, EFSC 90-4 at 44-45.

Accordingly, the Siting Council finds that Boston Edison has failed to establish that its initial employment forecast is reliable.

ii. Reforecast

The Siting Council notes that the methodology used by the Company to prepare its reforecast of employment is basically the same as the methodology used to prepare its initial employment forecast. Consistent with the finding regarding the methodology used by the Company to prepare its initial employment forecast, the Siting Council finds that Boston Edison has established that its reforecast of employment is reviewable and appropriate.

With respect to the reliability of the reforecast, the Siting Council first rejects the Company's argument that the initial forecast was designed to address uncertainty in forecast variables. The Siting Council notes that employment levels predicted in the 1991 DRI employment forecasts differ significantly from the levels predicted in the January, 1989 DRI forecast.[30] Table 3, below, sets out the various employment levels predicted by four DRI forecasts: January, 1989; August, 1990; February, 1991; and August, 1991. In this proceeding, the Company has not established that its initial forecast is designed to address changes in employment variables of the magnitude indicated by the DRI data. The record clearly illustrates a continuous and marked downward trend in the levels of employment predicted in each DRI forecast issued subsequent to the January, 1989 forecast.

The Siting Council acknowledges, however, the need to reach closure on the consideration of new information in a forecast review. We recognize that some measure of closure must be accorded to a company presenting a demand forecast methodology which is dynamic and flexible. Without such closure, companies could be subjected to endless requests to prepare new forecasts; requests that could have reliability implications when additional resources, in fact, are needed.

Nevertheless, the Siting Council would be remiss in its statutory obligation under G.L. c. 164, sec. 69H "to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost" if it were to simply ignore significant changes such as substantial variations in economic conditions.

Here, the August, 1991 DRI data shows a decline of 10 percent to 14 percent in projected non-agricultural employment in the state over the forecast period. For the years 1991 through 2000, the projected average employment level is nearly 193,000

30/ The difference in employment levels predicted in the two reports peaks at nearly 458,000 jobs in 1992, with employment levels over the range of the forecast years averaging between 10 percent and 14 percent lower in the August, 1991 report relative to the January, 1989 report (Exhs. MP-RR-11, MP-RR-10). Employment levels in the August, 1991 DRI forecast lag 11 to 17 years behind the levels predicted in the January, 1989 DRI forecast (id.). For example, the Massachusetts employment level predicted for 1994 (about 3.3 million jobs) in the January, 1989 DRI forecast is not reached until the year 2006 in the August, 1991 DRI forecast (id.).

jobs lower in the August, 1991 DRI forecast relative to the August, 1990 DRI forecast. See Table 3. Over the same time period, the projected average employment level is about 394,000 jobs lower in the August, 1991 DRI forecast relative to the January, 1989 DRI forecast. See Table 3. Such declines must be considered significant changes in economic conditions. The substantial and continuous declines in economic conditions identified early in this proceeding necessitated the reforecast in order to determine with sufficient accuracy the Company's resource need.

The Siting Council notes that the August, 1991 DRI data used by the Company in the reforecast was only about six months old at the time of the filing of the employment reforecast. Accordingly, the Siting Council finds BECo's reforecast of employment to be reliable.

d. Conclusions on the Employment Forecast

The Siting Council has found that the Company's initial employment forecast and reforecast of employment are reviewable and appropriate. The Siting Council also has found that the Company failed to establish that its initial employment forecast is reliable. In addition, the Siting Council has found the Company's reforecast of employment to be reliable. Therefore, the Siting Council finds BECo's reforecast of employment to be reviewable, appropriate and reliable.

2. Demographic Forecast

a. Initial Forecast

Boston Edison stated that it generated a forecast of population and households to predict the number of residential customers it will serve each year throughout the forecast period (Exh. BE-2, p. 19). BECo indicated that its demographic forecasting methodology remained essentially the same as that used in its previous filing before the Siting Council (id.). The Company stated that it utilized a forecast model which took population at the beginning of a given year, added births and net migration, and then subtracted deaths that were projected to occur during that year (id.).

BECo stated that it forecasted births and deaths by applying U.S. Census Bureau fertility and survival rate data to appropriate sex and age populations within its service territory (id., pp. 19-21).

The Company stated that its forecast of net migration[31] was based on an econometric equation which used economic inputs supplied by DRI (id., p. 22). BECo stated that the economic indicators used in the net migration equation were annual changes in U.S. wage and salary disbursements, Massachusetts employment, and the U.S. civilian labor force (id.).[32] BECo stated that the theoretical basis for the equation was the assumption that if the Massachusetts job market, the U.S. labor force, and U.S. wage and salary disbursements remain constant, a net in-migration to the Boston Edison service territory will result (id.).

The Company indicated that it conducted statistical analysis of its migration model to test the model's reliability and predictive capabilities (id.).[33]

b. Demographic Reforecast

Boston Edison stated that, in the computation of its reforecast, new values for U.S. wage and salary disbursements, Massachusetts employment, and U.S. labor force were used in the migration equation (Exh. HO-D-111, Base Case Attachment, p. 11). The Company indicated that the new inputs were taken from DRI's

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31/ Net migration is equal to the difference between the number of persons moving into a territory and the number of persons moving out of a territory.

32/ The Company indicated that for the years between 1990 and 2000, January, 1989 DRI projections for U.S. wage and salary disbursements ranged between $2.8 trillion and $5.8 trillion (Exh. MP-11, p. 3), Massachusetts employment ranged between 3.2 million and 3.5 million (id.), and the U.S. labor force ranged between 125 million and 139 million (id.).

33/ Boston Edison stated that its migration equation produced an R-squared value of .80 (Exh. BE-2, p. 22).

macroeconomic and regional forecasts from August, 1991 (id.).[34] Other than the use of new DRI data inputs, Boston Edison reported no methodological modifications to its reforecast of demographic change (id.).

c. Positions of Parties

MASSPIRG argued that the Company's migration equation failed to account for the effects of the current economic recession, and that, therefore, use of this equation is likely to result in an overestimate of population (MASSPIRG Initial Brief, p. 10). MASSPIRG further contended that, in BECo's demographic forecast, out-migration decreased and overall population increased, while DRI's forecasts predicted statewide population losses during the same time frame (id.). Thus, MASSPIRG argued, the Company's population forecast is at odds with the population forecast prepared by its own consultant (id.). MASSPIRG reiterated its concerns regarding the Company's migration equation in its March 12, 1992 comments on the Company's reforecast (HO-D-121, p. 1). In those comments, MASSPIRG also stated that the Company failed to distinguish between actual and projected population figures in its demographic reforecast (id.).

Boston Edison contended that its demographic forecast is sound, and that its forecast methodology is virtually the same methodology that was approved in the 1989 BECo Decision (BECo Initial Brief, p. 25). The Company stated that its migration equation is statistically significant and that the reforecast's projection of a slight in-migration over the long-term is the result of a relatively more pessimistic national economic outlook (id., p. 45). In addition, the Company has indicated that since its previous filing, it has repeatedly tested its migration

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34/ The Company indicated that for the years between 1990 and 2000, August, 1991 DRI projections for U.S. wage and salary disbursements ranged between $2.7 trillion and $4.8 trillion (Exh. HO-D-111, p. 31), Massachusetts employment ranged between 3.0 million and 3.1 million (Exh. BE-119), and the U.S. labor force ranged between 125 million and 141 million (Exh. HO-D-111, p. 31).

equation to confirm its continued statistical strength (Exh. BE-2, p. 19).

d. Analysis and Findings

The Siting Council notes that the Company's demographic forecasting methodology remains essentially the same as that used in its previous filing before the Siting Council. In the 1989 BECo Decision, the Siting Council found that Boston Edison's approach to forecasting demographic change within its service territory was basically sound (18 DOMSC at 213). In addition, the Company's use of data inputs supplied by DRI is consistent with input data approved in a number of other cases. See 1991 CECo/CELCo Decision, EFSC 90-4, p. 6; 1990 MMWEC Decision, 20 DOMSC at 14; 1988 EUA Decision, 18 DOMSC at 82; 1988 NU Decision, 17 DOMSC at 5. Further, the statistical strength of BECo's migration equation instills a high level of confidence in the reliability of the equation.

The Siting Council agrees with MASSPIRG that the Company's population projections run counter to the population projections of DRI. However, the differences between the DRI data and Boston Edison's projections are minimal, and therefore do not warrant rejection of the Company's migration equation or demographic forecast. Finally, the Siting Council notes that, although the January, 1989 data inputs to the Company's net migration equation for the initial demographic forecast were 16 months old at the time of filing, the updated August, 1991 data inputs did not substantially alter the results of the Company's demographic reforecast compared to the initial forecast.

Based on the foregoing, the Siting Council finds that, for the purposes of this review, both the Company's initial demographic forecast and demographic reforecast are reviewable, appropriate and reliable.

3. Electricity Price Forecast

a. Initial Forecast

BECo stated that, to project electricity price growth rates for its service territory, it developed independent forecasts for a base price component and a fuel price component (Exh. BE-2, p. 13). The Company stated that annual growth rates then were applied to electricity prices in each customer class (Exh. HO-D-89). The Company indicated that its electricity price forecast is an important input into its residential, commercial and industrial energy forecasts (id.).

To forecast the base price component, the Company stated that it used a simplified cost-of-service model (Exh. BE-2, p. 14). BECo stated that through the model, it estimated the value of net plant, which included existing plant, plant additions[35] and accumulated depreciation.[36] The Company stated that the net plant estimate was used to calculate a return on debt and equity (id.). BECo stated that projected operation and maintenance ("O&M") expenses[37] and taxes were then added to the estimated return on debt and equity[38] (id.).

Boston Edison stated that it used information supplied by DRI to arrive at projected O&M expenses and projected capital costs (id.). The Company further stated that depreciation rates

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35/ To estimate the value of plant additions, the Company stated that it assumed that the annual capital cost escalation rate will be 6.5 percent (Exh. BE-2, p. 14). BECo stated that capital cost escalation rates are based on forecasts that the Company received from DRI (id.).

36/ The Company indicated that it assumed annual depreciation rates to be: 3.90 percent for nuclear generating facilities; 3.87 percent for fossil fuel generating facilities; 2.94 percent for transmission and distribution facilities; and 4.72 percent for other plant (Exh. BE-2, p. 14).

37/ The Company stated that annual O&M cost escalation is assumed to be 5.8 percent (Exh. BE-2, p. 14).

38/ BECo stated that the MDPU allowed Boston Edison a 13.75 percent rate of return on equity (Exh. BE-2, p. 14). The Company projected that it would pay 11.0 percent on debt (id.).

and rate of return assumptions were derived from a recent Company filing before the MDPU in D.P.U. 89-100 (Exh. HO-D-86).

Finally, Boston Edison stated that it used DRI fuel forecast data as the basis for its fuel component forecast (id.). The Company indicated that oil and nuclear fuel prices were included in this projection (Exh. BE-2, pp. 16-17).

b. Electricity Price Reforecast

Boston Edison stated that, in the computation of its reforecast, the methodology and data inputs for the price forecast were exactly the same as those used to compute its initial forecasts (Exh. HO-D-111, Base Case Attachment, p. 10).

c. Analysis and Findings

The Company's electricity price forecasting methodology has remained basically unchanged since its previous filing. In the 1989 BECo Decision, the Siting Council approved BECO's electricity price forecast (18 DOMSC at 210). BECo's forecast of electricity price is generally sound. The strengths of this forecast include: (1) the breakdown of the total electricity price into base and fuel components, and (2) the application of projected price growth rates to each of the individual customer classes. Further, the Siting Council notes that although the data used to prepare the Company's initial electricity price forecast were 16 months old at the time of filing, more recent data are not likely to be substantially different.[39]

The Siting Council finds that, for the purposes of this review, both Boston Edison's initial electricity price forecast and reforecast of electricity price are reviewable, appropriate and reliable.

39/ The Siting Council notes that none of the intervenors opposed the Company's electricity price forecast.

4. Residential Energy Forecast

BECo stated that its residential sector energy demand was 3,382 gigawatthours ("GWH") in 1991, or approximately 26 percent of its overall energy sales in that year (Exh. HO-D-111). In its initial forecast, BECo's unadjusted residential energy demand was projected to increase from 3,523 GWH in 1991 to 4,124 GWH in 2000, a compound annual growth rate of 1.76 percent (Exh. BE-2, p. 68).[40] See Table 4, below. In its reforecast, BECo's unadjusted residential energy demand was projected to increase from 3,382 GWH in 1991 to 4,217 GWH in the year 2000, a compound annual growth rate of 2.48 percent (Exh. HO-D-111). See Table 5, below. As described in Sections II.B.1.a and II.B.1.b, above, the Company's ten-year residential forecast is derived from a combination of its short-run residential forecast and its long-run residential forecast. Each of these is described below.

a. Initial Forecast

i. Short-Run Forecast

(A) Description

BECo stated that it forecast residential energy sales in the short run using an econometric model (Exh. BE-2, p. 128). BECo stated that its short-run model is similar to the short-run model used in its previous forecast reviewed by the Siting Council (id., p. 129). However, BECo noted three modifications to its current short-run model: (1) its current model uses DRI economic projections, while its previous model used Wharton Economic Forecasting Associates projections; (2) its current model's database has been supplemented with 1988 and 1989 actual data; and (3) its current model was used to project energy sales

40/ The projections for energy demand in its initial forecast do not reflect savings resulting from Company-sponsored conservation and load management ("C&LM") programs (Exh. BE-2, p. 68). If these savings are included, residential energy demand is forecasted to increase from 3,482 GWH in 1991 to 4,059 GWH in 2000, a compound annual growth rate of 1.72 percent (id.).

for the initial four years of the forecast period as compared to the initial two years in its previous forecast filing (id.).

BECo stated that its residential short-run model was used to predict residential energy sales on a monthly basis for the 1990-1993 time period (id.; Tr. 3, p. 74). BECo stated that it assumed that residential energy sales in the short run would be driven largely by economic, weather, and customer behavior factors (Exh. BE-2, p. 129). BECo noted that it used seven variables to reflect the effects of economic, weather, and customer behavior factors: (1) disposable income, (2) temperature humidity index, (3) calendar use days, (4) heating degree days, (5) number of residential customer bills, (6) lighting hours, and (7) electricity price (id., pp. 131; Exh. HO-D-104).[41] BECo stated that disposable income data were obtained from DRI, but data for the remaining variables were obtained from Company sources (Exh. BE-2, pp. 128-130; Exh. HO-D-104). BECo asserted that its short-run residential model was theoretically sound and statistically valid (Exh. BE-2, p. 131).[42]

The Company's witness, Dr. Cuomo, stated that in the Company's initial forecast filing, short-run models generally were used for the 1990-1992 time period (Tr. 3, pp. 73-74).

41/ BECo stated that its "temperature humidity index" variable was designed to reflect the effect of summer weather on short-run energy sales (Exh. BE-2, p. 132). BECo stated that its "temperature humidity index" was estimated based on cooling degree day and cooling dewpoint data (id., p. 131). BECo stated that "calendar use days" are the actual number of calendar billing days during a month as established by the Company's meter reading schedule (id., pp. 128, 132, 138). BECo further stated that energy sales increase as a function of the number of billing days in a month (id.). Finally, BECo stated that "residential customer bills" reflected the number of bills sent out in any given month (id., p. 132).

42/ BECo stated that its seven variables were statistically significant to a confidence level of 96 percent or higher, and that its residential short-run equation produced an R-squared statistic of 0.95 (Exh. BE-2, pp. 130-131). For a discussion of R-squared statistical tests, see Footnote 25, above.

However, Dr. Cuomo noted that in the case of the residential sector that time period was extended to include 1993 (id.). Dr.Cuomo stated that use of its long-run model for 1993 would have resulted in a "very, very high" growth rate for the interface between the short-run forecast in 1993 and the long-run forecast in 1994 (id., p. 74). Dr. Cuomo stated that use of an additional year of short-run forecasting gave "relatively reasonable results" (id.).

(B) Analysis and Findings

In previous decisions, the Siting Council has accepted econometric equations for forecasting purposes. 1991 CECo/CELCo Decision, EFSC 90-4 at 29-30; 1990 MMWEC Decision, 20 DOMSC at 29-32. Here, the Siting Council notes (1) the Company has supported its residential short-run forecast model with demonstrations of statistical strength based on standard statistical tests, and (2) the Company continues to add to its informational database. The Siting Council also notes that the Company's short-run forecast methodology was accepted in the previous forecast filing review. 1989 BECo Decision, 18 DOMSC at 221.

However, in this proceeding, the Siting Council notes its concern regarding the expansion -- from two years to four years -- of BECo's residential short-run forecast period. While the Company's short-run model has demonstrated significant strengths, those strengths are based largely on the short-run model's statistical performance. Yet, the residential short-run model's statistical performance -- in and of itself -- has not been shown to warrant further use of that model over ever-increasing periods of time. By definition, the Company's short-run model is designed for use over a limited period of time. Moreover, extended implementation of BECo's econometric short-run model reduces usage of the Company's more detailed end-use residential model. In previous decisions, the Siting Council has recognized the enhanced forecasting capabilities of detailed end-use models relative to econometric models. 1991 CECo/CELCo Decision, EFSC 90-4 at 15, 21, 42-43; 1991 Nantucket Decision, 21 DOMSC at 229-230, 241. In addition, the Siting Council notes that another electric company used an econometric model to forecast its short-run energy sales over a one-year time period. See Northeast Utilities, EFSC 90-17, p. 11 (1992) ("1992 NU Decision"); 1988 NU Decision, 17 DOMSC at 9.

Nevertheless, for purposes of this review, the Siting Council finds the Company's residential short-run forecast to be reviewable, minimally appropriate, and minimally reliable at the time of filing. However, in order for the Siting Council to approve the short-run residential forecast in BECo's next filing, the Company must furnish full justification for the incorporation of the results of the short-run residential forecast and the period over which those results are applied.

ii. Long-Run Forecast

(A) Introduction

BECo stated that its long-run residential energy forecast extended from 1994 through 2000 (Exh. BE-2, p. 128; Tr. 3, p. 74). BECo forecasted its long-run residential energy demand to increase from 3,709 GWH in 1994 to 4,065 in 1999, a compound annual growth rate of 1.85 percent (Exh. BE-2, p. 68).

BECo indicated that its annual forecast of residential energy sales is based on three underlying components: (1) the number of residential customers; (2) the number of appliances per customer; and (3) the average annual electricity use per appliance (id., pp. 48-49, 54). BECo stated that residential energy consumption is projected as the sum of 20 residential appliances or end-uses (id., pp. 48-68).[43] BECo asserted that

43/ The 20 end-uses are: electric range, electric range (self-cleaning), refrigerator (frost-free), refrigerator (standard), refrigerator (second), freezer (frost-free), freezer (standard), dishwasher, room air conditioner, central air conditioner, clothes washer, electric dryer, electric water heater, microwave oven, television (color), television (black & white), electric space heating, heat pump, portable electric heater, and miscellaneous and lighting (Exh. BE-2, p. 48).

its current residential forecast methodology was similar to the methodology presented in its previous forecast filing, but included enhancements with respect to household income data, appliance efficiency standards, and further applications of elasticity (id., p. 48). BECo also stated that its assumptions regarding the projected number of electric space heating systems and miscellaneous appliance use were revised upward in the current forecast filing (Exh. HO-D-9).

(B) Number of Residential Customers

BECo stated that the number of residential customers was projected from its demographic forecast, which contained projections of population and households (Exh. BE-2, p. 19). BECo assumed that every household would represent one residential electricity customer (id.). In Section II.C.2, above, the Siting Council has found BECo's demographic forecast to be reviewable, appropriate, and reliable.

Based on the foregoing, the Siting Council finds that BECo's forecast of the number of residential customers is acceptable.

(C) Number of Appliances

(1) Description

BECo stated that it established the average number of appliances for 17 residential appliances by employing saturation-income equations (Exh. BE-2, p. 48). BECo maintained that saturation-income equations were suitable because household income is the major determinant of appliance saturations for most appliances (id., pp. 48, 55-57; Tr. 1, pp. 57-58, 103). However, BECo stated that saturation-income equations were not used for lighting and miscellaneous appliances because those appliances were assumed to be 100 percent saturated (Exh. BE-2, pp. 48-49). In addition, BECo indicated that saturations of electric space heating were forecast based on Company-derived data rather than saturation-income equations (id.).

BECo stated that its saturation-income equations were developed using 1986 customer survey data (id., p. 48).[44] BECo indicated that data from its 1989 customer survey would be used to update saturation-income equations for its next forecast filing (id.).[45] BECo asserted that its saturation-income equations were theoretically sound and statistically valid (id., pp. 55-57; Tr. 1, pp. 157-158).[46]

BECo stated that saturation of electric space heating systems was forecast based on a combination of two components (Exh. BE-2, p. 49; Tr. 1, pp. 59-60).[47] BECo stated that the first component of electric space heating saturation was the number of existing electric space heating systems (Exh. BE-2, p. 49). BECo stated that its estimate of the number of existing electric space heating systems was established through its residential customer survey (Tr. 1, p. 146). BECo stated that the second component of saturation was the projected number of new electric space heating systems due to new residential construction or conversions to electric space heating from another type of heating system (Exh. BE-2, p. 49, Exh. HO-D-9;

44/ BECo stated that its 1986 customer survey was a service territory-specific random sample of about 10,000 residential customers (Exh. HO-D-9). The Company indicated that its 1986 customer survey had a 50 percent response rate (id.). BECo also indicated that residential customers were surveyed approximately once every three years (Tr. 1, p. 156).

45/ BECo stated that its estimate of median household income was established through its 1986 customer survey (Exh. BE-2, pp. 49, 58; Exh. HO-D-1). BECo indicated that its forecast of household income was developed by applying DRI's growth rates to its 1986 median household income data (id.).

46/ BECo stated that its current saturation-income equations produced R-squared statistics ranging from 0.60 to 0.98 (Exh. BE-2, pp. 55-57).

47/ BECo stated that statistical test results were not "good" with respect to forecasting electric space heating saturation using saturation-income equations (Tr. 1, p. 60). BECo did not provide those statistical test results (id.).

Tr. 1, pp. 146-147, Tr. 5, pp. 24-25).[48] BECo defined that second component as "penetration" (Exh. BE-2, p. 49). BECo noted that its estimate of penetration for the current forecast filing was based on data covering the 1985-1988 period (Tr. 5, p. 43). BECo stated that its estimate of penetration over that period was developed as a single "weighted average" of actual electric space heating installations in new homes, new apartments, converted homes, and converted apartments (id., p. 38).[49] BECo noted that its penetration estimate did not include electric heat installations associated with room additions to existing residences (id., pp. 46, 57). However, Dr. Cuomo stated that electric space heating effects due to room additions were likely to be "extremely small" (id., p. 34; Tr. 1, p. 87). BECo noted that its weighted average penetration was applied to its forecast of new residences which included new homes and new apartments only (Tr. 5, p. 45).[50] BECo stated that the combination of the existing number of electric space heating systems and the estimated number of electric space heating systems to be added based on an application of its penetration estimate to its forecast of new households was used to project the total number of electric space heating systems for each year of the forecast period (Exh. HO-D-9; Tr. 1, p. 147).

In a change from its previous forecast filing, BECo stated that its level of electric space heat penetration had been increased from 35 percent to 40 percent for the period 1991 to 2000 (Exh. HO-D-9; Tr. 1, p. 78, Tr. 5, pp. 25-26). As

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48/ BECo stated that electric space heating penetration rates were determined by its energy services department based on accumulated historic data regarding electric space heating installations in the BECo service territory (Exh. HO-D-9; Tr. 2, pp. 168-172).

49/ BECo later provided 1989 and 1990 penetration data for new homes, new apartments, converted homes, converted apartments and new and converted condominiums (Exh. MP-RR-2).

50/ BECo stated that its forecast of new residences consisting of new homes and new apartments was established through its forecast of the number of households (Tr. 5, p. 46).

justification for that increase, BECo noted that over the 1985-1988 period actual electric space heating penetration rates averaged 67 percent (Exh. MP-4).[51] As further justification for that increase, Dr. Cuomo stated that residential energy consumption had been "underforecast" over the 1986-1989 winter periods, even with weather adjustment (Tr. 1, pp. 82-83, Tr. 5, p. 76). Specifically, BECo indicated that residential energy sales had been underforecast by amounts ranging from 1.0 percent to 11.1 percent per month when compared to actual energy sales over the 1986-1989 winter periods (Exh. MP-4, Attachment 1).[52] Dr. Cuomo stated that consistent underforecasting indicated that BECo's residential model was "missing something" (Tr. 1, pp. 143-145). Dr. Cuomo concluded that the underforecast was attributable to an underestimation of electric space heating penetration (id., pp. 82-83, Exh. HO-D-12).[53] Dr. Cuomo stated that selection of a 35 percent penetration rate had been based on an adjustment of penetration that "probably adjusted it downward too far" (Tr. 1, p. 83). BECo indicated that its electric space heating penetration forecast -- at the 40 percent level -- contributed a total of about 84 MW of new peak load by the year

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51/ BECo stated that actual electric space heating penetration rates for each year between 1985 and 1988 were: 81, 71, 66, and 49 percent, respectively (Exh. MP-4). BECo noted that the foregoing penetration rates were developed through its weighted average calculation (id.).

52/ For 1986-1988, winter sales were represented by six months of data, from October through March (Exh. MP-4, Attachment 1). However, 1989 sales were represented by only three months of data, from October through December (id.).

53/ Dr. Cuomo also stated that "quite possibly" furnace fan usage could contribute to the winter sales underforecast (Tr. 1, p. 99). Dr. Cuomo stated that furnace fans operate in conjunction with fossil-fueled forced-air heating systems, and that a furnace fan consumes an average of 650 kilowatthours ("kwh") per year (id., p. 98).

2014 (Exh. MP-22; Tr. 5, pp. 76-79).[54] Dr. Cuomo stated that the 5 percent increase in penetration -- from 35 percent to 40 percent -- amounted to "less than 10 MW" of that 84 MW peak load amount (Tr. 5, pp. 78-79).

BECo used a single average rate to represent electric space heating penetration for both new homes and new apartments (id., pp. 45, 47). BECo noted that over the 1985-1988 period electric space heat penetration rates for new homes and new apartments were "very close" (id., pp. 43-44). Specifically, BECo indicated that for each year over the 1985-1988 period, electric space heating penetration rates for new homes were 50, 47, 34, and 20 percent, respectively, while those of new apartments were 38, 25, 43, and 28 percent, respectively (Tr. 5, p. 45; Exh. MP-RR-2). Dr. Cuomo stated that based on those data, a 35 percent average penetration rate for both new homes and new apartments was "not at all distorted" (Tr. 5, p. 47). However, Dr. Cuomo stated that use of that average for both new homes and new apartments for 1989 and 1990 was "becoming distortive" (id., p. 52). BECo provided data for 1989 and 1990 that showed electric space heating penetration rates for new homes as 6.9 and 15.0 percent, respectively, while those of new apartments were 25.3 and 19.5 percent, respectively (Exh. MP-RR-2). Nonetheless, Dr. Cuomo stated that 1989 and 1990 data were less than

54/ The Company indicated that annual additions to peak load due to its electric space heating penetration forecast ranged from approximately 2 to 6 MW per year over the forecast period (Exh. MP-22).

representative for forecasting purposes because those years were "recession" years (Tr. 5, pp. 44, 50).[55]

(2) Positions of Parties

MASSPIRG argued that BECo has failed to substantiate its forecast of increased electric space heating penetration and that the Company's assumptions regarding electric space heating resulted in an overstated forecast of residential energy sales (MASSPIRG Initial Brief, pp. 3, 14-16). Specifically, MASSPIRG asserted that BECo's 40 percent level of electric space heating penetration was unsubstantiated because: (1) winter sales data provided by the Company failed to include weather adjustment and were not statistically analyzed; (2) room additions and furnace fan usage could have contributed to BECo's underforecast of winter sales; and (3) recent electric space heating penetration data trends indicated penetration of less than 40 percent (id., pp. 3, 14-16, MASSPIRG Reply Brief, p. 7). MASSPIRG further asserted that BECo's forecast of electric space heating penetration based on a single average for homes and apartments was faulty because home and apartment electric space heating penetration rates actually were different and average electricity usage for electrically space heated apartments was less than one-third that of electrically space heated homes (MASSPIRG Initial Brief, pp. 3, 14-16).

BECo argued that its use of a penetration rate of 40 percent for electric space heating was valid because:

55/ BECo stated that in 1991 new residential construction and conversion activity has been less than expected "due to the current economic decline" (Exh. MP-RR-15). Specifically, BECo indicated that for 1991, 402 single-family homes would be newly constructed or converted to electric heat as compared to 1,454 originally forecast; 103 multi-family homes would be newly constructed or converted to electric heat as compared to 1,391 originally forecast (id.). However, BECo contended that over the long run, new construction and conversion activity for homes would be consistent with the average for that activity over the 1979-1988 period (id.). BECo did not state what that average was, nor did BECo provide any justification for use of an average based on the 1979-1988 time period (id.).

(1) that rate was developed based on actual data covering the most complete historical record available, i.e., 1985-1988; (2) overall electric space heating penetration averaged 67 percent over the 1985-1988 time period; (3) its underforecast of winter energy sales supported an increase from its previously used 35 percent level of electric space heating penetration; and (4) its winter energy sales data in fact reflected weather adjustment (BECo Initial Brief, p. 47; BECo Reply Brief, p. 23). BECo further argued that averaging penetration rates of homes and apartments was reasonable because: (1) taken individually the penetration rates for homes and apartments each were considerably above 40 percent over the 1981-1988 time period,[56] and (2) 1991 penetration data was atypical of long-run penetration trends since it included only three months of 1991 experience and 1991 was a severe recession year (BECo Reply Brief, pp. 23-24).

(3) Analysis and Findings

In previous decisions, the Siting Council has approved methodologies for forecasting the number of appliances that are similar to BECo's methodology. 1990 MMWEC Decision, 20 DOMSC at 20; 1988 EECo/Montaup Decision, 18 DOMSC at 85-86. Here, BECo's saturation-income functions exhibit reasonable levels of statistical validity, and its assumed 100 percent levels of saturation for lighting and miscellaneous end-uses are accepted throughout the industry. However, several questions were raised regarding support for the Company's forecast of electric space heating penetration. The Siting Council addresses those questions below.

First, the Company presented several years of comparative data to support its contention of an underforecast of its winter residential energy sales. The Siting Council notes that the Company maintained that those data had been weather adjusted.

56/ Although previous statements by BECo relating to electric space heating penetration rate estimates referred to 1985-1988 data, in its Reply Brief BECo referred to the 1981-1988 time period (pp. 23-24).

While the Siting Council agrees with MASSPIRG that statistical analysis could have been used to provide an additional level of description regarding the Company's underforecast, the absence of statistical analysis does not disprove the Company's contention regarding an underforecast of winter residential energy sales. In fact, the record clearly indicates a disparity between actual and forecasted winter residential energy sales over the time period indicated by BECo.

Second, the Siting Council agrees generally with MASSPIRG's assertion regarding omissions of room additions as a possible contributory element to the Company's winter underforecast. Here, the Company has demonstrated that it determined its overall electric space heating penetration rate based on four dwelling types (new and converted homes and new and converted apartments). Yet, the Company's forecast of residences which are multiplied by that penetration rate encompasses only new homes and apartments. In addition, for 1989 and 1990 the Company included new and converted condominiums in its overall penetration rate calculation, yet omitted those same dwellings from previous years' calculations. In no instance did the Company include room additions in its electric space heating penetration calculations. The failure to systematically account for all dwelling space that is subject to electric space heat penetration, including condominiums and room additions, indicates a weakness in the Company's methodology. In future forecast filings the Company should provide a more complete and systematic assessment of all dwelling space subject to electric heat penetration, including complete documentation as to how each category of dwelling space is weighted in the Company's weighted average calculations. A more systematic approach may well provide additional insights into specific causes of the winter energy sales underforecasts reported by BECo. The Siting Council also notes that furnace fan usage data was not fully developed as a contributing factor to BECo's winter energy sales underforecasting. No evidence was introduced to indicate whether furnace fan usage had a major effect on winter energy sales or to indicate that furnace fan usage had been significantly understated over the 1986-1989 winter periods identified by BECo.

Third, as argued by MASSPIRG, recent data trends regarding actual installations of electric space heating demonstrate a marked decline when compared to the Company's 40 percent penetration level. The Siting Council recognizes that the Company's initial forecast filing was prepared at a time when that decline was not fully discernable. Yet, the Siting Council notes that the Company's database consisted of relatively few years -- a total of three. Despite that relatively limited database, which is likely to reflect only higher levels of economic activity rather than lower, the Company asserted that recent trends which are based on reduced economic activity are unrepresentative of long-run outcomes. The Siting Council disagrees with that assertion. To the extent that the Company's long-run forecast of electric space heating penetration encompasses the full range of economic activity, including lower levels as well as higher ones, that long-run forecast becomes more representative, not less. In the future, the Company should provide electric space heating penetration rate assumptions based on a broad range of economic activity and should address any long term trends indicated by their data. See 1991 Nantucket Decision, 21 DOMSC at 226-228.

Fourth, with respect to the Company's use of a single average electric space heating penetration rate for both homes and apartments, the Siting Council notes that electric space heating penetration rates of homes and apartments show considerable variation when compared on an annual basis. In 1986, for example, electric space heating penetration in homes was 47 percent while in apartments it was 25 percent. Thus, the Siting Council agrees with MASSPIRG's assertion that the difference between electric space heat penetration rates of new homes and that of new apartments raises a question regarding the continued validity of a single average penetration rate as representative of both dwelling types. In the future, the Company should monitor electric space heating penetration rates for both homes and apartments, and if those penetration rates continue to diverge, the Company should abandon its averaging approach in favor of developing separate electric space heating penetration rate forecasts for homes and apartments.

Nevertheless, the Siting Council notes that while annual increases to peak load in the range of from 2 to 6 MW are not insignificant, in this instance those amounts add to winter peak load requirements. Since BECo is a summer peaking system and is expected to remain so over the forecast period, the effects of the foregoing additional winter peak loads should not have a major effect on the Company's capacity requirements.

Finally, despite the foregoing criticisms regarding certain aspects of the Company's methodology for forecasting the number of residential appliances, that methodology relied largely on statistically valid saturation-income equations and recent historical experience. To support its forecast of the number of appliances, BECo has developed service-territory-specific data based on customer surveys taken at regular intervals. In the future, the Company can strengthen its forecast methodology by addressing the weaknesses associated with its forecast of electric space heating penetration.

Accordingly, for purposes of this review, the Siting Council finds that BECo's forecast of the number of appliances is acceptable.

(D) Average Use Per Appliance

(1) Description

BECo stated that it forecasted average use per appliance (i.e., kilowatthours ("kwh") per year) based on two major components: (1) a base year usage estimate, and (2) price-elasticity responses (Exh. BE-2, p. 49; Tr. 2, p. 184). BECo stated that the combination of those two components produced its forecast of average use per appliance for most of its residential appliances (id.). However, BECo stated that average use estimates for seven residential appliances also included the effects of government-sponsored appliance efficiency standards (Exh. BE-2, pp. 50-51).[57]

BECo stated that its methodology for establishing average use per appliance was similar to the methodology employed in its previous forecast filing (id., p. 48). However, BECo noted three enhancements to its current average use per appliance methodology: (1) price-elasticity responses are now included in its estimate of electric space heating average use, (2) state and national appliance efficiency standards are applied to average use estimates of standard, frost-free, and second refrigerators; standard and frost-free freezers; and room and central air conditioners, and (3) the growth rate assigned to the miscellaneous end-use category has been revised upward (id., p. 48; Tr. 1, pp. 73-74).

BECo stated that base year usage was an estimate of energy consumption of an appliance prior to modification by price elasticity effects and appliance efficiency standards (Exh. HO-D-15). BECo indicated that its base year usage estimates relied on non-Company as well as Company data sources (id.). BECo noted that its primary non-Company source of base usage data was the Edison Electric Institute ("EEI") (Exh. BE-2, p. 49).[58]. EEI data was used to establish base usage energy consumption levels for 12 residential appliances (id.). BECo stated that the vintage of EEI base year data was 1971 for all

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57/ BECo stated that two sets of appliance efficiency standards were employed in its forecast of appliance average use: (1) Massachusetts appliance efficiency standards were used for the 1988-1989 time period, and (2) national appliance efficiency standards were used for the 1990-2014 time period (Exh. HO-D-5). Although BECo noted that appliance efficiency standards were applied to second refrigerators, the Company's second refrigerator forecast was identical to the forecast for standard refrigerators (Exh. BE-2, p. 64).

58/ BECo stated that it relied on EEI data to estimate base year usage for the following appliances: electric range, electric range (self-cleaning), refrigerator (standard), refrigerator (second), freezer (standard), dishwasher, lighting, electric dryer, microwave oven, television (color), television (black & white), and portable electric heater (Exh. BE-2, p. 49).

appliances except microwave ovens, which was based on 1982 data (Exh. HO-D-17).[59] BECo further stated that EEI developed its data by accumulating appliance usage information on a national basis (id.). BECo noted that it was unaware of any information indicating that territory-specific data would be significantly different from the nationally-based data obtained from EEI (id.). BECo also stated that base usage estimates for room and central air conditioning were based on a combination of Association of Home Appliance Manufacturers ("AHAM") data and estimates from BECo's energy services department (Exh. BE-2, pp. 49-50). BECo indicated that central and room air conditioning base year data was also 1971 vintage (Exh. HO-D-15).

BECo stated that base year usage estimates for the seven remaining end-uses were based on Company-derived data (id., p. 49). Base year usage estimates for frost-free refrigerators, frost-free freezers, and clothes washers were based on the results of a Company-sponsored survey -- the Household Appliance Metering Study ("HAMS") (Exhs. HO-RR-1, HO-RR-2).[60] BECo stated that its HAMS data showed much higher usage for frost-free refrigerators, frost-free freezers, and clothes washers than the EEI data which had been used previously (Exh. BE-2, p. 49). BECo stated that the vintage of its HAMS data used in establishing base usages for frost-free refrigerators, frost-free freezers, and clothes washers was 1988 (Exh. HO-D-15). BECo further stated that its base usage estimates for electric space heating, heat pumps, and electric water heating were derived by averaging

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59/ BECo stated that EEI is presently updating its base usage data and that EEI's updated data will be analyzed for use in the Company's next residential forecast (Exh. HO-D-17).

60/ The Company described HAMS as a territory-specific survey based on random sampling and metering of frost-free refrigerators, frost-free freezers, and clothes washers over the 1987-1988 time period (Exh. HO-D-3).

actual sales data (Exh. BE-2, pp. 49-50).[61] BECo stated that sales data for electric space heating and electric water heating covered six years -- 1983-1988 -- and that those data had been weather normalized (id., p. 49). BECo indicated that the vintage of its electric water heating base year usage estimate was 1988, while the vintage for its electric space heating base year estimate was the "mid-80's" (Exh. HO-D-15; Tr. 2, pp. 173-174).[62]

Dr. Cuomo stated that the miscellaneous end-use category had no identifiable base year (Tr. 2, pp. 174-175). BECo noted that usage for its miscellaneous end-use was forecast as a "residual," i.e., miscellaneous energy use was based on energy use that was left over after accounting for energy use attributable to the specific end-uses included in its residential forecast (Exh. HO-D-18; Tr. 1, p. 63). BECo stated that its miscellaneous end-use residual was calculated as the difference between actual average use per household for 1989 and forecasted average use per household for 1989 (Exh. HO-D-18). BECo noted that its miscellaneous end-use category included major appliances such as lighting and furnace fans as well as numerous diverse appliances (id.; Exh. MP-3).[63]

61/ BECo stated that heat pump usage was estimated as 75 percent of electric resistance space heating usage (Exh. BE-2, p. 50).

62/ BECo stated that it participated in the Joint Utility Monitoring Project ("JUMP") which accumulated appliance usage data for frost-free refrigerators, uncontrolled electric water heaters, electric ranges, and electric clothes dryers (Exh. BE-2, p. 49). BECo stated that JUMP usage data was not used in its residential forecast due to sampling problems or similarity to existing data (id.).

63/ Based on a list developed by AHAM and EEI, BECo indicated that its miscellaneous end-use category reflected usage associated with appliances such as blender, broiler, carving knife, coffee maker, deep fryer, frying pan, mixer, roaster, sandwich grill, toaster, trash compactor, waffle iron, waste dispenser, iron, bed covering, dehumidifier, attic fan, circulating fan, rollaway fan, window fan, heating pad, humidifier, hair dryer, shaver, toothbrush, radio, radio/record player, clock, sewing machine, vacuum cleaner, VCR, and home computer (Exh. MP-2).

BECo stated that the average use estimates of all of its residential appliances were modified on an annual basis by the effects of price-elasticity responses (Exh. BE-2, pp. 49-50; Tr. 2, pp. 184-185). BECo noted that elasticity was estimated on a short-run and long-run basis, and that the same short-run and long-run elasticities were now applied to all of its residential appliances (Exhs. HO-D-7, HO-D-8). In response to a Siting Council directive, BECo stated that its forecast of electric space heating average use included price-elasticity responses (Exh. BE-2, p. 50). See 1989 BECo Decision, 18 DOMSC at 218. BECo noted that, with one exception, average use per appliance decreased over the forecast period due to price-elasticity responses based on rising electricity prices (Exh. BE-2, p. 50; Tr. 2, p. 186).[64] Dr. Cuomo stated that appliance manufacturers responded to rising prices by developing and marketing residential appliances that are "more efficient" over time (id.). Dr. Cuomo stated that the Company's elasticity estimates were designed to reflect the price-elasticity responses of consumers as well as the efficiency responses of manufacturers (Tr. 3, p. 47).

With respect to appliance efficiency standards, BECo stated that state appliance efficiency standards had been applied to its average use forecasts of standard and frost-free refrigerators, second refrigerators, standard and frost-free freezers, and room and central air conditioner average use for 1988 and 1989 (Exh. HO-D-5). The Company applied national appliance efficiency standards to its forecast of those appliances for 1990 and beyond because the national standards took effect in 1990 and were more "stringent" than the state

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64/ BECo noted that its miscellaneous end-use category was forecast to increase its average use over the forecast period (Exh. BE-2, p. 64).

standards (Tr. 1, p. 185).[65] In addition, Dr. Cuomo stated that national standards would "probably" be enforced more rigorously than state standards (id.). BECo stated that appliance efficiency standards were implemented on a new and replacement basis (Exh. BE-2, pp. 50-51).[66]

Dr. Cuomo stated that the Company had no direct information regarding effects on its residential forecast stemming from appliances which are designed to exceed national appliance efficiency standards (Tr. 1, p. 94). However, as an indirect means of assessing those effects, BECo analyzed the impacts of increased sales of the most efficient models of refrigerators, freezers, and room air conditioners included in

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65/ BECo stated that national standards set maximum standard refrigerator use at 763 kwh per year while state standards set that use at 864 kwh per year; national standards set maximum frost-free refrigerator use at 1,012 kwh per year while state standards set that use at 1,060 kwh per year; national standards set maximum standard freezer use at use at 614 kwh per year while state standards set that use at 848 kwh per year; national standards set maximum frost-free freezer use at 1,063 kwh per year while state standards set that use at 1,683 kwh per year; and that national and state efficiency standards for room and central air conditioning were identical (Exh. HO-D-5).

66/ For example, Dr. Cuomo stated a frost-free refrigerator's useful life was assumed as 19 years (Tr. 1, pp. 189-190). Consequently, BECo forecast replacements of existing frost-free refrigerators by efficient frost-free refrigerators at a rate of 1/19 per year (id.). New additions to the number of frost-free refrigerators were forecast at a rate consistent with the Company's forecast of new residential customers (id.).

its Appliance Labelling Program ("ALP") (Exh. MP-25).[67] BECo indicated that the highest level of increased sales analyzed -- represented by 40 percent of new and replacement frost-free refrigerators, frost-free freezers, and room air conditioners -- produced an overall savings of 32 GWH out of total residential sales of 5,142 GWH in the year 2014 (Exh. MP-25).[68] Based on that analysis, Dr. Cuomo concluded that the effect of appliances which are designed to exceed mandated efficiency standards on the residential forecast would be "almost imperceptible" (Tr. 1, p. 94; Exh. MP-25).

BECo provided one detailed example indicating how appliance efficiency standards were applied to its forecast of average use (Exh. MP-RR-4; Exh. HO-D-6).[69] In that example, BECo

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67/ BECo stated that its ALP was a residential C&LM program designed to (1) educate consumers and retailers regarding energy efficiency, and (2) promote sales of the most efficient models of refrigerators, freezers, and air conditioners (Exh. BE-42, pp. 80-82). BECo stated that only the top 15 percent of efficient refrigerators, freezers, and air conditioners were eligible to receive a high visibility "efficiency" label through its ALP (id.). BECo stated that its ALP would produce estimated energy savings of 100 kwh per year for refrigerators and freezers each, respectively, and energy savings of 40 kwh per year for room air conditioners (id.). BECo stated that its net forecast, i.e., including the impacts of C&LM programs, assumed maximum ALP-based sales of 12 percent of new refrigerators, 9 percent of new freezers, and 7 percent of new room air conditioners (id.).

68/ Usage differences between (1) standard and frost-free refrigerators, and (2) standard and frost-free freezers were not noted by BECo in its ALP documentation (Exh. BE-42, pp. 80-86). However, BECo's analysis of increased sales was based on frost-free refrigerators and freezers (Exh. MP-25).

69/ BECo stated that appliance efficiency standards were applied using appliance-specific formulae (Exh. BE-2, p. 63). For example, average use for a standard refrigerator was calculated as the sum of (1) a constant of 316, and (2) the "adjusted volume" of the refrigerator multiplied by a factor of 16.3 (id.). BECo stated that a standard refrigerator's "adjusted volume" consisted of the sum of: (1) its refrigerator volume, and (2) its freezer volume multiplied by 1.63 (id.). BECo stated that its volume data was based on 1987 weighted averages calculated by AHAM (id., p. 51).

applied the annual effects of appliance efficiency standards to its forecast of frost-free refrigerator average use (id.). Based on appliance efficiency standards in effect for 1989, BECo forecasted frost-free refrigerator average use as about 1,600 kwh for that year (id.).[70]

In a change from previous forecasts, BECo noted that the annual growth rate assigned to its miscellaneous end-use category had been increased from three percent to five percent (Exh. MP-2). BECo indicated that under its assumed five percent level of growth, miscellaneous energy use is projected to grow four-fold over the forecast period, increasing from 13 percent of total residential use in 1989 to about 33 percent of total residential use in 2014 (Exh. BE-2, p. 66). By the year 2000, the miscellaneous end-use becomes the single largest end-use in the Company's residential sector (id., p. 66).

Dr. Cuomo stated that miscellaneous was "the most difficult" end-use to forecast in the residential sector (Tr. 1, p. 66). Further, Dr. Cuomo stated that neither the three percent nor the five percent growth rate had been based on "anything empirical" (id., p. 74). Nonetheless, as justification for that increase, Dr. Cuomo stated that BECo's residential energy sales had been underforecast for the past five years, and that the miscellaneous category was the "real driver" of that underforecast (id., p. 64). As further justification for that increase, BECo stated that: (1) its forecast of miscellaneous average use did not compare favorably to an assumed level of miscellaneous use which utilized AHAM/EEI data; (2) dual-earner households were accounting for increasing levels of miscellaneous appliance use; and (3) rising household income should stimulate increasing levels of miscellaneous use (id., pp. 65-68).

70/ In its ALP, BECo estimated average use for refrigerators as 940 kwh per year prior to any savings due to the ALP (Exh. BE-42, p. 80). BECo did not indicate whether that usage estimate was for a frost-free or standard refrigerator (id.). While BECo did not indicate the date of that usage estimate, BECo's ALP covered a three-year period commencing in 1990 (id., p. 86).

BECo stated that for 1989 its residual forecast methodology resulted in a miscellaneous use level of 789 kwh (id., pp. 65-66). Nonetheless, Dr. Cuomo asserted that BECo's forecast level of 789 kwh was too low when compared with a miscellaneous use estimate derived from assumptions (id., Tr. 5, pp. 95-96).[71] [72]

Dr. Cuomo stated that characteristics of dual-earner households were also a major factor supporting an assumed higher level of increased miscellaneous energy use (Tr. 1, p. 68). Dr. Cuomo noted that no formal studies had been undertaken to establish the number of such households in BECo's service territory, but that dual-earner households represented "more than half" of BECo's residential households in his opinion (id., p. 151).[73] Dr. Cuomo asserted that miscellaneous energy increases were anticipated for all households, but that these increases would likely be "most pronounced" for dual-earner households (id., p. 152). Dr. Cuomo stated that preferences for

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71/ BECo stated that the energy use of all of the miscellaneous appliances shown in its AHAM/EEI-based list of miscellaneous appliances amounted to about 3,200 kwh for 1989 (Exh. MP-2) (See Footnote 52). Dr. Cuomo asserted that a "conservative" level of miscellaneous use for BECo's service territory was represented by one-third of 3,200 kwh per year, or about 1,000 kwh per year (Tr. 1, p. 101). Since BECo's miscellaneous category also included lighting, Dr. Cuomo added 300 kwh to the miscellaneous category for that appliance (id., pp. 65-66). Thus, BECo's assumed level of miscellaneous use reached 1,300 kwh for 1989, an amount higher than that of its forecast.

72/ With respect to energy use associated with lighting, Dr. Cuomo stated that BECo has not had "very good" historic lighting estimates (Tr. 1, p. 153). Dr. Cuomo stated that household lighting usage estimates have become "fluid" since lighting technologies have "improved so much" (id.). Dr. Cuomo stated that in the Company's next forecast filing, lighting would be forecast as a separate end-use, i.e., disaggregated from the miscellaneous end-use category (id.).

73/ Dr. Cuomo stated that the number of dual-earner households was "informally" estimated as 50 to 65 percent of BECo's households (Tr. 1, p. 151).

"convenience in the homes" of dual-earners supported a higher level of miscellaneous usage (id., p. 75).[74]

Dr. Cuomo stated that rising income levels were also a key element supporting higher estimates of miscellaneous energy use (id., pp. 67-68). Dr. Cuomo asserted that income levels were "clearly" higher than those of the past (id., p. 68). Dr. Cuomo stated that miscellaneous appliance use was "more sensitive" to changes in income than appliances such as refrigerators (id., p. 164). For example, Dr. Cuomo stated that if increased income resulted in a two percent increase in refrigerator use, that same level of increased income would produce miscellaneous use of "greater than two percent" (id., p. 164). Dr. Cuomo asserted that increased use of "gadgets" such as stereos and carving knives were related to income to "a great extent" (id., p. 61).[75] In addition, Dr. Cuomo noted that the costs of owning and using most miscellaneous appliances were "not exorbitant" (id., p. 75). However, Dr. Cuomo also contended that even falling income conditions would lead to increased miscellaneous use (id., pp. 75-76). Dr. Cuomo stated that unemployed workers "spend more time" at home, leading to an increased levels of miscellaneous energy use despite reduced levels of income (id., pp. 75-76).

(2) Positions of Parties

MASSPIRG raised three major arguments with respect to the Company's forecast of average use per appliance (MASSPIRG Initial Brief, pp. 3, 12-14, 16-17; MASSPIRG Reply Brief, p. 7).

First, MASSPIRG argued that BECo's estimates of appliance average use were erroneous because the Company assumed that no appliances would be purchased that are more efficient than required by minimum national appliance efficiency standards

74/ Dr. Cuomo offered VCRs, personal computers, security systems, and control systems as examples of convenience appliances (Tr. 1, p. 149).

75/ However, Dr. Cuomo stated that certain miscellaneous appliances such as toasters would be owned and operated "regardless of your income level" (Tr. 1, p. 62).

(MASSPIRG Initial Brief, pp. 3, 16-17; MASSPIRG Reply Brief, p. 7). Second, MASSPIRG asserted that BECo miscalculated the effects of appliance efficiency standards on its forecast of frost-free refrigerator average use (MASSPIRG Initial Brief, pp. 3, 16-17; MASSPIRG Reply Brief, p. 7).

Third, MASSPIRG argued that BECo has failed to support its assumed increased growth rate for the miscellaneous end-use category (MASSPIRG Initial Brief, pp. 3, 12-14). MASSPIRG argued that the Company's assumptions regarding the growth rate results in an overstated forecast of residential energy sales (id., p. 12). Specifically, MASSPIRG asserted that BECo's increased rate of growth as applied to its forecast of miscellaneous appliance average use is arbitrary and overstated because: (1) that increase was unsupported by evidence; (2) the Company's assumed level of miscellaneous use for 1989 -- amounting to about 1,300 kwh -- was purely subjective, and in addition, that level of usage raises serious questions regarding average use levels assigned to the remaining residential appliances; (3) household income has been forecast to decline, not increase, and therefore miscellaneous usage also should be forecast to decrease; and (4) appliances such as furnace fans and lighting are unlikely to increase at the five percent growth rate selected by BECo (id., pp. 3, 12-14; MASSPIRG Reply Brief, p. 7).

BECo responded that its estimates of average use per appliance assumed appliance efficiencies which exceeded those mandated by national appliance efficiency standards (BECo Reply Brief, p. 24). BECo asserted that forecasted increases in the price of electricity will lead to the design and production of improved-efficiency appliances (id.). BECo contended that its residential model captured that trend through its price-elasticity response (id.). Thus, BECo claimed that its "price-induced" response effectively represented improvements in appliance efficiencies beyond those required by mandated national efficiency standards (BECo Initial Brief, p. 47).

BECo further argued that its estimate of frost-free refrigerator average use was accurate (id.). BECo asserted that its calculations of frost-free refrigerator average use were based on territory-specific "adjusted volume" data and that the effects of mandated efficiency standards were properly taken into account in its calculations (id., BECo Reply Brief, p. 24).

Finally, BECo argued that its forecast of average use associated with the miscellaneous end-use category was valid and appropriately adjusted because: (1) the miscellaneous category consists of a large number of diverse appliances including new appliances that are difficult to forecast in the absence of a historical database; (2) average use for the miscellaneous category has been estimated as 1,300 kwh as opposed to 789 kwh projected by the Company's forecast; (3) using estimates of 1,300 kwh as a base level and applying a growth rate of three percent rate -- a growth rate which was approved by the Siting Council in its previous review of the Company's residential methodology -- yields an average use of 2,720 kwh in the year 2014, an amount that is above the Company's year 2014 estimate of 2,674 kwh as presented in its current forecast filing; and (4) the residential sector was previously underforecast, and therefore, if the effects of that underforecast cannot be attributed elsewhere, the effects must logically fall into the miscellaneous end-use residual (BECo Initial Brief, p. 46; BECo Reply Brief, pp. 22-23).

(3) Analysis and Findings

In a previous decision, the Siting Council accepted a methodology for forecasting average use per appliance that was similar to the methodology presented by BECo in this proceeding. 1990 MMWEC Decision, 20 DOMSC at 23-26. The Siting Council also approved BECo's residential forecast methodology in its previous review. 1989 BECo Decision, 18 DOMSC at 218. However, the Siting Council's previous review of BECo's residential appliance average use forecast was limited in scope, focussing primarily on the effects of elasticity on the Company's forecast of electric space heating average use. In recent decisions, the Siting Council has expanded its reviews to accommodate a wider range of issues related to residential appliance average use forecasting. 1991 CECo/CELCo Decision, EFSC 90-4 at 17-21; 1991 Nantucket Decision, 21 DOMSC at 223-231; 1990 MMWEC Decision, 20 DOMSC at 18-23; 1989 MECo/NEPCo Decision, 18 DOMSC at 305-310. Here, the Siting Council reviews BECo's forecast of average use per appliance consistent with recent decisions.

First, the Siting Council notes that the Company relied on non-service-territory-specific data for base year usage estimates for 12 residential appliances. In previous decisions, the Siting Council has criticized electric companies for use of non-service-territory-specific residential forecast data. 1991 Nantucket Decision, 21 DOMSC at 228-230; 1988 EECo/Montaup Decision, 18 DOMSC at 90. In addition, the Siting Council notes that BECo's 1971 non-Company base year usage data is of a vintage older than that used by another electric company reviewed recently by the Siting Council. 1990 MMWEC Decision, 20 DOMSC at 22-23. In previous decisions, the Siting Council has criticized electric companies for reliance on older residential data. 1991 CECo/CELCo Decision, EFSC 90-4 at 19-21; Eastern Edison Company/Montaup Electric Company, 14 DOMSC 41, 63-64 (1986); Eastern Edison Company/Montaup Electric Company, 11 DOMSC 61, 77 (1984); Commonwealth Electric Company/Cambridge Electric Light Company, 9 DOMSC 222, 313 (1983). However, the Siting Council recognizes that BECo has developed service-territory-specific data for seven major residential appliances representing about 60 percent of its residential energy requirements, and that those data are much more current than the non-service-territory-specific data also used in its average use forecast. Still, in future forecast filings, the Company should demonstrate that any non-service-territory-specific average use data is representative and current in terms of its own residential sector.

The Siting Council also notes that BECo's consideration of elasticity as a factor in the forecast of electric space heating average use is consistent with the Siting Council's directive in the 1989 BECo Decision. The Siting Council also notes that the Company's elasticity estimates were formulated to include market-based efficiency responses of appliance manufacturers, reflecting development of efficient appliances in response to rising electricity prices. The Company's use of elasticity -- and its quantitative analysis of increased purchases of highly efficient appliances -- counter MASSPIRG's claim that the Company failed to consider effects due to purchase of appliances which exceed mandated efficiency requirements.

In regard to MASSPIRG's argument that BECo miscalculated the effects of appliance efficiency standards on its forecast of frost-free refrigerator average use, the Siting Council notes that the question of frost-free refrigerator usage was subject to information requests, hearing time, and a record request. Despite the amount of evidence pertaining to that question, the Siting Council notes that in one exhibit the Company identified frost-free refrigerator use at 1,060 kwh per year including appliance efficiency standards, while in another exhibit that usage level is identified as 1,595 kwh per year. Further, in its arguments, MASSPIRG raised specific references to inconsistencies in the Company's frost-free refrigerator usage levels which were not responded to by the Company. While the Company argued that appliance efficiency standards were applied to frost-free refrigerators on an "adjusted volume" basis, the Company failed to demonstrate what level of usage would actually result from an application of its identified appliance efficiency standards. The Siting Council recognizes that "adjusted volume" may in fact represent a critical component of the Company's forecast of frost-free refrigerator average use. However, the Siting Council cannot fully review a forecast when pertinent information is presented in an inconsistent manner and not explained fully. In previous decisions, the Siting Council has criticized electric companies for use of inconsistent data and inadequate explanations. 1991 Nantucket Decision, 21 DOMSC at 241; 1990 MMWEC Decision, 20 DOMSC at 22; 1989 MECo/NEPCo Decision, 18 DOMSC at 308-310.

With regard to the increased growth rate for the forecast of miscellaneous end-use energy sales, the Company maintained that (1) residential energy sales had been underforecast in the past; (2) miscellaneous use was a key component of that energy underforecast; (3) dual-earner households were the most significant users of miscellaneous end-uses; and (4) increasing household income would lead to increased miscellaneous energy sales. Yet, in each of the foregoing instances, the Company provided little supporting evidence. First, BECo provided no information to support its claim of an underforecast in the residential sector. No data was provided to indicate the extent or magnitude of that underforecast. Second, BECo failed to provide analyses to indicate that any other residential end-uses had been examined as possible contributors to its residential underforecast. BECo's miscellaneous end-use methodology -- essentially derived as a "residual" -- should not be based on an assumption that forecast deficiencies which could be associated with other end-uses are to be assigned automatically to the miscellaneous end-use. Third, the Siting Council notes that BECo's claim regarding the convenience requirements of dual-earner households was not supported by evidence. While the Company asserted that dual-earner households would lead all other households in increased usage of miscellaneous appliances, no comparisons or other studies were provided to substantiate that assertion. Fourth, BECo presented contradictory claims regarding the effects of income on miscellaneous end-use energy sales. While BECo asserted that miscellaneous use was sensitive to income, BECo also asserted that reductions in income would have no effect on projected increasing levels of miscellaneous use. Further, the Company's reforecast of residential energy sales indicated a reduced level of household income growth (see Footnote 76, above). To the extent that the Company's forecast of miscellaneous end-use growth is sensitive to income, MASSPIRG's assertion regarding the effects of reduced household income growth would be valid. While the Company argued that its miscellaneous end-use category is difficult to forecast and lacks a historic database, the record indicates that major underlying factors of the Company's forecast of miscellaneous use were not substantiated. Consequently, the Siting Council agrees with MASSPIRG regarding the lack of supporting documentation for BECo's miscellaneous end-use category growth rate.

In addition, no evidence was offered by BECo to indicate that its assumed level of miscellaneous use, amounting to 1,300 kwh for 1989, was representative of miscellaneous use for BECo's residential customers or that such a level of use had been determined through a systematic methodology. Further, the Company's contention -- that a base level of 1,300 kwh combined with a three percent growth rate would yield greater miscellaneous usage in the year 2014 than that initially forecast by the Company -- is unpersuasive in the absence of documentation to support the base level of 1,300 kwh per year assumed by BECo.

In a previous decision, the Siting Council required an electric company to fully explain and justify its forecast of miscellaneous end-use energy sales. 1990 MMWEC Decision, 20 DOMSC at 23-24. Here, the Siting Council notes that the Company has identified a number of factors which could affect miscellaneous use, such as dual-earner households and household income. However, the Company's identified factors have not been supported by sufficient evidence to provide a sound basis for the increased growth rate applied to the Company's miscellaneous end-use category.

Nonetheless, the Siting Council notes that BECo has developed service-territory-specific data to support its forecasts of seven appliances which total about 60 percent of the Company's residential energy requirements for 1991 and has incorporated price-elasticity responses to all of the appliances identified in its forecast of average use.

Accordingly, based on the foregoing, the Siting Council finds the the Company's forecast of average use per appliance is minimally acceptable. However, in order for the Siting Council to approve BECo's residential forecast in its next filing, the Company must furnish (1) a complete explanation of how appliance efficiency standards were applied to its forecast of average use per appliance along with an average use forecast consistent with an application of those standards, and (2) full supporting documentation of its forecast of miscellaneous use including analyses of the major factors identified as contributing to miscellaneous use, and a complete justification of its selection of a growth rate for the miscellaneous end-use category based on those analyses.

(E) Conclusions on the Long-Run Forecast

The Siting Council has found that (1) BECo's forecast of the number of residential customers is acceptable; (2) BECo's forecast of the number of appliances is acceptable, and (3) BECo's forecast of the average use per appliance is minimally acceptable.

Accordingly, the Siting Council finds BECo's forecast of long-run residential energy requirements to be reviewable, minimally appropriate and minimally reliable at the time it was filed.

iii. Conclusions on the Initial Forecast

The Siting Council has found that BECo's residential short-run energy forecast is reviewable, minimally appropriate and minimally reliable at the time of filing. The Siting Council has also found that BECo's long-run residential energy forecast is reviewable, minimally appropriate and minimally reliable at the time it was filed. Accordingly, the Siting Council finds BECo's initial residential forecast to be reviewable, minimally appropriate and minimally reliable at the time it was filed.

b. Reforecast

i. Description

BECo stated that it reforecasted residential energy sales employing the same methodology used in its initial residential sales forecast (Exh. HO-D-111). However, BECo noted that its reforecast utilized updated economic inputs (id.). Specifically, the Company indicated that its reforecast relied on August, 1991 DRI data as opposed to the January, 1989 DRI data which was used in its initial forecast filing (id., Exh. BE-9). Based on that

August, 1991 DRI data, BECo noted changes in two key variables: (1) DRI's August, 1991 projection of income was lower than its January, 1989 income projection, and (2) the number of residential customers -- derived from a projection of population -- was higher based on DRI's August, 1991 data (Exh. HO-D-111).[76] In its reforecast, BECo projected residential energy sales to grow at a compound annual growth rate of 2.48 percent per year over the period 1991 to 2000, as opposed to a compound annual growth rate of 1.76 percent per year under the initial forecast (id., Exh. BE-2, p. 68).

ii. Analysis and Findings

The Siting Council has reviewed the Company's long-run forecast methodology (see Section II.C.4.a.ii, above). In that review, the Siting Council found the Company's long-run forecast to be reviewable, minimally appropriate, and minimally reliable at the time it was filed.

Here, the Siting Council notes that BECo's reforecast of residential energy sales utilized more recent data as an input to the same methodologies used in its initial forecast of residential energy sales. In previous decisions, the Siting Council has required companies to update elements of their forecasts to determine the effects of changed circumstances. Eastern Energy Corporation, EFSC 90-100, pp. 8, 19-23 (1991) ("Eastern"); 1990 MMWEC Decision, 20 DOMSC at 1, 7; Fitchburg Gas and Electric Light Company, 19 DOMSC 69, 74-75 (1989) ("1989 Fitchburg Decision"). The Siting Council notes that the use of updated economic data here led to revised projections of two

76/ BECo reported that income was projected to grow at a compound annual growth rate of 0.9 percent in DRI's August, 1991 projection, as opposed to a growth rate of 1.5 percent based on DRI's January, 1989 projection (Exh. HO-D-111). BECo did not specify the time period related to that growth rate comparison (id.). BECo indicated that over the period 1991-2000, the number of new residential customers was projected to grow at a compound annual growth rate of 0.77 percent based on DRI's August, 1991 data, as opposed to a growth rate of 0.44 percent based on DRI's January, 1989 data (id.).

components of residential consumption and thereby resulted in a residential energy requirements projection that is higher than that of the Company's initial forecast filing. Nevertheless, the Siting Council notes that more current economic data and the results of the reforecast using that data offer a higher degree of reliability than the data and results of the initial forecast.

Accordingly, for purposes of this review, the Siting Council finds BECo's residential reforecast to be reviewable, minimally appropriate, and reliable at the time of the reforecast.

c. Conclusions on Residential Forecast

The Siting Council has found that BECo's initial residential forecast is reviewable, minimally appropriate, and minimally reliable at the time it was filed. For purposes of this review, the Siting Council also has found that BECo's reforecast of residential energy demand is reviewable, minimally appropriate and reliable at the time of the reforecast.

The Siting Council notes that its current review is the first comprehensive review of BECo's residential demand forecast methodology. Here, the Siting Council has focussed on a broad range of issues which are pertinent to BECo's residential forecast and which reflect the level of review applied to electric companies in recent Siting Council decisions. In several instances, the Company's methodology has been identified as weak. Nonetheless, the Company has established a sound framework for residential demand forecasting, based largely on a disaggregated end-use model. In the future, the Company has the opportunity to strengthen its residential forecast methodology and to develop that methodology in accordance with electric companies of similar size and resource levels.

Accordingly, based on the foregoing, the Siting Council finds BECo's residential energy forecast to be reviewable, minimally appropriate, and reliable at the time of the reforecast.

5. Commercial Energy Forecast

BECo stated that its commercial sector energy demand was 7,112 GWH in 1991, or approximately 55 percent of its overall energy sales in that year (Exh. HO-D-111). BECo's unadjusted initial commercial energy demand was forecasted to increase from 7,601 GWH in 1991 to 9,031 GWH in 2000, a compound annual growth rate of 1.9 percent (Exh. BE-2, p. 102).[77] See Table 4, below. In the reforecast, BECo projected unadjusted commercial energy demand to increase from 7,112 GWH in 1991 to 7,937 GWH in 2000, a compound annual growth rate of 1.2 percent (Exh. HO-D-111). See Table 5, below. The Company's ten-year commercial forecast is derived from a combination of its short-run commercial forecast and its long-run commercial forecast. Each of these is described below.

a. Initial Forecast

i. Short-Run Forecast

(A) Description

Dr. Cuomo stated that short-run forecasts are more appropriate than long-run forecasts for determining demand in the short term (Tr. 3, p. 154). Therefore, the Company indicated that it employed an econometric methodology to forecast short-run commercial energy demand on a monthly basis for the three-year period 1990 through 1992 (Exh. BE-2, p. 128). BECo projected that its unadjusted short-run commercial forecast would increase from 7,347 GWH in 1990 to 7,827 GWH in 1992, a compound annual growth rate of 3.2 percent (id., p. 102). BECo later indicated that actual commercial electricity demand in 1990 was 7,183 GWH and in 1991 it was 7,112 GWH (Exhs. BE-9, HO-D-111).

77/ The projections for energy demand do not reflect savings resulting from Company-sponsored C&LM and self-generation (Exh. BE-2, p. 102). If these savings are included, commercial energy demand is forecasted to increase from 7,413 GWH in 1991 to 8,031 GWH in 2000, a compound annual growth rate of .9 percent (id.).

BECo stated that its short-run commercial model incorporated the following variables: (1) Massachusetts personal income; (2) heating degree days; (3) temperature/humidity; (4) employment by trade; (5) a dummy variable for the summer season;[78] (6) calendar use days;[79] and (7) price (Exh. BE-2, p. 134).

BECo indicated that it obtained data for the model from several sources (Exh. HO-D-104). BECo stated that it obtained Massachusetts personal income data from DRI, and the heating degree day data and temperature/humidity data from another external source (id.). BECo further stated that it used Company data for the calendar use days variable and the results of the price forecast for the price variable (id.). For a discussion of the price forecast, see Section II.C.3.a, above. The Company indicated that it used the results of the employment forecast for trade employment (id.). For a discussion of the employment forecast, see Section II.C.1.a.i, above. In addition, Dr. Cuomo stated that employment is a "key driver of commercial energy sales" (Exhs. MP-1, BE-2, pp. 77-81).

BECo stated that its commercial short-run forecast is accurate and reliable (Exh. BE-2, p. 130). The Company indicated that the results of the commercial short-run model satisfied all the relevant statistical tests (id.). BECo also indicated that each individual variable was statistically significant (id.).

(B) Analysis and Findings

In the past, the Siting Council has accepted the use of short-run models as an appropriate method for forecasting energy

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78/ A dummy variable is used to model the increased energy consumption during the summer months of June, July, August, and September (Exh. BE-2, p. 134).

79/ Calendar use days are the actual number of calendar billing days during the month, as opposed to the meter reading schedule (Exh. BE-2, p. 132). BECo stated that the use of actual calendar use days improved the statistical performance of its equation (id.).

demand in the short run. 1992 NU Decision, EFSC 90-17, p. 11; 1989 BECo Decision, 18 DOMSC at 221; 1988 NU Decision, 17 DOMSC at 6. In its previous filing, BECo used a two-year short-run forecast. 1989 BECo Decision, 18 DOMSC at 221. In this filing, however, BECo extended its short-run forecast period to three years. The Siting Council has serious concerns regarding the expansion of the short-run forecast to cover such an extended period of time. While the Siting Council recognizes the validity of using a short-run econometric methodology to determine the short-run effects on demand of certain variables, an econometric methodology applied over an extended period of time becomes both less representative of the determinants of demand and less reliable.

BECo has established that all its data, except the employment data, are derived from reasonably accurate and reliable sources. BECo obtained the employment data for the commercial short-run forecast from its employment forecast. The Siting Council has found that BECo has failed to establish that its initial employment forecast is reliable. See Section II.C.1.c.i, above. Since, as the Company has acknowledged, employment is a "key driver of commercial energy sales," a commercial short-run forecast based on substantially inaccurate employment data is unlikely to be reliable. In fact, the record indicates that BECo's short-run forecast of 7,347 GWH of commercial energy demand in 1990 is far greater than its actual commercial energy demand of 7,183 GWH for that same year. In addition, BECo's short-run commercial forecast indicated a growth rate of 3.6 percent from 1989 to 1990, while the actual growth rate for this period was only 1.2 percent.[80]

80/ The Company's projection of commercial demand in the second year of the short-run forecast did not reflect the decline in commercial energy demand which actually occurred. Specifically, BECo's short-run forecast predicted 7,827 GWH of commercial demand for 1991 while actual commercial demand amounted to 7,112 GWH for that same year (Exhs. BE-2, p. 102, HO-D-111).

Although the Company has failed to establish that (1) it is fully appropriate to implement a short-run forecast, (2) it is appropriate to extend its short-run forecast beyond two years, and (3) reliance on the initial employment forecast results in a reliable commercial forecast, BECo has established that its commercial short-run forecast methodology is statistically sound. Therefore the Siting Council finds that BECo's short-run commercial energy forecast is reviewable, and minimally appropriate. However, the Siting Council also finds that the Company has failed to establish that its short-run commercial forecast is reliable.

In order for the Siting Council to approve the short-run commercial forecast in BECo's next filing, the Company must furnish: (1) full justification for the use of a short-run commercial forecast and the period over which it is applied; and (2) evidence that all variables and data inputs into the short-run forecast are appropriate and reliable.

ii. Long-Run Forecast

(A) Description

BECo indicated that its long-run commercial energy forecast extended from 1993 through 1999 (Exh. BE-2, p. 102). BECo forecasted its unadjusted long-run commercial energy demand to increase from 8,068 GWH in 1993 to 8,875 GWH in 1999, a compound annual growth rate of 1.6 percent (id.).

BECo stated that its long-run commercial forecast methodology is essentially the same as the methodology approved by the Siting Council in the 1989 BECo Decision (18 DOMSC at 219; Exh. BE-2, p. 70). BECo stated that it employs an end-use model called the Commercial Energy Demand Modeling System ("CEDMS"), developed by Jerry Jackson & Associates (id.). CEDMS forecasts energy consumption for 12 building types[81] and eight end uses[82] (id., p. 69).

CEDMS calculates energy use for each building type and end use by multiplying the quantity of equipment, the maximum energy consumption of that equipment (Energy Use Index or "EUI"), and the percentage of energy actually consumed relative to the EUI ("utilization factor") for each building type (id., p. 71). The Company stated that the base year data for the model was developed by BECo in 1985 and recalibrated in 1987 (id., p. 70).

BECo stated that it determined the quantity of equipment from the quantity of floor space (Exh. BE-2, p. 71). BECo stated that it used employment as a proxy to determine the quantity of floor space (id.). The Company indicated that it obtained employment figures from the employment forecast (id.). For a discussion of the employment forecast, see Section II.C.1.a.i, above.

The Company stated that it forecasted floor space by multiplying estimates of the amount of floor space per employee by the number of employees (id.). BECo indicated that the floor space forecast included both existing floor space and new floor space additions (id.). BECo stated that it calculated new floor space additions as the difference between the floor space forecast and the amount of existing floor space (id.). The Company indicated that it calculated the amount of existing floor space over the forecast period by applying an age distribution to current floor space and using floor space removal rates (id.).

BECo stated that the EUI for each building type changes every year as new building additions are made and existing

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81/ The 12 building types are: offices, restaurants, retail trade, grocery stores, warehouses, elementary/secondary schools, colleges/universities, hospitals, other health services, hotels/motels, public (except office buildings), and miscellaneous (Exh. BE-2, p. 69).

82/ The eight end uses are: space heating, air conditioning, ventilation, water heating, cooking, refrigeration, lighting, and others (Exh. BE-2, p. 70).

buildings are removed (id.). The Company indicated that the EUIs for existing buildings remain the same over their lifetimes once they are established (id.). BECo stated that it used several different methodologies to calculate the EUIs for new building additions (id.).

BECo stated that it can model the EUI for each individual new building addition (id., p. 73). BECo further stated that the heating, ventilation, and air conditioning end-use EUIs are determined through a random selection method which accounts for energy use requirements, system costs, fuel prices, operating costs, and payback requirements (id., pp. 72-73). BECo determined the EUI for the lighting end use through a random selection method similar to that used to select the heating, ventilation, and air conditioning end-use EUIs (id.). The Company determined the EUIs for water heating, cooking, refrigeration, and other end uses by using fuel price and efficiency elasticities (id.). BECo calculated these elasticities through a time series analysis of commercial energy demand (id.).

BECo obtained utilization factors through the use of utilization elasticities (id.). The Company calculated utilization elasticities through econometric equations which considered electricity price, price of competing fuels, and climate variables (id., p. 77).

For the initial forecast, BECo stated that it had made several revisions to its data since its last filing (id.). The Company stated that it had redefined building types, restructured floor space and employment data according to the new building types, disaggregated cooking and refrigeration from the miscellaneous end use category, developed territory-specific EUIs, estimated short-run utilization elasticities, and recalibrated CEDMS to 1987 data (id.).

BECo's overall commercial energy forecast is derived from a blending of its short-run and long-run commercial energy forecasts (Tr. 3, p. 154). In an attempt to blend the short-run and long-run forecasts, the Company stated that it compared the

1992 short-run forecast figure with the 1993 long-run forecast figure and observed an "almost negligible" growth rate (id.). BECo stated that it considered this low growth rate to be "very unrealistic," and proceeded with a comparison of the 1992 short-run figure and the 1994 long-run figure (id.). However, this comparison also did not yield satisfactory growth rates (id.). BECo stated that it continued the comparisons until the year 2000, at which point the Company determined that the growth rate was reasonable (id.).

To bridge the 1993 to 1999 blending period, the Company employed a straight line time series analysis (Exh. HO-D-43). BECo used the 1992 short-run commercial sales forecast figure as a starting point and the year 2000 long-run commercial sales forecast figure as the endpoint, and calculated a compound annual growth rate between the two points (id.). BECo applied this compound annual growth rate to the 1992 short-run figure to obtain the 1993 forecast figure (id.). The Company then applied the compound annual growth rate to the 1993 figure to obtain the 1994 figure, and continued this process until it had obtained forecasts for the years 1993 through 1999 (id.).

BECo stated that the CEDMS model assumes an increase in commercial energy utilization as a response to efficiency improvements ("snapback effect") (Exh. MP-20). BECo stated that the snapback effect is equal to 15 percent of efficiency savings, or an average of 19 GWH per year from 1990 to 2000 (id., Exh. MP-RR-9). In support of its assumption, BECo cited several articles regarding the snapback effect in the residential sector (Exh. MP-17). The Company, however, did not provide any documentation or data in support of its assumption of a 15 percent snapback effect in the commercial sector (id., Exh. MP-18).

(B) Positions of Parties

MASSPIRG contends that the Company has overestimated commercial energy demand through the inclusion of the 15 percent snapback effect (MASSPIRG Initial Brief, p. 3). In response to

MASSPIRG's contention, BECo claimed that the 15 percent snapback effect is theoretically sound and should be incorporated into the long-run commercial forecast (BECo Initial Brief, p. 48).

MASSPIRG further contended that BECo has failed to account for the effect on demand of a recently implemented five percent Massachusetts sales tax on commercial and industrial electricity sales (MASSPIRG Initial Brief, p. 3). In response, BECo stated that commercial and industrial energy demand are determined by the demand for the products and services produced by these sectors, and that commercial and industrial energy demand would be affected only by a substantial increase in the price of electricity (BECO Initial Brief, p. 48). BECo indicated that the cost of electricity comprises only approximately three to four percent of total costs to the commercial sector, and therefore a five percent increase in the price of electricity "would not have a perceptible impact on electricity demand" (id.; Tr. 4, p. 184).

(C) Analysis and Findings

Generally, BECo's modifications to its long-run commercial model and improvements to its data represent significant efforts by the Company to continually improve its forecast. The Company has demonstrated that its improvements have likely increased the reliability of the results of its long-run forecast. The Siting Council has approved this same long-run commercial forecast methodology in the past with the understanding that BECo would continue to improve its data and assumptions. 1989 BECo Decision, 18 DOMSC at 219. Here, BECo has demonstrated that it is continuing to improve its data and assumptions.

Nonetheless, several aspects of BECo' methodology raise concerns. First, with regard to BECo's blending of its short-run and long-run commercial forecasts, the Siting Council notes that pursuant to G.L. c. 164, sec. 69I, BECo is required to present a ten-year forecast of demand and supply. Here this period extends from 1990 through the year 2000. The Siting Council notes that the results of the CEDMS long-run end-use forecast are only used for the year 2000. For the blending period between the short-run and long-run forecasts from 1993 through 1999, BECo employed a straight line time series projection. Consequently, for seven of the eight statutory forecast years that BECo designated as long-run forecast years, BECo did not use its long-run end-use methodology to forecast commercial energy demand.

The Siting Council has serious concerns regarding the appropriateness of blending the short-run and long-run commercial energy forecasts. In utilizing the blending methodology to produce the commercial energy forecast for the years 1993 through 1999, the Company seems to have undermined the intent of the implementation of an end-use forecasting methodology to forecast long-run commercial energy demand. The straight line time series projection cannot capture the level of detail necessary to reflect accurately annual variations in commercial energy demand. Moreover, the Siting Council notes that BECo did not use a similar methodology to blend the short-run and long-run residential energy forecasts. Instead, the short-run residential forecast and the long-run residential forecasts were simply combined. For a discussion of the short-run residential forecast, see Section II.C.4.a.i.(A), above.

Furthermore, the Siting Council notes that BECo failed to demonstrate that it applied a quantitative and reliable approach to determining the appropriate period over which to blend the results of the short-run and long-run commercial energy forecasts. In fact, the record indicates that the Company appears to have arbitrarily selected a blending period that would produce an expected growth rate. The Siting Council notes that this is the first time it has performed a detailed analysis of the blending of short-run and long-run forecasts in a forecasting methodology. Consequently, in spite of the detrimental effects of the blending methodology on the reliability and appropriateness of BECo's overall commercial energy forecast, the Siting Council accepts this methodology for the purposes of this review only.

Second, the Siting Council notes that BECo's long-run commercial forecast uses employment as a proxy for floor space.

Therefore, employment is a key driver of the long-run commercial forecast. BECo obtained the employment data for the long-run forecast from its employment forecast. The Siting Council has found that BECo has failed to establish that its initial employment forecast is reliable. See Section II.C.1.c.i, above. As a result, a long-run commercial forecast based on unreliable data is unlikely to be reliable.

Third, the Company also has failed to document or justify its inclusion of a 15 percent snapback effect in the long-run model. In past reviews of commercial forecasts, the Siting Council has required electric companies to provide sufficient documentation in support of their assumptions. 1991 CECo/CELCo Decision, EFSC 90-4 at 27; 1989 MECo/NEPCo Decision, 18 DOMSC at 335; 1988 NU Decision, 17 DOMSC at 11.

The Siting Council, however, agrees with the Company that the five percent sales tax on commercial energy may not significantly affect total commercial energy demand. Assuming electricity costs comprised four percent of total commercial costs, a five percent increase in the price of electricity would only amount to a 0.2 percent increase in total commercial costs. This magnitude of increase in electricity price would be unlikely to alter the electricity consumption patterns in the commercial sector.

In sum, BECo's dependence on unreliable employment data as a key driver for its long-run commercial forecast, its inclusion of a 15 percent snapback effect, and its blending of the short-run and long-run commercial forecasts may seriously impact the reliability of its overall commercial forecast. In fact, BECo's use of unreliable employment forecast data and incorporation of the 15 percent snapback effect may have caused it to overestimate its long-run commercial forecast.

Accordingly, the Siting Council finds that BECo's long-run commercial energy forecast is reviewable and minimally appropriate. The Siting Council also finds that the Company has failed to establish that its long-run commercial energy forecast is reliable. In order for the Siting Council to approve the commercial forecast in BECo's next filing, the Company must furnish: (1) full justification and documentation for the inclusion of any snapback effect in its long-run commercial forecast; (2) evidence that it has incorporated reliable employment data in the calculation of its long-run commercial forecast; and (3) either full justification for or omission of the practice of blending the short-run and long-run commercial forecasts over an extended period of time.

iii. Conclusions on the Initial Forecast

The Siting Council has found that BECo's short-run commercial energy forecast is reviewable and minimally appropriate. The Siting Council, however, also has found that the Company has failed to establish that its short-run commercial energy forecast is reliable. The Siting Council has found that BECo's long-run commercial energy forecast is reviewable and minimally appropriate. The Siting Council also has found that the Company has failed to establish that its long-run commercial energy forecast is reliable. Accordingly, the Siting Council finds that BECo's initial commercial energy forecast methodology is reviewable and minimally appropriate. However, the Siting Council also finds that the Company has failed to establish that its initial commercial energy forecast is reliable.

b. Reforecast

i. Description

BECo stated that its reforecast of commercial energy demand demonstrated slower growth than its initial forecast (Exh. HO-D-111). BECo indicated that its reforecast projected unadjusted commercial energy demand to increase from 7,112 GWH in 1991 to 7,937 GWH in 2000, a compound annual growth rate of 1.2 percent (id.). By contrast, the initial forecast produced unadjusted commercial energy demand figures of 7,601 GWH in 1991 increasing to 9,031 GWH in 2000, a compound annual growth rate of 1.9 percent (Exh. BE-9).

BECo stated that it used CEDMS to produce its reforecast of long-run commercial energy demand (Exh. HO-D-111). The Company indicated that it used the revised commercial employment forecast as the input for the reforecast (id.). For a discussion of the revised commercial employment forecast, see Section II.C.1.a.ii, above. The Company indicated that the reforecast utilized employment data that are approximately 31 months more recent than the data used in the initial forecast (id.).

ii. Analysis and Findings

BECo indicated that the methodology used for the reforecast of commercial energy demand is the same as that used for the initial forecast of commercial energy demand. Nevertheless, the methodological problems of blending and snapback are still present. However, the commercial employment forecast used in the reforecast is based on data that is 31 months more recent than that used in the initial forecast. Accordingly, the Siting Council finds BECo's reforecast of commercial energy demand to be reviewable, minimally appropriate and minimally reliable at the time of the reforecast.

c. Conclusions on the Commercial Energy Forecast

The Siting Council has found that BECo's initial commercial energy forecast is reviewable and minimally appropriate. The Siting Council also has found that BECo has failed to establish that its initial commercial energy forecast is reliable. The Siting Council has found BECo's reforecast of commercial energy demand to be reviewable, minimally appropriate, and minimally reliable at the time of the reforecast. Accordingly, the Siting Council finds BECo's commercial energy forecast to be reviewable, minimally appropriate, and minimally reliable at the time of the reforecast.

6. Industrial Energy Forecast

BECo stated that its industrial sector energy demand was 1,685 GWH in 1991, or approximately 13 percent of its overall energy sales in that year (Exh. HO-D-111). BECo's unadjusted initial industrial energy demand was forecasted to increase from 1,874 GWH in 1991 to 2,009 GWH in 2000, a compound annual growth rate of 0.8 percent (Exh. BE-2, p. 112).[83] See Table 4, below. In the reforecast, BECo projected unadjusted industrial energy demand to increase from 1,685 GWH in 1991 to 1,956 GWH in 2000, a compound annual growth rate of 1.6 percent (Exh. HO-D-111). See Table 5, below. The Company's ten-year industrial forecast is derived from a combination of its short-run industrial forecast and its long-run industrial forecast. Each of these is described below.

a. Initial Forecast

i. Short-Run Forecast

(A) Description

BECo indicated that it employed an econometric methodology to forecast short-run industrial energy demand on a monthly basis for the three-year period 1990 through 1992 (Exh. BE-2, p. 128). BECo forecasted its unadjusted short-run industrial energy demand to increase from 1,869 GWH in 1990 to 1,890 GWH in 1992, a compound annual growth rate of 0.6 percent (id., p. 112).

BECo stated that its short-run industrial forecasting model uses the following variables to determine industrial energy demand: (1) manufacturing employment; (2) U.S. industrial production index; (3) calendar use days; (4) U.S. producer price

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83/ The projections for energy demand do not reflect savings resulting from Company-sponsored C&LM and Time-of-Use ("TOU") rates (Exh. BE-2, p. 112). If these savings are included, BECo forecasts energy demand as 1,854 GWH in 1991 increasing to 1,952 GWH in 2000, a compound annual growth rate of 0.6 percent (id.).

index; (5) weather;[84] (6) price; and (7) U.S. inventory/sales ratio (id., p. 137). BECo indicated that manufacturing employment is the most significant variable (id.).

BECo indicated that it obtained the data for the industrial short-run forecast from various sources (Exh. HO-D-104). BECo stated that it obtained the U.S. industrial production index, the U.S. producer price index, and the U.S. inventory/sales ratio from DRI forecasts (id.). The Company indicated that it used the manufacturing employment forecast from its employment forecast for the manufacturing employment variable (id.). For a discussion of the manufacturing employment forecast, see Section II.C.1.a.i, above. BECo further stated that it used Company data for the calendar use days variable, a weather study by an external source for the weather variable, and the price forecast for the price variable (id.). For a discussion of the price forecast, see Section II.C.3.a, above.

BECo stated that the industrial short-run forecast was developed based on eight and one-half years of historical monthly data (Exh. BE-2, p. 137). The Company indicated that the results of the industrial short-run equation are all statistically significant (id.).

(B) Analysis and Findings

In the past, the Siting Council has accepted the use of short-run models as an appropriate method of forecasting energy demand in the short run. 1992 NU Decision, EFSC 90-17, p. 11; 1989 BECo Decision, 18 DOMSC at 221; 1988 NU Decision, 17 DOMSC at 6. As in the commercial forecast, however, BECo has extended its short-run industrial forecast period in this filing, in this case from two years to three years. The Siting Council expresses here the same concerns it raised in our review of the commercial

84/ The weather variable is calculated by summing temperature/humidity and the product of heating degree days and windspeed (Exh. BE-2, p. 137).

forecast regarding the appropriateness and reliability of using the short-run forecast over such an extended period of time. See Section II.C.5.a.i, above.

BECo has established that its data, with the exception of the employment data, are derived from reasonably accurate and reliable sources. BECo obtained the manufacturing employment data for the industrial short-run forecast from its employment forecast. For a discussion of the manufacturing employment forecast, see Section II.C.1.a.i, above. The Siting Council has found that the Company failed to establish that its initial employment forecast was reliable. The Siting Council also notes that employment is the most significant variable in the industrial short-run equation. Consequently, an industrial short-run forecast based on inaccurate employment data is not likely to be reliable.

The Siting Council has noted its concerns regarding the appropriateness and reliability of BECo's short-run industrial forecast. However, the Company has established that its industrial short-run model is statistically sound. Therefore, the Siting Council finds that BECo's short-run industrial energy forecast is reviewable and minimally appropriate. The Siting Council also finds that the Company has failed to establish that its short-run industrial energy forecast is reliable.

In order for the Siting Council to approve the short-run industrial energy forecast in BECo's next filing, the Company must furnish full justification for the incorporation of the results of a short-run industrial forecast and the period over which those results are applied.

ii. Long-Run Forecast

(A) Description

BECo indicated that its long-run industrial energy forecast extended from 1993 through 1999 (Exh. BE-2, p. 112). BECo forecasted its unadjusted long-run industrial energy demand to increase from 1,904 GWH in 1993 to 1,994 GWH in 1999, a compound annual growth rate of 0.8 percent (id.).

BECo indicated that the basic methodology used in its industrial long-run forecast has been modified from the methodology last approved by the Siting Council (Tr. 3, pp. 161-162). See 1989 BECo Decision, 18 DOMSC at 219-220. BECo stated that it previously forecasted long-run industrial energy requirements with a combination of end-use modeling and econometric equations (Tr. 3, pp. 161-162, Tr. 4, p. 6). Here, BECo's long-run industrial energy forecast methodology is based entirely on end-use modeling (Exh. BE-2, pp. 103, 104, 115). Further, BECo indicated that it has replaced the end use model used in its previous forecast with the current model (id., p. 103).

BECo forecasted long-run industrial class consumption by assuming that energy requirements were represented by the sum of 19 identified industrial SIC manufacturing groups in its service territory (id., pp. 113-119).[85] In addition, BECo assumed that the electricity requirements of its industrial customers were driven by two major factors: (1) the demand for manufactured goods (i.e., industrial output), and (2) the level of electricity use per unit of output (i.e., the intensity of manufacturers' electricity use) (id., p. 103; Tr. 3, p. 179). Thus, BECo asserted that changes in industrial energy consumption could be forecast by projecting the rates of change in output and energy intensity (Exh. BE-2, pp. 103-105). BECo indicated that the

85/ The 19 two-digit SIC groups are: food and kindred products (SIC 20); textile mills (22); apparel products (23); lumber and wood (24); furniture and fixtures (25); pulp and paper (26); printing and publishing (27); chemicals (28); petroleum products (29); rubber and plastics (30); leather products (31); stone, clay, and glass (32); primary metals (33); fabricated metals (34); non-electric machinery (35); electrical machinery (36); transportation equipment (37); instruments (38); and miscellaneous (39) (Exh. BE-2, p. 115).

Factor Decomposition Model ("FDM") implemented by the Company was designed to incorporate those rates of change (id., p. 103).[86]

BECo stated that its FDM model is being implemented in two phases (id., p. 104). BECo indicated that it presented Phase I in this filing (id., p. 104; Exh. HO-D-55). BECo stated that Phase II would involve expansions and refinements in data inputs (id.). BECo indicated that three factors -- fuel alternatives, energy efficiency, and building stock -- would be added to the model in Phase II (Exh. BE-2, pp. 104, 114).

BECo contended that end-use data would be identified fully and developed in Phase II (id., p. 106). BECo stated that "electric technology development" -- defined as end-use data covering saturation and penetration rates for end-use equipment such as efficient motors, heat pumps, and lighting, as well as industrial process and mechanical equipment -- was the most important variable affecting intensity (Exhs. HO-D-49, HO-D-50). As a consequence, BECo reported that data to support that variable presently was being developed based on its 1989 commercial/industrial customer survey (Exh. HO-D-50). Finally, Dr. Cuomo indicated that the manufacturers "most important" to the service territory -- the non-electric machinery (35), electrical machinery (36), and instruments (38) SIC groups -- would be analyzed for disaggregation to the three-digit SIC level (Tr. 3, p. 164).

BECo stated that its overall industrial energy forecast was derived from a blending of its short-run and long-run industrial energy forecasts (id., p. 74). BECo indicated that it used the same methodology to select the blending period for the short-run and long-run industrial forecasts that it used to select the blending period for the commercial forecast (id., p. 156). See Section II.C.5.a.ii.(A), above. BECo stated that its short-run industrial forecast produced very low results, and

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86/ Dr. Cuomo indicated that because the Company's previous end-use model -- the Production Input Decision Model -- required "extensive" data without a corresponding increase in accuracy, BECo adopted the FDM (Tr. 3, p. 162).

a comparison of those growth rates to the long-run industrial forecast results for the years 1993 through 1995 yielded "ridiculously high growth rates" (id., p. 78). BECo indicated that the long-run forecast predicted a rebound in the industrial sector (id.). Consequently, the Company stated that it selected 1993 through 1999 as the blending period for the short-run and long-run industrial forecasts (id.). BECo stated that the year 2000 "was a much more realistic long-run point to compare to the short-run forecast," which ends in 1992 (id.).

To bridge the 1993 through 1999 blending period, the Company employed a straight line time series analysis (Exh. HO-D-44). BECo used the 1992 short-run figure as a starting point and the year 2000 long-run figure as the endpoint, and calculated a compound annual growth rate between the two points (id.). BECo applied this compound annual growth rate to the 1992 short-run figure to obtain the 1993 forecast figure (id.). The Company then applied the compound annual growth rate to the 1993 figure to obtain the 1994 figure, and continued this process until it had obtained forecasts for the years 1993 through 1999 (id.).

MASSPIRG argued that BECo's industrial forecast was biased because effects of a recently enacted five percent energy tax were omitted (MASSPIRG Brief, p. 3). During this proceeding, Dr. Cuomo indicated that the effects on consumption attributable to such a tax would not be significant because: (1) electricity cost is a minor concern of manufacturers, since it averages about two percent of finished product cost, and (2) the energy tax included numerous exceptions and exemptions (Tr. 4, pp. 183-186).

(B) Analysis and Findings

The Siting Council notes that the Company's modifications to its industrial model relative to the model employed in its previous forecast represent an important advance toward a more comprehensive end-use methodology for the industrial sector. In fact, another electric company has begun to use similar end-use models to forecast industrial energy demand. 1992 NU Decision, EFSC 90-17, pp. 30-36.

However, the Siting Council has a number of concerns regarding the Company's long-run industrial forecast. First, although BECo has continued to modify its long-run industrial end-use forecasting methodology, the Siting Council notes that, as in the commercial methodology, the results of the long-run forecast are not utilized for the years 1993 through 1999. See Section II.C.5.a.iii. The actual forecast methodology BECo employed over this period is a straight line time series projection. Consequently, the Siting Council has significant concerns similar to those in the commercial forecast regarding the appropriateness and the reliability of using the blending methodology over such an extended period of time.

Second, in using a procedure similar to that used in the commercial forecast, BECo also has failed to demonstrate that it applied a quantitative and reliable approach in determining the blending period between the short-run and long-run industrial forecasts. In fact, the record indicates that in the industrial sector, the Company arbitrarily selected a blending period that would produce "a more realistic" compound annual growth rate. In addition, the straight line time series blending methodology fails to provide the level of detail necessary to accurately reflect annual variations in industrial energy demand.

Although the Siting Council has concerns regarding the use of a straight line time series methodology to blend the short-run and long-run industrial forecasts over a seven year period, the Siting Council notes that this is the first time it has performed a detailed analysis of the blending of short-run and long-run forecasts in a forecasting methodology. Therefore, in spite of the deficiencies of the blending methodology, the Siting Council accepts the use of this methodology for purposes of this review only.

Finally, another weakness in the Company's current industrial forecast is the use of proxies to represent the electric technology development variable. The Company, however, has stated that it intends to fully develop the effects of electric technology development during Phase II of model implementation.

Here, as in its review of the commercial forecast, the Siting Council agrees with the Company that the five percent sales tax on industrial energy is not likely to have a significant effect on total industrial energy demand. Assuming electricity costs comprised two percent of total industrial costs, as the Company maintains, a five percent increase in the price of electricity would amount to only a 0.1 percent increase in total industrial costs. This magnitude of increase would not be sufficient to substantially alter the electricity consumption patterns of the industrial sector. See Section II.C.5.a.ii.(B), above.

Still, BECo's use of the blending methodology, and its use of proxies to represent the electric technology development variable, may affect the reliability of the industrial energy forecast. Accordingly, the Siting Council finds BECo's long-run industrial energy forecast to be reviewable, minimally appropriate and minimally reliable at the time it was filed.

In order for the Siting Council to approve the industrial forecast in BECo's next filing, the Company must furnish: (1) reliable data and an appropriate methodology to model the effects of electric technology development; and (2) either full justification for or omission of the blending of the short-run and long-run industrial energy forecasts over an extended period of time.

iii. <u>Conclusions on the Initial Forecast</u>

The Siting Council has found that BECo's short-run industrial energy forecast is reviewable and minimally appropriate. The Siting Council also has found that the Company has failed to establish that its short-run industrial energy forecast is reliable. The Siting Council has found that BECo's long-run industrial energy forecast is reviewable, minimally appropriate and minimally reliable at the time it was filed.

Accordingly, the Siting Council finds that BECo's initial industrial forecast is reviewable and minimally appropriate. However, the Siting Council also finds that the Company has failed to establish that its initial industrial energy forecast is reliable.

b. Reforecast

i. Description

BECo indicated that its reforecast produced lower energy demand figures through 2000 (Exh. HO-D-111). However, BECo stated that, over the forecast period, its reforecast of industrial energy demand demonstrated higher growth rates than its initial forecast (id.). BECo indicated that its reforecast projected unadjusted industrial energy demand to be 1,685 GWH in 1991 increasing to 1,956 GWH in 2000, a compound annual growth rate of 1.6 percent (id.). See Table 5, below. By contrast, the initial forecast produced unadjusted industrial energy demand figures of 1,874 GWH in 1991 increasing to 2,009 GWH in 2000, a compound annual growth rate of 0.8 percent (Exh. BE-2, p. 112). See Table 4, below. However, the Company indicated that its actual industrial energy demand decreased 95 GWH between 1989 and 1990, and another 65 GWH between 1990 and 1991 (Exh. HO-D-111).

BECo stated that it used the FDM to produce its reforecast of industrial energy demand (id.). BECo indicated that it used the revised industrial employment forecast as the input for the reforecast (id.). For discussion of the revised industrial employment forecast, see Section II.C.1.a.ii, above. BECo did not indicate any differences in methodology between the initial industrial forecast and the reforecast (id.).

ii. Analysis and Findings

BECo indicated that the methodology used for the reforecast of industrial energy demand is the same as that used for the initial forecast of industrial energy demand. However, the inputs to the reforecast are revised, and therefore offer a higher level of reliability than those of the initial forecast.

Nonetheless, in light of the decrease in the actual industrial energy demand from 1989 to 1991, the Siting Council notes its concerns regarding the projected increased growth rate of the reforecast. Still, the results of the reforecast should be more reliable than those of the initial forecast.

Accordingly, the Siting Council finds BECo's reforecast of industrial energy demand to be reviewable, minimally appropriate and minimally reliable at the time of the reforecast.

c. Conclusions on the Industrial Energy Forecast

The Siting Council has found that BECo's initial industrial energy forecast is reviewable, and minimally appropriate. The Siting Council also has found that the Company has failed to establish that its initial industrial energy forecast is reliable. The Siting Council also has found BECo's reforecast of industrial energy demand to be reviewable, minimally appropriate and minimally reliable at the time of the reforecast. Accordingly, the Siting Council finds BECo's industrial energy forecast to be reviewable, minimally appropriate and minimally reliable at the time of the reforecast.

7. Other Energy Forecasts

In addition to forecasting electricity in the residential, commercial and industrial sectors, Boston Edison projected energy consumption for the following classes: streetlighting; municipal sales; MBTA; MWRA; and "losses and company use" (Exh. BE-2, pp. 121-123). See Tables 4 and 5 below.

a. Streetlighting Forecast

Boston Edison stated that streetlighting energy sales accounted for about one percent of total service territory sales in 1989 (id., p. 121). The Company stated that it expects sales in this category to decline from 129 GWH in 1990 to 110 GWH in 2000 (id., pp. 121, 124). BECo indicated that it expected constraints on municipal spending, particularly the provisions of "Proposition 2-1/2," and improvements in the energy efficiency of lamps used in streetlighting to reverse growth in streetlighting sales (id., p. 121). The Company stated that it assumed that through its C&LM programs 4,410 streetlights would be replaced annually for eight years, accounting for an average savings of 626 kwh per light (Exh. HO-D-81).

The Company stated that, because the streetlighting forecast is not sensitive to DRI economic projections, the initial streetlighting forecast was not changed in the reforecast (Exh. HO-D-111, p. 23.).

In a previous decision, the Siting Council rejected an electric company's streetlighting forecast because the company failed to provide documentation or support for the assumption that streetlighting sales would remain constant. See 1990 MMWEC Decision, 20 DOMSC at 36 and 37. Here, Boston Edison has provided limited documentation regarding its assumptions relative to its streetlighting C&LM programs and to its projections of declining streetlighting energy sales.

For purposes of this review, the Siting Council finds that the Company's streetlighting forecast to be reviewable, appropriate, and reliable at the time of the reforecast. In order for the Siting Council to approve BECo's streetlighting forecast methodology in its next filing, however, Boston Edison must furnish more extensive documentation to substantiate its assumptions regarding streetlighting sales. The Company's documentation of streetlighting sales assumptions should include, but not be limited to, information regarding the number of streetlights to be replaced, and the average savings per light.

b. Municipal Sales Forecast

Boston Edison stated that it sells electricity at wholesale to the municipal light departments in the Towns of Concord and Wellesley on an as-needed basis (Exh. BE-2, p. 121). The Company indicated that those light departments also purchase a small portion of their energy requirements from the New York Power Authority (id.). Boston Edison stated that municipal sales were expected to grow from 356 GWH in 1991 to 432 GWH in 2000 (id., p. 125).

To forecast municipal sales, Boston Edison stated that it used regression equations which operated under the assumption that the Towns' energy requirements were a function of GNP, personal income, and local employment (id.). The Company stated that Concord sales were a function of town employment and GNP, and that Wellesley sales were a function of personal income and GNP (Exh. HO-D-82). Employment forecasts were derived by applying territory employment growth rates to actual 1988 employment in Concord (Exh. BE-2, p. 125). The Company obtained GNP and personal income forecasts from DRI (id.).

The Company stated that the methodology used in the reforecast of municipal sales was the same as that used in the initial forecast. The Company indicated that, in the reforecast of municipal sales, August, 1991 DRI forecasts of employment, personal income and GNP were used (Exh. HO-D-111, p. 21). The Company stated that, in its reforecast, it expected municipal sales to grow from 333 GWH in 1991 to 421 GWH in 2000 (id., p. 22).

For the purposes of this review, the Siting Council finds Boston Edison's initial municipal sales forecast to be reviewable, appropriate and reliable at the time of filing. The Siting Council finds the Company's reforecast of municipal sales to be reviewable, appropriate and reliable at the time of the reforecast.

c. MBTA

Boston Edison stated that it had a "special contract" for energy sales with the MBTA (Exh. BE-2, p. 122). The Company stated that sales to the MBTA special account were forecasted to grow from 137 GWH in 1991 to 164 GWH in 2000 (id., p. 125). To forecast sales to the MBTA, the Company applied a projected commercial sector growth rate to 1988 MBTA consumption (id.).

BECo stated that, in the reforecast of sales to the MBTA, the Company used actual 1991 sales to the MBTA as a baseline, and applied a commercial sector growth rate from the reforecast

(Exh. HO-D-111, p. 23). Otherwise, the methodology used by the Company to forecast sales to the MBTA remained unchanged in the reforecast (id.).

For the purposes of this review, the Siting Council finds Boston Edison's initial MBTA sales forecast to be reviewable, appropriate and reliable at the time of filing. The Siting Council finds the Company's reforecast of sales to the MBTA to be reviewable, appropriate and reliable at the time of the reforecast.

d. MWRA

Boston Edison stated that it had a special contract with the MWRA for sales to the MWRA's Deer Island facility (Exh. BE-2, p. 122). The Company stated that it expected energy sales for this account to grow from 163 GWH in 1991 to 322 GWH in 2014 (id., pp. 122, 125). BECo stated that the forecast was developed from information obtained from the MWRA (id., p. 122).

The Company indicated that, because the forecast of sales to the MWRA is not sensitive to DRI economic projections, the initial forecast of sales to the MWRA was not changed in the reforecast (Exh. HO-D-111, p. 23).

For the purposes of this review, the Siting Council finds Boston Edison's forecast of MWRA sales to be reviewable, appropriate and reliable at the time of the reforecast.

e. Losses and Company Use

The Company stated that transmission and distribution system losses and company use would constitute approximately 9.1 percent of service territory sales over the forecast period (Exh. BE-2, pp. 122-123). BECo stated that this projection was slightly lower than the 9.4 percent forecasted in the Company's previous filing (id., pp. 122, 123, 126, and 127). The Company stated that losses and company use were projected to grow from 1,249 GWH in 1991 to 2,047 GWH in 2014 (id., pp. 126, 127). BECo stated that it calculated the loss percentage through an analysis of the Company's recent load data (id.).

In its reforecast filing, the Company provided no documentation of changes in methodology or data relative to its forecast of losses and company use.

For the purposes of this review, the Siting Council finds Boston Edison's forecast of losses and company use forecast to be reviewable, appropriate, and reliable.

f. Conclusions on the Other Energy Forecasts

The Siting Council has found BECo's forecast of streetlighting sales to be reviewable, appropriate, and reliable at the time of the reforecast. The Siting Council has also found the Company's initial forecasts of municipal sales and sales to the MBTA to be reviewable, appropriate and reliable at the time of filing, and the Company's reforecasts of municipal sales and sales to the MBTA to be reviewable, appropriate and reliable at the time of the reforecast. In addition, the Siting Council has found the Company's forecast of sales to the MWRA to be reviewable, appropriate and reliable at time of the reforecast. The Siting Council has also found the Company's forecast of losses and company use to be reviewable, appropriate, and reliable. Therefore, the Siting Council finds BECo's other energy forecasts to be reviewable, appropriate and reliable at the time of the reforecast.

8. Conclusions on the Energy Forecast

The Siting Council has found Boston Edison's employment forecast to be reviewable, appropriate and reliable at the time of the reforecast. The Siting Council has found BECo's initial demographic forecast and demographic reforecast to be reviewable, appropriate and reliable. The Siting Council also has found Boston Edison's price forecast to be reviewable, appropriate and reliable. In addition, the Siting Council has found BECo's residential energy forecast to be reviewable, minimally appropriate and reliable at the time of the reforecast. The Siting Council has found both BECo's commercial energy forecast and its industrial energy forecast to be reviewable, minimally appropriate and minimally reliable at the time of the reforecast. Finally, the Siting Council has found BECo's other energy forecasts to be reviewable, appropriate and reliable at the time of the reforecast.

Accordingly, the Siting Council finds BECo's forecast of energy requirements to be reviewable, minimally appropriate and reliable at the time of the reforecast.

D. Peak Load Forecast

1. Initial Forecast

a. Description

BECo stated that it is a summer peaking system and expects to remain so throughout the forecast period (Exh. BE-2, p. 145). BECo forecasted initial unadjusted summer peak load to increase from 2,809 MW in 1991 to 3,370 MW in 2000, a compound annual growth rate of 2.0 percent[87] (id., p. 11). See Table 1, below. BECo stated that it used the Electric Power Research Institute's ("EPRI") Load Management Strategy Testing Model ("LMSTM") to forecast peak load (id., p. 145). BECo indicated that LMSTM uses hourly load shapes and the energy forecast as inputs (id.). BECo stated that the data for the hourly load shapes were derived from territory-specific end-use load data obtained through load research conducted by the Company (id.).

BECo stated that LMSTM disaggregates hourly load shapes by sector[88] and end use[89] for each of four day types[90] and three

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87/ The unadjusted peak demand figures do not reflect the savings resulting from TOU rates, self-generation, and Company-sponsored C&LM (Exh. BE-2, p. 150). If these savings are included, the peak demand figures would be 2,603 MW in 1991 increasing to 2,852 MW in 2000, a compound annual growth rate of 1.0 percent (id.).

88/ The sectors are residential, commercial, industrial, streetlighting, MBTA, and MWRA (Exh. BE-2, pp. 151-153).

seasons[91] (id., p. 146). The Company stated that the energy forecast for each sector (i.e., residential, commercial, industrial, etc.) was allocated to the corresponding hourly load shape, by day type and season, for that sector to produce a peak load forecast for each sector (id.). BECo indicated that the peak load forecasts for all the sectors were summed to produce the peak load forecast for the service territory (Exh. HO-D-64).

BECo stated that it has disaggregated its peak load model adequately relative to its energy model, and that it plans to disaggregate the peak load model further in the future (Tr. 4, pp. 94-97). BECo indicated that it has disaggregated the most significant residential end uses, which represent approximately 40 percent of residential load (id., p. 94). The Company stated that it used 21 different load shapes to represent the base, heating and cooling loads in the commercial sector (Exh. HO-D-68). The Company further stated that it developed nine load shapes for the industrial class using data obtained from customers representing 75 percent of the industrial class (Exh. HO-D-69).

BECo indicated that the hourly load shapes were based on 1985 data because it was a normal weather year (Tr. 4, p. 85). The Company stated that it assumed normal weather conditions through the forecast period and did not adjust the peak load forecast for any weather abnormalities (Exh. HO-D-75). Dr. Cuomo

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89/ The end-use categories in the residential sector are heating, room air conditioning, central air conditioning, water heating, refrigeration, and others (Exh. BE-2, p. 151). The end-use categories for the commercial sector are heating, cooling and others (id., p. 152). The other sectors were not disaggregated by end use (id., pp. 152-153).

90/ The four day types are (1) weekdays, (2) weekends, (3) high days (the 14 days of highest demand in each season, excluding the peak day), and (4) peak days (Exh. BE-2, p. 146).

91/ The three seasons are winter (January, February, March and December), summer (June through September) and spring/fall (April, May, October and November) (Exh. BE-2, p. 146).

However, BECo failed to account for the effects of weather in its peak load forecasting methodology. The Company acknowledges through its choice of data that abnormal weather may have a significant impact on the Company's peak load. Consequently, any comparisons between actual peaks and forecasted peaks should be conducted under normalized weather assumptions.[92]

In addition, the Siting Council has concerns regarding BECo's inputs to the peak load model. BECo indicated that it used the output of the energy forecast as a direct input into the peak load model. The Siting Council, however, has expressed its concerns regarding the reliability of the initial energy forecast in previous sections. See Sections II.C.4.a, II.C.5.a, II.C.6.a, above. Consequently, BECo's overestimated peak load forecast may be unreliable as a result of the energy forecast inputs. BECo's failure to account for the effects of weather on peak load also may have affected the performance of its peak load forecast.

Accordingly, the Siting Council finds that BECo's initial peak load forecast is reviewable and appropriate. The Siting also finds that BECo has failed to establish that its initial peak load forecast is reliable. In order for the Siting Council to approve the peak load forecast in BECo's next filing, the Company must furnish (1) an analysis of the sensitivity of peak load to weather abnormalities for all seasons; and (2) evidence that it has incorporated reliable energy forecast data into its peak load methodology.

92/ BECo claimed that the July 23, 1991, all-time peak of 2,652 MW supports the reasonableness of its peak demand forecast even in light of the current economic recession. The Company, however, did not provide evidence regarding the effects that higher temperatures during the summer of 1991 may have had on peak demand. Consequently, in light of BECo's failure to model weather in its peak demand methodology, the 1991 summer peak cannot be compared with the initial forecast under the conditions specified.

2. Reforecast

a. Description

BECo's reforecast of peak load produced considerably lower figures than its initial forecast (Exh. HO-D-111). In the reforecast, BECo projected unadjusted peak loads of 2,652 MW in 1991 increasing to 3,152 MW in 2000, a compound annual growth rate of 1.94 percent (id.). See Table 2, below. By contrast, the initial forecast produced unadjusted peak load figures of 2,809 MW in 1991 increasing to 3,370 MW in 2000, a compound annual growth rate of 2.0 percent (Exh. BE-2, p. 149). See Table 1, below.

BECo stated that it used the same load factors generated by LMSTM for the initial forecast to calculate the reforecast (Exh. HO-D-111). The Company stated that it used the reforecast of energy derived from the August, 1991 DRI forecast as the input to LMSTM (id.).

b. Analysis and Findings

Because BECo indicated that its methodology for the reforecast of peak load is essentially the same as its initial forecast of peak load, we find that BECo's reforecast of peak load is reviewable and appropriate. In addition, the reforecasts of BECo's employment data and energy have been established to be more reliable than the initial forecasts of employment and energy. See Sections II.C.1.c.ii, II.C.4.b.ii, II.C.5.b.ii, II.C.6.b.ii, above. Consequently, the inputs to the reforecast of peak load have been established as more reliable than the inputs to the initial forecast of peak load. Therefore, the results of the reforecast of peak load are more reliable than the results of initial forecast of peak load. Accordingly, the Siting Council finds BECo's reforecast of peak load to be reviewable, appropriate and reliable at the time of the reforecast.

3. Conclusions on Peak Load Forecast

The Siting Council has found that BECo's initial peak load forecast is reviewable and appropriate. The Siting Council also has found that BECo has failed to establish that its initial peak load forecast is reliable. The Siting Council also has found BECo's reforecast of peak load to be reviewable, appropriate and reliable at the time of the reforecast. Accordingly, the Siting Council finds BECo's peak load forecast to be reviewable, appropriate, and reliable at the time of the reforecast.

E. Conclusions on Demand Forecast

The Siting Council has found: (1) BECo's forecast of energy requirements to be reviewable, minimally appropriate, and reliable at the time of the reforecast; and (2) BECo's peak load forecast to be reviewable, appropriate, and reliable at the time of the reforecast.

BECo presented three major arguments regarding its demand forecast.[93] BECo argued that (1) its reforecast was not a replacement for its initial demand forecast; (2) the growth rates associated with its initial forecast and its reforecast exhibited considerable similarities;[94] and (3) the peak load level of

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93/ MASSPIRG argued that the Company's initial forecast of demand should be rejected due to its reliance on outdated economic data (MASSPIRG Initial Brief, p. 9; MASSPIRG Reply Brief, pp. 1, 4; MASSPIRG Letter Brief, p. 4).

94/ Over the period 1991-2000, the high, base, and low case projections of energy requirements in BECo's initial forecast reflected compound annual growth rates of 2.4 percent, 1.8 percent, and 1.2 percent, respectively, while its high, base, and low case projections of peak load requirements reflected compound annual growth rates of 2.7 percent, 2.0 percent, and 1.4 percent, respectively (Exh. BE-2, pp. 191, 193). Over the same time period, the high, base, and low case projections of energy requirements in BECo's reforecast reflected compound annual growth rates of 2.3 percent, 1.9 percent, and 1.0 percent, respectively, while the high, base, and low case projections of peak load requirements reflected compound annual growth rates of 2.5 percent, 1.9 percent, and 1.0 percent, respectively (Exh. HO-D-111).

summer 1991 constituted evidence that declining economic activity had not produced a clear decrease in peak load[95] (BECo Initial Brief, pp. 38, 40; BECo Letter Brief, p. 2).

In response to BECo's arguments, the Siting Council recognizes that some methodological differences exist between BECo's initial forecast filing and its reforecast. Nonetheless, the record in this proceeding indicates that the Company's reforecast was based largely on the forecasting techniques used by the Company to develop its initial forecast filing.[96] In addition, the Company has provided a reforecast of energy and peak load requirements which incorporate the effects of more recent economic input data. In this decision, the Siting Council has recognized the significance of that more recent economic data, primarily in terms of the higher level of reliability which it offers in the Company's reforecast of energy and peak load requirements. See Sections II.C.1, II.C.4.b, II.C.5.b, II.C.6.b, and II.D.2, above.[97]

The Company also argued that the initial forecast and the reforecast exhibited considerable similarities in terms of growth rates. While the Siting Council acknowledges that fact,

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95/ BECo reported that it experienced a new historic high peak load of 2,652 MW on July 23, 1991 (BECo Initial Brief, Attachment 1).

96/ In previous decisions, the Siting Council has required companies to update elements of their forecasts to determine the effects of changed circumstances. 1991 Eastern Decision, EFSC 90-100 at 8, 19-23; 1990 MMWEC Decision, 20 DOMSC at 7; Fitchburg Gas and Electric Light Company, 19 DOMSC at 69, 74-75 (1989) ("1989 Fitchburg Decision"). In addition, the Siting Council has recognized that electric companies may be required to provide alternate forecasts of resource need as part of the reviews of the demand forecast and resource inventory under the new IRM framework. 1990 Final Decision, 21 DOMSC, 116.

97/ MASSPIRG raised a point regarding the use of outdated economic data in the Company's initial forecast, and the Siting Council has addressed that point in earlier sections of this decision regarding the Company's employment forecast, residential, commercial, and industrial energy forecasts, and peak load forecast.

throughout the forecast period the projected peak load levels of the reforecast are considerably lower than the peak load levels projected in the initial forecast despite similarities in growth rates. For example, 1992 peak load levels projected by the Company's reforecast are considerably lower than those projected by the Company's initial forecast, and peak load levels projected by the Company's initial forecast for 1996 would not be reached until 2000 according to the reforecast. See Tables 1 and 2, below. In every year of the forecast period the projected peak loads of the reforecast fall below the projected peak loads of the initial forecast. Clearly, the similarity in growth rates between the initial forecast and the reforecast fails to account for the sustained reduction in peak load levels reflected by the Company's reforecast.

With regard to the Company's reference to its July, 1991 summer peak load figure, the Siting Council notes that weather adjustment of that figure was not provided. See Section II.E.2.b., above. In the absence of such adjustment, the actual peak load level reported by the Company cannot be compared to other peak load data, either actual or projected, which have been adjusted for effects of weather. Weather has clear and pronounced impacts on energy consumption, and unless the peak load data in question have been recalculated in terms of a common weather reference point a comparison between various levels of peak load is rendered meaningless.

Accordingly, the Siting Council hereby APPROVES BECo's 1990 demand forecast based on its reforecast of energy and peak load requirements. In making this finding, the Siting Council notes that accurate projections of energy and peak load are of critical import to the determination of resource need in this proceeding. Here, we recognize that the significantly increased reliability associated with the reforecast meets this fundamental accuracy requirement.

III. ANALYSIS OF THE SUPPLY PLAN

A. Standard of Review

In keeping with its mandate in G.L. c. 164, sec. 69H, to "provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost," the Siting Council reviews two dimensions of an electric utility's supply plan: adequacy 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. 1991 Nantucket Decision, 21 DOMSC at 260; 1990 MMWEC Decision, 20 DOMSC at 41; 1989 MECo/NEPCo Decision, 18 DOMSC at 336; 1989 BECo Decision, 18 DOMSC at 224. The Siting Council has determined that different standards of review are appropriate and necessary to establish supply adequacy in the short run and the long run.[98] 1991 Nantucket Decision, 21 DOMSC at 260; 1990 MMWEC Decision, 20 DOMSC at 41; 1989 MECo/NEPCo Decision, 18 DOMSC at 336; 1989 BECo Decision, 18 DOMSC at 224. To establish adequacy in the short run, a company must demonstrate that it has an identified, secure, and reliable set of energy and power supplies. In essence, a company must own or have under contract sufficient resources to meet its capability responsibility under a reasonable range of contingencies. If a company cannot establish that it has adequate supplies in the short run, that company must then demonstrate that it operates pursuant to a specific action plan guiding it in being able to rely upon alternative supplies in the event of certain contingencies. 1991 Nantucket Decision, 21 DOMSC at 260; 1990 MMWEC Decision, 20 DOMSC at 41; 1989

98/ The Siting Council defines the short run as four years. The four year period is measured from the time in a proceeding that (1) the final discovery or record response is submitted, or (2) the final hearing is held, whichever is later. 1991 Nantucket Decision, 21 DOMSC at 260; 1990 MMWEC Decision, 20 DOMSC at 41-42; 1989 MECo/NEPCo Decision, 18 DOMSC at 336-337; 1989 BECo Decision, 18 DOMSC at 224-225.

MECo/NEPCo Decision, 18 DOMSC at 336; 1989 BECo Decision, 18 DOMSC at 224.

To establish adequacy in the long-run, a company must demonstrate that its planning processes can identify and fully evaluate a reasonable range of resource options on a continuing basis while allowing sufficient time for the company to make appropriate supply decisions to ensure adequate cost-effective energy and power resources over all forecast years.[99] Generally, a supply plan that meets the least-cost standards set forth below is deemed adequate in the long-run.

The Siting Council next determines whether a supply plan minimizes the cost of power (that is, whether it ensures least-cost supply) subject to trade-offs with adequacy, diversity and the environmental impacts of construction and operation of facilities. 1991 Nantucket Decision, 21 DOMSC at 261-310, 1990 MMWEC Decision, 20 DOMSC at 42-99, 1989 MECO/NEPCo Decision, 18 DOMSC at 337-371, 1989 BECo Decision, 18 DOMSC at 225, 232-281. Recognizing that supply planning is a dynamic process undertaken under circumstances which make it difficult for a company to identify with exactitude all the power resources it plans to rely upon in the latter years of its long-range forecast (1991 Nantucket Decision, 21 DOMSC at 261-277, 1990 MMWEC Decision, 20 DOMSC at 42-99, 1989 MECo/NEPCo Decision, 18 DOMSC at 337-348, 1989 BECO Decision, 18 DOMSC at 225, 232-250), the Siting Council's review of the long-run cost of the supply plan generally focuses on a company's supply planning methodology. 1991 Nantucket Decision, 21 DOMSC at 261-310, 1990 MMWEC Decision, 20 DOMSC at 42-99, 1989 MECo/NEPCo Decision, 18 DOMSC at 337-371, 1989 BECo Decision, 18 DOMSC at 225, 232-281.

The Siting Council reviews the company's processes of identifying and evaluating a variety of supply options. In reviewing a company's resources identification process, the

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99/ The Siting Council will evaluate the long-run adequacy of the Company's planning processes in Phase II of this Decision.

Siting Council focuses on whether that company identified a reasonable range of resource options by (1) compiling a comprehensive array of available resource options, and (2) developing and applying appropriate criteria for screening its array of available resource options. In reviewing a company's resource evaluation process, the Siting Council determines whether that company (1) developed a resource evaluation process which fully evaluates all resource options, including the treatment of all resource options on an equal footing, and (2) applied its identified resource options. 1991 Nantucket Decision, 21 DOMSC at 261-310, 1990 MMWEC Decision, 20 DOMSC at 43-99, 1989 MECo/NEPCo Decision, 18 DOMSC at 337-371, 1989 BECO Decision, 18 DOMSC at 225-226, 232-281.

B. Previous Supply Plan Review

In its 1989 BECo Decision, the Siting Council ordered Boston Edison to comply with the following Orders:

(1) to include as part of its supply planning process a comprehensive analysis of the Pilgrim unit, including sensitivity analyses for, at a minimum, the different operating and cost variables that MASSPIRG has questioned in this proceeding;

(2) to consider for inclusion in its array of available resource options a wider range of generation technologies which potentially could contribute to a least-cost supply plan;

(3) to implement a methodology which includes an adequate consideration of the environmental impacts of alternative resource options;

(4) to diversify the sources consulted inside and outside of the Company for the purposes of developing the probabilities assigned to each variable forecast in the Company's risk management process ("Survey Order"). (18 DOMSC at 282)

The Survey Order is addressed below. The other Orders will be addressed in Phase II of this Decision.

The Siting Council included the Survey Order in its 1989 BECo Decision because of concerns over the Company's assignment of probabilities to forecasts of key variables (18 DOMSC at 273-275).

In response to the Survey Order, the Company included several surveys to develop probabilities for key variables that are the basis of BECo's risk management process (Exh. HO-S-100).[100] The Company stated that it used "Delphi"

100/ BECo's risk management process is referred to as "reliability planning" in this decision, and is described in detail in Sections III.D.2, III.D.3, and III.E, below.

surveys[101] to gather opinions from many of its personnel throughout five Company departments, as well as several participants from outside of the Company (id.). The Company stated that survey participants from outside the Company were selected using two criteria: (1) the agency or firm for which the individual works, and (2) "the individual's expertise in the related fields" (id.). The Company's surveys of outside participants consistently included policy analysts from the Commonwealth and a public interest group (id.). However, the Company stated that it did not know the outside participants' experience in forecasting these key variables (id.). The Company also indicated that it was aware of professional forecasters other than DRI that prepare economic and energy forecasts for Massachusetts (Tr. 45, pp. 89-92).

The Company surveyed 13 BECo personnel, three participants from outside the Company, and DRI for their opinion of the probability of various fuel price forecasts (Exh. HO-S-100). For the load growth variable, seven Company personnel and four participants from outside the Company were surveyed (id.). For capacity additions, nine Company personnel and six participants from outside the Company were surveyed, including one person employed by the New England Power Pool's Planning organization (id.). For the two variables concerning demand-side management and unit availability, the Company surveyed only BECo personnel (id., Exh. BE-1, p. E-11).

The Company's survey required that participants rate their "acquired knowledge" in energy planning, except for DRI, which was assigned a ranking equal to the total of the other participants (Exh. HO-RR-70, HO-S-101). The Company weighted the

101/ A Delphi survey generally allows experts to provide opinions in several iterations, after receiving the results of the prior iterations. However, BECo did not explain why its surveys were characterized as Delphi surveys when outside participants did not provide second opinions (Tr. 34, pp. 70-74).

survey responses based on the expertise of the respondent (Exh. BE-1, p. E-10).[102]

CLF urged the Siting Council to reject BECo's use of "Delphi" surveys, arguing that the surveys lacked documentation, misused the Delphi methodology, and lacked reasoned explanation of its results (CLF Initial Brief, p. 21). CLF questioned the expertise of many of those who were consulted in the surveying process (id.). CLF argued that BECo may have influenced the outcome of the survey process through its selection of its employees to be polled (id.).

The Company's response to the Survey Order represents an improvement to the Company's past practice of relying exclusively on Company personnel to develop probabilities. BECo's effort to diversify its sources inside the Company through the participation of multiple departments within Boston Edison is a step towards compliance with the Survey Order. However, the Siting Council agrees with CLF that BECo's efforts to consult with sources outside of the Company were insufficient. In its last forecast, BECo indicated that it had consulted with Wharton Econometric Forecasting Associates for information on the accuracy of its load growth forecasts, and used DRI in assigning probabilities to the fuel price forecast. 1989 BECo Decision, 18 DOMSC at 240. Here, the Company did not use such supplemental information from professional forecasters beyond its use of the DRI fuel price forecast. The Siting Council's Survey Order

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102/ To assist the outside participants in assigning probabilities to the forecasts of each variable, the Company provided a limited description of each forecast (Exh. HO-RR-70). For example, the Company informed the participants of the current level of the price of oil, and the price in the year 2014 under high, base, and low forecasts (id.). The Company also provided the average annual rate of increase in price represented by each forecast (id.). The participants received this data during telephone calls in which they were asked to assess the probability of each forecast (id.). This procedure was repeated for the peak load forecast (id.). The capacity additions survey was mailed to outside participants and contained an additional table indicating the following information for each planned unit: name, location, fuel type and BECo's MW entitlement (id.).

required the Company to diversify the sources consulted inside and outside the Company. In the future, BECo should diversify the sources consulted outside of the Company, relying upon independent, professional forecasting experts. For forecasts that are Company-specific, the Siting Council encourages BECo to consult with outside professional forecasting experts that are familiar with the Company.

Nonetheless, the Siting Council finds BECo has complied with the Survey Order.

C. Reliability Planning

1. Overview

Consistent with the Siting Council's standard of review, this section addresses the reliability planning process by which Boston Edison projected its need for additional energy resources. In simplest terms, an electric company's need for additional energy resources can be assessed by comparing projected system loads to the ability of existing and planned resources to meet those loads. However, the reliability planning process is complex and ultimately requires detailed analysis of the factors that drive future load levels and those that affect contributions that may be anticipated from a company's existing and planned resources, all within the context of the uncertainties inherent in any forecasting process.

An appropriate reliability planning process has three essential components. First, a methodology must be developed that provides a theoretically sound basis for determining future resource requirements. A necessary part of this process is the development of a methodology for identifying a reliability planning target that strikes an appropriate balance between system reliability and cost. Second, appropriate input data must be selected and processed in a manner consistent with that methodology and which produces dependable projections of future resource requirements. Third, an implementation strategy reflecting least-cost objectives must be developed for achieving the reliability objectives prescribed via the first two steps of the process.

In Section III.C.2, below, Boston Edison's reliability planning process is assessed to determine whether its planning methodology, application of that methodology, and implementation strategy are appropriate. Alternative approaches to reliability planning suggested by Intervenors are addressed in Section III.C.3, below.

2. Boston Edison's Reliability Planning Process

a. The Methodology

Boston Edison's proposed reliability planning methodology can be separated into three distinct phases. The first phase of the process consisted of the development of a series of resource need scenarios that spanned the planning horizon and attempted to capture the variability in supply forecasting by representing the full range of potential resource requirement levels (Exh. BE-1, pp. E-1 to E-2). The Company's forecasts were based on the factors, or "key variables," proposed to have the greatest influence on the levels of future resources that could be required (id., pp. E-1 to E-2, E-6).

The second phase of the process involved the development of production cost projections associated with individual forecasts, representing the costs that would be incurred if the Company were to expand its current supply-side and demand-side resource portfolio to meet future requirements prescribed by those individual forecasts (id., p. E-2).

The third phase focussed on an effort to strike an appropriate balance between system reliability and cost (id., pp. E-2 to E-3). Here, the Company employed a process that weighed the production costs that would be incurred at successive levels of system expansion against the reliability that could be achieved, as measured by the costs of unmet energy that could be avoided (id., p. E-18).

The application of these phases of Boston Edison's reliability planning methodology are addressed in Section III.C.2.b, below.

The reliability planning methodology proposed by the Company in this proceeding was largely the same as that submitted and evaluated in the 1989 BECo Decision. In that Decision, the Siting Council accepted the Company's methodology, which entailed forecasting a reasonable range of future resource requirements, developing projections of future production costs, and striking the appropriate balance between reliability and cost (18 DOMSC at 272-276). However, the Siting Council also concluded that the methodology presented there only "served as a practical starting point" for such evaluations. Id. at 276.

Here, the Siting Council finds that the Company's methodology constitutes an acceptable theoretical foundation for reliability planning. However, during the course of these proceedings, many issues were raised regarding the data and calculations utilized in the application of the reliability planning methodology. The issues pertaining to the Company's application of its reliability planning methodology are addressed next.

b. Application of the Reliability Planning Methodology

i. Developing Resource Need Scenarios

(A) Overview

The objective of the initial phase of Boston Edison's reliability planning process was to develop a series of projections of resource requirements across the planning horizon, which taken in total, represented the full range of future need scenarios to which the Company might have to respond (Exh. BE-1, pp. E-1 to E-2). Toward this end, Boston Edison first identified the key variables anticipated to most influence future resource requirements.

In the 1989 BECo Decision, Boston Edison presented four variables that it believed would most affect future resource requirements: load; fuel prices; C&LM contributions; and capacity additions (18 DOMSC at 272). In that Decision, the Siting Council found that the Company had demonstrated that the four selected variables, in fact, significantly would affect resource requirements, but suggested that the Company also consider the forecasts of capacity factors for existing generating units, NEPOOL reserve requirements, and the timing of anticipated capacity additions. Id. at 271.

In this proceeding, the Company's forecasts of future resource requirements were based on what were initially five "key variables" (Exh. BE-1, p. E-6). These included "load growth," "fuel price," and the MW contributions from existing C&LM programs ("DSM penetration"), existing supply-side resources ("unit availabilities"), and planned supply-side resources ("capacity additions") (id.). BECo projected high, base, and low case MW levels for each variable (except for the "fuel price" variable), across the proposed 25-year planning horizon (id., pp. E-1 to E-2). Probability levels associated with the high, base, and low levels of each key variable also were developed (id., pp. E-10 to E-13).

With the high, base, and low MW and probability levels for each key variable serving as inputs, the Company used a decision tree program within its Integrated Decision Analysis System ("IDEAS") computer model to develop 81 scenarios representing different 25-year forecasts of incremental resource requirements and associated probability levels for each scenario (Exh. BE-1, pp. E-1, E-2, E-13). For each year in the forecast period, algorithms within the IDEAS decision tree model first subtracted the three "DSM penetration" MW levels from the three "load growth" MW levels to produce nine net load forecasts (Exh. BE-1, p. E-13). A reserve margin was next applied to each of the nine net load forecasts, reflecting the amount of capacity that BECo would acquire to be consistent with NEPOOL's capability responsibility calculation (id.).[103]

BECo indicated that it reduced the five key variables to four by combining the "unit availabilities" and "capacity additions" variables into a single variable designated "effective resources" with its own high, base, and low MW and probability levels (id.).[104] The "effective resources" MW levels were subtracted from the "capability responsibility" MW levels, resulting in 27 different levels of resource need for each year of the forecast period (id.). BECo stated that these need scenarios, when combined with the three fuel price forecasts and their associated probabilities, yielded 81 forecasts of resource need (id.).

Finally, the Company indicated that it undertook a process to reduce the 81 alternative resource requirement forecasts to thirty "representative" scenarios (ten different resource requirement forecasts at each of the three high, base, and low fuel price levels) (id., pp. E-15 to E-16). These thirty scenarios were utilized in the second and third phases of Boston Edison's reliability planning process.

In the 1989 BECo Decision, the Siting Council found that the decision tree analysis constituted an appropriate method for projecting future resource requirements (18 DOMSC at 273). For the purposes of this review, we find that the Company's decision tree analysis, and in particular the algorythms within the IDEAS

103/ Capability responsibility is a retroactive calculation done by NEPOOL to ensure that each NEPOOL participant provided, during a given billing period, an appropriate share of the total generating capacity (including reserves) necessary to meet NEPOOL-wide loads (Tr. 47, pp. 14-15; Exh. MP-38). The Company's capability responsibility is a function of Company loads (net of C&LM savings), the availabilities of its existing generating units over a prior four-year period, and other factors (Tr. 47, pp. 15-18; Exhs. HO-S-61, HO-S-213; MP-38).

104/ The derivation of BECo's "effective resources" key variable is presented and reviewed in Section III.C.2.b.i.(G), below.

model, represent an acceptable planning tool.[105] Further, the Siting Council finds that the Company's process for reducing the number of future scenarios from 81 to 30 is acceptable. A discussion and analysis of each of Boston Edison's key variables follows.[106]

(B) "Load Growth"

In Section II.D.1, above, the Siting Council has found that the Company has failed to establish that its initial peak demand forecast methodology is reliable. Accordingly, the Siting Council finds that the "load growth" projections from the initial demand forecast are not acceptable for the purpose of calculating future resource requirements.

(C) "Fuel Price"

Boston Edison stated that it selected "fuel price" as a key variable in the decision tree because, "while it does not

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105/ As indicated above, in calculating resource need through the IDEAS model, a reserve margin was applied to "net-of-DSM" load projections. The Siting Council notes that this method of projecting future resource requirements is consistent with generally accepted planning methods in the electric utility industry. However, we also note that, because the reserve margins utilized were based on the anticipated performance of BECo's existing generating units, resource need projections may be distorted to the extent that incremental load growth is met with resources having performance characteristics that differ from that of the Company's existing supply portfolio.

While this matter was not addressed on the record of this proceeding, it may be of consequence in future resource need assessments performed by the Company. We encourage the Company to address this issue in its next resource plan filing.

106/ As presented in Section I.B, above, during March 1992 the Company submitted updated information to the Siting Council concerning several of the variables affecting BECo's future resource requirements. However, the following sections contain an assessment of the input values for the key variables utilized in the Company's reliability planning process, which was presented in the May 1990 resource plan. Therefore, our evaluation of the key variables necessarily focusses on the record as it existed at the close of February, 1992 ("February 1992 Record").

directly impact required resources, it has a direct impact on load growth, C&LM and the amount of additional resources expected to come into service, as well as on the resources selected" (Exh. BE-1, p. E-6). BECo indicated that "fuel price" probabilities were developed through the Delphi process (id., p. E-10). BECo also stated that, although the "fuel price" variable did not directly affect the MW levels of the 81 forecasts of resource requirements, "fuel price" affected the decision tree results in terms of the probability levels attributed to individual need scenarios (id., p. E-36).

The Attorney General argued that "fuel price" should not have been treated as a key variable in the Company's decision tree analysis because it was a factor in the derivation of the Company's load growth forecasts, and because it did not affect the resource requirement levels that were the outcome of the decision tree analysis (Attorney General Initial Brief, pp. 87-88). The Attorney General maintained that the base load forecast assumes a base fuel price, the low load forecast assumes high fuel prices, and the high load forecast assumes low fuel prices (id., p. 88). Therefore, the Attorney General asserted that the Company created nonsensical scenarios in IDEAS by pairing, for example, its base case load forecast with high and low fuel prices when the Company's original base case load forecast was explicitly based on only the base case fuel forecast (id.).

The Siting Council agrees with the Attorney General that it may seem inappropriate to pair, for example, a high fuel price with a high load growth level in developing decision tree scenarios, when low fuel prices were a premise for the high "load growth" bandwidth. Nonetheless, the MW levels associated with the Company's key variable bandwidths are merely forecasts of possible future outcomes. It is possible, even if unlikely, that loads consistent with the high load growth forecast may be realized even with high fuel prices. To the extent that the Company's Delphi process appropriately recognized the low probability of such an event (and likewise yielded appropriate probability levels for other combinations of the affected key variables), the Company's treatment of the "fuel price" variable in the decision tree analysis is acceptable. In addition, we note that the results of the Delphi process, through which the relative probability assignments for the "load growth," "DSM penetration," and "fuel price" variables were assigned, recognized the interdependencies of these variables (see Exh. BE-1, pp. E-10, E-11, E-31).

While we are not convinced that the Company's "fuel price" key variable enhanced its analysis, based on the record in this proceeding the Siting Council finds that the Company's treatment of the "fuel price" variable is acceptable for the purpose of calculating future resource requirements.

(D) "DSM Penetration"

(1) Company Proposal

BECo indicated that its existing C&LM resource plan[107] contained 12 residential programs, 20 commercial and industrial ("C&I") programs and one streetlighting conversion program (Exh. BE-1, pp. B-20 to B-22). BECo stated that the projected contributions toward peak MW reduction of these C&LM programs in the base case were derived from projections developed through the collaborative process (id., p. E-7).[108] According to BECo, the base case "DSM penetration" projections assumed aggressive penetration into each market segment and BECo's payment of full

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107/ BECo asserted that its resource plan includes no planned C&LM programs, only existing programs (Exh. BE-111, p. 6).

108/ The parties to the collaborative process -- CLF, MASSPIRG, the Division of Energy Resources, the Attorney General, and the Company -- collectively designed C&LM measures and strategies for BECo's customers (Exh. BE-1, p. B-7). As part of the collaborative process, the collaborative parties issued a report entitled "Phase II Collaborative Document" (id., p. B-8).

measure cost below the Company's avoided cost (id., p. B-29). BECo stated that the high and low C&LM cases were developed using high and low penetration rates determined by Company personnel (id., p. E-7). BECo stated that the low C&LM case assumed lower penetration rates reflecting greater market barriers than were anticipated in the base case (id.). Similarly, BECo indicated that the high C&LM case assumed greater participation rates in the short-term than the base C&LM case, but the same participation rates as the base case by 2007 (id.).

BECo stated that some of the collaboratively designed C&I programs were not completed at the time of the development of the resource plan (id., p. B-27). Therefore, the Company indicated that it developed the resource plan using actual savings projections from the collaborative process for residential programs, but estimated the savings from "the yet to be designed C&I programs" in deriving base case "DSM penetration" projections (id.). The Company noted that the collaborative process did not include a review of all of the programs BECo currently offers, such as the load management programs, but stated that the load management programs were included in the resource plan (id.). The Company projected high, base and low "DSM penetration" projections for the year 2000 of 487 MW, 466 MW and 336 MW, respectively (id., p. E-32).

BECo stated that probabilities for the high, base and low C&LM cases of 36 percent, 44 percent and 20 percent, respectively, were assigned through the Delphi survey completed by BECo's C&LM personnel, taking load growth and fuel prices into consideration (id.).

(2) Positions of Parties

CLF argued that by relying on the Phase II Collaborative Document instead of developing its own methodology for estimating base case C&LM potential, BECo produced unreasonably static and low "DSM penetration" MW projections (CLF Initial Brief, p. 5). CLF defined the Phase II Collaborative Document as a program design guide, not a resource planning projection (id.). CLF maintained that the Phase II Collaborative Document did not purport to review or estimate the size of BECo's C&LM resources; rather, the document only outlined cost-effective programs for initial implementation (id.). CLF also asserted that BECo's load-management program was not reviewed by the collaborative parties, so BECo cannot properly claim that the parties to the collaborative process took part in its estimates (id., p. 9). Further, CLF asserted that BECo incorporated estimates of its own C&I programs in the resource plan, not estimates of the collaboratively-designed C&I programs (id., p. 15; Exh. CLF-1, pp. 12-13; CLF Reply Letter, p. 2). Finally, CLF stated that "residential programs are arbitrarily assumed to terminate after five years and most C&I programs end soon after" (CLF Initial Brief, p. 15).

MASSPIRG argued that BECo did not consider all cost-effective C&LM in its resource plan (MASSPIRG Initial Brief, p. 21). MASSPIRG agreed with CLF that the Company inappropriately used the collaborative planning targets for the first five years of those programs as the maximum C&LM potential (id.). MASSPIRG further asserted that BECo made no attempt to extend certain programs, especially residential programs, throughout the full planning horizon (id.).

The Attorney General criticized the use of the collaborative C&LM estimates for planning purposes (Attorney General Initial Brief, pp. 27-29). The Attorney General presented as a witness the technical coordinator for the non-utility parties to the collaborative, who testified that the collaborative estimates were produced for the "purpose of short-term program design" and were not intended to project C&LM potential or to be used for long-term resource planning (id.; Exh. CLF-2, p. 8).

The Attorney General also argued that the Company deliberately limited the effectiveness of existing C&LM programs (Attorney General Initial Brief, p. 25). The Attorney General noted that BECo acknowledged that its own marketing plans for certain 1991 conservation programs were "very limited" and refully controlled so that an excess of leads were not generated" (id.; Exh. BE-111, p. 6). According to the Attorney General, the residential high-use program achieved only four percent of its implementation goal during the first half of 1991 (Attorney General Initial Brief, p. 25; Exh. AG-RR-74). In addition, the Attorney General noted that the Company reached only 15 percent of its goal for the C&I programs (Attorney General Initial Brief, p. 26).

Finally, the Attorney General criticized the Company's assumption that new participation in residential programs would stop in 1994, because BECo had acknowledged that "additional DSM is a potential resource" and that "actual participation rates...will probably be small (but non-zero) in years after 1994" (parenthesis in original) (Attorney General Initial Brief, p. 26; Exh. BE-43, p. 2; Tr. 8, pp. 84-85).

BECo argued that it made "enhancements" to its process for forecasting C&LM resources -- a process which has been reviewed previously by the Siting Council -- to include the contribution of the comprehensive and aggressive programs developed through the collaborative process (Company Initial Brief, p. 81). The Company claimed that it had no reason to believe that there was any better source of savings projections from its existing programs than the collaborative (id., p. 108).

The Company stated that because nearly all the residential programs were developed by the collaborative to achieve reasonable penetration rates (generally around 30 percent) in five years, "no additional penetration was projected beyond 1994 because of uncertainty in the remaining market and [the] cost to penetrate that market" (Exhs. BE-43, p. 2, HO-S-183). BECo stated that C&I programs, however, were extended beyond 2000, "because of the difficulty in saturating the market" (Exh. HO-S-183). BECo added that while some additional C&LM savings were likely, it believed that the collaborative C&LM projections, taken on the whole, were "aggressive" (Tr. 8, p. 85).

The Company also stated that it is even likely that it will not be able to achieve as much C&LM savings in the early years of the forecast period as it had projected, but some incremental residential conservation will occur after 1994 (Company Initial Brief, pp. 72-73).

(3) Analysis and Findings

The Siting Council focusses on the accuracy and reasonableness of forecasting techniques in the review of the Company's projections of C&LM resource contribution (as well as our review of projections of planned capacity additions and existing generating unit availabilities). The Company's process for identifying and evaluating C&LM resources (including questions of the Company's aggressiveness in C&LM planning) is addressed in Phase II of this Decision.

CLF, MASSPIRG and the Attorney General have criticized the Company's reliance on the collaborative process to determine "DSM penetration" projections. The record indicates that the Phase II Collaborative Document is a program design guide, and the MW savings projected by the collaborative process are based on the initial implementation of an array of C&LM programs. The projection of C&LM savings at the beginning of a comprehensive new program is a challenging task. Ultimately, some programs will exceed their projections, others will not, and programs which do not prove to be cost-effective will be discontinued. For purposes of this proceeding, the collaborative C&LM design projections constitute a reasonable, good-faith effort by the Company to estimate the contribution of C&LM.[109]

109/ The Attorney General raised concerns about the low participation rates that have been experienced with certain of the Company's C&LM programs. However, issues concerning BECo's diligence in implementing its C&LM programs are properly a matter for Phase II of this Decision and in proceedings before the Department.

The Attorney General, CLF and MASSPIRG also criticized the Company for ending certain C&LM programs after only five years.[110] The record indeed reflects that none of the Company's existing residential C&LM programs extend beyond the five-year period identified in the Company's resource plan, while C&I programs extend 7 to 15 years (see Exh. CLF-1, p. 15). Therefore, the C&LM MW savings figures presented by the Company do not reflect any incremental savings associated with these programs after their termination dates.

The Siting Council notes that there is little likelihood that BECo will not offer residential C&LM programs after 1994. Specifically, it would be unlikely (and inappropriate) for the Company to ignore C&LM opportunities that present themselves in new residential construction beyond 1994. However, these programs, as currently planned, conclude in 1994. Therefore, no incremental MW savings would be anticipated from them beyond that date, and it would be inappropriate to assume otherwise for the purpose of determining resource need. While recognition of the planned end-dates of C&LM programs (or any resource) might result in unmet need in subsequent years, it may be determined in Phase II of this Decision that reinstituting similar C&LM programs represents the most cost-effective means by which to meet that need. In this proceeding, the Company has met its burden of presenting an adequate C&LM plan. Accordingly, the Siting Council finds that BECo's "DSM penetration" projections are acceptable for the purpose of calculating future resource requirements.

110/ The Siting Council notes the distinction between the duration of a C&LM program and the savings associated with that program. Although a program may end, i.e., the financial support for and installation of associated C&LM measures may terminate, the actual capacity and energy savings associated with program measures installed to that point may continue for many years.

(E) "Capacity Additions"

(1) Company Proposal

In the resource need calculation presented in its resource plan, the Company proposed to include the following units as planned resources: Ocean State Power ("OSP");[111] Hydro Quebec II ("HQ II");[112] Northeast Energy Associates ("NEA") 1 and 2;[113] Everett Energy;[114] L'Energia;[115] Patriot Energy;[116] Wheelabrator Urban Woods;[117] AES Riverside;[118] and the winning bids from

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111/ OSP is comprised of two gas-fired combined cycle units located in Burrillville, Rhode Island. The February 1992 Record indicates that BECo's summer entitlement from OSP is 116.6 MW (Exh. HO-S-60).

112/ HQ II represents an energy-only power sales agreement ("PSA") between BECo and Hydro Quebec. The February 1992 Record indicates that BECo's summer entitlement from HQ II is 171.1 MW (Exhs. HO-S-60, HO-S-118).

113/ NEA 1 and 2, located in Bellingham, Massachusetts, are gas-fired combined cycle cogeneration units. The February 1992 Record indicates that BECo's summer entitlement from NEA 1 is 130.7 MW, while its entitlement from NEA 2 is 68 MW (Exh. HO-S-60).

114/ The February 1992 Record indicates that BECo and Everett Energy signed a PSA, entitling the Company to 80 MW from the gas-fired facility in Everett, Massachusetts (Exh. HO-S-60).

115/ L'Energia is a gas-fired combined cycle qualifying facility located in Lowell, Massachusetts. The February 1992 Record indicates that the Company's summer entitlement from this unit is 48.8 MW (Exh. HO-S-60).

116/ BECo and Patriot Energy signed a PSA pursuant to BECo's RFP #1. The February 1992 Record indicates that this PSA entitles the Company to 200 MW from the coal-fired cogeneration facility (Exh. HO-S-60).

117/ BECo and Wheelabrator Urban Woods signed a PSA pursuant to BECo's RFP #1. The February 1992 Record indicates that the PSA entitles BECo to 25 MW from this waste wood facility.

118/ The February 1992 Record indicates that BECo and AES Riverside signed a PSA entitling BECo to 81 MW from this coal plant in Woonsocket, Rhode Island (Exh. HO-S-60).

BECo's RFP #2[119,120] (Exh. BE-1, p. C-24).[121] The Company's calculations of future resource need thus reflected projected contributions from planned capacity additions, which generally increased in terms of total MW between 1991 to 1996, remained constant between 1996 and the year 2000, and then decreased through 2014 (id., p. C-13).

BECo used its Delphi survey to forecast a number of different possible capacity additions levels that might result from the group of planned units identified above (Exh. AG-59; Tr. 34, p. 70). Using these different capacity additions levels and their associated probabilities, BECo determined that the statistically expected value of capacity additions would be 637 MW (id.). The Company then calculated this expected value as a percentage of the total capacity assuming all planned units were to successfully enter service, and found it to represent roughly 57 percent of the total (Exh. HO-S-113).

To develop its base case "capacity additions" forecast, the Company first determined the total possible MW that planned units might contribute in each year of the forecast period, assuming that all projects would enter service by the dates and at the capacity levels anticipated in the signed contracts (Exh. BE-1, pp. E-8, E-34). The base case "capacity additions" projection for each year was derived by applying the 57 percent

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119/ MASSPOWER is a member of BECo's RFP #2 award group. The PSA between BECo and MASSPOWER was approved by the Department on December 19, 1990. MASSPOWER is a gas-fired cogeneration facility, located near Springfield, Massachusetts. The February 1992 Record indicates that BECo's summer entitlement from MASSPOWER is 100 MW (Exh. HO-S-60).

120/ Cogen Technologies is a member of BECo's RFP #2 award group. The February 1992 Record indicates that BECo's summer entitlement from Cogen Technologies is 100 MW (Exh. HO-S-60). However, no PSA has been signed between BECo and Cogen Technologies.

121/ The February 1992 Record indicates that the total MW contribution of all planned facilities, if completed, is approximately 1125 MW (Exh. HO-S-60).

figure described above to the total possible capacity additions MW level for each year (Exh. HO-S-114).

The Company did not identify the success rates that had been attributed to specific projects in its filing. The Company indicated that revealing the probabilities of success that it assigned to specific projects could jeopardize a project developer's ability to bring a project to fruition (Exh. AG-59, p. 1).

The Company used a similar process to develop its high case "capacity additions" forecast. For the high case projections, the Company selected a 1038 MW estimate from the Delphi survey process as representative of the high end of the capacity addition range because any MW level above this estimate was anticipated to have a low likelihood of occurring (Exh. BE-1, p. E-8; Tr. 34, p. 71). The Company determined that 1038 MW represented roughly 92 percent of the total capacity level if all planned units were to successfully enter service (Exh. BE-1, p. E-34). The high case forecast for each year was derived by applying the 92 percent figure to the total possible capacity additions MW level for each year (id.).

The Company also used this process to develop its low case "capacity additions" forecast. For the low case projections, the Company selected a 450 MW estimate from the Delphi survey process as representative of the low end of the capacity additions range, because any MW level below this was anticipated to have a low likelihood of occurring (Exh. BE-1, p. E-8; Tr. 34, p. 71). The Company determined that 450 MW represented roughly 40 percent of the total capacity level if all planned units were to successfully enter service (Exh. BE-1, p. E-34). The low case forecast for each year was derived by applying the 40 percent figure to the total possible capacity additions MW level for each year (id.).

During the proceeding, the Company updated the status of its planned resources. BECo indicated that OSP was on-line as of June 21, 1991 (Tr. 49, p. 33) and that HQ II was expected to enter full commercial operation on July 1, 1991 (Exhs. HO-S-118;

Tr. 49, p. 33). BECo also stated that NEA 1 and 2 were undergoing start-up testing as of June 21, 1991, and as a result, BECo was receiving some energy from the units with full-power operation anticipated in late 1991, or early 1992 (Exh. HO-S-21; Tr. 49, p. 33). In addition, BECo indicated that L'Energia had experienced some difficulties with its construction contract, but financing was underway (Exh. HO-S-21). BECo indicated that its contracts with Everett Energy, Patriot Energy, Wheelabrator Urban Woods had been terminated, and that the AES Riverside project had been cancelled (id.). Finally, regarding the award group members from BECo's RFP #2, BECo estimated a start-up date of late 1995 for MASSPOWER (id.). BECo also indicated that it was negotiating a PSA with Cogen Technologies, the other winner in RFP #2, and that the start-up date for that project was uncertain (id.).

(2) Analysis and Findings

The Siting Council is concerned that the process by which the Company projected "capacity additions" levels introduced distortions to the resource requirements calculations. The record reflects that in developing high, base and low case forecasts, a single percentage (92 percent in the high case, 57 percent in the base case, and 40 percent in the low case) was applied across total possible capacity additions MW levels for each year. This method of forecasting capacity additions is problematic because, although it might produce reasonable projections for the planning horizon taken as a whole, it sacrifices a significant degree of accuracy by neglecting the contributions associated with specific projects that may enter service in a particular forecast year.[122,123]

The Siting Council acknowledges that there is much uncertainty involved in any planning process and that use of a standardized approach to estimate capacity additions may be warranted. However, the use of a standardized approach should not allow a company to ignore clear and definite information about certain projects. While the averaging of probabilities of success across all years may yield reasonable results in the long run, the averaging approach sacrifices accuracy in the short run.

This problem with the Company's methodology for projecting the MW value from capacity additions is underscored by the updated information provided by the Company, which reveals that the status of certain planned projects has changed considerably. For example, OSP and HQ II already have entered service, and NEA 1 and 2 are about to enter service. Based on this evidence, it appears that the low case "capacity additions" projections projected by the Company are substantially understated in the early forecast years. Moreover, because contracts for all other planned additions have been terminated, OSP, HQ II, NEA 1 and 2,

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122/ For example, in a case where an average success rate is calculated based on anticipated contributions from a group of planned projects, one of the planned projects may have a very high likelihood of success, and would enter service during an early forecast year; the rest of the planned projects may have very low likelihoods of success and would enter service during the later years of forecast. Application of the Company's approach to forecasting capacity additions would result in understated capacity additions during early forecast years; i.e., at the relatively low averaged rate rather than at the high rate attributable to the high probability-of-success project. Similar inaccuracies also might occur in later years of a forecast depending on the individual success rates and timing of capacity additions.

123/ Even if the Company had updated its "capacity additions" variable and the need calculation within the reliability planning process to reflect the changes in the status of planned units, the "capacity additions" MW values still would not be acceptable, since the methodology that would be used to derive those values is flawed.

and L'Energia now represent the only planned units that could be in service by 1994. As a consequence, the high case "capacity additions" values during early forecast years are clearly overstated.[124]

The Siting Council recognizes the Company's concern about publicly revealing the probabilities of success associated with specific planned projects. However, because "capacity additions" projections are essential to the resource need calculations, which in turn play a role in substantial investment decisions, the Siting Council finds it critical that the "capacity additions" projections be as accurate as possible. Since OSP, HQ II, and NEA 1 and 2 already are providing BECo with power, there would be little damage to these NUGs if their probabilities of success were publicly and specifically assigned. Similarly, the record reflects that several of the PSAs for planned projects have been terminated. For the remaining planned projects still under development, steps can be taken to bring accurate and confidential information concerning their status into the planning process.

Although the "capacity additions" projections undoubtedly were developed using the best information available to the Company at the time its filing was being prepared, the Company's methodology failed to project accurately short-term capacity additions. Because the projections of contributions from capacity additions represent a critical component in the resource need calculation, and because findings on resource need (especially in the short-term) may have significant reliability

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124/ The Siting Council notes that G.L. c. 164, sec. 69I prescribes a ten-year horizon for planning purposes. By contrast, the Company has developed key variable values and forecasts of resource requirements over a 25-year planning horizon. Given the uncertainties associated with forecasting resource need, any evaluation of need that attempts to look beyond ten years, let alone out to 25 years, bears minimal value. Even if the Company believes its long-term projections are beneficial, accuracy in the near-term is critical if the forecasts are to be used in support of investment decisions.

and cost consequences, the accuracy of the short-term projections is essential.

Accordingly, the Siting Council finds that the Company's "capacity additions" projections are not acceptable for the purpose of calculating future resource requirements. In future filings, the Company should develop a reasonable process for projecting the contribution from capacity additions, which accommodates and incorporates specific information regarding the contributions of individual projects in the short-term.

(F) "Unit Availabilities"

(1) Company Proposal

BECo selected the availability of its existing generation units as a key variable in its resource planning process, because unit performance significantly affects the Company's resource requirements (Exh. BE-1, p. E-8). In developing forecasts of the anticipated MW contribution from existing generating units, the Company analyzed separately the availability of its fossil fuel units and Pilgrim (id.).[125]

BECo identified its fossil fuel units as New Boston 1 and 2, Mystic 4, 5, and 6, Mystic 7, and combustion turbine units ("Jets") (id., p. E-8). By surveying several Company personnel, BECo submitted that the base case, "most likely" equivalent availability factor ("EAF") was 81.6 percent for Mystic 4, 5 and 6; 75.8 percent for Mystic 7; 79.3 percent for New Boston 1 and 2; and 78.7 percent for the Jets (id.). In further developing its "unit availabilities" forecasts, BECo assumed performance incentive program ("PIP") targets established by NEPOOL as the high case EAF and assumed average historical EAFs as the low case EAF for its fossil fuel units (id.).

The Company indicated that it employed a different process to derive EAFs for Pilgrim (id., p. E-9). The Company maintained

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125/ The Company made no presentation regarding how it determined unit availabilities for non-Company-owned units in its resource plan.

that because of the "significant improvements" made at Pilgrim during a recent overhaul, historical performance would not be indicative of future performance (id.). Therefore, the Company projected Pilgrim's availability by relying on a combination of historical data from similar nuclear units and data reflecting the Company's expectations of improved future performance at Pilgrim (Exh. HO-S-158). Using a statistical methodology, the Company derived a high case EAF of 76.63 percent, a base case EAF of 68.62 percent, and a low case EAF of 60.05 percent for Pilgrim (Exh. BE-1, p. E-9).[126] Corresponding probabilities assigned through the Delphi survey were 13 percent for the high case, 50 percent for the base case, and 37 percent for the low case (id.).

BECo indicated that in order to forecast total MW contributions from the Company's existing resources, the contributions from fossil units and Pilgrim were combined (id., p. E-9). The base case "unit availabilities" forecasts were derived through an assessment of the base case EAFs for all units, including Pilgrim (id.). Similarly, the high case "unit availabilities" forecast combined high band EAFs for all units including Pilgrim, and the low case EAF level combined low band EAFs for all units including Pilgrim (id.). The high, base and low "unit availabilities" probabilities for all units, including Pilgrim, were 26 percent, 43 percent, and 31 percent, respectively (id., p. E-13).

126/ In order to determine high, base and low case EAFs for Pilgrim, the Company calculated three EAF distributions for Pilgrim, using the mean EAF between 1985 and 1987 for all boiling water reactors ("BWRs") (61.6 percent), the mean EAF between 1985 and 1987 for BWRs similar to Pilgrim (68 percent), and BECo's own projection of Pilgrim's EAF (68 percent) (Exh. BE-1, p. E-9). The Company indicated that the three distributions were combined using discrete probability distribution calculations to generate a single probability distribution (id.). The Company stated that the resulting distribution ranged from a 48.52 percent EAF to an 81.93 percent EAF (id.). A mathematical condensation technique transformed the curve into high, base and low case EAFs, to which corresponding Delphi-developed probabilities were assigned (id.).

(2) Positions of Parties

The Attorney General asserted that the Delphi survey, which resulted in BECo's "most likely" base case EAF values, "is a combination of negotiated values that are wrongly interpreted by the Company" (Attorney General Initial Brief, p. 86). The Attorney General alleged that some responses to specific questions in the Delphi survey were internally inconsistent (Attorney General Reply Brief, p. 40).

According to the Attorney General, it is appropriate to determine the need for additional capacity under a range of scenarios that reflects consideration of historic EAFs (Attorney General Reply Brief, p. 46). However, the Attorney General contended that historic EAFs should not represent the base case EAF in the Company's analysis, because such an approach would serve to foster "continued poor performance" of the Company's existing units (id.).

CLF urged the Siting Council to reject BECo's resource plan, arguing that the Delphi survey used to establish EAFs for existing units suffers from lack of documentation, misuse of the methodology, and lack of reasoned explanation of its results (CLF Initial Brief, p. 21; Exh. CLF-1, pp. 51-52). In addition, CLF questioned the expertise of many of those who were consulted in the surveying process (CLF Initial Brief, p. 21). CLF also criticized the fact that the Company determined how many and which of its employees were polled and the weight assigned to their responses (CLF Initial Brief, p. 21; Exh. CLF-1, pp. 52-53).

According to MASSPIRG, the Company's expected EAFs were more appropriate than historic EAFs for use in the base case (MASSPIRG Initial Brief, p. 20). MASSPIRG agreed with the Attorney General that the use of historical plant performance presented a dilemma (id., p. 19). MASSPIRG acknowledged that it may be overly optimistic to assume that a plant that has had a long history of poor performance will improve to target levels, thereby leading to capacity shortages if the projected improvement does not occur (id.). Conversely, MASSPIRG asserted that if all units are assumed to perform at historical levels for the purposes of long-run planning, then the effect may be to encourage utility companies to invest in new plants rather than make cost-effective investments in existing plants to improve their availability (id.).

MASSPIRG also questioned the Company's assignment of a 68.62 percent EAF as the base case for Pilgrim, noting that this is "well above" its historic capacity factor (id., p. 24). According to MASSPIRG, it is impossible to forecast accurately Pilgrim's EAF in light of its history and the recent improvements (id.).

(3) Analysis and Findings

The Siting Council has substantial concerns regarding the base case EAF values which the Company applied in developing the base "unit availabilities" forecasts within its decision tree analysis.[127] If the resource requirements calculation is to reflect a realistic assessment of the Company's future needs, it is essential that the "unit availabilities" forecasts reflect realistic estimates of the contribution that can be anticipated from existing resources.

The Siting Council notes that, in general terms, the level at which a generating unit has been performing -- the historic EAF level -- is the best indicator of future performance (especially where investment decisions in the short-term are at issue). Historic EAFs, however, may not always accurately forecast future performance. Therefore, if recent performance trends or substantial recent capital improvements can better

127/ We note that the Company did not present any MW projections associated with the "unit availabilities" variable. Consistent with the Company's presentation, this analysis focusses on unit EAFs, which were later used to calculate the MW contribution from existing fossil units and Pilgrim in the Company's derivation of "effective resources." As presented in Section III.C.2.b.i(G), below, the Company reflected the contributions from existing units and planned capacity additions through a single "effective resources" variable.

predict future performance levels, an analysis which reflects such trends and improvements should be employed. In this regard, if substantial capital improvements, for example, are anticipated to significantly affect future performance, the estimated effect of these improvements should be quantified and presented.

The record reflects that the base case EAF projections for the Company's fossil units are based on the estimates of Company personnel as developed through the Delphi process. In the absence of reliable evidence of clearly discernible recent performance trends or substantial recent capital improvements on the Company's fossil units, the Delphi projections are largely unsubstantiated. Therefore, the Siting Council finds that the EAFs reflecting historic fossil unit performance are appropriate for the purpose of calculating the base case MW contribution from existing fossil units.[128]

Since the EAFs which reflect historic unit performance now will be used for the purpose of developing base case forecasts for fossil units, the Siting Council rejects the EAFs used to derive the low case "unit availabilities" forecasts for existing fossil units as well. Accordingly, the Siting Council finds that the EAFs used by the Company in deriving the base case and low case "unit availabilities" forecasts for fossil units are not acceptable for the purpose of calculating future resource requirements.

As noted above, the high case EAFs for fossil units set out by the Company reflect PIP standards. Although very

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128/ Although the Siting Council recognizes the legitimacy of the Intervenors' concerns regarding the possibility of fostering poor plant performance if historic EAFs are assigned to the base case, the necessary focus in this Phase I Decision is to identify the most reasonable estimates of future plant performance in order to calculate accurately the contribution from existing units and subsequently, resource need. Matters concerning what resource options (including enhancements to the performance or output of existing units) would constitute the most cost-effective additions to the Company's resource portfolio are more properly the subject of Phase II of this Decision.

substantial improvements in unit performance would be necessary in order to achieve the PIP standards, for purposes of this review, the Siting Council finds that the PIP standards are acceptable as the basis for calculating the high case "unit availabilities" forecast for existing fossil units. Accordingly, the Siting Council finds that the EAFs used by the Company in deriving the high case "unit availabilities" forecasts for fossil units are acceptable for the purpose of calculating future resource requirements.

Finally, in light of the substantial capital improvements to Pilgrim, we agree with the Company that it is more appropriate to consider the historic performance of comparable nuclear power plants as an indicator of future Pilgrim performance until such time as the historic performance of Pilgrim is deemed an acceptable indicator of future performance. We note that in a number of recent regulatory proceedings, BECo has displayed a substantial commitment to improving the performance of Pilgrim. See Boston Edison Company, D.P.U. 88-28/88-48/89-100, pp. 15-17 (1989). Accordingly, the Siting Council finds that the EAFs used by the Company in deriving the high case, base case and low case "unit availabilities" forecasts for Pilgrim are acceptable for the purpose of calculating future resource requirements.[129]

(G) "Effective Resources"

(1) Company Position

The Company indicated that before applying its key variables projections to the IDEAS decision tree, it went through a process by which it "condensed" or integrated the "unit availabilities" variable and "capacity additions" variable into a single "effective resources" variable (Exh. BE-1, pp. E-1, E-2,

129/ Here, we make no findings concerning the acceptability of the "unit availabilities" MW projections, because the Company's filing presented none. The existing fossil unit and Pilgrim EAFs discussed in this Section were used directly in the derivation of "effective resources," as presented in Section III.C.2.b.i(G).

E-13). BECo stated that it condensed these two variables in order to simplify the calculation of future resource requirements (id., p. E-13).

The Company's explanation of its derivation of "effective resources" was abbreviated. The Company indicated that "effective resources" MW values for each forecast year were developed by combining the high, base, and low "unit availabilities" and the high, base, and low "capacity additions" projections to produce nine MW levels (Exh. AG-35, p. 1). The resulting nine MW levels for each forecast year were placed in ascending order and then, using a mathematical technique for condensing discrete probability distributions, condensed into three levels representing high, base, and low "effective resources" forecasts (Exh. AG-35, p. 1, Supplement).

The Company asserted that "capacity additions" represent more MWs than "unit availabilities," and that "capacity additions" was the "driving force" in the condensation process (Exh. BE-1, p. E-13). BECo indicated that the "effective resource" levels were therefore "developed in a manner to have similar probabilities to the 'capacity additions' levels," and were assigned probabilities of 7 percent, 52 percent, and 40 percent in the high, base, and low cases, respectively (id.).

(2) Attorney General Position

In criticizing the Company's "effective resources" variable, the Attorney General's witness, Susan Geller, presented a table which outlined the method by which "effective resources" MW values and probabilities were derived (see Exh. AG-60, Fig. 4). According to the Attorney General, the Company first determined a total MW value for its existing units at their full capabilities (id.). Second, the Company added the high, base, and low capacity additions forecast for each year to the total existing unit capability level, producing high, base, and low interim projections (id.). To each of these three levels of interim projections, the Company added a figure representing the MW effect on its capability responsibility to NEPOOL if its existing units were to perform at EAF levels implicit in each of the high, base, and low "unit availabilities" forecasts (id.). The resulting nine MW levels were placed in ascending order, and probabilities were calculated for each of the nine levels reflecting the high, base, and low "capacity additions" and "unit availabilities" probabilities from which each of the nine levels was derived (id.).

Finally, according to the Attorney General, the nine MW levels were separated into high, base, and low groups such that the total probability of each group matched that of the respective high, base, or low "capacity additions" probability (id.). The nine levels were condensed into three by calculating a single statistically expected MW value within each high, base, and low group based on the relative probabilities of MW levels within each group (id.). These expected MW values became the high, base, and low case "effective resources" forecasts.

The Attorney General criticized the combination of the "unit availability" variable and "capacity additions" variable into one "effective resources" variable (Exh. AG-60, pp. 8-9). The Attorney General asserted that the condensation process compromised the results of the Company's decision tree analysis (id., p. 8). The Attorney General claimed that the base case EAFs were factored into calculation of the low case value of "effective resources" and the high case EAFs were factored into the calculation of the base case value of "effective resources" (id.). The Attorney General also noted that, had "capacity additions" and "unit availabilities" been considered separately, the result would have been a much larger decision tree with 243 possible scenarios (id., p. 9).

(3) Analysis and Findings

The Siting Council notes that, from a strictly theoretical standpoint, it would not be inappropriate to seek to reduce two key variables to one variable in order to simplify a decision tree analysis. Nor is it problematic that base case EAFs entered into the calculation of low case "effective resources," provided that accurate calculations within the condensation process indicate that base case EAFs indeed contribute to the low "effective resources" projections. However, the Siting Council shares the Attorney General's concern regarding the condensation of two key variables into the single "effective resources" variable for several reasons.

First, the record reflects that the final high, base, and low case "effective resources" MW values are the statistically expected values of various groupings of the nine MW levels representing the different possible combinations of the "capacity additions" and "unit availabilities" variables. As a consequence, the MW levels that would reflect a pairing of the low case "capacity additions" projections with the low case "unit availabilities" projections are not represented in the final "effective resources" projections.

In a reliability planning study, the resource requirements scenarios that result from a decision tree analysis would be incomplete if they failed to reflect a reasonably possible, worst-case condition to which the Company might have to respond. If the low case "capacity additions" and low case "unit availabilities" MW values represent realistic contingency conditions (even if at low probabilities), then their simultaneous occurrence must be considered in any comprehensive reliability planning process. Therefore, we question the value of the Company's condensation process because it eliminated the MW values commensurate with a low case "capacity additions" and low case "unit availabilities" pairing.

Our second concern pertains to the probabilities implicit in the "effective resources" derivations. The Company asserted that "capacity additions" represent more MW than "unit availability" and were thus the "driving force" in the condensation process. However, a comparison of the range of "capacity additions" MW values that might be anticipated to those for "unit availabilities" (based on findings presented in Sections III.C.2.b.i(E)(2) and (F)(3), above,) reveals that, in the critical early years of the planning horizon, it is "unit availabilities" that has the greatest range in terms of total MW (see Sections III.C.2.b.i(E) and (F), above, and Sections III.D.2.d and e, below). The Company's approach is problematic to the extent that its results are used to support near-term investment decisions.

Finally, the Siting Council questions the general value of condensing "capacity additions" and "unit availabilities" into a single "effective resources" variable. The Company presented both unit availabilities and capacity additions as "key" factors affecting future needs. The Siting Council agrees with the Company that both unit availabilities and capacity additions represent important and independent factors in the resource planning process. Therefore, both unit availabilities and capacity additions could better have been treated as important and independent factors in developing future need scenarios. The condensation process introduced by the Company contravened this objective, sacrificing comprehensiveness and additional accuracy for a gain in simplicity.

Accordingly, based on the foregoing, the Siting Council finds that the Company has failed to demonstrate that the "effective resources" projections are acceptable for the purpose of calculating future resource requirements.

(H) <u>Conclusions on the Proposed Need Scenarios</u>

The Siting Council has found the decision tree to represent an acceptable planning tool. The Siting Council also has found that the Company's process for reducing the number of future scenarios from 81 to 30 is acceptable.

With regard to the selection and application of the key variable input values used in the IDEAS decision tree analysis, the Siting Council has found that: (1) the "load growth" projections from the initial forecast are not acceptable for the purpose of calculating future resource requirements; (2) the Company's treatment of the "fuel price" variable is acceptable for the purpose of calculating future resource requirements;

(3) the Company's "DSM penetration" projections are acceptable for the purpose of calculating future resource requirements; (4) the Company's "capacity additions" projections are not acceptable for purpose of calculating future resource requirements; (5) the EAFs used by the Company in deriving the base and low case "unit availabilities" forecasts for fossil units are not acceptable for the purpose of calculating future resource requirements; (6) the EAFs used by the Company in deriving the high case "unit availabilities" forecasts for fossil units are acceptable for the purpose of calculating future resource requirements; (7) the EAFs used by the Company in deriving the high, base and low case "unit availabilities" forecasts for Pilgrim are acceptable for the purpose of calculating future resource requirements; and (8) the Company has failed to establish that its "effective resources" projections are acceptable for the purpose of calculating future resource requirements.

The Siting Council finds that the Company has not established that its decision tree methodology was applied in a manner that yields acceptable projected alternative scenarios of resource requirements. The Siting Council further finds that the 81 scenarios developed by the Company do not constitute a reliable projection of the range of future resource requirements.

Accordingly, the Siting Council finds that the Company has failed to establish that its determination of resource need is acceptable.[130]

130/ The resource requirement scenarios that result from the first phase of the Company's reliability planning process are essential to later phases of the process. However, the fact that the Siting Council has rejected the Company's determination of resource need does not obviate the need for further review of Boston Edison's reliability planning process. Boston Edison, or other companies, may choose to use this reliability planning methodology as the basis for its filings in future proceedings before the Siting Council. Therefore, we will complete our evaluation of how the methodology was applied in this proceeding, and make findings regarding whether BECo's application of its methodology is acceptable.

ii. Production Costs to Meet Resource Needs

After the Company developed the 30 representative forecasts of resource requirements from the original 81 scenarios (which reflected ten alternate patterns of future resource requirements across the planning horizon at the high, base, and low fuel price levels) the second phase of its reliability planning process began. BECo used its Electric Generation Expansion Analysis System ("EGEAS") computer model to evaluate the 30 representative forecast scenarios (Exh. BE-1, pp. E-2, E-41).[131] The Company indicated that the objective of this effort was to assess the costs and timing of new resources associated with a series of least-cost resource portfolios that could be implemented to meet loads under each of the 30 scenarios (id., p. E-2). The Company indicated that it considered a number of resource alternatives in developing its "optimal" resource portfolios, and that the associated costs constituted the Company's production engineering department's estimates of the costs of the various resource alternatives (id., pp. C-7, E-2). BECo used a screening process and the EGEAS model to optimize resource portfolios under alternative expansion plans and to project associated production costs (id., p. E-15). The Company stated that both the "optimal" resource selections and their corresponding production cost projections were the output of the Company's EGEAS model (id., pp. E-15, E-38 to E-40).

The Attorney General criticized the Company's EGEAS calculations, arguing that they were inconsistent with the

131/ The Company presented EGEAS as a state-of-the-art generation optimization program which was developed under a grant from the Electric Power Research Institute by the Massachusetts Institute of Technology and Stone and Webster Engineering Corporation (Exh. BE-1, p. C-8). Utilizing input assumptions on load forecasts, required reserve levels, fuel forecasts, capital and O&M costs, unit operating characteristics, carrying costs, etc., EGEAS has the capability of costing out thousands of potential resource plans (id.). The EGEAS program prioritizes potential resource plans in terms of economic preference; that is, it is able to identify an optimal resource plan by selecting among various input resource options (id.).

results of the IDEAS decision tree analysis (Exh. AG-60, pp. 8-11). The Attorney General reiterated a Company statement that EGEAS uses availability data on a per-unit basis rather than a system-wide basis (id., p. 11). The Attorney General indicated that the availability data used in EGEAS was understated in comparison to the data used in deriving resource requirements through the IDEAS decision tree (id.). The Attorney General asserted that the EGEAS-based production costs thus were distorted (id.).

The Siting Council does not agree with the Attorney General that different unit availability assumptions in the IDEAS decision tree and EGEAS models undermined the system production cost calculations. As presented in Section III.C.2.b.i(A), above, the 81 decision tree scenarios were reduced to 30 representative forecasts in an acceptable manner. The nature of the need behind each of those 30 scenarios is not critical to the EGEAS production cost calculations; rather, the focus of the EGEAS analysis is necessarily on the cost of additional resources that would be incurred by the Company in responding to various need levels with appropriate levels of resource additions. While we accept that some loss of precision may result if the EAFs used in EGEAS are not absolutely consistent with those reflected in the need levels to which EGEAS is responding, based on this record, we are not convinced that any significant distortions were produced in the system production cost calculations.

However, as presented in Section III.C.2.b.i(H), above, the Siting Council has found that the 81 scenarios developed by the Company do not constitute a reliable projection of the range of future resource requirements. Because the various need levels upon which the production cost calculations were based have not been accepted, the Siting Council finds that the various production cost totals associated with different expansion plans cannot be accepted as relevant to the reliability planning process in this proceeding.

Finally, we note that the Company's production cost calculations place an important issue before the Siting Council.

If the production costs associated with differing levels of system expansion are to be realistic, they must reflect portfolios containing least-cost, least-environmental-impact energy resources, as would be required under G.L. c. 164, sec. 69I. There are serious questions concerning the implications of our approving the production cost projections associated with the various expansion plans as both least-cost and least-environmental-impact, and thus implicitly designating the new resources within those plans as least-cost and least-environmental-impact, without thorough review of the individual new resources.[132]

The Company has developed its proposal for reliability planning based on an analysis that employs production cost projections which reflect a series of expansion plans proposed as "optimal" by the Company. While it would not be possible for the Siting Council to find each expansion plan to be "optimal," i.e., least-cost and least-environmental-impact, based solely on the cursory presentation supporting the EGEAS production cost analysis, without some reasonable projections of production costs under alternative expansion plans, a system reliability evaluation that considers those production costs simply could not be developed. Reasonable production cost projections are necessary to evaluate the different reliability levels that might be achieved with different levels of investment in new resources. In past Decisions, the Siting Council has emphasized the importance of assessing the costs of planning to different reliability levels. Massachusetts Electric Company/New England Power Company, 21 DOMSC 325, 374-375 (1991) ("1991 MECo/NEPCo Decision"); 1991 Nantucket Decision, 21 DOMSC at 260-262, 268; Bay State Gas Company, 21 DOMSC 1, 11-15, 42-43 ("1990 Bay State Decision"); Berkshire Gas Company (Phase I), 19 DOMSC 247, 268

132/ For example, the Siting Council will not address until Phase II of this proceeding whether Edgar constitutes a least-cost, least-environmental-impact addition to Boston Edison's resource portfolio.

(1990) ("1990 Berkshire Decision"); 1989 BECo Decision, 18 DOMSC at 276, 277.

Many new resource options could be included in the series of future expansion plans by which a company might respond to different need levels across a long-run planning horizon. The Siting Council notes that the presentation and regulatory review necessary to determine whether each resource option represents a least-cost, least-environmental-impact alternative would be extremely burdensome task. Therefore, if cost considerations are to enter into the reliability planning process, some reasonable but less rigorous approach to forecasting production costs is necessary. Production cost models, such as the EGEAS model used by BECo, are a commonly used industry tool which can provide reasonable estimates of the production costs that would be incurred under alternate potential least-cost expansion plans, without necessitating specific review and findings concerning the particular resources reflected in the cost estimates. In this instance we defer our review of the EGEAS model and its application by the Company to least-cost planning to Phase II of this Decision.

iii. Risk vs. Cost Analysis

The Company implemented the final step of its reliability planning process in order to identify an appropriate planning level for system expansion that balances the costs of unserved energy and system expansion (Exh. BE-1, pp. E-2 to E-3, E-16). First, using the probabilities associated with each forecast, BECo stated that the ten alternative forecasts of resource requirements within the 30 representative scenarios were transformed into a matrix of resource requirements set out at different confidence levels (id., pp. E-17, E-43). The Company stated that those levels that did not represent major changes (in terms of incremental resource requirements) from succeeding levels were dropped from the analysis; a total of seven confidence levels -- 10, 25, 40, 60, 70, 80, and 95 percent -- remained for further analysis (id., p. E-17).

The Company next assumed implementation of a least-cost expansion plan that could meet loads implicit in each of the seven identified confidence levels (id., p. E-17). The Company used its EGEAS model to forecast the unserved energy hours that could be anticipated if needs were to materialize consistent with each of the original 81 scenarios (id., p. E-18). Specifically, for the expansion plans corresponding to each of the seven confidence levels, the Company combined the probability and projected number of unserved energy hours for each of the 27 different need levels implicit in the original 81 scenarios to derive the statistically expected value for unserved energy hours that could be anticipated in each year of the forecast (Exh. HO-S-132).

The Company did not identify explicitly the cost of unserved energy in dollars-per-megawatthour ("MWH") terms (Exh. BE-1, p. E-18). Rather, in the final step of its risk-versus-cost analysis, Boston Edison calculated the cost of unserved energy at which it would be cost effective to accept the incremental costs of expanding the generation system to meet loads commensurate with the subsequent confidence level (id., pp. E-18, E-46). More specifically, the Company compared the system production costs and expected unserved energy costs that would be anticipated under an expansion plan commensurate with each confidence level to the system production costs and expected unserved energy costs that would be anticipated if its system were to be expanded to the next highest level (id.). The Company indicated that unserved energy hours were calculated for the Boston Edison system on an own-load basis (Exh. HO-S-132; Tr. 49, pp. 53-55). The Company asserted that, in this manner, the reliability gains associated with avoiding unserved energy hours through system expansion could be compared to the additional production costs that could be incurred in so doing (id.).

Based on this analysis, the Company stated that system expansion to a level that would meet future resource requirements commensurate with the 80 percent confidence level could be justified in the period between 1990 and the year 2000

(Exh. BE-1, pp. E-18 to E-19). The Company identified $510 per MWH as the minimum unserved energy cost value at which expansion to the 80 percent confidence level in the period ending in the year 2000 would be justified (id.).

The Attorney General opposed Boston Edison's proposal to plan to an 80 percent confidence level. The Attorney General maintained that the Company has inflated its calculation of need from 119 MW to 400 MW in the base case "by extravagantly planning to build to an 80 percent confidence level" (Attorney General Reply Brief, p. 9). The Attorney General offers the following explanation of the 80 percent confidence level: "The 80 percent confidence level means that NEPOOL's [one-day-in-ten-years reliability] criterion is not met in 20 percent of projected scenarios; it does not mean that blackouts would occur 20 percent of the time" (Attorney General Initial Brief, p. 84).[133] He continued, "to maintain compliance with the [one-day-in-ten-years] criterion, NEPOOL relies on a 50 percent confidence level, and reviews load and capacity annually, using short-term resources to provide any needed additional capacity" (id.).

MASSPIRG echoed both the Attorney General's criticism of BECo's proposed 80 percent confidence level and the suggestion that NEPOOL's 50 percent confidence level represented a better approach to reliability planning (MASSPIRG Reply Brief, pp. 9-10).

As a preliminary matter, the Siting Council first addresses the comments submitted by Intervenors concerning the Company's proposed 80 percent confidence level. Both the Attorney General and MASSPIRG expressed their dissatisfaction

133/ The "one-day-in-ten-years" standard reflects a loss-of-load probability (or, more accurately, a loss-of-energy probability projection), which is often proclaimed as an industry standard in assessing reliability (Exhs. BE-1, p. E-16, HO-S-163, p. 2). For purposes of this proceeding, the Siting Council interprets "one-day-in-ten-years" to mean that, if that standard is achieved, on average customers will experience the loss of electric service for, at most, a total of 24 hours during any ten-year period because of generating system deficiencies.

with the results of the risk-versus-cost analysis that supported BECo's proposal to plan to an 80 percent confidence level. However, neither the Attorney General nor MASSPIRG commented on the risk-versus-cost analysis itself, or why the 80 percent confidence level would not strike an appropriate balance between system reliability and cost. The Intervenors' proposed alternative approach to reliability planning, i.e., planning to NEPOOL's 50 percent confidence level, is addressed in Section III.C.3, below.

In the 1989 BECo Decision, the Siting Council evaluated the risk-versus-cost analysis that Boston Edison used to develop a resource plan commensurate with a 70 percent confidence level (18 DOMSC at 276). In that Decision, the Siting Council generally accepted the approach taken by the Company in its risk-versus-cost analysis. Id. at 277. However, in that case, the Company provided a wide range of estimates concerning the cost of unserved energy, from $125 per MWH to "well over" $1,000 per MWH. Id. at 276. In the 1989 BECo Decision, the Siting Council stated that, while Boston Edison's risk-versus-cost methodology "serve[d] as a practical starting point for balancing resource adequacy and cost," the Company should begin researching methods to better evaluate or quantify the societal costs of an outage (18 DOMSC at 276).

In this proceeding, however, the Company has made no effort to more precisely define the cost of unserved energy. Rather than respond to the Siting Council's directive in the 1989 BECo Decision, the Company's approach was to define the cost per MWH of unserved energy at which investment in additional resources representing expansion of its system to a higher reliability level would be justified. Generally, the Company's more simple alternative approach would be appropriate if it could demonstrate that the true cost of unserved energy is greater than the identified levels at which the cost per MWH of unserved energy cost would economically justify system expansions. Here, the Company has not made this demonstration.

The record reflects that the Company's approach of planning to an 80 percent confidence level could be justified if unserved energy costs exceeded $510 per MWH. However, this figure represents roughly the midpoint of a wide range of unserved energy cost estimates assessed in the 1989 BECo Decision. The broad extent of this range of estimates was the reason the Siting Council directed the Company to further study and define the cost of unserved energy more narrowly. Because the Company did not more precisely define the true cost of unserved energy, the record in this proceeding does not demonstrate that unserved energy costs do, in fact, exceed $510 per MWH. Therefore, the Company has not established that system expansion to an 80 percent confidence level is justified.

Other important concerns regarding BECo's risk-versus-cost analysis pertain to the Company's calculation of the quantities of unserved energy hours that were factored into the risk-versus-cost analysis. First, the record reflects that unserved energy hours were calculated for the Boston Edison system on an own-load basis. Consequently, the Company's calculation does not reflect the reliability benefits that the Company obtains for its customers simply by virtue of being a member of NEPOOL.

Therefore, the unserved energy hours that formed the basis of the risk-versus-cost analysis are not realistic.[134] The reliability benefits that accrue to utilities through NEPOOL participation represent a resource, like any other, for Boston Edison. As is the case for other resources, NEPOOL reliability benefits should be assessed in terms of the number of MW that can be expected from NEPOOL under varying circumstances. While

134/ The Siting Council notes, for example, that the Company presented unserved energy hours across the entire range of the Company's forecast need scenarios, even under system expansion to very high confidence levels (Exh. HO-S-132). It is highly unlikely, under many of the low need scenarios (which generally reflect low load growth conditions), that NEPOOL would not be able to assist the Company with capacity sufficient to prevent Boston Edison customers from experiencing service disruptions.

deriving estimates of reliability contributions from NEPOOL under different scenarios may be difficult to do with precision, even a rough estimate of NEPOOL contributions would be preferable to ignoring this valuable resource altogether.[135] The Company should not make investments in additional supplies in order to avoid unserved energy hours that are not realistic.

The second deficiency in the quantification of unserved energy hours pertains to the time periods across which energy deficiencies were anticipated to last in the Company's calculations. The Company's calculations would suggest that, if little system expansion occurs (i.e., Boston Edison develops its system only to the 10 or 25 percent confidence level) and loads commensurate with the high need scenarios materialize in the future, then high levels of unserved energy hours could be anticipated across a 25-year horizon. This outcome is highly unlikely. If the Company were to construct its system to one confidence level, and resource requirements consistent with a higher confidence level were to materialize, Boston Edison would not refuse to act while customer needs went underserved across two decades. Rather, pursuant to an appropriate long-run supply planning process consistent with Company's statutory responsibility, the Company would take prompt and appropriate action to expand its system to a level that could deliver least-cost, environmentally acceptable energy to meet customer demands. Therefore, because the Company's calculation of unserved energy hours misstates the period across which energy deficiencies would reasonably be anticipated to persist in the

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135/ The Siting Council does not suggest that the Company should neglect its responsibility, as a member of NEPOOL, to make an appropriate level of resources available to the pool. We simply emphasize that the reliability benefits that accrue to NEPOOL members must be recognized in some manner in the reliability planning process.

event of an undersupply, the Company's projections of unserved energy hours may be greatly overstated.[136]

As we have stated in past Decisions, individual utilities should attempt to achieve an optimal balance between reliability and cost in making resource procurement decisions. 1991 MECo/NEPCo Decision, 21 DOMSC at 374-375; 1991 Nantucket Decision, 21 DOMSC at 260-262, 268; 1990 Bay State Decision, 21 DOMSC at 11-15, 42-43; 1990 Berkshire Decision, 19 DOMSC at 268; 1989 BECo Decision, 18 DOMSC at 276, 277. Generally, an electric company should consider both the positive and negative aspects of NEPOOL membership in determining what level of system reliability would be appropriate for its customers. Once NEPOOL, and all other existing and planned energy resources have been properly considered, an electric company may be able to demonstrate that system expansion to a higher reliability level is justified.

Accordingly, based on the foregoing, the Siting Council finds that the Company has failed to establish that the results of its risk-versus-cost analysis are acceptable. Therefore, for purposes of this review, the Siting Council finds that the Company has not established that its proposal to plan to an 80 percent confidence level is acceptable. In the future BECo must better evaluate and quantify the costs of unserved energy.

136/ The Siting Council notes that, to the extent that loads in fact materialize on a region-wide basis that exceed the levels to which NEPOOL members have planned generally, the fact that Boston Edison might have developed its system to a reliability level consistent with meeting those higher loads may not fully benefit its own customers. Rather, as a NEPOOL member, Boston Edison would be expected to join other utilities in implementing NEPOOL emergency procedures in the event of a region-wide capacity deficiency.

While investments in system reliability may thus only accrue in part to the Company's ratepayers, Boston Edison's pursuit of higher reliability levels would not necessarily be precluded. Only a comprehensive analysis of the costs and true benefits of investing to higher reliability levels in the context of BECo's NEPOOL membership would reveal whether investing to the higher levels would be justified.

c. Boston Edison's Reliability Implementation Strategy

The Company stated that its "decision analysis established the economic basis for planning to a target confidence level of 80 percent through the year 2000" (Exh. BE-1, pp. E-3, E-23). The Company indicated that in 1994 an additional 400 MW would be needed at the 80 percent level (id., p. E-21). Therefore, consistent with its proposed "near term" planning target, the Company indicated its intent to pursue immediate licensing and construction of a 306 MW facility for service by 1994 (id., p. E-22). BECo also indicated that it would "monitor load and resource conditions and would enter into (short term) purchases if (need commensurate with the 80 percent confidence level) materializes" (id., pp. E-22 to E-23).

The Company indicated that "[i]t is not necessary...to commit to additional resources for the 1995-2000 period at this time" (id., p. E-23). Rather, the Company proposed to assess the type and amount of resources needed as time progresses (id.). The Company stated that the resources which it proposed to rely upon in the "mid-term" included potential new C&LM programs, purchases from non-utility generators through competitive solicitations, and prelicensing existing generation sites, such as the existing combustion turbine site in Medway (id.).

The Attorney General argued that the Company failed to demonstrate that building "excess" capacity is the least-cost way to achieve reliability (Attorney General Brief, p. 85). The Attorney General claimed that the Company has presented no analysis that evaluated the costs of pursuing short-term purchases or contingency resources, such as a Medway combustion turbine, as alternative approaches to ensuring an appropriate level of reliability (id.).

The Attorney General proposed that "the most economical way to plan, and the way that NEPOOL plans, is flexibly, reviewing load and capacity annually and adjusting plans for changes with short-term resources and contingency resources, which have shortened lead times" (Attorney General Reply Brief,

p. 10). The Attorney General cited a NEPOOL report, "Assessing NEPOOL's Resource Adequacy and Potential Resources," to support his proposition (id., p. 11; Exh. AG-25, pp. 15, 18). The Attorney General asserted that the Company chose what NEPOOL recognizes as the most expensive way of meeting need -- construction to meet a single need forecast at a high confidence level -- apparently because that is the only analysis that would allow its proposed project to meet a reliability need (Attorney General Reply Brief, p. 11).

While the Attorney General criticized Boston Edison's decision to ensure system reliability to an 80 percent confidence level, there is no real disagreement between the Company and the Attorney General concerning implementation strategies. Both indicate that it may not be necessary to make immediate investments in resources to a level commensurate with future planning targets. In addition, both appear to recognize that proper planning requires flexibility such that potential resources may be held in a contingency status until ensuring an ability to achieve predetermined reliability objectives dictates implementation.

Accordingly, the Siting Council finds that the Company's stated strategy for meeting an identified reliability objective is acceptable. We note that in Phase II of this Decision, the Siting Council will determine whether the Company's proposed resource plan effectively implements this strategy in a least-cost manner that minimizes environmental impacts.[137]

3. Intervenors' Alternative Approach to Reliability Planning

a. Introduction

The Siting Council has found that Boston Edison has failed to establish that it should plan its system to an 80 percent confidence level. During the course of these proceedings, several Intervenors proffered an alternative approach to reliability planning which they argue is superior to the Company's proposal. We address the Intervenors' suggestion below.

137/ The Siting Council notes that both the Attorney General and MASSPIRG have expressed concern over the size of the reserve margins that may result as a consequence of the Company's proposed reliability planning process (Attorney General Initial Brief, p. 84; MASSPIRG Reply Brief, p. 10). We note, however, that reserve margins are properly an outcome of the reliability planning process, not a determinant within the process. While implementation of a planning strategy that gives due consideration to achieving reliability objectives in a least-cost manner will not necessarily produce high reserve levels, it is also possible that actions taken to ensure a high level of system reliability may result in reserve levels that might appear excessive if the Company's actual future need materializes at lower levels than initially projected.

In general, implementation of a flexible implementation strategy would allow the Company to respond to unexpectedly low demand levels by postponing short-term resource options, thereby holding down the reserve margins. However, high reserve margins may occur if a company initiates implementation of additional resources commensurate with a reliability planning objective that requires it to be positioned to meet potential high growth in resource requirements in the short-term, and then that growth fails to materialize. Given the uncertainties of load forecasting, it is inevitable that planning to appropriately high reliability levels occasionally will result in reserve margins that might seem high relative to base and low load forecasts, and high relative to the load levels that actually materialize.

b. Attorney General Position

The Attorney General asserted that BECo has failed to establish that, on a company-specific basis, it has sufficient need to warrant construction of additional capacity in the short term (Attorney General Initial Brief, p. 20). Rather, the Attorney General claimed that updated economic forecasts show "sharply delayed need in the Company's service territory" and an expected capacity deficiency in 1994 of only 17 MW in the base case (id., pp. 18-19). The Attorney General maintained that the Company's next need for a resource addition would come between 1999 and 2001 (Attorney General Reply Brief, p. 5). The Attorney General opposed Boston Edison's proposal to plan to an 80 percent confidence level, suggesting instead that the 50 percent confidence level used by NEPOOL would better serve Boston Edison as a basis for planning (Attorney General Initial Brief, p. 84). The Attorney General asserted that if NEPOOL operates at the 50 percent confidence level, individual utilities should be able to operate at lower confidence levels, with pooling benefits increasing overall reliability (id.).

c. MASSPIRG Position

MASSPIRG asserted that the Company failed to demonstrate a need for additional energy resources (MASSPIRG Initial Brief, p. 3). MASSPIRG argued that, for reliability purposes, Boston Edison has no need to add 306 MW to its resource portfolio until at least 1999 (id., pp. 3, 18).[138] MASSPIRG claimed that the Company's proposal to develop its system to meet an 80 percent confidence level is unsupported (MASSPIRG Reply Brief, pp. 9-10). MASSPIRG asserted that "[t]he Company implies that a 50 percent confidence level means only a 50 percent chance that the lights

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138/ MASSPIRG, in its brief, uses "Edgar" to refer to "the Company's proposal to build a 306 MW combined cycle generating station at the proposed time, price and terms" (MASSPIRG Brief, p. 2). We interpret subsequent MASSPIRG arguments that "Edgar" is not needed as meaning that the Company has no near-term need for an additional 306 MW.

will stay on. In fact, the 50 percent confidence level means that the Company is most likely to be on target to be able to meet its customers needs for every day but one in ten years" (id., p. 10). MASSPIRG stated that "[t]his standard, which is used by NEPOOL and is virtually standard throughout the industry, already provides a very high confidence level in the reliability of electric service" (id.).

d. Business Associations Position

Business Associations presented arguments that would suggest that they would oppose adopting an alternative approach to reliability planning if such alternative resulted in reducing the targeted reliability level below that identified by Boston Edison (Business Associations Brief, pp. 1-8). Business Associations stated that ensuring adequate and reliable future electric supplies is crucial to the Commonwealth and the entire New England Region (id., p. 3). They expressed a concern that the projections of future DSM savings and the projections of new, non-utility power supplies supported by the Attorney General and CLF may not be realistic (id., p. 4).

Business Associations further asserted that "approving a plant that ultimately proves to be unneeded will mean, at worst, the waste of some money which will harm BECo's shareholders and perhaps, to a diminishing degree, its ratepayers.... On the other hand, denying approval for a plant..., will worsen the quality of life in New England and may prevent the economic growth which is the best hope for those in our society who most need additional economic opportunities" (id., p. 5).[139]

e. Discussion and Analysis

At the outset, the Siting Council notes that the Company's proposed reliability planning process differs from a loss-of-load

139/ NECA stated that it was taking no position with respect to Boston Edison's presentation concerning the need for additional capacity (NECA Initial Brief, p. 43).

(or loss-of-energy) probability calculation, which the Company identifies as long having been a standard in the industry to ensure adequate generation to meet load requirements. NEPOOL's one-day-in-ten-years reliability criterion constitutes a loss-of-energy probability measure of system reliability.[140] Here, Boston Edison has proposed, as a reliability planning target, that it position itself to acquire supply-side and demand-side resources to a level that would provide sufficient capacity to meet system loads under 80 percent (i.e., to the 80th percentile in terms of probability of occurrence) of the potential future resource need scenarios that the Company projected may occur across a 25-year planning horizon.

Intervenors in this proceeding have raised the issue of whether an alternative planning approach, namely one that relies on NEPOOL's standards and approaches to reliability planning, might offer Boston Edison's customers an appropriate level of reliability at a lower cost than the Company's approach. Intervenors' comments focussed on NEPOOL's one-day-in-ten-years planning criterion and the 50 percent confidence level asserted to be the basis for NEPOOL reliability planning. In assessing whether NEPOOL's planning process might represent an alternative or superior approach to reliability planning, the Siting Council reviews the NEPOOL reliability planning process as presented in the record in this proceeding.

The planning standards recommended by the intervenors (i.e., one-day-in-ten-years and the 50 percent confidence level) pertain to the method by which NEPOOL calculates its objective capability. Objective capability, expressed in MW, is the

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140/ While "one-day-in-ten-years" has been asserted by several parties to be a planning standard throughout the electric utility industry, the Siting Council has yet to be presented with a company supply plan wherein it is demonstrated that, if the company plans its system to an identified level, generation outages will be expected during, at most, 24 hours across a ten year period. As discussed below, "one-day-in-ten-years" is applied to a 50 percent probability load forecast by NEPOOL in projecting objective capability for billing purposes (Exhs. HO-S-163; HO-D-111, p. 2).

minimum amount of capacity that NEPOOL members must make available on a cumulative basis if NEPOOL is to meet its reliability standards during a given year (Exh. HO-S-163, p. 2).[141] Through a separate capability responsibility calculation, the NEPOOL objective capability figure is divided into capacity assignments to individual member utilities (Exh. HO-S-50; Tr. 47, p. 15).

NEPOOL's objective capability is generated to meet the Northeast Power Coordinating Council's generation reliability criterion that "the probability of disconnecting customers due to generation deficiency will be no more than one day in ten years" (Exh. MP-38). NEPOOL's reserve margin, which is reflected in its objective capability figure, is derived in consideration of this one-day-in-ten-years reliability standard (id.; Exh. HO-S-163, pp. 2-3).

The process by which NEPOOL calculates annual objective capability figures is based on a Westinghouse Generation Planning Capacity Model ("Westinghouse Model"), which uses probabilistic mathematics to simulate the uncertainty and random nature of future peak loads and resource availability (Exh. HO-S-163, p. 3). Peak load forecasts, which NEPOOL staff develop for the New England region, are a key input to the Westinghouse Model (id.; Tr. 47, p. 4). The Westinghouse Model reflects the uncertainties associated with and inherent in the normal random variations of daily peak loads due to weather variations (Exh. HO-S-163, p. 3).

The Company's witness, Mr. Killgoar, testified that the Westinghouse Model performs a loss-of-energy probability calculation by which NEPOOL determines the probability of losing

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141/ The record indicates that, while estimates of future objective capability figures are routinely projected across a four- to five-year period, NEPOOL formally establishes objective capability for only a single year at a time, largely for billing purposes (Tr. 47, p. 5; Exhs. HO-S-163, HO-D-111, p. 2). Consequently, as a forecast of regional resource requirements, NEPOOL's objective capability projections represent only "unofficial" and short-term forecasts.

load for a particular year under study, given an input peak load level and capability and availability assumptions concerning existing and planned resources (Tr. 47, pp. 9-10). As a result of this calculation, NEPOOL identifies a level of resources, i.e., an "objective capability," believed necessary to ensure that the loss-of-energy probability does not exceed one-day-in-ten-years (id.).[142] NEPOOL employs a set of formulas to assign a "capability responsibility" figure to member utilities, representing the MW level that each company is expected to make available in order to ensure that NEPOOL can meet its objective capability (Tr. 47, pp. 14-15; Exh. MP-38).

A problem arises with the calculation from the standpoint of reliability planning. The peak load data that represents a key input to the Westinghouse Model that NEPOOL uses to project objective capability is derived from the load forecast of the most recent CELT report, which reflects a 50 percent probability level (Exh. AG-25, Technical Supplement p. 9; Tr. 47, p. 7, Tr. 49, p. 59). Economic and demographic parameters that might contribute to higher load forecasts are not evaluated for sensitivity in the objective capability calculation (Exh. HO-S-163, p. 3; Tr. 47, p. 10). At the 50 percent probability level, there is a 50 percent chance that future loads realized by NEPOOL will fall below the CELT forecast level, but also a 50 percent chance that future loads will exceed the CELT forecast level (Exh. AG-24; Tr. 47, p. 8; Tr. 42, p. 26).

Therefore, NEPOOL's objective capability calculation does not anticipate the upper 50 percent of potential future load levels (Exh. HO-D-111, p. 1).[143] Given a strictly analytical and very long term perspective, if NEPOOL participants were to plan

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142/ The record reflects a possibility that the resource requirements prescribed by the computer model may be adjusted subjectively in setting a final objective capability because of differing views among NEPOOL planners as to the appropriateness of the input assumptions to the model (Tr. 47, p. 14).

143/ Moreover, as noted above, NEPOOL establishes final objective capability figures for only one year at a time.

their systems based on the 50 percent probability load levels used to project objective capability, the one-day-in-ten-years reliability level would be achieved if, and only if, future loads were at or below that 50 percent probability level. To the extent loads exceeded that level in some years (the 50 percent probability level would be exceeded to some extent in half of future years), it is likely that NEPOOL's one-day-in-ten-years planning standard would not be achieved in the long run, although it is difficult to predict the effect on system reliability and associated costs.[144]

Moreover, the record shows that NEPOOL itself questions the 50 percent level as a basis for reliability planning (Exh. HO-D-111, p. 2). In its Resource Adequacy Assessment report, NEPOOL explored the costs and reliability benefits of pursuing different reliability planning levels, such as the 80 percent confidence level (Exh. HO-S-171; Tr. 49, p. 76). While NEPOOL's evaluation of planning to an 80 percent confidence level, in and of itself, does not necessarily mean that such a level would be appropriate for Boston Edison, the NEPOOL Resource Adequacy Assessment does provide further support for the conclusion that planning to a 50 percent confidence level might not ensure sufficient levels of reliability in the long run.

Mr. Killgoar also suggested that there is a "self-correcting mechanism" in the NEPOOL planning process (Tr. 49, p. 59). The Company stated that "if NEPOOL predicted a particular load level in a given year and the loads turn out to be much higher when you add up the individual participants' loads, and each participant is responsible for their own loads, then the amount of capacity that would have to be supported

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144/ It is possible that NEPOOL's objective capability calculation might result in reliability somewhat above a 50 percent confidence level. For example, we note that the effects of weather variation on the input load level, as is factored into the objective capability calculation, might encompass certain load levels above the 50 percent probability level. However, the record is not clear on this particular aspect of the issue.

within NEPOOL would be much higher than that MW value that is established" (id., pp. 59-60). The Company indicated that if NEPOOL underestimated a load forecast, the capability responsibility calculation eventually would "assign a greater capacity need to all utilities in New England" (id., p. 60).

The Siting Council draws two conclusions in regard to this apparent self-correcting mechanism. First, if a correction is applied to a period after an unexpectedly high load has been realized, then it would be too late to remedy any loss of reliability during that initial period when the unexpected loads first materialized. Second, if NEPOOL's capability responsibility assignment does not predict system requirements dependably, rather than relying on any self-correcting mechanism, it may be more appropriate for the Company to employ an approach to reliability planning that begins with and accurately projects the full range of reasonably anticipated loads.

In sum, in this proceeding the Siting Council does not agree with the Attorney General and MASSPIRG that planning to a 50 percent probability level would permit the Company to be positioned to meet customers' demand for every day but one in ten years. The record in this proceeding demonstrates that, if the Company were to plan its system to a 50 percent probability level, then in 50 percent of future years the Company might well fall short of the proposed one-day-in-ten-years reliability planning target. The intervenors have proposed that the Company should plan to a 50 percent confidence level, then implement short-term resources if resource need commensurate with higher confidence levels does materialize. The intervenors' strategy presents two significant weaknesses. First, sufficient short-term resources may not be available, or even identified, unless the Company happened to have anticipated they might be needed and planned to a higher reliability level. Second, even if sufficient short-term resources happen to be available at a later date, the resources may come at a higher cost to the Company and ratepayers.[145]

The Siting Council emphasizes this distinguishing point in reliability planning: if a company has no choice but to initiate immediately a particular resource option in order to ensure an appropriate level of reliability at some future date (i.e., other shorter lead-time options that could be implemented later to meet that level of reliability are not available in sufficient quantity), then prudent planning would dictate that that project be initiated. The essential difference in targeting one reliability level versus another pertains to the point in time at which investment decisions would have to be made by a company, given the lead times associated with various resource options. A company planning to an 80 percent confidence level would be expected to initiate larger projects sooner than one planning to a lower reliability level. As a consequence, a company that plans in an appropriate manner to a higher reliability level would be expected to be positioned to have sufficient energy resources available to respond to certain contingencies that a company planning to a lower reliability level would not be able to meet. We also reiterate that securing additional capacity needed to meet unanticipated higher load levels, on short notice, also could result in costs to ratepayers that might be avoided if

145/ There is nothing in the record that would suggest that the 50 percent confidence level identified in the Company's filing (see Exhibit BE-1, p. E-29) would match exactly a 50 percent confidence level as might be calculated in a manner consistent with the NEPOOL objective capability methodology (i.e., by applying an appropriate reserve margin to a 50 percent probability load forecast). We note, however, that both approaches to identifying a 50 percent confidence level in reliability planning would suffer from the deficiencies discussed above. Moreover, while the Attorney General and MASSPIRG have argued that Boston Edison should plan to the 50 percent confidence level used by NEPOOL, the Siting Council has yet to have a NEPOOL member present it with a reliability plan based upon a 50 percent probability load forecast and reserve margin consistent with what is suggested to be a regional planning standard.

those higher load levels are anticipated in a company's planning process.

This discussion and analysis supports a conclusion consistent with the position of Business Associations that the assurance of adequate and reliable future electric supplies may warrant planning to above the 50 percent confidence level, where cost-effective. The limiting factor in planning to higher reliability levels would be the costs that a company would incur in purchasing resources commensurate with higher reliability. However, if system reliability can be enhanced at reasonable cost to ratepayers, a company would be expected to pursue such opportunities. As the Siting Council has emphasized in past Decisions, resource costs are the determinant factor in reliability planning decisions. 1991 MECo/NEPCo Decision, 21 DOMSC at 374-375; 1991 Nantucket Decision, 21 DOMSC at 260-262, 268; 1990 Bay State Decision, 21 DOMSC at 11-15, 42-43; 1990 Berkshire Decision, 19 DOMSC at 268; 1989 BECo Decision, 18 DOMSC at 276, 277. Therefore, in theory, to optimize system reliability a company should make investments in additional resources as long as such investments remain cost-effective for ratepayers. An analysis that properly balances cost and system reliability will define the point to which investments in additional resources would be consistent with ratepayers interests.

Accordingly, for the purpose of this review, the Siting Council finds that planning to a 50 percent confidence level has not been established as an acceptable alternative approach to reliability planning.

D. Determination of Resource Need

1. Introduction

As presented in Section III.C.2, above, the Siting Council has given careful consideration to Boston Edison's proposal to plan its system to an 80 percent confidence level. However, in that section, the Siting Council determined that the Company's presentation contains several critical deficiencies. First, because many of the input values (i.e., key variables) used in calculating resource need were inaccurate or inappropriate, the Siting Council has found that the 81 scenarios developed by the Company do not constitute a reliable projection of the range of future resource requirements (see Section III.C.2.b.i(H)). Second, because the various need levels upon which the production cost calculations were based have not been accepted, the Siting Council has found that the various production cost totals associated with different expansion plans cannot be accepted as relevant to the reliability planning process in this proceeding (see Section III.C.2.b.ii). Finally, because the Company's presentation fails to adequately identify the cost of unserved energy and fails to adequately identify the quantity of unserved energy hours that would be anticipated under the proposed alternate planning scenarios, the Siting Council has found that the Company has failed to establish that the results of its risk-versus-cost analysis are acceptable (see Section III.C.2.iii).

Accordingly, the Siting Council has found that the Company has not established that its proposal to plan to an 80 percent confidence level is acceptable (see Section III.C.2.iii).

As presented in Section III.C.3, above, the Siting Council has given careful consideration to the Intervenors' alternative approach to reliability planning, which focussed on the process by which NEPOOL develops objective capability projections. However, the record of this proceeding reveals substantial deficiencies in this alternative approach to reliability planning. Because the Company might fall short of a "one-day-in-ten-years" reliability target in 50 percent of future years if system planning were based on 50 percent probability load inputs, and because simply targeting a 50 percent confidence level would preclude a balancing of reliability and cost in reliability planning, the Siting Council has found that planning to a 50 percent confidence level has not been established as an acceptable alternative approach to reliability planning (see Section III.C.3).

In considering an approach to identifying Boston Edison's need for additional resources that would be supported by the record of this proceeding, the Siting Council notes that planning to a 70 percent confidence level was approved in the 1989 BECo Decision. Therefore, we consider here whether the record in this proceeding would support a finding that the Company's current need for additional resources can be based on a 70 percent confidence level calculation.[146]

A comparison of the record upon which the 1989 BECo Decision was based to that of this proceeding reflects many substantive changes to the calculations in Boston Edison's reliability planning process. Most importantly, the fact that the essential inputs (i.e., the key variables and their respective MW values and probabilities) have changed since the time of the 1989 BECo Decision dictates that the results of that earlier reliability planning study are not valid for determining resource need here. Therefore, it is necessary to evaluate the 70 percent confidence level within the context of the record in this proceeding.

Our review of Boston Edison's reliability planning process in this proceeding reveals that a proposal to plan to a 70 percent confidence level would suffer from the same flaws as does the Company's presentation at the 80 percent confidence level. Because the Company failed to reliably project future needs (at

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146/ Although the Siting Council has not made specific findings on resource need in the past, it is appropriate for the Siting Council to do so in this proceeding. Clearly, G.L. c. 164, sec. 69I invests us with the authority to determine an electric company's resource need when that company proposes to construct a generating facility such as Edgar. Otherwise, the Siting Council could not "ensure a necessary energy supply for the Commonwealth." G.L. c. 164, sec. 69H.

Our decision to make findings in this proceeding regarding the Company's need for additional resources also is consistent with our responsibilities under the IRM regulations. 220 CMR 10.00 et. seq.; 980 CMR 12.00 et. seq. Under IRM, the Siting Council is required, in some cases, to make findings regarding the level of additional resources needed by an electric company when that company's own forecast of demand or resource inventory are found to be unacceptable. 1990 Final IRM Order, 21 DOMSC at 118; 980 CMR 12.03(5)(a).

any level, including the 70 percent confidence level) and failed to identify the true costs and benefits of investing in new resources to meet alternate need levels (at any level, including the 70 percent confidence level), the Siting Council finds that planning to a 70 percent confidence level cannot be approved on the record of this proceeding.

The Siting Council's standard of review, as set out in Section III.A, above, defines adequacy of supply as a utility's ability to provide sufficient capacity to meet its peak loads and reserve requirements throughout the forecast period. The Siting Council has directed, and continues to direct, electric companies to balance risk and cost in long term supply planning. However, for the purpose of assessing Boston Edison's need for additional resources in the absence of an acceptable reliability presentation, we find it appropriate to apply a methodology consistent with our standard of review for determining the adequacy of supply throughout the forecast period.

Therefore, the following sections present an assessment of Boston Edison's need for additional resources in 1996 and 1997 under a scenario that considers the base case, "most likely" projections of peak loads and the other variables relevant to a resource need calculation, in conjunction with an appropriate reserve level.[147,148]

147/ The Siting Council makes findings on the need for additional resources in 1996 and 1997 because the Company has proposed to construct Edgar, for which BECo now projects a January, 1996 in-service date (see Section I.B, above).

In regard to the base case projections of the key variables affecting resource need, we note that the March 1992 Record Update included extensive information to the Siting Council, updating data which were used in the derivation of the key variables (Exh. BE-121). Problems associated with a calculation of resource need based upon this data are presented in Section III.D.3.a, below. Nonetheless, under the circumstances, it is important to evaluate whether this information would have a substantial impact on the outcome of this proceeding.

Therefore, in Section III.D.2, below, the Siting Council makes findings concerning BECo's need for additional resources based on the February 1992 Record. In Section III.D.3, below, the Siting Council presents a calculation of BECo's need for additional resources using appropriate information presented in the March 1992 Record Update. Finally, in Section III.D.4, below, the Siting Council presents its conclusions concerning BECo's need for additional resources.

148/ The Siting Council's use of this approach for the purpose of determining resource need in this proceeding does not constitute an endorsement of reliability planning that focusses only on a company's "most likely" peak load, and other base case projections. This methodology accommodates neither a range of reasonably possible future need scenarios, nor a balancing of risk and cost across that range -- both of which are important components to a reliability planning process. Moreover, we note that our IRM regulations require electric companies to conduct sensitivity analyses regarding the major assumptions contained in demand forecasts, for the purpose of evaluating alternate need scenarios. 980 CMR 12.03(5)(e).

However, in the absence of a record that would adequately support a resource need calculation that incorporates a risk-versus-cost evaluation across a range of future need scenarios, we make findings using base case projections consistent with our standard of review to ensure an adequate energy supply.

2. Resource Need Based on the February 1992 Record

a. Variables Affecting the Need for Additional Resources

i. Overview

Based on the February 1992 Record in this proceeding, the Siting Council finds that four variables can be anticipated to have a direct and significant effect on the level of resources needed by the Company in the future: (1) load growth; (2) the contributions from the Company's existing C&LM programs; (3) the contributions from planned capacity additions; and (4) the contributions from existing supply-side resources. In the following sections, the Siting Council makes findings on the appropriate base case values of these variables for use in determining resource need, based on the February 1992 Record.

ii. Load Growth

In Section II.E, above, the Siting Council has found the Company's reforecast of peak load to represent a reasonable projection of peak load in the base, "most likely" case. For the year 1996, this reforecast shows a peak level of 2,919 MW. The record indicates that the demand of the town of Reading, time-of-use rates, and self-generation would combine to increase the natural peak load projection by three MW in that year (Exh. BE-1, p. E-32). Therefore, for the purpose of calculating future resource requirements, the Siting Council finds 2,922 MW to represent a reasonable projection of peak load, before C&LM reductions, for the year 1996.

The reforecast also identifies 2,970 MW as the peak load in the base, "most likely" case for the year 1997. The record indicates that the demand of the town of Reading, time-of-use rates, and self-generation would combine to reduce the natural peak load projection by one MW in that year (Exhibit BE-1, p. E-32). Therefore, for the purpose of calculating future resource requirements, the Siting Council finds 2,969 MW to represent a reasonable projection of peak load, before C&LM reductions, for the year 1997.

iii. Contribution From Existing C&LM Resources

Based on the February 1992 record, the Siting Council has found that the Company's "DSM penetration" projections are acceptable for the purpose of calculating future resource requirements (see Section III.C.2.b.i(D), above). The base case value for the projected C&LM contribution toward peak load reduction in 1996 is 400 MW (Exh. BE-1, p. E-32). Similarly, the base case value for the projected C&LM contribution toward peak load reduction in 1997 is 425 MW (id.). Therefore, for the purpose of calculating future resource requirements, the Siting Council finds 400 MW and 425 MW to represent reasonable projections of the C&LM contribution toward peak load reduction for the years 1996 and 1997, respectively.

iv. Contribution from Planned Capacity Additions

The February 1992 Record indicates that a number of planned capacity additions that had been identified in BECo's May 1990 Resource Plan filing are no longer anticipated to enter service. In particular, BECo indicated that its contracts with Everett Energy, Patriot Energy, and Wheelabrator Urban Woods had been terminated, and that the AES Riverside project had been cancelled (Exh. HO-S-21). Therefore, for the purpose of calculating future resource requirements in 1996 and 1997, the Siting Council finds that no capacity contribution would be anticipated from those units.

The February 1992 Record also identifies BECo's peak season entitlement in OSP as 117 MW, and indicates that OSP was on-line as of a June 21, 1991 hearing (Exhs. BE-1, p. C-13; Tr. 49, p. 33). Therefore, for the purpose of calculating future resource requirements in 1996 and 1997, the Siting Council finds it appropriate to recognize BECo's full 117 MW entitlement in OSP.

The February 1992 Record further identifies BECo's entitlement in HQ II as 171 MW, and indicates that HQ II was expected to enter full commercial operation by July 1, 1991

(Exhs. HO-S-118; BE-1, p. C-13; Tr. 49, p. 33). Therefore, for the purpose of calculating future resource requirements in 1996 and 1997, the Siting Council finds it appropriate to recognize BECo's full 171 MW entitlement in HQ II.

The February 1992 Record further identifies BECo's peak season entitlement in NEA 1 and 2 as 199 MW, and indicates that NEA was undergoing startup testing as of a June 21, 1991 hearing (Exh. BE-1, p. C-13; Tr. 49, p. 33). Therefore, for the purpose of calculating future resource requirements in 1996 and 1997, the Siting Council finds it appropriate to recognize BECo's full 199 MW entitlement in NEA 1 and 2.

The February 1992 Record further identifies BECo's peak season entitlement in L'Energia as 49 MW (Exh. BE-1, p. C-13). The record reflects that the Company applied a 57 percent success rates to planned units, in the base case (Exh. HO-S-113). In assessing BECo's need for additional resources, the Siting Council finds it appropriate to recognize BECo's entitlement in L'Energia at a 57 percent success rate. Therefore, for the purpose of calculating future resource requirements in 1996 and 1997, the Siting Council finds that a 28 MW capability contribution would be anticipated from L'Energia.

Finally, BECo's RFP #2 and RFP #3 were issued for new supplies totalling 200 MW and 132 MW, respectively (Exh. BE-1, p. C-13; Boston Edison Company, D.P.U. 90-270-C (1992)).[149] The Siting Council finds it appropriate to recognize planned capacity additions from RFP #2 and RFP #3 at the same 57 percent success rate. Therefore, for the purpose of calculating future resource requirements in 1996 and 1997, the Siting Council finds that a 189 MW capability contribution would be anticipated from RFP #2 and RFP #3, combined.

Accordingly, for the purpose of calculating future resource requirements in 1996 and 1997, the Siting Council finds

149/ The Siting Council hereby takes administrative notice of the Department's Order in Boston Edison Company, D.P.U. 90-270-C (1992), which set the RFP#3 supply block at 132 MW.

704 MW to represent a reasonable projection of the capability contribution from planned capacity additions.

v. Contribution from Existing Supply-side Resources

The February 1992 Record indicates that the capability of the existing units in the Company's supply portfolio (including purchases) totals 2,767 MW (Exh. BE-1, p. E-34). The Siting Council finds it appropriate to reduce this existing unit total capability value by 16 MW, consistent with the fact that, in February 1992, Yankee Rowe ceased generation operations.[150] Therefore, for the purpose of calculating future resource requirements in 1996 and 1997, the Siting Council finds 2,751 MW to represent a reasonable projection of the capability contribution from existing supply-side resources.

b. Conclusions on Resource Need Based on the February 1992 Record

Based on findings presented above, Boston Edison's need for additional energy resources during 1996 is calculated as follows. A C&LM contribution of 400 MW is subtracted from the 2,922 MW peak load projection, before C&LM, yielding a 2,522 MW peak load projection, after C&LM. Application of a 31.1 percent reserve margin,[151] consistent with findings in Section III.C.2.b.i(F), to the peak load projection, after C&LM, yields a target capability level of 3,306 MW.

As presented above, the anticipated capability contribution from planned capacity additions is 704 MW, and the anticipated capability contribution from existing generating units is 2,751 MW. Accordingly, the Siting Council finds that

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150/ The March 1992 Record Update indicates that no MW contribution from that unit is anticipated in future years (Exh. BE-121). No party in this proceeding disputes this fact.

151/ This reserve margin was taken from Exhibit HO-S-157, p. 4.

BECo can be anticipated to experience a capacity surplus totalling 149 MW in 1996 (see Table 6).

Based on findings presented above, Boston Edison's need for additional energy resources during 1997 is calculated as follows. A C&LM contribution of 425 MW is subtracted from the 2,969 MW peak load projection, before C&LM, yielding a 2,544 MW peak load projection, after C&LM. Application of the above 31.1 percent reserve margin, consistent with findings in Section III.C.2.b.i(F), to the peak load projection, after C&LM, yields a target capability level of 3,335 MW (see Table 6).

As presented above, the anticipated capability contribution from planned capacity additions is 704 MW, and the anticipated capability contribution from existing generating units is 2,751 MW. Accordingly, the Siting Council finds that BECo can be anticipated to experience a capacity surplus totalling 120 MW in 1997.

3. March 1992 Record Update

a. Introduction

As noted in Section I.B, above, a procedural conference was held on March 2, 1992 to discuss what record information, if any, should be updated as a result of the Company's decision to postpone the projected in-service date for Edgar from January 1, 1994 to January 1, 1996.[152] The Attorney General asserted that several areas in the record required updating and that any new evidence presented should entitle all parties to "due process rights" to additional discovery, cross-examination of Company witnesses, testimony from other parties' witnesses, and additional briefing before the Phase I Decision could be issued (March 2, 1992 Procedural Conference, Tr. pp. 8-10, 26-30, 58-64,

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152/ At the outset of this procedural conference, BECo Associate General Counsel Douglas Horan stated that "the Phase I Decision and record would not be impacted directly in any event by the change of the in-service date ..." and offered no further record updates (March 2, 1992 Procedural Conference, Tr. p. 6).

78).[153] BECo acknowledged the need for "some additional data" consistent with an expedited review process (March 2, 1992 Procedural Conference, Tr. p. 18).

After extensive discussion regarding the scope and extent of necessary updates, the Siting Council staff directed the Company to present further information on four specific issues: (1) the status of Yankee Rowe; (2) the status and projected attrition rates for planned capacity additions from RFP #2; (3) the status and projected attrition rates for planned capacity additions from RFP #3; and (4) the projection of savings from BECo's C&LM programs, specifically its C&I conservation programs (March 2, 1992 Procedural Conference, Tr. p. 26-30, 56-57, 67-74, 77, 79-80).[154]

On March 12, 1992, the Company filed the March 1992 Record Update. In addition to updating the four specific areas discussed at the March 2, 1992 Procedural Conference, BECo filed substantial additional information (Exh. BE-121).[155]

153/ Both the Attorney General and MASSPIRG also suggested that the determination of resource need be deferred until IRM. BECo's IRM filing is due in November 1992. A decision in that IRM proceeding is not anticipated until 1995 -- some five years after the Company's filing in this proceeding. Such a delay clearly would be inappropriate and unwarranted if sufficient evidence exists upon which to base a decision at this time (see Section III.D.4).

154/ The Siting Council staff expressly asked whether any other issues needed updating in order to determine BECo resource need for 1996 and 1997, and none were specified by any parties (March 2, 1992 Procedural Conference, Tr. pp. 77-79). The Siting Council also directed the Company to consult with other parties before filing the updates in order to avoid any evidentiary disputes and close the record (March 2, 1992 Procedural Conference, Tr. pp. 57, 65-67). BECo agreed to consult with the other parties prior to submission of its updates (March 2, 1992 Procedural Conference, Tr. pp. 74, 84).

155/ On March 18 and 19, 1992, the Company also presented nearly 300 pages of supporting documentation in response to information requests issued by the Attorney General without authorization from the Siting Council (Exhs. AG-87 to AG-103).

As discussed in Section I.C, above, the Attorney General and MASSPIRG filed motions asking the Siting Council to postpone consideration of the March 1992 Record Update to the IRM review or to Phase II, or in the alternative, to afford them an opportunity for additional discovery, new evidence, cross-examination of Company witnesses, and briefing in Phase I, arguing that the updated information was a matter of factual dispute among the parties.

The Siting Council agrees that the March 1992 Record Update is the subject of factual dispute which normally would entitle intervenors to discovery and comment.[156] G.L. c. 164, sec. 69J; G.L. c. 30A, sec. 11. In order for the Siting Council to rely upon the new information in determining resource need in this proceeding, the intervenors would have to be afforded their full due process rights. We note, however, that such a course of action could extend the proceedings for several more weeks or even months. In light of the already lengthy proceedings in this case, and the fact that further delay could lead to additional, legitimate requests to update the record, the Siting Council considers it appropriate to consider the potential impact of the new evidence before determining whether further examination of and reliance upon that evidence is warranted in this proceeding. Therefore, in the following sections we examine how the variables affecting resource need as identified in Section III.D.2.a(1),

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156/ As noted earlier, the Company's Yankee Rowe update was not contested and, therefore, is considered in our determination of resource need. In addition, we have deferred consideration of BECo's new load management proposal to Phase II.

above, would be impacted in the event that BECo could substantiate the numbers in its March 1992 Record Update.[157]

b. Variables Affecting the Need for Additional Resources Under the March 1992 Record Update

i. Overview

As presented in Section III.D.2.a(i), above, the Siting Council has found that four variables can be anticipated to have a direct and significant effect on the level of resources needed by the Company in the future: (1) load growth; (2) the contributions from the Company's existing C&LM programs; (3) the contributions from planned capacity additions; and (4) the contributions from existing supply-side resources. In the following sections, the Siting Council presents a calculation of BECo's need for additional resources using information provided in the March 12 Record Update to develop base case projections for each of these four variables.

ii. Load Growth

In Section II.E, above, the Siting Council has found the Company's reforecast of peak load to represent a reasonable projection of peak load in the base, "most likely" case. For the year 1996, this reforecast shows a peak level of 2,919 MW. The

157/ In its March 1992 Record Update, the Company proposed to recalculate resource need based on new load management projections, reserve margins based on "most likely" EAF performance for existing generating units, and other information. As discussed in Section I.C, consideration of the Company's load management proposal will be deferred to Phase II. With respect to the reserve margins based on "most likely" EAFs, nothing in the March 1992 Record Update convinces us that our finding that historic fossil unit EAFs are appropriate for reliability planning in the base case is not valid (see Section III.C.2.b.i.(F), above). The remaining information presented in the March 1992 Record Update is evaluated in Sections III.D.3.b and c, below. We note that even if we had relied upon all the new data in the March 1992 Record Update (including the new load management projections and the reserve margins based upon the Company's proposed "most likely" EAFs), BECo projects a base case surplus of five MW in 1996 and a deficiency of 18 MW in 1997 (Exh. BE-121, Table 3, p. 1).

record indicates that the demand of the town of Reading, time-of-use rates, and self-generation would combine to increase the natural peak load projection by three MW in that year (Exh. BE-1, p. E-32). Therefore, for the purpose of calculating future resource requirements, the Siting Council finds 2,922 MW to represent a reasonable projection of peak load, before C&LM reductions, for the year 1996.

The reforecast also identifies 2,970 MW as the peak load in the base, "most likely" case for the year 1997. The record indicates that the demand of the town of Reading, time-of-use rates, and self-generation would combine to reduce the natural peak load projection by one MW in that year (Exhibit BE-1, p. E-32). Therefore, for the purpose of calculating future resource requirements, the Siting Council finds 2,969 MW to represent a reasonable projection of peak load, before C&LM reductions, for the year 1997.

iii. Contribution From Existing C&LM Resources

The March 1992 Record Update suggests that conservation programs would reduce loads by 166 MW in 1996, and 184 MW in 1997 (Exh. BE-121).

As is discussed in Section III.D.3.a, above, the Company's proposal to reduce its load management programs will be addressed in Phase II of this Decision. Therefore, the Siting Council finds that the load management contributions contained in the May 1990 Resource Plan would still be appropriate for the purpose of calculating future resource requirements here. Data contained in the March 1992 Record Update concerning the May 1990 Resource Plan filed by the Company identifies contributions from load management programs that would contribute to load reductions of 251 MW in 1996, and 260 MW in 1997 (Exh. BE-121).

Therefore, for the purpose of calculating future resource requirements, information contained in the March 1992 Record Update, as adjusted above, suggests that the total MW contribution from C&LM resources would be 417 MW in 1996, and 444 MW in 1997.

iv. Contribution from Planned Capacity Additions

As presented in Section III.D.1, above, the Company has presented updated information concerning the capability contributions that might be anticipated from planned capacity additions during the years 1996 and 1997.

Based on the Company's March 1992 Record Update, for the purpose of calculating future resource requirements in the base case during 1996 and 1997, the planned capacity additions would be treated as follows: AES would be anticipated to contribute 23 MW; HQ II would be anticipated to contribute 201 MW; OSP would be anticipated to contribute 110 MW; NEA 1 and 2 would be anticipated to contribute a total of 209 MW; L'Energia would be anticipated to contribute 49 MW; the RFP #2 units would be anticipated to contribute 128 MW; and the RFP #3 units would be anticipated to contribute 37 MW. Therefore, for the purpose of calculating future resource requirements in the during 1996 and 1997, information contained in the March 1992 Record Update suggests that the capability contribution from planned capacity additions would total 757 MW.

v. Contribution from Existing Supply-side Resources

The Company's March 1992 Record Update reflects that the capability of the existing units in the Company's supply portfolio would total 2,544 MW (Exh. BE-121, Table 3). Information provided in the March 1992 Record Update indicates that it would be appropriate to add to this total the capability contributions from Canal 1 at 142 MW, MWRA at 1 MW, and from Peat Products, which is now projected to contribute six MW given application of a 28 percent success rate (Exh. BE-121, Tables 1,3). Accordingly, for the purpose of calculating future resource requirements in during 1996 and 1997, information contained in the March 1992 Record Update suggests that it would be appropriate to anticipate a capability contribution of 2,693 MW from existing supply-side resources.

c. Conclusions on Resource Need Based on the March 1992 Record Update

Based on information presented in the March 1992 Record Update, BECo's need for additional energy resources during 1996 would be calculated as follows. A C&LM contribution of 417 MW is subtracted from the 2,922 MW peak load projection, before C&LM, yielding a 2,505 MW peak load projection, after C&LM. Application of the 31.1 percent reserve margin used in Section III.D.2.b, consistent with findings in Section III.C.2.b.i(F), to the peak load projection, after C&LM, yields a target capability level of 3,284 MW.

As presented above, the anticipated capability contribution from planned capacity additions would be 757 MW, and the anticipated capability contribution from existing generating units would be 2,693 MW. Accordingly, information contained in the March 1992 Record Update suggests that BECo would be anticipated to experience a capacity surplus totalling 166 MW in 1996 (see Table 6).

Based on the March 1992 Record Update, BECo's need for additional energy resources during 1997 would be calculated as follows. A C&LM contribution of 444 MW is subtracted from the 2,969 MW peak load projection, before C&LM, yielding a 2,525 MW peak load projection, after C&LM. Application of the 31.1 percent reserve margin, consistent with findings in Section III.C.2.b.i(F), to the peak load projection, after C&LM, yields a target capability level of 3,310 MW.

As presented above, the anticipated capability contribution from planned capacity additions would be 757 MW, and the anticipated capability contribution from existing generating units would be 2,693 MW. Accordingly, information contained in the March 1992 Record Update suggests that BECo would be anticipated to experience a capacity surplus totalling 140 MW in 1997 (Table 6).

4. Conclusions on Resource Need

As presented in Section III.D.2.b, above, based on the February 1992 Record, the Siting Council has found that BECo can be anticipated to experience capacity surpluses totalling 149 MW in 1996, and 120 MW in 1997. As presented in Section III.D.3.c, above, the Siting Council's evaluation of information contained in the March 1992 Record Update suggests that if such information were substantiated after further proceedings, BECo would be anticipated to experience capacity surpluses totalling 166 MW in 1996, and 140 MW in 1997.

The Siting Council is committed to making findings based on the most accurate information available. In fact, during the course of this lengthy proceeding, the Siting Council has repeatedly emphasized the need for all parties to update the record to ensure that our findings are based on accurate information. The Siting Council always has made findings only after giving all parties to a proceeding a full and fair opportunity to develop the record and to comment on all relevant issues. As noted in Section III.D.3.a, above, normally the presentation of new or updated evidence which is the subject of factual dispute would warrant a full opportunity for such discovery and comment. Departure from this fundamental procedure must be limited to those extraordinary circumstances where the benefits of further discovery and comment on new or updated information are outweighed by the disadvantages of the corresponding extension of the proceedings.

Here we are presented with just such extraordinary circumstances. The calculations of BECo's need for additional resources based on BECo's March 1992 Record Update result in capacity surpluses for 1996 and 1997 that are even greater than those using the February 1992 Record. In determining resource need for reliability purposes, the size of any surplus is irrelevant.[158] Therefore, to conduct additional proceedings over several weeks in order to determine whether the larger surplus indicated by BECo's update actually would exist would unnecessarily delay this Decision. Similarly, to extend the proceedings to allow intervenors the opportunity to demonstrate that the surplus should be even larger than BECo's data indicates would serve no purpose.

The Siting Council is charged with assuring a "necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost." G.L. c. 164, sec. 69H. This statutory mandate obligates us to expedite our review of filings, consistent with the development of a complete and adequate record. This proceeding has lasted nearly two years already due to the complexity of the issues and the participation of 18 intervenors. The record is now sufficiently complete and accurate to enable us to proceed with this Phase I Decision, including a determination of resource need.

Accordingly, the Siting Council finds that Boston Edison can be anticipated to experience a capacity surplus totalling 149 MW in 1996, and 120 MW in 1997.

E. Adequacy of the Supply Plan

1. Adequacy of the Supply Plan in the Short Run

a. Definition of the Short Run

As noted in Section III.A, above, in the past the Siting Council has defined the short run for all electric companies as four years from the date of the final hearing or from the date of the response to the final record request, whichever is later. BECo's final hearing was held on June 21, 1991 and the final record request response was dated July 19, 1991. Consistent with previous Siting Council decisions, the short run in this

158/ In the case of a surplus, the focus in least-cost resource planning turns to the existing resource mix. Therefore, Edgar or other resource alternatives may be found to be necessary in Phase II on economic efficiency grounds.

proceeding extends from the summer of 1992 through the summer of 1995.

b. Base Case Supply Plan

The data shown in Table 6 compare BECo's projected system resource capability to its peak load capability responsibility over the years 1992 through 1995.[159] These data indicate that BECo is projecting short-run capability surpluses ranging from 388 MW (11.9 percent) in 1992 to 138 MW (4.2 percent) in 1995 (see Table 7).

Accordingly, the Siting Council finds that BECo has established that its base case plan is adequate to meet requirements in the short run.

c. Short Run Contingency Analysis

In order to establish adequacy in the short run, a company must establish that it can meet its forecasted needs under a reasonable range of contingencies. To evaluate the adequacy of BECo's short-run supply plan, the Siting Council analyzes the following contingencies: (1) high load growth as represented by the Company's high case demand forecast;[160] (2) the delay of supplies from RFP #2 and RFP #3 beyond the summer of 1995; (3) the double contingency of the high case demand forecast and the delay of RFP #2 and RFP #3 supplies.

159/ The Siting Council developed the base case supply inventory by adding the summer capacity available from (1) BECo's existing units and entitlements, and (2) 57 percent of the entitlements for planned units that have contracts.

160/ For the purpose of reviewing short-run adequacy under the contingency of higher than expected load growth, the Siting Council uses the high case peak demand forecast as included in the reforecast (Exh. HO-D-111).

i. <u>High Case Demand Forecast</u>

Under its high case demand forecast, BECo projected that its summer peak load would grow from 2,516 MW in 1992 to 2,569 MW in 1995 (Exh. HO-D-111). In the event that load growth occurs at this rate, and if all resources in its base case supply plan remain available, BECo would experience a resource deficiency during the summer of 1994 of 49 MW (1.4 percent) (see Table 8).

In the event of the occurrence of the high demand forecast, BECo stated that it has an action plan to address this deficiency, involving the use of C&LM, construction of a combustion turbine in Medway, and short-term utility purchases (Exhs. BE-1, pp. E-23; HO-S-170; Tr. 45, pp. 46-47, 49, 57). The Company indicated that it would review its C&LM programs for potential acceleration (Exh. BE-1, p. E-23; Tr. 45, p. 57). In addition, BECo stated that it identified an additional combustion turbine at the Medway site as a "contingency resource" (Tr. 45, p. 47). The Company stated that this combustion turbine could be available in 1994 or 1995, and that the Company has commenced environmental studies for permitting (<u>id.</u>, Exh. HO-S-34). Finally, BECo indicated that it can purchase capacity from other utilities in NEPOOL, in New York, New Jersey, and Pennsylvania, and Canada to address short-run contingencies (Exh. HO-S-17; Tr. 45, pp. 41-42, 44). BECo explained that it has frequent contact with other utilities in order to arrange short-term purchases, economy transactions, and capacity exchanges (Tr. 45, pp. 41-42). The Company estimated that a purchase of capacity for more than one year likely would require one year to evaluate and negotiate (<u>id.</u>, pp. 42-46).

The Siting Council initially notes that an option in BECo's action plan -- Medway turbine -- may not be available to meet a resource deficiency in the summer of 1994. At the same time, we acknowledge that a number of other options in BECo's action plan -- accelerated C&LM and power purchases from other utilities -- could be available in 1994. Therefore the Siting Council finds that BECo has an action plan consisting of sufficient resource options to meet capability responsibility, and thereby avoid deficiencies in the summer of 1994 in the event of the contingency of the high case demand forecast.

ii. Delay of RFP #2 and RFP #3

BECo stated that it expects non-utility generators from RFP #2 and RFP #3 to provide 189 MW in the summer of 1995 and to continue to provide that level of power throughout the summers of the forecast period (Exhs. HO-S-21, HO-S-169; See Boston Edison Company, D.P.U. 90-270-C). If BECo experiences a delay of RFP #2 and RFP #3 supplies, and if all other resources in its base case supply plan remain available to BECo, BECo would experience a resource deficiency of 200 MW (6.0 percent) in 1995 (see Table 9).

In the event of a delay of RFP #2 and RFP #3 supplies, BECo identified an action plan involving a combustion turbine in Medway, short-term utility purchases, and additional C&LM (Exhs. BE-1, pp. E-22, E-23, HO-S-170; Tr. 45, pp. 46-47, 49, 57). See Section III.E.4.c.i, above. Therefore the Siting Council finds that BECo has an action plan consisting of sufficient resource options to meet capability responsibility, and thereby avoid deficiencies in the summer of 1995 in the event of the contingency of a delay of RFP #2 and RFP #3 supplies.

Accordingly, the Siting Council finds that BECo has established that it has an action plan to meet requirements in the short run in the event of the delay of RFP #2 and RFP #3.

iii. Double Contingency of High Case Demand Forecast and Delay of RFP #2 and RFP #3

One possible combination of short-run contingencies would be the occurrence of the high case demand forecast and the delay of the RFP #2 and RFP #3 supplies. If all other resources in its base case supply plan remain available to BECo, and BECo faced that combination of the above contingencies, BECo would experience resource deficiencies of 49 MW (1.4 percent) during the summer of 1994, and 290 MW (8.5 percent) during the summer of 1995 (see Table 10).

In the event of the occurrence of the high demand forecast and a delay of RFP #2 and RFP #3 supplies, BECo identified an action plan involving additional C&LM, a combustion turbine in Medway, and short-term utility purchases (Exhs. BE-1, pp. E-22, E-23, HO-S-170; Tr. 45, pp. 46-47, 49, 57). See Section III.E.4.c.i, above.

The Siting Council initially notes that an option in BECo's action plan -- Medway turbine -- may not be available to meet resource deficiencies in the summer of 1994. At the same time, we acknowledge that a number of other options in BECo's action plan -- accelerated C&LM and power purchases from other utilities -- could be available in 1994. Therefore the Siting Council finds that BECo has an action plan consisting of sufficient resource options to meet capability responsibility, and thereby avoid deficiencies in the summers of 1994 and 1995 in the event of this double contingency of the occurrence of the high demand forecast and the delay of RFP #2 and RFP #3 supplies.

iv. Conclusions on the Short-Run Contingency Analysis

The Siting Council has found that BECo has established that it has: (1) an action plan to meet any resource deficiencies in the summer of 1994 in the event of the occurrence of the high demand forecast; (2) an action plan to meet any resource deficiencies in the summer of 1994 in the event of a delay of RFP #2 and RFP #3 supplies; and (3) an action plan to meet any resource deficiencies in the summers of 1994 and 1995 in the event of the double contingency of the occurrence of the high demand forecast and a delay of RFP #2 and RFP #3 supplies.

2. Conclusions on Adequacy of the Supply Plan in the Short Run

The Siting Council has found that BECo has established that its base case plan is adequate to meet requirements in the short run. The Siting Council has also found that BECo has established that its supply plan is adequate to meet its capability responsibility in the short run under a reasonable range of contingencies.

Accordingly, the Siting Council finds that BECo has established that it has adequate resources to meet its projected requirements in the short run.

IV. DECISION

The Siting Council hereby APPROVES the 1990 demand forecast of the Boston Edison Company at the time of the reforecast.[161]

In so deciding, the Siting Council has detailed specific information that the Company must provide in its next filing in order for the Siting Council to approve BECo's next demand forecast. This specific information is necessary for the Siting Council to fulfill its statutory mandate, including its need to determine whether the 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 and include an adequate consideration of conservation and load management.

Therefore, in order for the Siting Council to approve BECo's next demand forecast filing, the Company must furnish:

(1) full justification for the incorporation of the results of the short-run residential forecast and the period over which those results are applied;

(2) (a) a complete explanation of how appliance efficiency standards were applied to its forecast of average use per appliance along with an average use forecast consistent with an application of those standards; and (b) full supporting documentation of its forecast of miscellaneous use including analyses of the major factors identified as contributing to miscellaneous use, and a complete justification for its selection of a growth rate for the miscellaneous end-use category based on those analyses;

161/ Findings on the Company's supply plan will be made in Phase II of this Decision. The findings in Phase I on the determination of resource need and the adequacy of the supply plan in the short run will be incorporated into our findings on the supply plan in Phase II.

(3) (a) full justification for the use of a short-run commercial forecast and the period over which it is applied; and (b) evidence that all variables and data inputs into the short-run forecast are appropriate and reliable;

(4) (a) full justification and documentation for the inclusion of any snapback effect in its long-run commercial forecast; (b) evidence that it has incorporated reliable employment data in the calculation of its long-run commercial forecast; and (c) either full justification for or omission of blending the short-run and long-run commercial forecasts over an extended period of time;

(5) full justification for the incorporation of the results of a short-run industrial forecast and the period over which those results are applied;

(6) (a) reliable data and an appropriate methodology to model the effects of electric technology development; and (b) either full justification for or omission of the blending of the short-run and long-run industrial energy forecasts over an extended period of time;

(7) more extensive documentation to substantiate its assumptions regarding streetlighting sales; and

(8) (a) an analysis of the sensitivity of peak demand to weather abnormalities for all seasons; and (b) evidence that it has incorporated reliable energy forecast data into its peak load methodology.

The Siting Council further notes that the Company's next demand forecast and supply plan will be submitted in its first IRM filing which is scheduled to be submitted on November 1, 1992.

Frank P Pozniak /ME

Frank P. Pozniak
Hearing Officer

Michael D Ernst

Michael D. Ernst
Hearing Officer

Robert D. Shapiro /ME

Robert D. Shapiro
Hearing Officer

Dated this 31st day of March, 1992

APPROVED by the Energy Facilities Siting Council at its meeting of April 10, 1992 by the members and designees present and eligible to vote. Voting for approval of the Tentative Decision as amended: Gloria Cordes Larson (Secretary of Consumer Affairs and Business Regulation); Andrew Greene (for Susan F. Tierney, Secretary of Environmental Affairs); Joseph Donovan (for Stephen P. Tocco, Secretary of Environmental Affairs; Stephen J. Remen (Commissioner of Energy Resources); Mindy Lubber (Public Environmental Member); Michael Ruane (Public Electric Member); and Kenneth Astill (Public Engineering Member). Voting against the Tentative Decision as amended: Joseph C. Faherty (Public Labor Member).

Gloria C. Larson

Gloria Cordes Larson
Chairperson

Dated this 10th day of April, 1992

TABLE 1

BOSTON EDISON COMPANY
Base Case Initial Forecast of Annual Sales and Peak Demand*
1990-2000

Year	Annual Energy Sales (GWh)	% Growth	Summer Peak (MW)	% Growth	Winter Peak (MW)	% Growth
1990	13,355	----	2,729	----	2,585	----
1991	13,786	3.23	2,809	2.93	2,674	3.44
1992	14,127	2.47	2,886	2.74	2,743	2.58
1993	14,476	2.47	2,964	2.70	2,813	2.55
1994	14,696	1.52	3,016	1.75	2,858	1.60
1995	14,928	1.58	3,072	1.86	2,902	1.54
1996	15,221	1.96	3,138	2.15	2,960	2.00
1997	15,481	1.71	3,202	2.04	3,013	1.79
1998	15,720	1.54	3,261	1.84	3,062	1.63
1999	15,974	1.62	3,312	1.56	3,106	1.44
2000	16,214	1.50	3,370	1.75	3,156	1.61

Notes: *Unadjusted for Company-sponsored C&LM

Source: Exh. BE-2, pp. 10-12

TABLE 2

BOSTON EDISON COMPANY
Base Case Reforecast of Annual Sales and Peak Demand^
1990-2000

Year	Annual Energy Sales (GWh)	% Growth	Summer Peak (MW)	% Growth	Winter Peak (MW)	% Growth
1990*	12,975	----	2,548	----	2,283	----
1991*	12,812	-1.27	2,652	4.08	2,333	2.19
1992	13,347	4.18	2,725	2.75	2,590	11.02
1993	13,557	1.57	2,774	1.80	2,633	1.66
1994	13,758	1.48	2,822	1.73	2,674	1.56
1995	13,943	1.34	2,868	1.63	2,709	1.31
1996	14,167	1.61	2,919	1.78	2,753	1.62
1997	14,369	1.43	2,970	1.75	2,795	1.53
1998	14,593	1.56	3,025	1.85	2,840	1.61
1999	14,948	2.43	3,099	2.45	2,906	2.32
2000	15,168	1.47	3,152	1.71	2,951	1.55

Notes: ^Unadjusted for Company-sponsored C&LM *Actual figures

Source: Exh. HO-D-111

TABLE 3

DRI FORECASTS OF MASSACHUSETTS EMPLOYMENT
(x 1000)

Year	1/89 Forecast	8/90 Forecast	2/91 Forecast	8/91 Forecast	1/89- 8/90	8/90- 8/91	1/89- 8/91
1990	3192	3063	3040	2978	129	85	214
1991	3228	3035	2943	2831	193	204	397
1992	3267	3043	2944	2809	224	234	458
1993	3282	3059	2978	2851	223	208	431
1994	3296	3093	3029	2908	204	185	389
1995	3332	3129	3077	2951	203	177	381
1996	3380	3166	3111	2998	214	168	382
1997	3422	3210	3140	3031	212	179	391
1998	3451	3252	3169	3066	198	186	384
1999	3478	3296	3202	3108	182	188	370
2000	3503	3337	3237	3141	165	196	362

Sources: Exhs. BE-9, MP-RR-10, and BE-119.

TABLE 4

BOSTON EDISON COMPANY
Base Case Initial Forecast of Energy Sales By Customer Class*
1990 - 2000
GWH

Year	Residential	Commercial	Industrial	Streetlighting	MBTA	MWRA	Municipals
1990	3453	7347	1869	132	136	73	345
1991	3523	7601	1874	132	137	163	356
1992	3608	7827	1890	132	142	163	365
1993	3671	8068	1904	132	144	186	371
1994	3709	8226	1919	132	146	186	378
1995	3756	8358	1934	132	149	211	388
1996	3864	8514	1949	132	153	211	398
1997	3940	8671	1964	132	156	211	407
1998	3995	8828	1979	132	159	211	416
1999	4065	8875	1994	132	161	322	425
2000	4124	9031	2009	132	164	322	432

Notes: *Not adjusted for Company-sponsored C&LM

Sources: Exh. BE-2, pp. 68, 102, 112, 124, 125

TABLE 5

BOSTON EDISON COMPANY
Base Case Reforecast of Energy Sales By Customer Class^
1990 - 2000
GWH

Year	Residential	Commercial	Industrial	Streetlighting	MBTA	MWRA	Municipals
1990*	3431	7183	1750	132	143	0	336
1991*	3382	7112	1685	131	149	20	333
1992	3569	7318	1672	132	150	163	343
1993	3652	7385	1695	132	155	186	352
1994	3730	7455	1732	132	160	186	363
1995	3789	7528	1747	132	164	211	372
1996	3904	7603	1766	132	169	211	382
1997	3991	7682	1789	132	173	211	391
1998	4058	7764	1851	132	176	211	401
1999	4144	7849	1909	132	180	322	412
2000	4217	7937	1956	132	183	322	421

Notes: ^Not adjusted for Company-sponsored C&LM *Actual Figures

Source: Exhs. BE-9; HO-D-111

TABLE 6
BOSTON EDISON COMPANY
RESOURCE NEED
(MW)

Variables Affecting Need	February 1992 Record 1996	February 1992 Record 1997	March 1992 Update 1996	March 1992 Update 1997
Peak Load	2922	2969	2922	2969
less:				
Conservation	149	165	166	184
Load Management	251	260	251	260
Reserve Margin	31.1%	31.1%	31.1%	31.1%
Capability Target	3306	3335	3284	3310
Supply Resources				
Planned Capacity Additions	704	704	757	757
Existing Units	2751	2751	2693	2693
Total	3455	3455	3450	3450
Resource Surplus	149	120	165	140

Sources:

Peak Load: Exhs. HO-D-111, BE-1, p. E-32.
C&LM: Exhs. BE-1, p. E-32, BE-121.
Reserve Margin: Exh. HO-S-157, p. 4
Planned Capacity Additions: Exhs. BE-1, p. C-13, HO-S-21, HO-S-113, HO-S-118; Boston Edison Company, D.P. U. 90-270-C (1992)
Existing Units: Exhs. BE-1, p. E-34, BE-121

TABLE 7

BOSTON EDISON COMPANY
Short Run Base Case Demand Forecast and Supply Plan
Summer Peak

Year	Capability Respons.(1) (MW)	Existing Capability(2) (MW)	Base Case Surplus (MW)	Percent Surplus
1992	3249	3637 (3)	388	11.9
1993	3201	3571 (4)	370	11.5
1994	3248	3272	24	0.7
1995	3283	3420 (5)	138	4.2

Notes:

(1) Capability Responsibility was calculated from the following factors: Peak Demand Forecast as presented in reforecast (Exh. HO-D-111); adjustments for Town of Reading Demand, TOUR, self-generation and base level C&LM reduction in peak (Exh. BE-1, p. E-32); and Reserve Requirement Forecast presented by the Company for historic EAF's (Exh. HO-S-157).

(2) Existing capability includes resources represented as"existing" in Exh. HO-S-159, Attachment A, line 1, with exception of Yankee Rowe (16 MW); "purchases" line 8; and MWRA Southboro (0.8 MW) and Peat Products (22.6 MW).

(3) 1992 and following years include entitlement to HQ II (171.1 MW); OSP (116.6 MW); NEA 1 (130.7 MW); and NEA 2 (68.0 MW).

(4) 1993 and following years include 57% of entitlement to L'Energia (34 MW).

(5) 1995 includes 57% of RFP #2 supply (114 MW) and 57% of RFP #3 supply (75 MW).

Sources: Exhs. BE-1, pp. C-13, E-32, HO-D-111, HO-S-21, HO-S-116, HO-S-157, HO-S-159.

TABLE 8

High Case Demand Forecast and Base Case Supply Plan Summer Peak

Year	Capability Respons. (MW)	Existing Capability (MW)	Base Case Sur/(Def) (MW)	Percent Sur/(Def)
1992	3283	3637	354	10.7
1993	3256	3571	315	9.6
1994	3321	3272	(49)	(1.4)
1995	3373	3420	47	1.3

TABLE 9

Base Case Demand Forecast and Delay of RFP #2 and RFP #3 Summer Peak

Year	Capability Respons. (MW)	Existing Capability (MW)	Base Case Sur/(Def) (MW)	Percent Sur/(Def)
1992	3249	3637	388	11.9
1993	3201	3571	370	11.5
1994	3248	3272	24	0.7
1995	3283	3083	(200)	(6.0)

TABLE 10

High Case Demand Forecast and Delay of RFP #2 and RFP #3 Summer Peak

Year	Capability Respons. (MW)	Existing Capability (MW)	Base Case Sur/(Def) (MW)	Percent Sur/(Def)
1992	3283	3637	354	10.7
1993	3256	3571	315	9.6
1994	3321	3272	(49)	(1.4)
1995	3373	3083	(290)	(8.5)

Appeal as to matters of law from any final decision, order or ruling of the Siting Council may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the order of the Siting Council be modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Siting Council within twenty days after the date of service of the decision, order or ruling of the Siting Council, or within such further time as the Siting Council may allow upon request filed prior to the expiration of the twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the clerk of said court. (Massachusetts General Laws, Chapter 25, Sec. 5; Chapter 164, Sec. 69P).

COMMONWEALTH OF MASSACHUSETTS

Energy Facilities Siting Council

In the Matter of the Petition of the Fitchburg Gas and Electric Light Company for Approval of its 1991 Long-Range Forecast of Electric Requirements and Resources	)	EFSC 91-11(B)

FINAL DECISION

Jolette Westbrook
Hearing Officer
May 15, 1992

On the Decision:

Peter Banwell

TABLE OF CONTENTS

The Energy Facilities Siting Council hereby APPROVES the 1991 demand forecast and supply plan of Fitchburg Gas and Electric Light Company.

I. INTRODUCTION

A. Background

Fitchburg Gas and Electric Light Company ("Fitchburg" or "Company") is a small-investor owned electric and gas utility serving the towns of Fitchburg, Lunenburg, Townsend, and Ashby. In 1990 Fitchburg had total sales of 408,133 megawatthours ("MWH") and a summer peak system load of 74.6 megawatts ("MW") (Exh. HO-1A, App. A-2, Table 9). Total system requirements for 1990 were 2.2 percent lower than in 1989 (id.).

Fitchburg has entitlement ownership to units in New England and Canada (Exh. HO-1B, Section 3, Figure 3-5). The Company's summer entitlements located in New England consist of 19.6 MW of New Haven Harbor (oil/gas), 2.5 MW of Millstone #3 (nuclear), and 1.1 MW of Wymann #4 (oil) (Exh. HO-1B, App. B-1, Schedule 2).[1] The Company also leases a #7 oil/gas-fired combustion turbine ("#7 generator") with a peak summer capacity of 18.9 MW (id.).[2] In addition, Canadian hydropower imports contribute 7.8 MW of summer capacity to the Company's resource portfolio (id.).

In 1990, Fitchburg sold 35.3 percent of its energy to residential customers, 28.2 percent to commercial customers, 35.2

1/ New Haven Harbor and Millstone #3 are located in Connecticut, and Wymann #4 is located in Maine (Exh. HO-1B, App. B-1, Schedule 2).

2/ The #7 generator, which is leased from Industrial Leasing Corporation, is located within Fitchburg's service territory and is connected to the Company's transmission system via Company-owned transmission facilities (Exh. HO-S-3).

percent to industrial customers, and 0.8 percent to the streetlighting sector (Exh. HO-1A, pp. A-5, A-10, A-13, App. A-2, Table 6).[3]

In its most recent review of Fitchburg's demand forecast and supply plan, the Energy Facilities Siting Council ("Siting Council" or "EFSC") rejected the Company's demand forecast and supply plan. Fitchburg Gas and Electric Light Company, 13 DOMSC 85 (1985) ("1985 Fitchburg Decision").[4]

In 1992, a merger between Fitchburg and Unitil Corporation ("Unitil") was approved by the Massachusetts Department of Public Utilities ("Department" or "DPU"). Joint Petition of Fitchburg Gas and Electric Light Company and UMC Electric Company, Inc., DPU 89-66 (1992). Fitchburg stated that it has had a long relationship with Unitil Corporation, a New Hampshire public utility holding company. For purposes of this decision, Unitil also refers to its affiliates Unitil Service Corp. and Unitil Power Corp.

B. Procedural History

Fitchburg filed its 1991 demand forecast and supply plan ("1991 Forecast and Supply Plan") with the Siting Council on June 3, 1991 (Exhs. HO-1A, HO-1B). On July 9, 1991, the Hearing

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3/ The Company indicated that Company use accounted for approximately 0.3 percent of total Company sales in 1990 (Exh. HO-1A, App. A-2, Table 8).

4/ In October, 1986 Fitchburg filed its demand forecast and supply plan with the Siting Council. The Siting Council opened a proceeding on this matter which was docketed as EFSC 86-11(B). Thereafter, the Siting Council closed the proceeding without making any determinations or findings, and established April 1, 1991 as the next date for Fitchburg to file a new demand forecast and supply plan. Final Decision of the Siting Council on Integrated Resource Management (IRM) Rulemaking, 21 DOMSC 91, 155 (1990) ("1990 Final IRM Decision").

Officer issued a Notice of Adjudication for the 1991 Forecast and Supply Plan and directed Fitchburg to publish and post the Notice in accordance with 980 CMR 1.03(2). Fitchburg subsequently submitted confirmation of publication and posting. The Siting Council received no petitions to intervene in the proceeding.

The Siting Council held evidentiary hearings on September 17, 18, 24, and 25, 1991. Fitchburg presented three witnesses: Mark H. Collin, manager of regulatory services for Unitil who testified regarding the Company's demand forecast; Paul Weiss, manager of resource planning for Unitil, who testified regarding supply planning; and James McGuigan, assistant vice president of electric operations at Fitchburg, who testified regarding the June 29, 1991 system outage. For a further discussion of the 1991 system outage, see Section III.F, below.

The Hearing Officer entered 137 exhibits into the record, primarily composed of the Company's responses to information and record requests. Fitchburg entered 2 exhibits into the record. Pursuant to a briefing schedule established by the Hearing Officer, Fitchburg filed its brief on October 22, 1991.

II. ANALYSIS OF THE DEMAND FORECAST

A. Standard of Review

As part of its statutory mandate "to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost," the Siting Council determines whether "projections of the demand for electric power ... are based on substantially accurate historical information and reasonable statistical projection methods." G.L.c. 164, secs. 69H, 69J. To ensure that the foregoing standard is met, the Siting Council applies three criteria to demand forecasts: reviewability, appropriateness, and reliability.

A demand forecast is reviewable if it contains enough information to allow a full understanding of the forecasting methodology. A forecast is appropriate if the methodology used to produce the forecast is technically suitable to the size and nature of the utility that produced it. A forecast is reliable if the methodology provides a measure of confidence that its data, assumptions, and judgements produce a forecast of what is most likely to occur. Boston Edison Company, EFSC 90-12/90-12A, p. 8 (1992) ("1992 BECo Decision"); Braintree Electric Light Department, EFSC 89-32, p. 5 (1992) ("1992 Braintree Decision"); Nantucket Electric Company, 21 DOMSC, 208, 214 (1991) ("1991 Nantucket Decision"); Boston Edison Company, 15 DOMSC 287, 294 (1987) ("1987 BECo Decision"); 1985 Fitchburg Decision, 13 DOMSC at 3; Nantucket Electric Company, 13 DOMSC 1, 6 (1985).

B. Previous Demand Forecast Review

In the 1985 Fitchburg Decision, the Siting Council rejected Fitchburg's demand forecast and established broad guidelines for the Company to follow in its demand forecasting methodology (13 DOMSC at 117). Those guidelines direct the Company:

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

(2) To develop and implement a new methodology for forecasting commercial and residential requirements.

In response to the first guideline, the Company made some revisions to its industrial demand forecast methodology (Exh. HO-1A, p. A-13). The forecast employs a customer survey as well as regional employment estimates by standard industrial code ("SIC") classifications from Wharton Econometric Forecasting Association ("WEFA") (id.). The Company made attempts at econometric modelling in the industrial sector but was unable to achieve satisfactory results (id.).[5] While the latest survey instrument is an improvement on the previous survey reviewed by the Siting Council in the 1985 Fitchburg Decision, it still fails to consider electricity prices. Further, the survey continues to subjectively estimate electricity demand in part due to the low response rate to the survey. For a detailed discussion of the survey, see Section II.C.6, below.

5/ Time series modelling was also attempted but due to the downward trend of the paper industry, which overshadowed smaller industries, the Company determined that methodology to be inappropriate. (Exh. HO-1A, p. 13).

Based on the foregoing, the Siting Council finds that the Company failed to satisfy the first guideline.

With respect to the second guideline, the Company developed a new methodology for forecasting residential and commercial requirements. The Siting Council notes that the Company has made significant improvements in the development and methodology of both new forecasts as noted in Sections II.C.4, and II.C.5, below. Further, the Company incorporated electricity price and employment variables by developing econometric models for the residential and commercial sectors.

Accordingly, the Siting Council finds that the Company has satisfied the second guideline.

C. Energy Forecast

1. Overview

The forecast currently under review extends from 1991-2001 and forecasts an average growth rate of approximately one percent per year (Exh. HO-1A, App. A-2, Table 8). The Company estimated that total system requirements in 2001 will be 453,830 MWH (id.).

Fitchburg stated that it used econometric models to forecast annual energy requirements for its residential and commercial sectors (id., pp. A-5, A-10). To forecast energy requirements in the commercial sector, the Company stated that it developed a linear econometric model using employment estimates developed by WEFA (id., p. A-10).

To forecast energy requirements in the industrial sector, the Company explained that it used the results of an industrial survey and data from employment forecasts provided by WEFA (id., p. A-13). The Company stated that by reviewing both the survey results and the WEFA data, it judgementally estimated sales by individual SIC classifications (id., p. 14). Finally, the Company stated that streetlighting sales are forecasted to grow at zero percent over the forecast period (id., p. A-16).[6]

In order to account for uncertainties in the base assumptions of electricity price, economic activity and personal income variables, the Company formulated three growth scenarios for each customer sector resulting in low, base and high estimates of energy requirements (id., p. A-20, App. A-3, "Scenario Workpapers").

In general, the Siting Council notes that Fitchburg's energy forecast exhibits greater attention to statistical detail and a more complete examination of historical data than what was shown in the Company's 1984 forecast filing reviewed by the Siting Council in the 1985 Fitchburg Decision. The results of Fitchburg's energy forecast are presented in Table 1. The Siting Council reviews the individual components of Fitchburg's forecast below.

2. Economic and Demographic Forecasts

Fitchburg purchased Worcester County economic and demographic forecast statistics for the years 1991-2001 from WEFA, and used these data in its residential, commercial and industrial models (Exhs. HO-1A, p. A-3, HO-D-5). The Company stated that its service territory, with the exception of the Town of Townsend,[7] falls almost entirely within Worcester County (Tr. 1, p. 152). The Company stated that it was possible to obtain territory-specific data by contracting for a special study

6/ Fitchburg also projected Company use to grow at zero percent since the Company does not plan to change its electrical requirements over the forecast period (id.).

7/ The Town of Townsend is in Middlesex County and comprises approximately 10 percent of the total requirements of the Fitchburg system (Tr. 1, p. 152).

(id., p. 39). However, the Company indicated that it does not have the historical territory-specific data to develop a statistically significant forecast (id.). As a result, the Company used Worcester County economic and demographic data and adjusted such data to reflect the Company's service area. The Company stated that, based on Fitchburg's calculations, the Company's service territory population was equal to ten percent of Worcester County's population (Exh. HO-D-5). Additionally, Fitchburg stated that using estimates of population growth[8] in the Towns served by the Company and historical and forecasted Worcester County population data developed by WEFA, it developed a ratio of the Company's service territory population to the population in Worcester County (id.).

The Company stated that the economic forecast was based on personal disposable income, industrial sector employment by two-digit SICs, aggregate manufacturing and non-manufacturing employment data, fuel prices, the Boston consumer price index ("Boston CPI"), and Massachusetts Gross State Product (id.). The Company further stated that the data used for the demographic forecast included population estimates and housing statistics (Exh. HO-1A, p. A-3). Fitchburg stated that the economic forecast was used in its commercial, residential and industrial models (id., p. 5).

Finally, in order to account for forecasting uncertainties, the Company developed "high" and "low" economic growth rates for use in its residential, commercial and industrial forecasts (id., p. A-20). The Company stated that the data used to develop the scenarios were provided by WEFA (id.)

Overall, the Siting Council notes that the Company has

8/ The Company used the estimates of population growth compiled by the North Central Massachusetts Chamber of Commerce (Exh. HO-D-25).

selected data that is likely to reflect projected economic and demographic activity in the Fitchburg service territory. However, the Company should continue to seek to integrate territory-specific economic data in its future forecasts. For purposes of this review, the Siting Council finds that Fitchburg's economic and demographic forecasts are reviewable, appropriate, and reliable.

3. Electricity Price Forecast

a. Description

For the 1991 through 1995 time period, the Company stated that it forecasted electricity prices for each customer class by adding forecast fuel charge rate adjustments, production costs, demand charges, and transmission charges to the classes' current rate base (id. p. A-3).[9] The Company stated that over the five year forecast period, it does not anticipate filing a rate case for a base price increase (Tr. 1, p. 29). The Company stated that the price forecasts were used in the Company's residential and commercial econometric models as independent variables (Exh. HO-1A, pp. A-6, A-10).

The Company forecasted production costs using the Electric Utility Planning System ("UPLAN") (id.). Fitchburg stated that its 1991 through 1995 capital budget served as the basis for the

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9/ The fuel charge is a portion of electrical rates that fluctuates with the prices of fuels used by the Company, subject to quarterly adjustment by the DPU.

UPLAN estimates (Tr. 1, p. 30).[10] The Company also stated that demand and transmission costs are forecasted based on fixed charges from suppliers and internal Company estimates (id.). The Company stated that it anticipates that from 1991 through 1995, the real price of electricity for the residential and commercial sectors will decrease by 2.6 percent and 2.9 percent, respectively (Exh. HO-1A, pp. A-7, A-11). In order to account for forecasting uncertainties, the Company developed "high" and "low" price scenarios, for the residential and commercial sectors (id., p. 20).

The Company stated that it did not have accurate estimates of capital budgets beyond the 1995 period (Tr. 1, p. 30). Therefore, the Company forecasted prices for 1996-2001 to increase at 4.3 percent per year, at a rate equal to inflation as specified by WEFA (id.). In real terms, the price increase equals zero percent per year from 1996 through 2001 (id.).

b. Analysis

For the 1991 through 1995 time period, the Company employed a sound methodology which incorporated essential electricity price determinants as well as high and low estimates of price increases. However, the methodology employed for the 1996 through 2001 time period assumed that price would increase at the level of inflation. This methodology raises reliability concerns in part because from 1996 through 2001, the forecast of price increases significantly faster than the pre-1996 rate

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10/ The Company also included estimates of the rate impacts of the Kenetech facility. The Kenetech facility is a biomass-fired 16 MW generation facility currently under construction in Fitchburg's service territory and scheduled to come on-line in November 1992 (Exh. HO-1B, Figure 3-5; Tr. 1, p. 32). The Company has contracted for 13.5 MW of power from Kenetech (id.).

simply due to the methodological change. In the 1985 Fitchburg Decision, the Siting Council criticized Fitchburg for applying different methodologies to the same forecast because of the inconsistency that results from this practice (13 DOMSC at 99).

Nevertheless, for the purposes of this review, the Siting Council finds that the Company's electricity price forecast is reviewable, minimally appropriate and minimally reliable. In order for the Siting Council to approve the Company's electricity price forecast in its next forecast filing, the Company must either provide specific estimates of price increases for the time period extending beyond the capital budget period or utilize a methodology which is applied consistently throughout the entire forecast period.

4. Residential Energy Forecast

a. Description

In 1990, the Company had 22,743 residential customers and total residential sales of 122,672 MWH (Exh. HO-1A, App. A-2). Fitchburg stated that the residential sector accounted for approximately 35.3 percent of total electricity sales in 1990 (id., p. A-5). Further, Fitchburg stated that residential heating sales currently account for approximately 2.2 percent of total Company electricity sales (id., App. A-2, Table 3).

Fitchburg stated that it forecasted aggregate residential energy requirements using an econometric model (id., p. A-5). The Company stated that it would not be beneficial to use end-use modeling due to the expense involved and the Company's satisfaction with the results of the current forecast (Tr. 1, pp. 10-11). In its residential model, the Company stated that two independent variables, number of customers and the average use per customer, were multiplied together to produce the total residential sales forecast (id.).[11]

The Company explained that it determined the number of non-heating customers by equating the growth in the number of customers (i.e., net customer gains) to the projected growth rate in housing stock, as provided by WEFA (id., p. A-9). The Company stated that the number of customers variable accounts for 79 percent of the forecasted increase in electricity sales for the residential sector (Exh. HO-D-28). The Company further stated that for forecasting non-heating sales, one residential electric meter represented one residential customer (Tr. 1, p. 37).

The Company stated that the number of electrically heated homes in the Fitchburg area was separately calculated based on the Company's rate and revenue code classifications for residential customers (Exh. HO-D-8). In its forecast, the Company assumes that electrical heating sales will remain constant at 8,456 MWH per year over the forecast period (Exh. HO-1A, App. A-2, Table 3).

The Company stated that for non-heating sales, the average use per customer was estimated using ten years of historic data for four independent variables: (1) cooling degree days ("CDD"); (2) heating degree days ("HDD"); (3) real average price of electricity ("RPRICE"); and (4) real disposable income ("RINCOME") (Exh. HO-1A, p. A-6).[12] [13]

11/ The Company indicated that the residential model exhibited a coefficient of determination ("R-Squared") of .96 (Exh. HO-1A, p. A-8). R-squared is a measure of the amount of variation in the dependent variable which is explained by the variation in the independent variables. Each of the independent variables in the residential model were significant at the 95 percent level of confidence with T tests greater than 2.0 (Exh. HO-1A, p. A-8).

12/ The Company stated that it purchased HDD data from Weather Services Inc. for its gas operations and uses the same degree day estimates for its electrical forecast (Exh. HO-D-6).

The Company hypothesized that weather (CDD and HDD variables) would influence sales since both electrical heating and cooling are weather dependant (Exh. HO-1A, p. A-6). In support of its hypothesis, the Company provided documentation of the seasonal fluctuations in electric sales for both heating customers and non-heating customers (id., App. A-3, "Actual Residential Sales Non-Heat," "Actual Residential Sales Heat"). The Company explained that its non-heating sales are influenced by weather because of increased water heater losses into unheated areas due to additional cycling requirements during winter months, increased lighting due to shorter daylight hours during winter months, and the use of portable electric space heaters (Exh. HO-D-23).

The third variable utilized in the residential sector is RPRICE which is determined using the Company's electricity price forecast, see Section II.C.3, above. The Company indicated that residential electricity sales would respond inversely to price increases and decreases (Exh. HO-1A, p. A-7). The Company also indicated that during the forecast period, the real price of electricity will decrease during 1991 through 1996, and remain constant during 1996 through 2001 (id.).

The final variable in the average use per customer equation is RINCOME. The Company contended that increasing personal incomes would increase residential electricity demand (id., p. A-7). The Company stated that it relied on WEFA estimates of personal income for its forecast (id.).

The Company contended that federal appliance efficiency

13/ The Company stated that CDD are determined by taking hourly temperature readings at its #7 generator and dividing the sum of the hourly readings by 24 to arrive at an average daily temperature (Exh. HO-D-7). Cooling degrees are defined as the number of degrees that are higher than a base of 65 degrees (id.).

standards were implicitly incorporated in its residential forecast (Tr. 1, p. 26). The Company explained that since the electricity price and personal income coefficients captured past efficiency gains, future efficiency gains are therefore incorporated in the current residential energy forecast through electricity price and personal income coefficients (id., pp. 26-27).

The Company estimated that residential sales will increase at a compound annual rate of approximately 1.26 percent per year over the forecast period (Exh. HO-1A, p. A-5). This increase is less than half the actual growth rate experienced by the Company during 1982-1990 (id.). Finally, the Company also developed high and low scenarios of conservation growth for the residential sector (id., p. A-20). The Company stated that the scenarios were used as inputs to develop high and low energy and peak load forecasts for the Fitchburg system.

b. Analysis

Fitchburg has refined and enhanced its residential energy forecast since the 1985 Fitchburg Decision. Fitchburg's methodology for forecasting the number of customers and then multiplying this estimate by the average use per customer is an appropriate methodology to determine total electricity use for a company of Fitchburg's size. Further, the Company's use of WEFA economic data combined with territory specific estimates of CDD and HDD is a vast improvement over the methodology and data sources reviewed by the Siting Council in the 1985 Fitchburg Decision. In a recent decision, the Siting Council approved the use of an econometric forecast to predict residential energy requirements similar to Fitchburg's. 1992 Braintree Decision, EFSC 89-32 at 14.

The most influential variable in the residential forecast is the number of customers which accounts for over 79 percent of projected growth in the forecast. The Company relied on WEFA estimates of growth in housing stock to determine the changes in the number of customers variable. In the past, the Siting Council has accepted this type of methodology for estimating the change in the number of customers. Massachusetts Municipal Wholesale Electric Company, 20 DOMSC 1, 15 (1990) ("1990 MMWEC Decision"). Given the significance of the number of customers variable to the residential forecast, the Siting Council expects the Company to continue to make all reasonable efforts to obtain accurate territory-specific data, which could include investigation of the most recent U.S. Census data.

Despite the improvement in the Company's methodology and data sources, the Siting Council has concerns with certain elements of the residential forecast methodology. The Company asserts that government mandated appliance efficiency gains can be captured by electricity price and personal income variables. The Siting Council does not agree this assertion. Rather, we note that one of the limitations of the linear econometric modeling technique is that the relationships of the variables cannot change over the forecast period to incorporate exogenous influences such as government-mandated appliance efficiency standards. 1992 Braintree Decision, EFSC 89-32 at 19; Commonwealth Electric Company/Cambridge Electric Company, EFSC 90-4, p. 43 (1991) ("1991 CECo/CELCo Decision").[14] In order for the Siting Council to approve the Company's residential forecast in its next filing the Company must explicitly include the impacts of government-mandated appliance efficiency standards.

14/ The Siting Council regulations recognize government efficiency standards and other "natural conservation" as appropriate considerations in demand forecasts. 980 CMR 7.09 (2)(d).

Overall, the Company has significantly improved the methodology used to forecast residential energy requirements. Accordingly, the Siting Council finds that Fitchburg's residential energy forecast is reviewable, appropriate and reliable.

5. Commercial Energy Forecast

a. Description

Fitchburg stated that the commercial sector accounted for approximately 28 percent of total electricity sales in 1990 (Exh. HO-1A, p. A-10). The Company indicated that in recent years, commercial sector sales have decreased significantly, and as a result, the Company estimated that sales will not return to 1988 levels until the year 2000 (id.). However, the Company's forecast projects a 1.2 percent growth rate in sales through the year 2001 (id.) This rate of increase compares with an historic average of 1.8 percent increase between 1982 and 1990 (id.). The Company indicated that it also estimated three scenarios of load growth for the commercial sector (id., p. A-20). The Company stated that the scenarios were used as inputs to develop high and low peak load and energy requirement scenarios for the entire Fitchburg system (id.).

The Company stated that it used an econometric model to forecast energy requirements for the commercial sector (id.). The Company indicated that it was satisfied with both the methodology and results of the recent forecast and had not considered end-use-modeling or any other forecast methodology to utilize in future filings (Tr. 1, p. 61).

The Company explained that the commercial energy forecast uses four independent variables to estimate future sales: (1) HDD, (2) CDD, (3) non-manufacturing employment data, and

(4) the price of electricity (id., p. 64; Exh. HO-1A, p. A-10).[15]

The Company stated that HDD and CDD data used in the commercial forecast were the same data used in the residential forecast (Exh. HO-1A, p. A-11). The Company also stated that commercial sales were forecast assuming normal weather during the forecast period (id.).

The Company stated that it used historical data from 1982-1990 for electricity sales data, HDD, CDD, electricity price and number of customers data in its forecast (Tr. 1, p. 67). The Company indicated that it was difficult to incorporate more than eight years of historical data since data prior to 1982 was filed under different rate codes (Tr. 1, p. 68).

The Company used historical and estimated non-manufacturing employment data compiled by WEFA to estimate economic activity in its service area (Exh. HO-1A, p. A-11). The Company stated that the data were estimated for Worcester County, and adjusted by the Company to reflect Fitchburg's service

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15/ The Company performed statistical tests on each of its independent variables. The Company stated that each of the variables had the expected signs indicating that the theoretical relationships of the variables were confirmed (price increases would decrease sales if the price has a negative sign) (Exh. HO-1A, p. A-12). The Company also indicated that each variable was significant at the 90 percent level of confidence (id.). The Company stated that the model was corrected for autocorrelation using the Cochrane-Orcutt procedure (id.). The final model's R-Squared was approximately 0.92 indicating that 92 percent of the variation in the dependent variable is explained by the model (id., App. A-3, "Commercial Workpapers").

territory (Exh. HO-D-5).[16] The Company explained that it had attempted to incorporate a lagged variable of non-manufacturing employment, population, quarterly dummy variables, time trend, and nominal price, but that it was unable to improve the statistical validity of the existing model (Tr. 1, p. 65).

For the commercial sector, the Company used electricity price data developed in its price forecast, see Section II.C.3, above. The Company estimated that the price elasticity in the commercial sector was 0.23 percent (all other factors held constant), which indicates that a one percent increase in electricity price will reduce electrical sales by 0.23 percent (Exh. HO-D-14).

b. Analysis

The Siting Council notes that the Company has made significant improvements in its commercial forecast methodology since the 1985 Fitchburg Decision. Specifically, using WEFA data, including a separate price forecast, and testing the statistical validity of the commercial model demonstrates the improvements made by Fitchburg. The Siting Council also notes that the economic downturn, as reflected in the WEFA data, provides a technical foundation for the Company's forecast of slow growth. Further, the Company provided adequate justification that the use of WEFA data for Worcester County area was appropriate to use for the Fitchburg service area. However, in future filings, the Company should continue to strive to

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16/ The Company indicated that it adjusted Worcester County data by calculating the relationship between the population of Worcester County and the population of the Fitchburg service territory (Exh. HO-D-5). Based on that calculation, the Company multiplied all of the WEFA data by .1 to reflect the ratio of populations between Worcester County and Fitchburg's service territory (id.).

improve its commercial sector model. In particular, the Company should explore the availability of territory-specific commercial employment figures for use in future forecasts.

Accordingly, the Siting Council finds that the Company's commercial forecast is reviewable, appropriate and reliable.

6. Industrial Forecast

a. Description

The industrial class represents less than one percent of the Company's total customers but accounts for 35 percent of total sales (Exh. HO-1A, p. A-13). The Company anticipated that industrial sector sales will increase approximately .54 percent per year during the forecast period (id.).[17]

The Company stated that it attempted econometric and time series modeling to develop its industrial forecast, but that it was not able to successfully develop a statistically significant model (Exh. HO-1A, p. A-13; Tr. 1, p. 94). Therefore, Fitchburg stated that it developed its industrial forecast model using two data sources: (1) WEFA employment projections according to SIC classifications for Worcester County;[18] and (2) a survey which the Company sent to all of its industrial customers asking them

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17/ The Company indicated that the slow growth trend in the industrial sector may be the continuation of a trend that has been underway since 1982 (Exh. HO-1A, p. A-13). The Company theorized that the decline in the growth rate of the industrial sector was caused by the regional economic downturn combined with the relocation of several large industrial customers during the 1982 through 1990 period (id.).

18/ The five largest SIC classifications are: paper and allied products (SIC 26); rubber and miscellaneous plastics products (SIC 30); primary metal industries (SIC 33); fabricated metal products (SIC 34); and educational services (SIC 82) (Exh. HO-1A, p. A-13). The Company stated that these five SIC classifications encompassed 72 percent of industrial sales in 1990 (id.).

to state their anticipated electric usage through the year 2001 (id.). With respect to the survey, the Company stated that it sent surveys to 30 customers and had a response rate of slightly over 40 percent (Tr. 1, p. 102). The Company considered this response rate good but anticipates a higher response rate in the future (id., pp. 102, 117). Using both the survey and WEFA data sources, the Company judgementally estimated future sales by SIC classification.

The Company stated that while important background material was revealed by all questions in the survey, the forecast essentially relied on two survey questions -- (1) "(d)o you expect your electrical requirements to increase in 1991," and (2) "(w)hat amount of electricity do you expect your Company to need for the years listed below (1991-2001)" (Exh. HO-1A, App. A-1, Figure 8, Tr. 1, p. 125). Fitchburg explained that if industrial customers responded, and Fitchburg judgementally determined the response to be accurate, then the survey data was used in the forecast instead of the WEFA data (Tr. 1, p. 125). In the case where an industrial customer did not respond to the survey or Fitchburg did not receive a survey response to indicate that a change in WEFA data was warranted, then the WEFA data were used in the forecast (id., p. 110).

When survey responses appeared to be inaccurate or inconsistent, Fitchburg would contact the industrial customer and question the person who completed the survey (id., p. 126). Fitchburg would then use its judgment to determine what data should be used for that particular customer (id.). Out of the 16 industrial customers who responded, six did not completely answer all of the survey questions (Exh. HO-RR-10, pp. 4, 10, 20, 22, 24, 26).

b. Analysis

The Siting Council notes several areas of concern with Fitchburg's current industrial forecast methodology. The Siting Council is concerned by Fitchburg's continued reliance on a survey based methodology. While it may be appropriate for Fitchburg's customers to provide data to Fitchburg for use in an industrial forecast methodology (i.e., floor space data, energy intensity data, data on lighting efficiency measures), here Fitchburg has inappropriately shifted its forecasting responsibility to its customers. Fitchburg's continued reliance on customer self-forecasts may result in supply decisions that clearly do not serve the best interests of its industrial customers, and in fact, may lead to inaccurate forecasts based on erroneous assumptions from those industrial customers.

The Siting Council also has concerns related to the survey itself. The low response rate (40 percent) indicates that the survey results could be subject to non-response bias.[19] Fitchburg has not developed a comprehensive survey methodology such as follow up questionnaires or phone calls to address this possible bias. In addition, the high percentage of incomplete survey responses indicates that the Company has not established firm survey contacts at each industrial site. Given the size of the industrial class, unreliable estimates by individual firms could influence the accuracy of the entire Fitchburg forecast. Since the industrial class consists of only 30 customers, identifying reliable and knowledgeable contacts at each site should not be overly burdensome on the Company.

In addition, the Company failed to justify using WEFA data as a proxy for growth in electrical use in the industrial sector.

19/ Non-response bias occurs when the data that is not collected by the survey influences the actual forecast.

The low response rate associated with the survey makes this assumption significant in terms of impact on the forecast results. Such unsubstantiated assumptions cannot be accepted as appropriate forecasting methodologies for such a large portion of the Company's total forecast.

Finally, the Siting Council has found that the Company failed to satisfy the first guideline contained the 1985 Fitchburg Decision, calling for a new industrial forecast methodology which relies less on subjective data sources, see Section II.B, above.

Accordingly, based on the above, the Siting Council finds that the Company's industrial forecast is reviewable, but not appropriate or reliable.

In order for the Siting Council to approve Fitchburg's industrial forecast in its next forecast filing, Fitchburg must develop an industrial methodology that provides non-subjective estimates of future electricity use based on accurate data and projections gathered from reliable sources. However, we realize that Fitchburg may not have sufficient time to fully implement this new methodology by the IRM initial filing date. In the event that Fitchburg cannot implement a new methodology and a survey is used in the Company's IRM filing, Fitchburg must: (1) develop a new survey methodology that reflects a larger number of industrial customers, (2) ensure that the survey is prepared by the person(s) within the customer's company with the appropriate expertise, (3) ensure that the survey results are integrated with WEFA data using a clearly defined methodology, and (4) provide additional justification of the use of WEFA data as a proxy for future sales growth.

7. Streetlighting Forecast

The Company stated that streetlighting sales accounted for 3,152 MWH (.8 percent) of Fitchburg's total annual sales in 1990 (Exh. HO-1A, App. A-2, Table 6). Fitchburg explained that it expected streetlighting requirements to decline slightly in 1991 then remain stable throughout the forecast period (id.). The Company stated that this assumption was based on the Company's knowledge of municipal streetlighting requirements and historical data for the years 1986-1990 (id., p. A-16, App. A-2, Table 6). The Company explained that the forecast was derived by averaging streetlighting use from the past 5 years and extrapolating into the future at zero percent increase each year (id., App. A-2, Table 6).

The Siting Council finds that Fitchburg's streetlighting forecast is reviewable, appropriate and reliable.

8. Conclusions on the Energy Forecast

The Siting Council has found that Fitchburg's (1) economic and demographic forecasts are reviewable, appropriate and reliable, (2) price forecast is reviewable, minimally appropriate and minimally reliable, (3) residential energy forecast is reviewable, appropriate and reliable, (4) commercial energy forecast is reviewable, appropriate and reliable, (5) industrial energy forecast is reviewable, but not appropriate or reliable, and (6) streetlighting forecast is reviewable, appropriate and reliable.

The Siting Council notes that a significant strength of Fitchburg's energy forecast was the use of high and low growth scenarios, see Section II.C, above. The Siting Council notes that the use of scenarios lessens the uncertainties associated with unpredictable future economic cycles and is commendable for a company the size of Fitchburg. Further, the development of new forecast methodologies in the residential and commercial sectors and the incorporation of WEFA data in those forecasts significantly improved the overall reliability of the forecast since the 1985 Fitchburg Decision.

The Siting Council however, has continued concerns with the Company's industrial forecast. The survey methodology employed by the Company contained significant weaknesses. Given that the industrial sector accounts for approximately one-third of the entire energy forecast, the reliability of the industrial sector forecast has a significant impact on the overall reliability of the energy forecast.

Nevertheless, the Siting Council finds that, on balance, Fitchburg's forecast of energy requirements is reviewable, minimally appropriate and minimally reliable.

D. Peak Load Forecast

1. Description

The Company stated that it expects to remain a summer peaking system during the forecast period (Exh. HO-1A, App. A-2, Table 9). The Company forecasts its summer peak to grow from 70.7 MW in 1991 to 77.8 MW by the year 2001 (id., p. A-20). The Company forecasts its winter peak to increase from 66.5 MW in 1991 to 73.1 MW in 2001 (id.). The Company stated that it expects its winter peak to grow at .96 percent per year over the forecast period (id.). The Company also stated that it expects its summer peak load to grow at .97 percent through the year 2001 (id.). The results of Fitchburg's peak load forecast are presented in Table 2, below.

Fitchburg stated that it developed its peak load forecast using an hourly load model (id., p. A-18). The Company stated that data inputs to the hourly load model consisted of type of day, hour, weather, customer load shapes and scaling factors (id.).[20] Based on the Company's energy forecast, sales data were allocated into residential, commercial, and industrial class sectors and applied to the peak load model (id., p. A-19).

The Company indicated that the model allocated annual energy forecasts for three specific day types including Mondays, other week days and weekends (Exh. HO-D-18). The Company stated that weather data was forecasted assuming normal weather.[21] The Company stated that customer use patterns were developed using a detailed load research study completed for the Company in 1989 by Unitil (id., pp. 1-115).[22] The Unitil study determined load shapes for residential, commercial and industrial customers by measuring actual metered loads (id.). The peak load forecast was adjusted for conservation programs by subtracting the conservation program impacts from the predicted peak load (Exh. HO-RR-20).

Fitchburg developed low, base and high load growth scenarios for both summer and winter peak load (Exh. HO-1A, p. A-20). The low growth scenario winter forecast predicts a .35 percent compound growth rate and the high growth scenario summer forecast predicts a 1.5 percent compound rate over the forecast period (id.).

20/ Scaling factors are adjustments to the peak load made by determining the relationship between peak day load shapes and typical day load shapes (Exh. HO-D-19).

21/ The Company explained that normal weather was assumed to be the average of historical degree days for each day in the forecast period (Exh. HO-1A, p. A-18).

22/ The load research study included the installation of 280 solid state recorders to measure and store data. The meters were installed for 100 percent of the industrial customers and on a stratified sample basis for commercial and residential customers (Exh. HO-D-18A).

2. Analysis

Fitchburg has demonstrated that it has developed and implemented a peak load forecast methodology that accounts for many of the variables which significantly affect peak load. The Company has also demonstrated that its peak load model captures the effects of weather, type of day, consumption patterns, and conservation programs. The Company's peak load methodology however, incorporates the use of scaling factors which raises some reliability concerns.

The Siting Council recognizes that in the absence of a detailed end-use methodology for forecasting peak load, the use of methodologies which incorporate the use of projected load or scaling factors may be appropriate. 1991 Nantucket Decision, 21 DOMSC at 247-253; 1990 MMWEC Decision, 20 DOMSC at 37-39; Eastern Utilities Associates, 14 DOMSC 41, 71 (1986) ("1986 EUA Decision").

Fitchburg has developed a detailed hourly peak load forecast that is disaggregated by customer class and includes weather variables, complemented by peak load scenarios. Accordingly, the Siting Council finds that the Company's forecast of peak load requirements is reviewable, appropriate and reliable.

E. Conclusions on the Demand Forecast

The Siting Council has found that (1) on balance, Fitchburg's forecast of energy requirements is reviewable, minimally appropriate and minimally reliable, and (2) Fitchburg's forecast of peak load is reviewable, appropriate and reliable.

Accordingly, the Siting Council hereby APPROVES Fitchburg's 1991 demand forecast.

III. ANALYSIS OF THE SUPPLY PLAN

A. Standard of Review

In keeping with its mandate in G.L. c. 164, sec. 69H, to "provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost," the Siting Council reviews two dimensions of an electric utility's supply plan: adequacy and cost.[23]

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. 1991 Nantucket Decision, 21 DOMSC at 49; Cambridge Electric Light Company/Commonwealth Electric Company, 12 DOMSC 39, 72 (1985). The Siting Council has determined that different standards of review are appropriate and necessary to establish supply adequacy in the short run and the long run. Cambridge Electric Light Company/Commonwealth Electric Company, 15 DOMSC 125, 134 (1986). To establish adequacy in the short run, a company must demonstrate that it has an identified, secure and reliable set of energy and power supplies. In essence, the company must own or have under contract sufficient resources to meet its capability responsibility under a reasonable range of contingencies. If a company cannot establish that it has adequate supplies in the short run, that company must then demonstrate that it operates pursuant to a specific action plan enabling it to rely on alternative supplies in the event of certain contingencies. 1991 Nantucket Decision, 21 DOMSC at 60-65; 1987 BECo Decision,

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23/ Diversity, which in past Siting Council decisions has been discussed separately, now is treated within the discussion of least cost (see Section III.E.2.b, below).

15 DOMSC at 309-322.[24]

To establish adequacy in the long run, a company must demonstrate that its planning process can identify and fully evaluate a reasonable range of resource options on a continuing basis while allowing sufficient time for the company to make appropriate supply decisions to ensure adequate, cost-effective energy and power resources over all forecast years. Generally, a supply plan that meets the least-cost standards set forth below is deemed adequate in the long run.

The Siting Council next determines whether a supply plan minimizes the cost of power (that is, whether it ensures least-cost supply) subject to trade-offs with adequacy, diversity, and environmental impacts of construction and operation of facilities. 1991 Nantucket Decision, 21 DOMSC at 261; 1987 BECo Decision, 15 DOMSC at 301, 322-323, 339-348. In light of the evolving circumstances inherent in the supply planning process, the Siting Council's review of the long run cost of the supply plan generally focuses on a company's supply planning methodology. 1992 Braintree Decision, EFSC 89-32 at 31; 1991 Nantucket Decision, 21 DOMSC at 50; 1987 BECo Decision, 15 DOMSC at 339-349.

The Siting Council reviews the company's processes of identifying and evaluating a variety of supply options. In reviewing a company's resource identification process, the Siting Council analyzes whether that company identified a reasonable

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24/ The Siting Council defines the short run as four years. The four year period is measured from the time in a proceeding that (1) the final discovery or record response is submitted, or (2) the final hearing is held, whichever is later. 1991 Nantucket Decision, 21 DOMSC at 49; 1989 MECo/NEPCo Decision, 18 DOMSC at 343; Boston Edison Company, 18 DOMSC 201, 225 n. 10, 245 (1989) ("1989 BECo Decision").

range of resource options by (1) compiling a comprehensive array of available resource options, and (2) developing and applying appropriate criteria for screening its array of available resource options. In reviewing a company's resource evaluation process, the Siting Council determines whether that company (1) developed a resource evaluation process which fully evaluates all resource options, including the treatment of all resource options on an equal footing; and (2) applied its resource evaluation process to all of its identified resource options. 1991 Nantucket Decision, 21 DOMSC at 261-262; 1989 MECo/NEPCo Decision, 18 DOMSC at 338; 1989 BECo Decision, 18 DOMSC at 250-280.

B. Previous Supply Plan Review

In the 1985 Fitchburg Decision, the Siting Council rejected the Company's supply plan (13 DOMSC at 102-118). In that decision, the Siting Council established broad guidelines for the Company to follow in its supply planning. Those guidelines specify that:[25]

> 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,

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25/ The numbers preceding each guideline correspond to their order of presentation in the 1985 Fitchburg Decision.

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 of the programs; cost estimates; and the lead time required for program implementation. This analysis shall be integrated into the supply plan.[26]

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.[27]

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.

With respect to the third guideline, Fitchburg indicated that Unitil develops Fitchburg's demand forecast and supply plan (including RFP evaluation), while Fitchburg plans and implements its own DSM programs (Exh. HO-B-1). The Company stated that Unitil develops and executes Letters of Intent upon approval of Fitchburg management regarding potential power sources (id.). In addition, the Company stated that Unitil develops contracts to be executed by officers of Fitchburg (id.). However, the Company indicated that it does not believe that Unitil has the legal

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26/ The Siting Council addresses the Company's response to the fourth guideline in Section III.E.2.a.(2), below.

27/ The Siting Council addresses the Company's response to the fifth guideline in Section III.C, below.

authority to bind Fitchburg to a power supply (id.).[28] Based on the above, the Siting Council finds that Fitchburg has satisfied the third guideline.

With respect to the sixth guideline, the Company filed the interim report with the Siting Council on February 27, 1986. Accordingly, the Siting Council finds that the Company has satisfied the sixth guideline.

C. Supply Planning Process

The Company stated that the overall goal of its supply planning process is to ensure that the Company's requirements are met in a least-cost, least-environmental impact manner (Tr. 2, pp. 7-8). Fitchburg stated that its supply planning process is comprised of four separate phases: (1) identification of system requirements, (2) optimization of supply options based on system requirements, (3) testing of supply options against current power supply market, and (4) evaluation of C&LM options as a means of addressing system requirements (Exh. HO-1B, p. B-1).

The Company developed a forecast of system requirements using the Company's load forecast and a projection of required NEPOOL reserve margins (id., p. B-2). Fitchburg stated that, as a NEPOOL member, it is required to maintain adequate reserve margins (Tr. 2, p. 8). Since NEPOOL does not forecast anticipated reserve margins for its members, Fitchburg stated that it develops its own estimates based on historical reserve margins and estimates of future load growth (id.).

The Company stated that when capacity requirements have been determined over the forecast period, it develops a base-case supply plan using utility planning software UPLAN (Exh. HO-1B,

28/ Fitchburg made this assertion prior to the decision by the DPU approving the merger between Fitchburg and Unitil. Joint Petition of Fitchburg and UMC, DPU 89-66 (1992).

p. B-2).[29] Fitchburg stated that the base-case supply plan is the supply plan that would be pursued by the Company without considering resources available from the regional power supply market, i.e. using generic options only (Tr. 4, p. 10). Fitchburg asserted that its base-case supply plan results in a consistent set of life-cycle cost estimates for a variety of resources which can be evaluated against each other (Exh. HO-1B, p. B-31). The source of the cost and operational characteristics data for the generic options is the NEPLAN Generation Task Force Long Range Assumptions Handbook ("GTF Handbook") (Exh. HO-1B, p. B-22).

The Company stated that base-case supply plan resources are then tested against potential entitlements to specific projects available from the regional power supply market and Company-owned generation (id., p. B-3). Cost estimates for specific projects and Company-owned generation were based on assumptions by developers and engineering estimates (id., pp. B-23-24). The Company stated that the generic units, specific projects and Company-owned resources are evaluated using UPLAN in order to determine the impact of each resource on total system costs (id., p. B-31). The Company contended that this evaluation indicates the types of resources that are most suited for its service area prior to conducting a comparison with resources developed through the RFP process (id., p. B-2). The Company stated that the next step in this evaluation is to determine the levelized cost of each potential units' full load

29/ UPLAN III is a commercially available software planning package used by several New England utilities.

at different capacity factors (id., p. B-31).[30]

The Company stated that it then integrates C&LM programs into its supply plan by first comparing the cost of C&LM programs with the avoided cost of the least-cost supply plan (Exh. HO-1B, p. B-4). The Company stated that the C&LM programs that produce positive cost benefits are considered potential system resources and that system supply requirements are adjusted to reflect the effect of that C&LM program (id.). Next, the Company stated that the production cost of the system is determined using UPLAN's production cost model (id.). The Company asserted that if the net present value of the system production costs is lowered by including the potential C&LM program, this program is then committed and a new resource plan is established (id.).

Based on the supply planning process as identified above, the Siting Council finds that the Company has satisfied the fifth guideline.

D. Adequacy of the Supply Plan

1. Adequacy of the Supply Plan in the Short Run

a. Definition of the Short Run

As noted in Section III.A, above, the Siting Council has defined the short run for all electric companies as four years from the date of the final hearing or from the date of the response to the final record request, whichever is later. 1991 Nantucket Decision, 21 DOMSC at 497; 1989 BECo Decision, 18 DOMSC at 225 n. 10. Fitchburg's final hearing was on September 25, 1991 and the final record request was dated October 11, 1991. Consistent with previous Siting Council decisions, the

30/ Using this analysis the Company determined that nuclear units may be more cost effective at high capacity factors while combustion turbines may be more cost effective at low levels of operation (Exh. HO-1B, p. B-31).

short run in this proceeding extends from the winter of 1991-1992 through the summer of 1995.

b. Base Case Supply Plan

The data shown in Table 3 compare Fitchburg's projected resource capability to its capability responsibility over the short-run forecast period. These data indicate that Fitchburg is projecting a short-run capability surplus above their reserve margin of between 6.3 percent and 26.6 percent during summer peak periods.

Accordingly, the Siting Council finds that Fitchburg has established that its base case supply plan is adequate to meet requirements in the short run.

c. Short-Run Contingency Analysis

In order to establish adequacy in the short run, a company must establish that it can meet its forecasted needs under a reasonable range of contingencies. Fitchburg identified four contingencies at the time of its filing which could impact its short-run adequacy: (1) high load growth, (2) delay or cancellation of Hydro-Quebec II and Kenetech purchases,[31] (3) regulatory disapproval of the extension of a Northeast Utilities ("NU") contract,[32] and (4) multiple contingencies of

31/ During the course of the proceeding, the Company indicated that it started receiving power from Hydro-Quebec II effective July 1, 1991 (Tr. 2, p. 152). Therefore, the Company no longer considered the contract delay or cancellation of Hydro-Quebec II to be a contingency (id.).

32/ During the course of the proceeding, the Company stated that it is highly unlikely that it will attempt to extend the 20 MW NU contract because it plans to replace the contract with resources acquired through the RFP process (Tr. 2, p. 153). Therefore, the Siting Council will not analyze the NU contract as a short-run contingency for Fitchburg.

the above three items occurring (Exh. HO-1B, p. B-9).

For the purposes of this review, the Siting Council will analyze three contingencies: (1) high load growth, (2) delay or possible cancellation of the Kenetech facility, and (3) the double contingency of both of these occurring.

(1) High Load Growth

Under its high case demand forecast, Fitchburg projected that its summer peak load would grow from 71.7 MW in 1992 to 75.9 MW in 1995 (Exh. HO-1A, p. A-20). In the event that load growth occurs at this rate, and if all resources in its base case supply plan remain available, Fitchburg would not experience a resource deficiency during the forecast period (id., Figure 3-5), see Table 4.

Accordingly, the Siting Council finds that the Company has adequate resources in the event of a high load growth contingency.

(2) Delay or Cancellation of the Kenetech Facility

If the Kenetech facility were delayed or cancelled, the Company would be unable to receive the 13.5 MW of capacity in the winter of 1992-3 and the 13.0 MW in the summer of 1993 that Kenetech is scheduled to provide. In the event of this occurrence, and if all other resources in its base case supply plan remain available, Fitchburg would not experience a resource deficiency during the forecast period (Exh. HO-1A, Figure 3-5), see Table 4.

Accordingly, the Siting Council finds that the Company has adequate resources in the event of delay or cancellation of the Kenetech facility.

(3) Double Contingency Scenario

A possible combination of short-run contingencies would be high load growth and the delay or cancellation of the Kenetech facility. The high load growth scenario coupled with the loss of the Kenetech resource would result in the elimination of 15.8 MW from the Company's reserve in the summer of 1995. In the event of this occurrence, and if other all resources in its base case supply plan remain available, Fitchburg would not experience a resource deficiency during the forecast period, see Table 4.

Accordingly, the Siting Council finds that the Company has adequate resources in the event of the double contingency of high load growth and the delay or cancellation of the Kenetech facility.

(4) Conclusions on the Short-Run Contingency Analysis

The Siting Council has found that Fitchburg can meet its system capability responsibility in the short run in the event of (1) high load growth, (2) delay or cancellation of the Kenetech Facility, or (3) a double contingency scenario of both of these occurring.

Accordingly, the Siting Council finds that Fitchburg has established that its supply plan contains adequate resources to meet its system capability responsibility in the short-run under a reasonable range of contingencies.

2. Adequacy of the Supply Plan in the Long Run

Fitchburg's long-run planning period is the remaining forecast horizon beyond the short run; this extends from the winter of 1995-1996 through the winter of 1999-2001.

As previously discussed in Section III.A, above, the Siting Council requires an electric company to establish adequacy in the long run by demonstrating that its planning process can identify and fully evaluate a reasonable range of resource options. The ability of Fitchburg's supply planning process to identify and fully evaluate a reasonable range of resource options is fully discussed from the perspective of least-cost supply planning in Section III.E, below.

As indicated in Section III.E.1.c, below, the Siting Council has found that Fitchburg has established that it identified a reasonable range of resource options. The Siting Council has made no finding on whether Fitchburg has evaluated a reasonable range of resource options (see Section III.E.2.e, below). Accordingly, the Siting Council makes no finding on whether Fitchburg has established that its supply planning process ensures adequate resources to meet requirements in the long run.

3. Conclusions on Adequacy of the Supply Plan

The Siting Council has found that Fitchburg has established that (1) its base case supply plan is adequate to meet requirements in the short run, and (2) its supply plan contains adequate resources to meet its system capability responsibility in the short-run under a reasonable range of contingencies. The Siting Council has made no finding on whether Fitchburg established that its supply planning process ensures adequate resources to meet requirements in the long run. However, the Siting Council notes that Fitchburg's base case supply plan would satisfy its capability responsibility throughout the long run planning period (Exh. HO-1B, Figure 3-5).

Accordingly, the Siting Council finds that, on balance, Fitchburg has established that its supply plan ensures adequate resources to meet projected requirements throughout the forecast period.

E. Least Cost Supply

In this section, the Siting Council reviews Fitchburg's process for identifying and evaluating future resource options.

1. Identification of Resource Options

The Siting Council focuses its review on whether Fitchburg identified a reasonable range of resource options by (1) compiling a comprehensive array of available resource options, and (2) developing and applying appropriate criteria for screening its array of resource options.

a. Available Resource Options

In order to determine whether Fitchburg compiled a comprehensive array of available resource options, the Siting Council must determine whether Fitchburg compiled adequate sets of available resource options for each type of resource identified during this proceeding.

(1) Types of Resource Sets

In the course of this proceeding, Fitchburg identified four types of resource sets for consideration in its supply planning process: (1) new Company-owned combustion turbine and generic units, (2) C&LM programs, (3) purchases from New England utilities, and (4) purchases from non-utility developers (Exh. HO-1B, pp. B-1-4).

Accordingly, the Siting Council finds that Fitchburg has identified a reasonable range of resource sets.

(2) Compilation of Resource Sets

The Company stated that it had compiled information on the construction of a new Company-owned combustion turbine from an engineering study performed for Fitchburg and Unitil by Stone and

Webster Inc. in 1989 (Exhs. HO-S-27, HO-1B, p. B-18; Tr. 4, p. 5). The Company stated that this feasibility study analyzed a 40 MW combustion turbine project which could be constructed in 29 months (Exh. HO-S-27; Tr. 4, p. 10).

Fitchburg stated that information on generic units was compiled from the GTF handbook for an 80 MW combustion turbine, a 100 MW natural gas-fired combined cycle unit, and a 100 MW coal-fired steam cycle unit (Exh. HO-1B, p. B-18).[33] In addition, an entitlement to a 440 MW integrated coal gasification combined cycle unit was analyzed based on assumptions provided by prospective project developers (Exh. HO-B-18).

Accordingly, based on the above, the Siting Council finds that Fitchburg has compiled an adequate set of a new Company-owned combustion turbine and generic units.

The Company stated that its C&LM programs were compiled based on a study completed by Cummings Consulting, Inc. (Exh. HO-S-2A).[34] The study included the technical potential of C&LM and fuel switching for numerous end-uses and sectors in its service territory (id.).[35] [36]

33/ The Company utilized the GTF Handbook as a source for standard cost and generation technology assumptions for various supply resources.

34/ This study was previously submitted to the DPU with the Company's conservation pre-approval filing (Exh. HO-S-2A). During the course of the current proceeding, the Siting Council took administrative notice of the Department's decision regarding the Company's conservation pre-approval filing. Investigation by the Department of the Cost Effectiveness and Program Design of Certain Conservation and Load Management Programs of Fitchburg Gas and Electric Company, D.P.U. 89-179 (1991).

35/ Fitchburg is currently not a member of the Collaborative Process. In a previous decision, the Siting Council identified the Collaborative Process as a valuable data resource for development of C&LM resources. 1991 Nantucket Decision, 21 DOMSC at 280.

Accordingly, based on the above, the Siting Council finds that the Company has compiled an adequate set of C&LM resources.

In order to compile resource sets from purchases from New England utilities and purchases from non-utility developers, the Company participated in a RFP process with Unitil.[37] [38] The Company stated that the Unitil RFP process produced 2,642 MW of potential resources from 36 potential suppliers (Exh. HO-RR-16). For a more detailed discussion regarding the Unitil RFP, see Section III.E.2.a.(3), below.

Accordingly, the Siting Council finds that the Company has compiled an adequate set of resources from purchases from New England utilities and purchases from non-utility developers.

(3) Conclusions on Available Resource Options

The Siting Council has found that Fitchburg has identified a reasonable range of resource sets. The Siting Council has also found that Fitchburg has compiled: (1) an adequate set of

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36/ The Siting Council notes that a technical potential study of C&LM resources is required under the IRM regulations. 980 CMR 12.03(9)2; See Final Decision on IRM Rulemaking, 21 DOMSC at 91.

37/ Fitchburg stated that it has a 20 MW contract with Northeast Utilities which expires in 1997 (Tr. 2, p. 91). Fitchburg has an option to renew this contract through 1997 but stated that it was highly unlikely that the Company will pursue the renewal option (id.). Therefore, the Siting council will not analyze the extension of the Northeast Utilities contract in the purchases from New England utilities resource set.

38/ In July, 1990 the Company submitted its Qualifying Facility RFP #2 to the DPU for approval (Exh. HO-S-9). In January, 1991 Fitchburg filed a request with the DPU for suspension of its RFP #2 in order to jointly participate with Unitil in a solicitation from utility and non-utility suppliers. On July 23, 1991 the DPU granted the Company's request (Exh. HO-RR-16).

purchases from a new Company-owned combustion turbine and generic units, (2) an adequate set of C&LM resources, and (3) an adequate set of purchases from New England utilities and non-utility developers.

Accordingly, the Siting Council finds that Fitchburg has demonstrated that it has compiled a comprehensive array of available resource options.

b. Development and Application of Screening Criteria

To determine whether Fitchburg developed and applied appropriate criteria for screening its array of available resource options, the Siting Council reviews the criteria developed and applied to each of Fitchburg's resource sets. The Siting Council has found that Fitchburg compiled an adequate resource set of purchases from a new Company-owned combustion turbine and new generic units, C&LM resources, purchases from New England utilities and purchases from non-utility developers. Therefore, the Siting Council reviews Fitchburg's development and application of screening criteria for each of these sets.

The Company stated that it evaluated candidate resource options from the above resource sets using both cost and non-cost factors (Exh. HO-1B, p. B-18). In regard to supply side resource options, the Company stated that it used the following cost factors in its screening of resource options: heat rate, unit capital cost, operation and maintenance costs, and fuel costs (id.). Upon completion of screening of resource options based on these cost factors, the Company stated that it applied further screening criteria to analyze the costs of each supply source at differing levels of annual operation (id., pp. B-6, B-31).

The Company indicated that cost data from a new Company-owned combustion turbine, generic units and purchases from New England utilities and non-utility developers were analyzed using UPLAN (id.). The UPLAN software allows the Company to perform supply iterations based on cost data assumptions attached to each specific supply source (id.). The overall goal of the UPLAN screening process is to develop a supply plan that minimizes the net present value of production costs over the planning period (id.).

The Company relied on a variety of data sources in order to develop accurate cost estimates for its supply-side resource options. For example, costs for a new Company-owned combustion turbine were specified in a study performed for the Company by Stone and Webster, Inc. (id.). In addition, generic units' costs were determined using the NEPLAN GTF Long Range Planning Book (id.). Finally, costs for purchases from New England utilities and non-utility purchases, were estimated based on specific responses to the Unitil RFP (Exh. HO-1B, p. B-3). For further discussion of the Company's integration of cost into its resource planning process, see Section III.E.2.a, below.

Fitchburg stated that it used non-cost factors to screen its supply-side resource options to ensure that the resources selected as least-cost were in fact the best resources for the Company (Exh. HO-1B, p. B-18). For example, the Company claimed that the UPLAN process may select a resource that does not fit the Company's resource planning guidelines regarding timing, size or type of fuel, but by applying the non-cost factors, the Company ensured that the best system fit was selected (id.). The Company stated that the non-cost factors applied to each resource option were: (1) operating/in service date, (2) length of the contract, (3) status of permits and/or construction progress, and (4) environmental impact (id., p. B-31).

The Company's use of UPLAN to analyze the cost of resource options is an acceptable methodology for considering the cost of options. In addition, the Company also has demonstrated that it has developed and appropriately applied its non-cost criteria to supply-side resource options.

Accordingly, the Siting Council finds that Fitchburg has developed and applied appropriate criteria for screening purchases from a new Company-owned combustion turbine and generic units, purchases from New England utilities, and purchases from non-utility developers.

In regard to C&LM resource options, the Company stated that once a least-cost plan has been established, it judgementally determines which C&LM programs have the greatest likelihood of being implemented (Exh. HO-1B, p. B-32). The Company stated that the candidate programs are then screened at different levels of market penetration (id.). After calculating the avoided marginal costs of supply resources displaced by C&LM resources, the Company stated that plots of cost/benefit ratios versus percent of market penetration were used to determine the programs that have the potential to lower system production costs (Exh. HO-1B, p. 33). The Company stated that the final analysis takes place to determine which programs have a cost/benefit ratio of less than one at reasonable levels of market penetration (Exh. HO-1B, p. B-32).

The Siting Council is concerned that the Company uses its judgment rather than clearly identifiable criteria in determining which C&LM programs have the greatest likelihood of being implemented. As a result, the Siting Council is unable to determine whether Fitchburg's screening criteria were generally well-founded in terms of the Company's ability to assess the attributes of the C&LM options. Such a judgmental determination exposes the Company to the risk of inappropriately eliminating potential least-cost options from further evaluation. Therefore, the Siting Council finds that Fitchburg has failed to develop and apply appropriate criteria for screening its C&LM options.

The Siting Council notes that, with the exception of its criteria for screening C&LM options, Fitchburg has developed criteria in a logical and well-founded manner and appropriately has used cost and non-cost factors in screening its resource options. Such factors allow the Company to compare its resource options using a consistent set of cost and non-cost criteria.

Accordingly, on balance, the Siting Council finds that Fitchburg has developed and applied appropriate criteria for screening its array of available resource options.

c. Conclusions on Identification of Resource Options

The Siting Council has found that Fitchburg has identified a comprehensive array of available resource options. The Siting Council also has found that Fitchburg has demonstrated that it has developed and applied appropriate criteria for screening its array of available resource options.

Accordingly, the Siting Council finds that Fitchburg has established that it has identified a reasonable range of resource options.

2. Evaluation of Resource Options

The Siting Council reviews Fitchburg's resource evaluation process to determine whether Fitchburg: (1) has developed a resource evaluation process which fully evaluates all resource options on an equal footing, and (2) has applied its resource evaluation process to all of the resource options identified in Section III.E.1, above.

In order to make this determination, the Siting Council reviews a company's supply plan to determine whether it reflects an adequate consideration of appropriate cost, diversity, and risk minimization objectives. 1992 Braintree Decision, EFSC 89-32 at 52; 1991 Nantucket Decision, 21 DOMSC at 304; 1990 MMWEC Decision, 20 DOMSC at 83. In addition, the Siting Council also has an obligation to balance economic considerations with environmental impacts in ensuring that the Commonwealth has a necessary supply of energy. G.L. c. 164, sec. 69H. Thus, in this section, the Siting Council analyzes the extent to which Fitchburg incorporates cost, diversity, risk minimization, and environmental impacts in its supply planning process.

a. Cost

Fitchburg's overall supply planning objective is to develop an integrated resource plan that ensures that system requirements are met on a least-cost basis (Exh. HO-1B, p. B-2). Here, the Siting Council reviews Fitchburg's incorporation of its cost objective in its evaluation of resource options.

The Company stated that it developed a cost analysis formula called the "production cost factor" which it used to analyze competing supply plan additions (id.). The production cost factor was defined as the ratio of the net present value of the competing plan's production cost to the base case plan's production cost (Exh. HO-1B, p.B-8). The Company stated that following the evaluation of supply-side resources, the Company then evaluated the costs associated with C&LM resources using an avoided marginal cost analysis (id., p. B-4).

(1) New Company-Owned Combustion Turbine and Generic Units

The Company analyzed several base case supply plans which included a new Company-owned combustion turbine and generic units (Exh. HO-1B, p. B-18). The Company explained that costs associated with a new-Company owned combustion turbine were estimated based on a detailed study prepared for the Company by Stone and Webster, Inc. (id.). The Company explained that such costs were compared with generic units of different fuel types using the GTF Handbook (id.).

The Company analyzed costs and carrying charges over a 25-year period for a new Company-owned combustion turbine, a 35-year period for a gas-fired combined cycle unit, a 35-year period for a coal gasification unit, and a 35-year period for a coal steam unit (Exh. HO-1B, pp. B-21-30).

Based on the above, the Siting Council finds that Fitchburg's evaluation of its resource sets from the purchases of a new Company-owned combustion turbine and generic units adequately considered Fitchburg's least-cost planning objective.

(2) C&LM Resources

The Company stated that C&LM resources were committed to the supply plan based on an explicit evaluation of cost criteria (Exh. HO-1B, p. B-4). The Company stated that it evaluates and implements C&LM programs if the system production costs are lowered by the integration of specific C&LM programs (id.).[39] The Company stated that it evaluates C&LM after the evaluation of supply options (Exh. HO-1B, p. 32).

39/ The Company stated that it was currently implementing three conservation programs: (1) a commercial lighting incentive program; (2) a residential water heater wrap program; and (3) a small commercial lighting program (Exh. HO-S-2). The Company stated that two additional conservation programs, an industrial lighting program and a comprehensive efficiency program, have been approved for cost recovery with the DPU but have not yet been implemented (Exh. HO-1B, App. B-2). Fitchburg stated that it has not implemented any load management programs to date and had not planned for any for the future (Tr. 2, p.77; Exh. HO-S-2A, p. 44). Pursuant to G.L. c. 164 sec. 69J, electric utilities are directed to provide an adequate consideration of load management in their supply plans.

The analysis presented by the Company provides an adequate foundation for developing a methodology for evaluating the cost of C&LM resources. In particular, the development of an avoided marginal cost analysis should allow the Company to effectively evaluate the cost of C&LM resources. However, the analysis of C&LM after the evaluation of supply additions may place C&LM at a disadvantage as it prevents a direct comparison of C&LM and supply options. Supply-side and demand-side resource options should be evaluated coincidentally in order to ensure that the least-cost mix of resources is obtained. Failure to examine supply-side and demand-side resources at the same time could lead to the elimination of least-cost C&LM options in favor of supply options. Accordingly, the Siting Council finds that Fitchburg's evaluation of C&LM did not adequately consider Fitchburg's least-cost planning objective. The Siting Council also finds that the Company has not satisfied the fourth guideline.

(3) Purchases From New England Utilities and Non-Utility Generators

The Company stated that it utilized a market-based RFP process, in cooperation with Unitil, to evaluate purchases from New England utilities and non-utility developers (Exh. HO-1B, p. B-31). Since Unitil is a New Hampshire utility, the Unitil RFP being utilized by Fitchburg was not approved by the DPU. Therefore, the Unitil RFP process will be reviewed herein to ensure that its use in the evaluation of least-cost resource options is consistent with the policies of the Commonwealth.

The Company stated that Unitil's RFP is an appropriate substitute for Fitchburg's own RFP for the following reasons: (1) the Unitil RFP process would take less time than a separate Fitchburg RFP because it is already underway and would offer more timely responses (Exh. HO-S-26), (2) the power increments sought by the Unitil RFP are similar in size to those sought by Fitchburg (Exh. HO-1B, p. B-17), and (3) most proposals identified within the RFP would be made available to Fitchburg (Exh. HO-RR-16).[40]

With respect to the first point, the Company asserted that it could lose opportunities for beneficial purchases in the period necessary to develop and seek approval of its own RFP (id., p. 2). With respect to the second point the Company stated that it is seeking 15 MW in 1996 primarily as a replacement for its 20 MW NU contract (Exhs. HO-RR-16-1, HO-S-33). The Company stated that Unitil is seeking 20 MW in 1993, an additional 10 MW in 1994, an additional 15 MW in 1995 and an additional 30 MW in 1996 (Exh. HO-1B, p. B-17). In addition, with respect to the third point, the Company stated that of the 80 proposals received by Unitil in its RFP, 62 proposals for a total of 2,642 MW, have been made available to Fitchburg (Exh. HO-RR-16).[41]

In order for the Unitil RFP process to sufficiently serve Fitchburg's needs, the power increments sought by both companies must be similar in timing and size in order to attract bids useful for Fitchburg. In addition, the results of Unitil's RFP responses must be available to Fitchburg. Based on the record, the power increments sought by Fitchburg and Unitil are similar in timing and size, and Unitil's RFP will likely attract proposals and bids that will be available and appropriate for Fitchburg's use. Accordingly, the Siting Council finds that the

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40/ The Company stated that it plans to request adjustments in RFP responses to reflect the different geographic delivery points for Fitchburg and Unitil (Exh. HO-S-25). The Company also stated that they expect the adjustments to be insignificant (Exh. HO-S-26).

41/ The Company stated that Unitil will review the responses to the RFP both for its own use and for use by Fitchburg (Exh. HO-3, p. 7).

Unitil RFP is an appropriate mechanism for Fitchburg to use to pursue purchases from New England utilities and non-utility developers.

The Company indicated that the costs of the RFP proposals from New England utilities and non-utility developers were evaluated using UPLAN (Exh. HO-1B, p. B-18). The model evaluates numerous cost aspects including capacity, capacity rate, variable rate, energy rate, and fuel forecast (id., Section 5, p. 7).[42]

Accordingly, based on the above, the Siting Council finds that Fitchburg's evaluation of purchases from New England utilities and non-utility developers adequately considers Fitchburg's least-cost planning objective.

(4) Conclusions on Cost

The Siting Council has found that Fitchburg's evaluation of its resource sets (1) from the purchases of a new Company-owned combustion turbine and generic units adequately considered Fitchburg's least-cost planning objective, (2) of C&LM did not adequately consider Fitchburg's least-cost planning objective, and (3) of purchases from New England utilities and non-utility developers adequately considers Fitchburg's least-cost planning objective.

Accordingly, the Siting Council finds that, on balance, Fitchburg has established that its supply planning process adequately considers Fitchburg's least-cost planning objectives.

b. Diversity

The Company indicated that its diversity objectives were to: (1) maintain a balanced fuel diversity and limit reliance on a single fuel type to 50 percent of its energy requirements

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42/ These data were compiled by all respondents to the Unitil RFP and are different components of cost submitted by each of the respondents to Unitil's RFP.

("energy diversity objective"), (2) limit dependance on any single unit to roughly 15 percent of its load ("single unit objective"), (3) limit dependance on Canadian resources to approximately 15 percent of long-term and 25 percent of short-term (2-3 years) capability responsibility ("Canadian resource objective"), (4) limit reliance on any single power supply vendor to approximately 25 percent of capability responsibility ("single vendor objective"), and (5) balance demand-side and supply-side resource acquisitions ("demand and supply objective") (Exh. HO-1B, p. B-12).

The Company indicated that it relied on oil for between 23 percent and 60 percent of total monthly energy from January 1990 through August 1991 (Exh. HO-RR-22, p. 1). The Company also indicated that it relied on nuclear energy for between 28 percent and 68 percent of total energy from January 1990 through August 1991 (id.). As a result, during various times between January 1990 and August 1991, the Company relied on both oil and nuclear energy in excess of 50 percent. Therefore, the Company has not consistently achieved its stated energy diversity objective.

Fitchburg indicated that the Company does not depend on any single unit for roughly more than 15 percent of load except for the #7 generator and the Company's entitlements in New Haven Harbor (Exh. HO-1B, p. B-32). Fitchburg indicated that the Company plans to rely on energy from New Haven Harbor for approximately 25.7 percent of its 1992 summer capability responsibility and plans to rely on the #7 generator for approximately 34 percent of 1992 summer capability responsibility (id.).

The Siting Council notes that the single unit objective was developed after the contracts for supply from New Haven Harbor and the #7 generator were made. Since the diversity objectives post-date the New Haven Harbor and the #7 generator purchases, the Siting Council focuses on future supply plans to determine compliance with the Company's stated objectives. The Company indicated that it has no plans to rely on any other unit for more that 15 percent of load. Therefore, the Company has achieved its stated single unit objective.

With respect to the Canadian resource objective, the Company indicated that it relied on Canadian resources for approximately 7.7 MW (Exh. HO-1B, p. B-12). Therefore, the Company has achieved its stated Canadian resource objective.

With respect to the single vendor objective, the Company indicated that its upcoming single vendor power contract with Kenetech for 13.5 MW meets the Company's single power vendor objective. Therefore, the Company has achieved its stated single vendor objective.

Finally, the Company provided no information on how it addressed its demand and supply objective. Therefore, the Siting Council makes no finding regarding whether the Company has achieved its stated demand and supply objective.

Accordingly, on balance, the Siting Council finds that Fitchburg has established that its supply planning process adequately considers Fitchburg's diversity objectives. However, the Siting Council is concerned that there is no indication that the Company implemented its stated demand and supply objective. The Siting Council notes that in its IRM filing, the Company will be required to include in its resource inventory, a summary of capacity and energy resources relative to demand-side resources. 1990 Final IRM Decision, 21 DOMSC at 141; 980 CMR 12.07. The Siting Council also notes that the IRM regulations will require the Company to include diversity objectives relative to both supply-side and demand-side resources. 980 CMR 12.03(8).

c. Risk Minimization

The Company stated that it seeks to minimize the impacts of potential risks to its supply plans by (1) incorporating multiple demand scenarios in its demand forecast (Exh. HO-1A, p. A-20), and (2) formulating action plans to address supply contingencies. As described in Section III.C, above, Fitchburg developed a total of three demand forecast scenarios of high, base and low growth. The Siting Council notes that for a company of the size of Fitchburg, the use of scenarios is commendable. Further, as a means of minimizing risk in its supply plan, the record in this proceeding shows that Fitchburg has developed action plans to address supply contingencies and seeks to purchase power from third parties.

In previous cases, electric companies have addressed risk minimization by means of: (1) incorporating multiple scenarios into the demand forecasts to address uncertainty in the need for new supplies; (2) formulating action plans to address supply contingencies; or (3) minimizing financial risk through purchases from third parties. 1991 Nantucket Decision, 21 DOMSC at 306; 1990 MMWEC Decision, 20 DOMSC at 88-91; 1989 MECo Decision, 18 DOMSC at 366-368; 1989 BECo Decision, 18 DOMSC at 238-239, 271-272.

Accordingly, the Siting Council finds that Fitchburg has established that its supply planning process adequately considers the Company's risk minimization objective.

d. Environmental Impacts

In previous decisions, the Siting Council has considered whether an electric company has attributed environmental impacts or benefits to different resource options.
1992 Braintree Decision, EFSC 89-32 at 62;
1991 Nantucket Decision, 21 DOMSC at 307-308;

1990 MMWEC Decision, 20 DOMSC at 93-95; 1989 MECo Decision, 18 DOMSC at 368-369; 1989 BECo Decision, 18 DOMSC at 270. The Siting Council's standard of review for supply plans explicitly requires utilities to evaluate new supply options in a manner that ensures an adequate supply of least-cost, least-environmental impact energy, see Section III.A, above.

In the present proceeding, Fitchburg asserted that although environmental impacts of supply plans are "incorporated," the Company did not possess a specific methodology for determining the environmental impacts of its resource options (Tr. 2, p. 97, Tr. 4, p. 12-13). The Company's witness, Mr. Weiss, stated that the Company currently is developing that specific methodology (Tr. 2, p. 96).

The Siting Council notes that the Unitil RFP solicitation process is ideally suited for evaluating the environmental attributes of supply options. However, the Company has failed to present a specific methodology for determining the environmental impacts of the RFP resources or any other resource options.

Accordingly, the Siting Council finds that Fitchburg has failed to establish that its supply planning process adequately considers environmental impacts.

e. Conclusions on the Resource Evaluation Process

The Siting Council has found that Fitchburg has established that: (1) on balance, its supply planning process adequately considers Fitchburg's least-cost planning objectives, (2) its supply planning process adequately considers the Company's diversity objectives, and (3) its supply planning process adequately considers the Company's risk minimization objective. The Siting Council also has found that Fitchburg has failed to establish that its supply planning process adequately considers environmental impacts.

While the Siting Council has found that the Company has adequately considered cost, diversity and risk minimization in its evaluation of resource options, the Siting Council notes that the Company evaluates C&LM programs following the selection of supply-side options. By using this approach, the Company effectively eliminates the possibility of pursuing least-cost C&LM options instead of potentially higher cost supply options. Further, the Company's process prevents the Company and the Siting Council from determining if in fact this has occurred.

Based on the foregoing, the Siting Council makes no finding on whether Fitchburg developed a resource evaluation process which fully evaluates all resource options on an equal footing.

Nevertheless, the Siting Council notes that the Company's process was applied to all resources considered by the Company. Further, the use of UPLAN allows the Company to evaluate consistent criteria for all supply-side options. Accordingly, the Siting Council finds that Fitchburg applied its resource evaluation process to all resource options.

The Siting Council notes that the RFP process undertaken by the Company permitted Fitchburg to evaluate a wide variety of resource options. In addition, the Siting Council notes that the Company has also developed an appropriate resource evaluation process with respect to risk minimization through the use of demand forecast scenarios, action plans to address supply contingencies and power purchases from third parties. However, the same thorough process that the Company used in for these supply-side resources should have been conducted with respect to demand-side resources. While the Siting Council finds that the Company applied its resource evaluation process to all resources considered by the Company, the fact remains that its evaluation process inherently fails to analyze demand-side resources with supply-side resources. Accordingly, the Siting Council makes no finding on whether Fitchburg evaluated a reasonable range of resource options.

3. Conclusions on Least-Cost Supply

The Siting Council has found that Fitchburg has identified a reasonable range of resource options. The Siting Council has made no finding on whether Fitchburg has evaluated a reasonable range of resource options.

Accordingly, the Siting Council makes no finding on whether Fitchburg has established that its supply plan ensures a least-cost energy supply.

In making no finding on least-cost, the Siting Council recognizes that the Company exhibited significant strengths in its resource evaluation process. The strengths include the Company's evaluation of supply-side options, particularly its use of detailed studies to evaluate its set of new-Company owned generation and generic units, in addition to the Company's participation in Unitil's RFP. These strengths, however, relate to the evaluation of supply-side options only. In regard to demand-side resources, the Company simply failed to appropriately screen and evaluate a wide-range of C&LM options. As previously stated, the Company has developed and implemented only three conservation programs and no load management programs.

The limited number of programs developed and implemented by the Company is a clear indication that the Company has not evaluated a sufficient number of comprehensive C&LM programs. In the 1991 Nantucket Decision, that Company evaluated 14 separate technologies for C&LM with detailed analyses of administrative costs, market penetrations, program customer goals, overall budgets, incentive rebate levels and program duration (21 DOMSC at 301). Also, in the 1991 MMWEC Decision, that Company applied a rigorous screening methodology to 57 separate C&LM measures (20 DOMSC at 64). By contrast, in the present case, the conservation programs underway are targeted at only two electrical end uses: commercial lighting and residential hot water.[43]

The Siting Council recognizes that the Company's next filing is its IRM filing scheduled to be submitted on August 1, 1992. Under the IRM regulations, the Company must explicitly incorporate conservation and load management programs. Indeed, the IRM regulations mandate that supply and demand-side resources be evaluated on an equal footing. The Siting Council expects to see a much more aggressive approach toward C&LM reflected in Fitchburg's IRM filing.

F. Adequacy of the Company's System Planning

During the proceeding, the Siting Council reviewed the adequacy of the Company's system planning. This review was necessary as a result of a series of system outage events in the Fitchburg service territory during the summer of 1991. The Company stated that its primary source of bulk power comes from the Company's only link with the NEPOOL system at the Flagg Pond Substation ("Flagg Pond"). On June 29, 1991, the Company experienced a system outage following the failure of both transformers at Flagg Pond. In the following sections the Siting Council reviews the Company's existing system and contingency planning, and the Company's response to the system outage in order to determine whether the Company's system planning is

43/ In DPU 89-179, the Department stated that "Fitchburg programs do not provide C&LM services to a comprehensive range of customer sectors and sub-sectors and do not target a comprehensive range of end uses" (p. 7). Further, the Siting Council notes that the fourth guideline from the 1985 Fitchburg Decision specifically required the Company to integrate load management programs into the Company's supply plan.

adequate to ensure a reliable supply of electricity to its customers.[44]

1. Description of Existing System

The Company stated that its primary source of bulk power comes from its interconnection with NEPOOL at Flagg Pond (Exh. HO-1B, Figure 3-5, App. B-3, Schedule 7). The Company stated that Flagg Pond, which is located in Fitchburg's service territory, is the Company's only tie-in with the NEPOOL grid (Exh. HO-SO-1). Flagg Pond is served by two transformers (hereinafter referred to as transformer #1 and transformer #2), which reduce voltage from 115 kilovolts ("kV") to 69 kV (id.). Two 69 kV transmission lines leave the substation and provide service to most of Fitchburg's loads (Exh. HO-SO-1, p. 8). The Company further stated that both transformers #1 and #2 were installed in 1978 and have a maximum rating of 56 Megavolt Amperes (MVA) each (Exh. SO-11; Tr. 3, p. 44). The Company

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44/ In considering system planning issues in the current review of the Company's long-range supply plan, the Siting Council is clearly fulfilling its statutory mandate of ensuring a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. G.L. c. 164, sec. 69H. The Siting Council's broad statutory mandate clearly requires the Siting Council to review a company's ability to meet peak day as well as annual electricity requirements. Without an adequate generation, transmission and distribution system, a company can not provide reliable and uninterrupted service to its customers. The Siting Council notes that for other electric companies, the Siting Council has addressed the issue of the adequacy of the transmission system in a proceeding where the company had proposed no jurisdictional facilities, Massachusetts Electric Company/New England Power Company, 15 DOMSC at 241 (1986), as well as a case where a facility proposal had been severed from the complete filing in order to expedite a review 1987 BECo Decision, 15 DOMSC at 287 (1987). Additionally, the Siting Council has addressed the adequacy of the distribution system of a gas company. Boston Gas Company, 19 DOMSC 332 at 429 (1990).

stated that its peak demand reached 79.4 MW in 1988, thereby exceeding the individual rating of both transformer #1 and transformer #2 (Exh. HO-SO-11).

Fitchburg stated that the only source of generation located within the Company's service territory is the #7 generator which the Company leases from Industrial Leasing Corp. (Exh. HO-1B, App. B-3, Schedule 7). The Company further stated that the winter capacity rating of the #7 generator is 26.8 MW while the summer rating is 18.9 MW (id., Figure 3-5). The Company indicated that the #7 generator has the capacity to supply approximately 26 percent of the Company's summer peak load (id.).[45]

The Company stated that its Flagg Pond interconnection was designed to withstand three separate types of single contingencies: (1) the loss of one transformer, (2) the loss of one transmission tower containing two incoming 115 kV lines, or (3) the loss of one of its two outgoing 69 kV lines (Exh. HO-SO-1, p. 8).

In the event of a loss of a single transformer at Flagg Pond, the Company stated that it would rely on the #7 generator to make up the difference between the capability of the

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45/ The Company provided information indicating that the #7 generator has a history of forced outages due to various mechanical and operational problems including: a lubricating oil leak in 1987; diesel engine starting clutch failure, station service breaker trip, starting diesel problems and diesel fuel problems in 1988; combustion gas leaks, speedtronic control system circuit board failure, stuck servo valve, electric fault and a manhole fire in 1989; electric fault and manhole fire, faulty purge air check valve and diesel starting problems in 1990; and bearing failure on the gas cooling fan and exhaust thermocouple problems in 1991 (Exhs. HO-1B, App. B-1, Schedule 9, HO-S-16, HO-S-19, HO-S-20, HO-SO-24, HO-SO-25). Further, the Company stated that the historic forced outage rate of the #7 generator was 72.4 percent in 1987, 70.5 percent in 1988, 57.9 percent in 1989 and 57 percent in 1990 (Exh. HO-S-20).

inoperable transformer and the system load (Tr. 3, p. 21). In addition to relying on the #7 generator, the Company stated that it would also obtain a mobile transformer from the New England Electric System ("NEES") (id.). Further, the Company indicated that it had knowledge of two NEES spare transformers almost "identical" to those at Flagg Pond which could be used in the event of the loss of one transformer at Flagg Pond (id.).

2. System Outage Resulting From Transformer Failure at Flagg Pond

Fitchburg stated that on June 29, 1991, at approximately 7:01 p.m., transformer #1 at Flagg Pond failed due to an internal winding fault (Exh. HO-SO-1, p. 1). The Company stated that this caused transformer #1 to trip off-line, separating it from the electrical grid and instantly transporting the electrical load from the failed transformer to transformer #2 (Exh. HO-SO-1, p. 2). Fitchburg stated that, immediately following the loading of transformer #2, a lightning arrestor on transformer #2 failed, causing this transformer to de-energize and be separated from the electrical grid (id., p. 5). The Company stated that with both transformers tripped off-line, no power could be imported from outside the Fitchburg territory, resulting in a complete loss of service to the entire Fitchburg service area which lasted approximately five hours (Exh. HO-4, p. 4).

The Company stated that its senior electrical engineer immediately contacted the NEPOOL dispatcher in order to determine the appropriate course of action (id., p. 3). Fitchburg stated that pursuant to that consultation, it was decided that transformer #2 should be re-energized (Exh. HO-SO-1, p. 3). The Company stated that upon re-energizing, "sparks and smoke were observed emanating from the phase C 69 kV lightning arrestor" mounted on transformer #2 (Exh. HO-SO-4, p. 3). As a result, the

Company decided to physically disconnect the failed lightning arrestor and try again to energize transformer #2 (id., Exh. HO-4, p. 4). The Company stated that transformer #2 then energized successfully resulting in the restoration of the Company's 69 kV transmission system at 10:45 p.m. (Exhs. HO-S-1, p. 3, HO-4, p. 4). The Company stated that it achieved complete restoration of service just before midnight (id.).

With only transformer #2 functioning, the Company stated that it immediately began to search for a replacement for the failed transformer #1 (Tr. 3, p. 22). Fitchburg stated that on July 1, 1991 it notified NEPOOL regarding the Company's need for a transformer and, as a result, NEPOOL solicited industry contacts in the United States and Canada for suitable transformer replacements (id., p. 23). Also on July 1, 1991, the Company contacted NEES in order to acquire its mobile transformer (id.).[46] However, the Company stated that it was initially unable to "contact the higher echelon" at NEES and was ultimately unable to make that acquisition (id., p. 23).[47] The Company stated that had the NEES mobile transformer been available, it could have been installed at Flagg Pond in approximately three days (id., p. 24). However, since the mobile transformer was unavailable, the Company stated that it reached an agreement with NEES to use its "spare" transformer located in Westborough (id., p. 25).

46/ The mobile transformer differs from the spare transformers in that the mobile transformer (1) is rated with a lower capability, and (2) is able to be moved quickly between sites since it is mounted on a tractor trailer unit (Tr. 3, p. 23).

47/ The Company stated that although the use of the NEES mobile transformer was built into the Company's contingency planning process, the Company had no formal agreement with NEES to that effect (Tr. 3, p. 21).

The Company stated that due to the time involved in removing the oil from the spare transformer, obtaining the requisite permits, and drafting the necessary legal documents, the NEES spare transformer was not energized at Flagg Pond until July 26, 1991 (id., pp. 25-26). Fitchburg stated that the NEES spare transformer, while still on site at Flagg Pond, is a "loan" and subject to immediate recall by NEES (Exh. HO-1, p. 7; Tr. 3, p. 20).

From June 29 through July 26, 1991, the Company relied solely on its transformer #2 and the #7 generator to meet its load requirements (Tr. 3, p. 21).[48] The Company stated that during that time period, there were two incidents related to the #7 generator that resulted in the loss of service to customers (Exh. HO-SO-15). The first incident occurred on July 20, 1991 when the #7 generator tripped off-line due to a high temperature alarm (id.). Fitchburg stated that during the three and one half hours the #7 generator was off-line, the Company was required to shed load through rolling blackouts (id.). The second event occurred on July 22, 1991 when the #7 generator tripped off-line for approximately 25 minutes, again due to a high temperature alarm (id.). The Company stated that during the time that the #7 generator was restarting, Fitchburg again shed load to protect transformer #2 (id.).

Fitchburg explained that despite the use of rolling blackouts, the Company was forced to operate transformer #2 above its nameplate rating when the #7 generator was off-line

48/ It was necessary for the Company to bring the #7 generator on line because the system load exceeded the maximum rating (56 MVA) of transformer #2.

(Exh. HO-SO-13).[49] Fitchburg stated that, while it is not uncommon for some electric companies to routinely operate transformers in excess of their nameplate ratings, operating a transformer above the nameplate rating can diminish its useful life (id., pp. 17, 19). The Company stated that to avoid damage during the time transformer #2 was operated in excess of its maximum rating, the transformer was continuously monitored to avoid excess heat buildup (id., p. 18).

The Company stated that in the event of a catastrophic loss of transformer #2 during the June 29 through July 26, 1991 time period, the Company would have been able to provide power only to approximately 25 percent of its customers who are served by the #7 generator, (id., p. 16; Exh. HO-1B, Figure 3-5).

3. Company's Response to System Outage

The Company explained that the June 29, 1991, system outage occurred because of the near-simultaneous losses of transformer #1 and transformer #2 at Flagg Pond (Exh. HO-SO-1). The Company suspects that the failure of transformer #2's phase C 69 kV lightning arrestor, which subsequently led to the trip of transformer #2, was caused by electrical over-stressing of the arrestor (id.). The Company explained that this over-stressing of the arrestor was most likely the result of electrical surges associated with the winding failure on transformer #1 (Exhs. HO-4, p. 4, HO-SO-1, pp. 5-6; Tr. 3, pp. 11-14). The Company further stated that prior to the system outage, the failed lighting arrestor had problems with moisture, which may have weakened the arrestor, causing it to be more susceptible to failure (Tr. 3, pp. 13-14). Fitchburg stated that tests will be

49/ On July 22, the Company stated that it operated transformer #2 at 57.9 MVA, and on July 26, the Company operated transformer #2 at 59.6 MVA (Tr. 3, p. 21).

conducted on the failed lightning arrestor, following completion of an ongoing overhaul of the #7 generator (Exh. HO-SO-20).[50] The Company further stated that the failed transformer #1 has been inspected by Eastern Electric Apparatus Repair Company and will be repaired and returned to Flagg Pond by mid-March 1992 (Exh. HO-SO-20).

In order to compensate for the possible future loss of a transformer at Flagg Pond, Fitchburg stated that it had leased a back-up transformer with a maximum rating of 37 MVA from Magnetek Transformer Company ("Magnetek") (Exh. HO-SO-1, p. 7; Tr. 3, p. 28). The Company stated that the Magnetek transformer is not a direct replacement for transformer #1 because it cannot operate in parallel with transformer #2 (Exh. HO-SO-1, p. 7). Nevertheless, the Company indicated that the Magnetek transformer could be used to replace a portion of the load of either transformer #1 or #2 in the event that one of these transformers is removed from service (Exh. HO-SO-23).[51]

The Company asserted that the June 29, 1991 system outage was the result of a double contingency loss and that the Flagg Pond interconnection was designed to withstand only a single contingency loss (Exh. HO-SO-1, p. 8). The Company stated that Flagg Pond is capable of serving the Company's entire base load

50/ The Company indicated that the #7 generator recently underwent major repairs during a three month period in the fall of 1991 (Exh. HO-SO-24).

51/ Fitchburg stated that it had the Magnetek transformer tested by an independent company prior to committing to delivery (HO-SO-18). Since no significant defects were found, Fitchburg stated that it notified Magnetek of the Company's interest in purchasing the transformer (Exh. HO-SO-20). The Company indicated that, while the Company has made an oral commitment to purchase the unit and the necessary papers have been received to complete the sales agreement, no written commitment has yet been made by Fitchburg (Exh. HO-SO-22).

under a single contingency loss (id.). The Company also stated that single contingencies should be of short duration due to the availability of a mobile transformer and two other spare transformers located at NEES (Tr. 3, p. 21). Fitchburg contended that simultaneous faults in two transformer substations cannot be anticipated and that: "for the system as a whole, it is generally recognized and accepted that continuous service cannot be assured under double contingencies at a reasonable or acceptable cost" (Exh. HO-SO-1, pp. 8-9). The Company stated that both transformer #1 and #2 were periodically tested and that the results did not indicate that any failures were forthcoming (id., pp. 6-7).

Finally, the Company stated that it has initiated steps to improve overall system reliability by budgeting for a system-wide distribution study (Exhs. id., p. 7, SO-19; Tr. 3, p. 33). The Company stated that the study will be used to plan for future system expansion including the possible addition of tie-ins with the NEPOOL system (id.). The Company also indicated that system reliability will be enhanced following the construction of the Kenetech facility, which will be located within the Fitchburg service territory (Tr. 3, pp. 54-55).[52] Fitchburg also stated that transformer #1 will be upgraded before it is put back into use (Tr. 3, pp. 51-52). Fitchburg contended that this will result in additional system reliability benefits since the upgrade will increase the present maximum rating of transformer #1 from 56 MVA to 70 MVA (id.).

52/ The Company stated that output from the Kenetech facility will not pass through Flagg Pond and therefore will eliminate some of the stress currently at this substation (Tr. 3, pp. 54-55).

4. Analysis of the System Outage

The Siting Council notes several areas of concern with the Company's system planning practices which likely contributed to the system related failures of the summer of 1991. First, the Siting Council is concerned that the Company's contingency plan relied on the use of the #7 generator as a vital component, despite the knowledge of repeated maintenance problems and a high forced outage rate. This clear pattern of unreliability should have indicated to the Company that the #7 generator may not provide a reliable back-up in the event of a loss of one of the two transformers at Flagg Pond. In fact, the unreliability of the #7 generator was evident during the system outage when the generator dropped off-line on two separate occasions. On such occasions, the Company was forced to run its transformer #2 in excess of its nameplate rating -- a practice which the Company admitted can shorten the useful life of the transformer.

Second, despite the Company's assertion that it could obtain the NEES mobile transformer, the Siting Council notes that the Company was, in fact, unsuccessful in its attempt to acquire it, and that it took 27 days for the Company to obtain and put in place the NEES spare transformer. During that time period, the Fitchburg system was at risk, since failure of transformer #2 would have resulted in loss of service for approximately 75 percent of the Company's customers. The Company's need to "contact the higher echelon" to obtain the mobile transformer confirms that the Company had not established an agreement with NEES which would ensure the use of its mobile transformer. The Company's assumptions that the NEES transformer would be available without a agreement exposed the Company to an unnecessary level of risk.

Despite our concerns with Fitchburg's previous practices, the Siting Council notes that the Company has taken significant measures to improve the reliability of its transmission and generation system. Specifically, future single contingency transformer losses will be adequately backed up by the Magnetek transformer currently on-site at Flagg Pond. Additionally, the Company plans to upgrade transformer #1 and implement a system-wide transmission study.

Accordingly, based on the system improvements undertaken by the Company, the Siting Council finds that the Company now operates with a sufficient contingency plan for the loss of a single transformer at Flagg Pond.[53] Further, the Siting Council finds that Fitchburg has adequately rectified the deficiencies formerly present in its contingency planning and that the current plan ensures a reliable power supply for its customers.

However, despite these improvements, the Siting Council notes that the adequacy of the Company's transmission and generation system remains in question because: (1) tests on the lighting arrestors of transformer #2 to determine the cause of the failure are not yet complete, and (2) the #7 generator, a component of the Company's contingency plan, was recently out of service from September 11, 1991 through December 9, 1991 while it underwent unplanned major repairs.

Therefore in order for the Siting Council to approve the adequacy of the Company's system planning in its next filing, the Company must: (1) present the results of the transmission study, scheduled to have been performed by Unitil in 1991, and present plans for any equipment upgrades based on the report, (2) develop detailed single-contingency loss plans including testing and maintenance schedules for back up equipment, (3) provide test

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53/ This finding is based on the Company's assertion that the Magentek transformer is on-site at Flagg Pond Substation and that the Company has orally committed and will finalize the agreement, to purchase the Magnetek transformer.

results from the lightning arresters for transformer #2, and (4) provide a maintenance report that details the work performed on the #7 generator from 1985 to present. The maintenance report should include (a) costs, (b) nature of the repairs and length of time necessary to implement the repairs, and (c) Company plans for future investments of any kind in the unit.

G. Conclusions on the Supply Plan

The Siting Council has found that, on balance, the Company has adequate resources to meet projected requirements throughout the forecast period. The Siting Council has made no finding on whether the Company's supply planning process ensures a least-cost energy supply. The Siting Council also has found that Fitchburg has adequately rectified the deficiencies formerly present in its contingency planning and that the current plan ensures a reliable supply for its customers. In reaching these findings, the Siting Council has noted significant concerns related to the Company's treatment of C&LM resources. Nevertheless, the strengths of the supply plan exhibited by the Company outweigh the deficiencies with respect to C&LM.

Accordingly, the Siting Council hereby APPROVES Fitchburg's 1991 supply plan.

IV. DECISION

The Siting Council hereby APPROVES the 1991 demand forecast and supply plan of Fitchburg Gas and Electric Light Company.

In so deciding, the Siting Council has detailed specific information that Fitchburg must provide in its next filing in order for the Siting Council to approve Fitchburg's next demand forecast and supply plan. This specific information is necessary for the Siting Council to fulfill its statutory mandate including its need to determine whether: (1) all information relating to current activities, environmental impact, facilities agreements and energy policies as adopted by the Commonwealth is substantially accurate and complete, (2) the 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 and include an adequate consideration of conservation and load management and (3) the long-range forecasts are consistent with the policy of providing a necessary, least-cost, minimum environmental impact power supply for the Commonwealth.

Therefore, in order for the Siting Council to approve Fitchburg's next filing, Fitchburg must:

(1) either provide specific estimates of price increases for the time period extending beyond the capital budget period or utilize a methodology which is applied consistently throughout the entire forecast period;

(2) explicitly incorporate the impacts of government-mandated appliance efficiency standards;

(3) develop a new industrial methodology that provides non-subjective estimates of future electricity use based on accurate data and projections gathered from reliable sources. In the event that Fitchburg cannot implement new industrial methodology and a survey is used in the Company's IRM filing, Fitchburg must: (1) develop a new survey methodology that reflects a larger number of industrial customers, (2) ensure that the survey is prepared by the person(s) within the customer's company with the appropriate expertise, (3) ensure that the survey results are integrated with WEFA data using a clearly defined methodology, and (4) provide additional justification of the use of WEFA data as a proxy for future sales growth.

(4) (1) present the results of the transmission study, scheduled to have been performed by Unitil in 1991, and present plans for any equipment upgrades based on the report, (2) develop detailed single-contingency loss plans including testing and maintenance schedules for back up equipment, (3) provide test results from the lightning arresters for transformer #2, and (4) provide a maintenance report that details the work performed on the #7 generator from 1985 to present. The maintenance report should include (a) costs, (b) nature of the repairs and the length of time necessary to implement the repairs, and (c) Company plans for future investments of any kind in the unit.

The Siting Council notes that the Company's next demand forecast and supply plan will be its first IRM filing which is scheduled to be submitted on August 1, 1992.

Jolette A. Westbrook
Hearing Officer

Dated this 15th day of May, 1992

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of May 15, 1992 by the members and designees present and voting. Voting for approval of the Tentative Decision as amended: Gloria Larson, Secretary of Consumer Affairs and Business Regulation; Chris Donodeo-Cashman (for Stephen Remen, Commissioner of Energy Resources); Andrew Greene (for Susan Tierney, Secretary of Environmental Affairs); Joseph Faherty (Public Labor Member); and Michael Ruane (Public Electricity Member).

Gloria C. Larson

Gloria C. Larson
Chairperson

Dated this 15th day of May, 1992

TABLE 1

FITCHBURG GAS AND ELECTRIC LIGHT COMPANY

Year	Total Energy Requirements* (MWH)
1991	412,258
1992	414,674
1993	416,608
1994	419,861
1995	424,683
1996	429,217
1997	433,863
1998	439,031
1999	444,034
2000	448,855
2001	453,830

Source: Exh. HO-1A, Table 8.

*adjusted for C&LM

TABLE 2

FITCHBURG GAS AND ELECTRIC COMPANY

Peak Load*

Year	Summer Peak (MW)	Winter Peak (MW)
1991	70.7	66.5
1992	71.0	66.6
1993	71.4	66.9
1994	72.0	67.4
1995	72.8	68.2
1996	73.6	69.0
1997	74.4	69.8
1998	75.3	70.6
1999	76.1	71.5
2000	77.0	72.3

Source: Exh. HO-1A, Table 9.
*adjusted for C&LM

TABLE 3

FITCHBURG GAS AND ELECTRIC COMPANY

Base Case Supply Plan*

Year	Capability Responsibility (MW)	Total Capacity (MW)	Surplus Capacity (%)
Winter 1991-2	74.63	88.90	19.0%
Summer 1992	78.05	83.00	6.3%
Winter 1992-3	74.70	102.40	37.1%
Summer 1993	76.42	96.00	25.6%
Winter 1993-4	74.54	102.40	37.4%
Summer 1994	75.82	96.00	26.6%
Winter 1994-5	80.47	102.10	26.9%
Summer 1995	83.00	102.10	23.0%

Source: Exh. HO-1B, section 3, Figure 3-5.
*adjusted for C&LM

TABLE 4

FITCHBURG GAS AND ELECTRIC COMPANY

Short-Run Contingency Analysis*

High Load Growth Contingency

Year	Summer Peak (MW)	Total Capacity (MW)	Contingency Surp/(Def) (%)	Contingency Surp/(Def) (MW)
1992	71.7	83.0	15.8	11.3
1993	72.8	96.0	31.7	23.1
1994	74.0	96.0	29.7	22.0
1995	75.9	102.1	34.5	26.2

Cancellation or Non-Performance of the Kenetech Facility

Year	Summer Peak (MW)	Total Capacity (MW)	Contingency Surp/(Def) (%)	Contingency Surp/(Def) (MW)
1992	71.3	83.0	16.4	11.7
1993	72.0	83.0	15.2	11.0
1994	72.7	83.0	14.1	10.3
1995	73.4	89.1	21.3	15.7

Double Contingency Scenario

Year	Summer Peak (MW)	Total Capacity (MW)	Contingency Surp/(Def) (%)	Contingency Surp/(Def) (MW)
1992	71.7	83.0	15.8	11.3
1993	72.9	83.0	13.9	10.1
1994	74.0	83.0	12.2	9.0
1995	75.9	89.1	17.4	13.2

Source: Exh. HO-1A, p. A-20.

*adjusted for C&LM

Appeal as to matters of law from any final decision, order or ruling of the Siting Council may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the order of the Siting Council be modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Siting Council within twenty days after the date of service of the decision, order or ruling of the Siting Council, or within such further time as the Siting Council may allow upon request filed prior to the expiration of the twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the clerk of said court. (Massachusetts General Laws, Chapter 25, Sec. 5; Chapter 164, Sec. 69P).