DECISIONS AND ORDERS

MASSACHUSETTS ENERGY

FACILITIES SITING COUNCIL

VOLUME 18

TABLE OF CONTENTS

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Braintree Electric Light Department to Construct a 115 Kilovolt-to-13.8 Kilovolt Substation and Two 115 Kilovolt Electric Transmission Lines	EFSC 87-32

FINAL DECISION

Frank P. Pozniak
Hearing Officer
September 8, 1988

On the Decision:

Robert J. Harrold
Brian G. Hoefler

TABLE OF CONTENTS

TABLES AND FIGURES:

The Energy Facilities Siting Council hereby APPROVES the supply plan of the Braintree Electric Light Department and CONDITIONALLY APPROVES the petition of Braintree Electric Light Department to construct a 115 kilovolt-to-13.8 kilovolt substation located at the proposed site described herein, and two parallel 1.5-mile, 115 kilovolt electric underground transmission lines along the proposed route described herein.

I. INTRODUCTION

A. Summary of the Proposed Project and Facilities

Braintree Electric Light Department ("BELD" or "Department") is a municipally-owned utility supplying electricity to residential and commercial customers in the Town of Braintree ("Town" or "Braintree"). The Department serves approximately 13,000 customers (Exh. BELD-1, p. 5). In 1985, annual energy consumption totalled approximately 298,000 megawatt-hours with a system peak of about 75 megavolt-amperes ("MVA") (id., pp. 5-6). In 1987, BELD experienced a system peak of 74 MVA (Exh. HO-N-9).

BELD's electricity supplies are delivered entirely through interconnections with the Boston Edison Company ("BECo") (Exh. HO-N-2). BELD owns a 71 megawatt ("MW") (summer rating) oil-fired combined-cycle unit and a 4 MW diesel generating unit, both located at the Potter Generating Station ("Potter") in the Town (Exh. BELD-1, p. 11; Exh. HO-S-14). The combined-cycle unit is dispatched by the New England Power Pool ("NEPOOL") (Exh. BELD-1, p. 11). BELD also owns a 15 MW gas/oil-fired unit at Potter which is currently not in operation (Exhs. HO-S-2, HO-S-7).

BELD proposes to construct two parallel 1.5-mile, 115 kilovolt ("kV") underground transmission lines ("proposed underground lines") (Exh. BELD-1, p. 31). The route of the proposed underground lines ("proposed underground route") would be located within Braintree following Town streets for virtually all of its length (id., Figure 11). As an alternative to the proposed underground lines, BELD proposes to construct two parallel 1.5-mile, 115 kV overhead transmission lines ("alternative overhead lines") (id., pp. 34-35). The route of the alternative overhead lines ("alternative overhead route") would be located within the Town following Town streets for virtually all of its length (Exh. HO-E-7). The alternative overhead route would be substantially the same as the proposed underground route (id.). See Section IV.B.2.b, infra. BELD also identified another alternative to the proposed underground lines. Under this alternative, BELD would construct two parallel 1.5-mile, 115 kV underground lines ("alternative underground lines") (Exh. HO-E-1). The route of the alternative underground lines ("alternative underground route") would be the same as the alternative overhead route (id.).

BELD also proposes to construct a 115 kV-to-13.8 kV substation ("proposed substation 8") to be supplied by the proposed 115 kV transmission lines (Exh. BELD-1, p. 31). The Department would construct proposed substation 8 on property owned by the Braintree Water and Sewer Department ("BWSD") located off Lakeside Drive in the northwest part of Town ("proposed site") (id.). See Section IV.B.1.a and b, infra. In addition, BELD identified two alternative sites for proposed substation 8 also located in the northwest part of Braintree. See Section IV.B.1.c, infra.

BELD proposes to interconnect the proposed substation 8 to the existing 115 kV transmission system with the proposed 115 kV transmission lines (Exh. HO-N-18) (see Figures 2 and 3). BELD asserted that the proposed 115 kV transmission lines would allow continuous operation of proposed substation 8 if a 115 kV transmission line outage were to occur elsewhere in the system (id.). BELD also asserted that the proposed facilities would provide transformer capacity to ensure a reliable supply of energy in the event of a transformer outage (Exh. HO-N-20), and would provide firm service beyond the 10-year forecast period (Exh. HO-N-17).

B. Procedural History

On April 14, 1987, BELD filed an Occasional Supplement with the Energy Facilities Siting Council ("Siting Council") requesting approval to construct the proposed 115 kV transmission lines and proposed substation 8 in Braintree (Exh. BELD-1).

On June 18, 1987, the Siting Council conducted a public hearing in Braintree. In accordance with the directions of the Hearing Officer, the Department provided notice of the public hearing and adjudication.

On September 15, 1987, the Hearing Officer notified the Department that a pre-hearing conference would be scheduled to address the issue of whether BELD should be required to file an individual demand forecast and supply plan in light of the Siting Council's recent decision in Massachusetts Municipal Wholesale Electric Company, 16 DOMSC 95 (1987) ("MMWEC decision").[1]

On December 22, 1987, BELD filed (1) a memorandum in support of its Occasional Supplement ("pre-hearing memorandum") and (2) a demand forecast and supply plan. In its pre-hearing memorandum, the Department argued, among other things, that the MMWEC decision did not require the Siting Council to approve an individual BELD demand forecast and supply plan in order to approve BELD's proposed 115 kV transmission lines and proposed substation 8. The Department also requested that the Siting Council waive G.L. c. 164, sec. 69I, which requires that a facility proposal be consistent with an applicant's most recently approved forecast and supply plan.

On January 22, 1988, the Hearing Officer conducted a pre-hearing conference (1) to consider whether BELD should be required to file an individual demand forecast and supply plan, and (2) to establish a procedural schedule for the remainder of the proceeding. Given the requirements of G.L. c. 164, sec. 69I, and the uncertainty as to whether the MMWEC decision applied to BELD (because the Department had withdrawn from MMWEC), the Hearing Officer required BELD to file both a demand forecast and supply plan (Tr. I, pp. 5-6). Consequently, BELD also was required to publish and post a notice of adjudication regarding the review of the demand forecast and supply plan (id., p. 6). In

---

1/ The Siting Council issued its MMWEC decision on July 28, 1987. In that decision, the Siting Council approved MMWEC's 1985 demand forecast while rejecting its 1985 supply plan.

accordance with the directions of the Hearing Officer, the Department confirmed publication and posting of the notice of adjudication.

On March 7, 1988, the Siting Council conducted an evidentiary hearing. The Department presented five witnesses: James Dolan, an engineering consultant; Robert Keenan, a BELD employee who testified on the supply plan; Walter McGrath, general manager for BELD; Mayhew Seavey, a demand forecast and supply planning consultant; and Barbara Mohrman, an environmental consultant.

The Hearing Officer entered 148 exhibits in the record, largely composed of Department responses to information and record requests. BELD offered three exhibits.

Finally, the Department filed a brief on April 20, 1988.

C. Jurisdiction

The Company's Occasional Supplement is filed in accordance with G.L. c. 164, sec. 69H, which requires the Siting Council to ensure a necessary energy supply for the Commonwealth with minimum impact on the environment at the lowest possible cost, and G.L. c. 164, sec. 69I, which requires electric companies to obtain Siting Council approval for construction of proposed facilities at a proposed site before a construction permit may be issued by any other state agency.

The Department's proposal to construct two parallel 1.5-mile, 115 kV electric transmission lines falls squarely within the second definition of "facility" set forth in G.L. c. 164, sec. 69G:

> (2) any new electric transmission line having a design rating of sixty-nine kilovolts or more which is one mile or more in length except reconductoring or rebuilding of existing transmission lines at the same voltage.

At the same time, construction of proposed substation 8 falls within the third definition of "facility" set forth in G.L. c. 164, sec. 69G:

> (3) any ancillary structure including fuel storage facilities which is an integrated part of the operation of any electric generating unit or transmission line which is a facility.

In accordance with G.L. c. 164, sec. 69H, before approving an application to construct facilities, the Siting Council requires applicants to justify facility applications in three phases. First, the Siting Council requires the applicant to show that the facilities are needed (see Section III.A, infra). Next, the Siting Council requires the applicant to present plans that satisfy the previously identified need and that are superior to alternative plans in terms of cost and environmental impact (see Section III.B, infra). Finally, the Siting Council requires the applicant to show that the proposed site for the facility is superior to alternate sites in terms of cost, environmental impacts, and reliability of supply (see Section IV, infra).

D. MMWEC Decision and BELD's Demand Forecast and Supply Plan

In accordance with G.L. c. 164, sec. 69I, a "company shall not commence construction of a facility at a site unless the facility is consistent with the most recently approved long-range forecast or supplement thereto." On July 28, 1987, the Siting Council issued its MMWEC decision approving the MMWEC's 1985 demand forecast while rejecting its 1985 supply plan. In reaching that decision on MMWEC as a whole, the Siting Council stated that its "findings on MMWEC's forecast and supply plan do not operate as an approval or rejection of the forecasts and supply plans of member towns." Massachusetts Municipal Wholesale Electric Company, 16 DOMSC 95, 139 (1987). The Siting Council further noted that the MMWEC decision "would not preclude an MMWEC member from seeking the Siting Council's approval to construct a jurisdictional facility." Id. In fact, on June 30, 1988, Middleborough Gas and Electric Department ("MGED"), an MMWEC member, was granted approval to construct a jurisdictional facility. Middleborough Gas and Electric Department, 17 DOMSC 197 (1988).[2]

2/ In that case, MGED was required to file an individual supply plan, but not an individual demand forecast since MMWEC's 1985 demand forecast was approved in the MMWEC decision. The Siting Council approved MGED's supply plan. Middleborough Gas and Electric Department, 17 DOMSC 197, 203-213 (1988).

In this proceeding, BELD seeks the Siting Council's approval to construct a jurisdictional facility. The Department asserts that the MMWEC decision applies to BELD (Brief, pp. 20, 29-31). The Department argues that it participated in the MMWEC's 1985 demand forecast approved by the Siting Council in the MMWEC decision (id., pp. 19-20). The Department also argues that rejection of MMWEC's supply plan does not require the filing of an individual supply plan in order to obtain approval of the Department's proposed facility (id., p. 29). In particular, BELD submits that its facility proposal was filed four months prior to the Siting Council's MMWEC decision, and therefore was consistent with the "most recently approved long-range forecast or supplement thereto" at time of filing (id., p. 30). Finally, the Department argues that a "retroactive" application of the MMWEC decision would operate to violate BELD's due process rights (id., pp. 30-31).

At the time when MMWEC filed its 1985 demand forecast and supply plan,[3] BELD was a member of MMWEC and participated in that forecast. The MMWEC decision issued by the Siting Council included BELD and was based on the forecast of demand and supply in Braintree as incorporated in MMWEC's 1985 demand forecast and supply plan. At no time during the proceeding, nor at any time before the issuance of the MMWEC decision, did MMWEC amend its forecast to reflect BELD's withdrawal from MMWEC. In fact, BELD's withdrawal from MMWEC was not effective until March, 24, 1987 (Exh. HO-RR-5), well after the filing of MMWEC's 1985 demand forecast and supply plan.

The Siting Council finds that the 1987 MMWEC decision applies to BELD. Because the Siting Council approved MMWEC's demand forecast in that decision, the Siting Council need not review the demand forecast filed by BELD. The Hearing Officer ruled, however, that the Department must file and have approved by the Siting Council an independent supply plan prior to constructing its proposed facility (Tr. I, p. 5). This ruling is consistent with the Siting Council's finding in Middleborough Gas and Electric Department, supra, at 201-202, and it is appropriate

---

3/ MMWEC filed its 1985 demand forecast on August 1, 1985, and its 1985 supply plan on August 19, 1985.

here.

As the Siting Council stated in the Middleborough case,

> G.L. c. 164, sec. 69I, requires that a jurisdictional facility be consistent with an approved forecast and supply plan. This statutory linkage between a facility and an approved forecast and supply plan is essential to ensure that facility proposals are developed in the context of reviewable, appropriate, and reliable forecasting techniques and adequate, least-cost supply planning. Absent this integration, the Siting Council cannot determine whether a facility proposal is necessary and cost effective [p. 5].

The Siting Council declines to grant the Department's request to waive the requirement of a supply plan (assuming, arguendo, that the Siting Council has the authority to do so).

Although the Department argues that reviewing BELD's supply plan amounts to some type of improper retroactive application of the MMWEC decision, this is not the case. In light of the rejection of the MMWEC supply plan in July 1987 there is no approved supply plan for BELD. Until the Department has an approved supply plan the Department is barred from constructing the proposed facilities. The Siting Council has safeguarded the Department's due process rights by conducting a full adjudicatory review of BELD's supply plan in which BELD had ample opportunity to participate.

The Siting Council will review, consistent with the above finding, the Department's supply plan in Section II, infra. The Siting Council notes that BELD, as a municipal utility independent of MMWEC, henceforth is required, pursuant to G.L. c. 164, sec. 69I, to file its demand forecast and supply plan annually.

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

The adequacy of supply is a utility's ability to provide sufficient capacity to meet its peak loads and reserve requirements throughout the forecast period. Cambridge Electric Light Company, 12 DOMSC 39, 72 (1985); Boston Edison Company, 10 DOMSC 203, 245 (1984). The diversity of supply measures the relative mixture of supply sources and facility types. The Siting Council's working principle is that a more diverse supply mix, like a diversified financial portfolio, offers lower risks. Boston Edison Company, 15 DOMSC 287, 350 (1987). The Siting Council also evaluates whether a supply plan minimizes the cost of power subject to trade-offs with adequacy, diversity, and the environmental impacts of construction and operation of new facilities. Nantucket Electric Company, 15 DOMSC 363, 384-390 (1987). The Siting Council's evaluation of the long-run cost of the supply plan generally focuses on a company's supply planning methodology. Boston Edison Company, supra, at 339-349; Cambridge Electric Light Company, 15 DOMSC 125, 136-138, 165-166 (1986). Finally, the Siting Council determines whether utilities treat all resources -- including demand management, conventional power plants, and purchases from cogeneration and small power projects and from other utility and non-utility suppliers -- on the same basis when attempting to develop an adequate, diverse, and least-cost supply plan.[4] Boston Edison Company, supra, at 315-323;

4/ In 1986, the Massachusetts Legislature amended the Siting Council's statute to require the Siting Council to approve a company's forecast only if the Siting Council determines that a company has demonstrated that its forecast "include[s] an adequate consideration of conservation and load management." G.L. c. 164, sec. 69J.

Cambridge Electric Light Company, supra, at 133-135, 151-155, 166.

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

The Siting Council has determined that different standards of review are appropriate and necessary to establish supply adequacy in the short run and the long run. Cambridge Electric Light Company, supra, 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 should necessary projects not develop as originally planned. Boston Edison Company, supra, at 309-322; Cambridge Electric Light Company, supra, at 134-135, 144-150, 165-166. The Siting Council has defined the short run as the period of time necessary to place into service sufficient resources obtainable from the shortest-lead-time resource option under a given company's control in a timely and cost-effective manner. The short run may vary on a company-by-company basis. Boston Edison Company, supra, at 297, 307-308.

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

B. Supply Planning Process

BELD plans its supplies based on a minimization of revenue requirements subject to ensuring adequacy of supply (Exh. BELD-2, pp. 8, 12; Exh. HO-S-1). The Department stated that its supply planning objectives include long-run cost minimization, reduced oil dependency, diversity, and rate stability (Exh. BELD-2, p. 9). In its supply planning process, the Department first assumed an initial resource combination, then compared other resource options to the initial resource combination (id., pp. 12-13). This comparison involved screening resource options with the Supply Screening Model, determining production costs by running POWRSYM, a production costing model, and using BELD's Revenue Requirements Model to calculate the revenue requirements of the resource combination (id., pp. 10-12).

The initial resource combination consisted of (1) all existing supply resources, and (2) certain "generic capacity additions" where projections of existing supply resources indicated insufficient supply to meet requirements projected by BELD's Demand Forecasting Model (id., pp. 12-13). Generic capacity additions consisted of coal-fired, fluidized-bed power plants for baseload capacity and gas-fired combustion turbine power plants for peaking capacity (id.). Since BELD retained this initial resource combination as a basis for comparing other supply resources, the Department determined initial resource combination production costs and revenue requirements (id.).

To develop a least-cost supply plan, BELD identified other resource options and compared them to the initial resource combination to determine whether they would provide net benefits to the Department's customers (Exh. BELD-2, p. 14; Exh. HO-S-1). The Supply Screening Model evaluated an alternative resource option (1) by testing the sensitivity of the initial resource combination with that option to changes in key variables such as load growth, inflation, and fuel prices, and (2) by calculating approximate production costs (Exh. BELD-2, p. 10). For each alternative resource option that met the screening criteria, the Department used its Production Costing Model to calculate more precise production costs of the initial resource combination with each particular option (id., pp. 10-12). Based on these production costs, BELD determined the resultant revenue requirements from the Revenue Requirements Model (id., pp. 12, 14). Next, BELD compared revenue requirements of resource combinations with and without each identified resource option in order to determine whether the options would reduce revenue requirements (id., p. 14). If an option reduced revenue requirements, the Department updated its initial resource combination to include that option (id.).[5]

Thus, the Department asserted that its methodology resulted in a supply plan that is adequate, least cost, and diverse (id., p. 14).

5/ If the electricity prices generated by the Revenue Requirements Model varied significantly from those assumed in the demand forecast, BELD prepared a new demand forecast, recalculated production costs, and revised system revenue requirements (Exh. BELD-2, p. 12).

C. Adequacy of the Supply Plan

1. Adequacy of Supply in the Short Run

a. Definition of the Short Run

A company's short-run planning period is defined as the time required for a company to place into service resources under its direct control in sufficient quantities to meet the projected need for new capacity. Braintree stated that its shortest-lead-time resource would be the dormant Potter Unit 1 generator, a 15 MW gas/oil-fired unit which could be placed in service in about one year (Exhs. HO-S-2, HO-S-7).

Accordingly, for purposes of this review, the Siting Council finds that Braintree's short-run planning period is one year extending through the summer of 1989.

b. Base Case Supply Plan

Table 1 compares BELD's projected capacity to its peak load capability responsibility for the forecast period. This Table indicates that BELD is projecting a short-run capacity surplus of about 22 percent during the summer of 1989.

Accordingly, for purposes of this review, 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

The Department plans to add a new supply source, Seabrook 1, during the short run (Exh. BELD-2, Table E-17). If all other resources in its base case supply plan remain available to the Department, cancellation or delay of Seabrook 1 beyond BELD's short-run planning period would not cause a supply deficiency (see Table 2).

Accordingly, the Siting Council finds that BELD has established that it has adequate supplies to meet requirements in the short run in the event of a cancellation or delay of Seabrook 1.

2. Adequacy of Supply in the Long Run

BELD's long-run planning period is the remaining forecast horizon beyond the short run, from the winter of 1989-90 through power year 1997-98. Based on BELD's projected compound average annual increase in peak load of 2.5 percent over the 10-year period, BELD's base case supply plan would satisfy capability responsibility throughout the long-run planning period (see Table 1) (Exh. HO-D-2).

As previously discussed in Section II.A, supra, 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 supply options. The ability of BELD's supply planning process to identify and fully evaluate a reasonable range of supply options is fully discussed from the perspective of least-cost supply planning in Section II.D, infra.

As indicated in Section II.D, infra, BELD has identified a reasonable range of supply options, but has failed to demonstrate that it fully evaluated those resource options. Accordingly, the Siting Council finds that BELD has failed to establish that its supply plan ensures adequate resources for its customers in the long run.

3. Conclusions on the Adequacy of Supply

The Siting Council has found that BELD has established (1) that its base case supply plan is adequate to meet requirements in the short run, and (2) that it has adequate supplies to meet requirements in the short run in the event of a cancellation or delay of Seabrook 1. The Siting Council also has found that BELD has failed to establish that its supply plan ensures adequate resources for its customers in the long run.

However, the Siting Council notes that BELD's base case supply plan would satisfy capability responsibility and sales agreements throughout the long-run planning periods (see Section II.C.2, supra). Accordingly, the Siting Council finds that, on balance, BELD has established that its supply plan ensures adequate resources to meet projected requirements.

D. Least-Cost Supply

1. Identification of Resource Options

BELD provided examples of the types of resource options it had identified for evaluation. These included the sale of 40 MW of Potter II and purchase of 25 MW of Canal; the purchase of 6 MW of capacity from the Newbay generating plant; gas supply and gas transmission contracts related to the possible conversion of Potter II; the purchase of capacity and energy from Cleary 9; and demand-side options such as (1) efficient lighting and appliance rebates, (2) free installation of window insulation and low-flow shower heads, and (3) water heater wraps (Exh. HO-S-1). However, BELD presented no evidence indicating how resource options were identified, other than to state that its planning objectives included lowest present-worth of revenue requirements, rate impact, long-run rate stability, unit and fuel diversity, and impact on the local economy (id.). In addition, BELD failed to include the Potter I generating plant in its inventory of resource options, despite the statement of BELD's witness, Mr. Seavey, that "BELD could at some point in time determine that it could be in the economic interests of its ratepayers to put that unit on line and sell some other source of capacity at a greater cost producing a net benefit to ratepayers" (Tr. II, pp. 87-88).

Nonetheless, BELD identified a number of resource options for further evaluation, including both supply-side and demand-side resources. Therefore, for purposes of this review, the Siting Council finds that BELD has identified a reasonable range of resource options.

2. Evaluation of Resource Options

a. Analysis of Resource Combinations

As described in Section II.B, supra, the Department's analysis of resource costs essentially determines the revenue requirements necessary to provide the energy and capacity associated with various resource combinations (Exh. BELD-2, pp. 8, 12; Tr. II, pp. 68-69). The Siting

Council finds that the basic structure of this analysis -- identifying combinations of resources, determining the revenue requirements associated with those combinations, then choosing the combination that minimizes revenue requirements -- is a reasonable approach to planning least-cost supplies for a company of the size and resources of BELD.

The Department provided an example of its resource option analysis based on its recent decision to sign a purchase agreement with Newbay Corporation for 6 MW of coal-fired capacity beginning in 1991 (Exh. HO-S-11). BELD stated that this capacity purchase decision was based on a net reduction in revenue requirements, as well as improved fuel and unit diversity (id.). However, the Department stated that its other identified resource options were not involved in that decision (Tr. II, p. 68). Instead, the Newbay purchase was compared to an MMWEC combined-cycle "proxy" unit, which was not a resource included in BELD's inventory of identified resource options (id.). In addition, the Department provided no evidence that it evaluated any other combinations of resources. For instance, BELD identified efficient appliance and lighting rebates as potential resource options (see Section II.D.1, supra). Yet, the Department provided no analyses of its projected revenue requirements based on resource combinations including either of these options. While the decision to purchase Newbay capacity may have yielded a combination of resources with lower revenue requirements than the base case, there may be other combinations of resources excluding Newbay capacity that would yield still lower revenue requirements. Thus, the Department's least-cost mix does not necessarily include the Newbay capacity purchase.

Although BELD described its methodology for analyzing costs associated with various resource combinations, BELD has not demonstrated that it, in fact, implemented this methodology or relies upon it in making supply decisions. Accordingly, the Siting Council finds that the Department's analysis of resource combinations fails to ensure that it identifies a least-cost resource mix.

b. Adequacy/Cost Tradeoff

In finding that the Department's analysis of resource combinations fails to ensure that it identifies a least-cost resource mix (see Section II.D.2.a, supra), the Siting Council must note the Department's intention to increase its resource base during the forecast period. BELD's supply plan indicates that beginning in 1989 it will have surplus summer capacity ranging from 13.7 percent to 24.5 percent and surplus winter capacity ranging from 14.3 percent to 30.0 percent (see Table 1). The Department justified such surpluses by stating that (1) they serve as a buffer against contingencies, and (2) any excess may be sold to other utilities (Exh. BELD-2, p. 6; Tr. II, pp. 75, 86-89, 112-113).

Contingencies identified by the Department include high load growth, loss or delay of Seabrook I (7.06 MW beginning in summer 1989), loss or delay of Hydro Quebec Phase II (4.63 MW beginning in summer 1991), and loss or delay of Newbay Corporation (6.00 MW beginning in winter 1991) (Tr. II, pp. 75, 87-89, 91; Exh. BELD-2, Table E-17). However, in that BELD did not provide a high load growth forecast, the Siting Council must reject the Department's resource addition justification based on a high load growth contingency. If BELD were to lose its capacity and energy purchases from Seabrook I, Hydro Quebec Phase II, and Newbay Corporation simultaneously under peak conditions, BELD still would not experience a supply deficit until 1993. Further, if BELD were to respond to such contingencies by implementing its shortest-lead-time resource, Potter I, then capacity deficits would not occur until about 1997. Therefore, the Siting Council rejects the Department's argument that its surplus capacity is necessary to respond to contingencies.

Regarding its argument that any excess capacity may be sold to other utilities, BELD provided no analysis of potential markets for this capacity. Instead, BELD asserted that, since "a tight supply situation appears to be the most likely scenario," markets should be available for any excess capacity (Tr. II, p. 78). However, a company's mere assertion, without more, that excess capacity is marketable does not constitute prudent supply planning.

In the short run, -- one year for BELD (see Section II.C.1.a, supra) -- the Siting Council requires a company to own or have under contract sufficient resources to meet its capability responsibility under a reasonable range of contingencies. The Siting Council already has found that the Department meets this requirement (see Section II.C.1.c, supra). In the long run, the Siting Council generally reviews supply adequacy in the context of a company's ability to identify and fully evaluate a reasonable range of supply options; the Siting Council does not require a company to demonstrate that it owns or has under contract sufficient resources to meet its capability responsibility under a reasonable range of contingencies. In implementing its long-run adequacy standard, the Siting Council explicitly recognized the risks associated with projections of demand and resources as well as the necessity for utilities to plan resources in a creative and dynamic manner. Cambridge Electric Light Company, supra, at 134-135.

By contracting for additional capacity in the long run that only serves to increase the surplus above the Department's own capability responsibility projections, the Department has failed to address the critical trade-off between adequacy and cost encouraged by the Siting Council. In placing an inordinate emphasis upon adequacy, at the expense of cost considerations, the Department has subjected its ratepayers to the risk of substantially increased costs without commensurate benefits. For example, given the level of supply planned by BELD, a decrease in load growth would trigger cost consequences that would be particularly detrimental to ratepayers.

Because the Department has not demonstrated that addition of capacity and/or energy from Seabrook I, Hydro Quebec Phase II, and Newbay Corporation (1) results in a least-cost resource mix, (2) is needed to respond to contingencies, and (3) is marketable in the event of any excess capacity, BELD has not justified these resource additions on either adequacy or cost grounds. Thus, based on the record, the Siting Council finds that the Department has not demonstrated that it considered adequacy/cost tradeoffs in its analysis of resource combinations.

c. Comparison of Resource Options on an Equal Footing

BELD asserted that its supply plan analyzes supply and demand options "in the same neutral manner" (Exh. BELD-2, p. 14). In addition, BELD claimed that it used the supply plan to select demand-side options such as rebates for efficient lighting, lighting retrofit, and rebates for efficient appliances (Exh. HO-S-1). Nonetheless, the Department failed to provide evidence showing how these resource options were analyzed, or to indicate how such analyses would lead to resource implementation. In fact, the Department stated that while cogeneration programs could provide about one MW, "the remaining load management and conservation programs cannot be quantified in actuality with any degree of exactitude" (Exh. HO-N-13).

Thus, despite the list of demand-side and supply-side options presented by BELD, the record in this proceeding lacks sufficient evidence to demonstrate that BELD treats all resource options on an equal footing.

Because the record in this proceeding neither supports nor refutes the Department's assertion that it analyzes resource options in a neutral manner, the Siting Council makes no findings here regarding the comparison of resources on an equal footing.

d. Conclusions on Evaluation of Resource Options

The Siting Council has found that the Department's analysis of resource combinations fails to ensure that it identifies the least-cost resource mix. The Siting Council also has found that the Department has not demonstrated that it considered adequacy/cost tradeoffs in its analysis of resource combinations. Finally, the Siting Council has made no findings regarding whether the Department compared demand-side and supply-side options on an equal footing.

Accordingly, the Siting Council finds that the Department has failed to fully evaluate a reasonable range of resource options.

3. Conclusions on Least-Cost Supply

The Siting Council has found that BELD has identified a reasonable range of resource options, but that the Department failed to fully evaluate those resource options.

Accordingly, the Siting Council finds that BELD's supply plan does not ensure a least-cost energy supply.

E. Diversity of Supply

Based on information provided by BELD, supply resources consist of 13 separate units powered by at least five fuel types (Exh. BELD-2, Table E-17; Exh. HO-S-14). BELD indicated that it increased the diversity of its supply mix through the Newbay purchase, and that it intends to continue to diversify (Exh. HO-S-1). BELD projected a decreasing dependence on oil and nuclear resources over the forecast period, and an increasing presence of coal and gas-fired resources (see Table 3) (Exh. HO-S-5).

Accordingly, the Siting Council finds that BELD has demonstrated that its supply plan is adequately diversified.

F. Conclusions on the Supply Plan

The Siting Council has found that BELD's supply plan (1) ensures adequate resources to meet projected requirements, (2) does not ensure a least-cost energy supply, and (3) is adequately diversified. However, the Siting Council notes that this supply plan is the first such document submitted by the Department. In addition, the Department has stated its intention to increase its analytical and evaluative capabilities, and to apply them in its supply planning process (Exh. BELD-2, pp. 4, 8; Tr. II, p. 50). See Middleborough Gas and Electric Department, supra, at 212-213.

Accordingly, in balancing these considerations, the Siting Council hereby APPROVES the supply plan of BELD.

III. ANALYSIS OF THE PROPOSED PROJECT

A. Need Analysis

1. Standard of Review

In accordance with G.L. c. 164, sec. 69H, the Siting Council is charged with the responsibility for implementing energy policies to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

In carrying out this statutory mandate with respect to proposals to construct energy facilities in the Commonwealth, the Siting Council evaluates whether there is a need for additional energy resources[6] to meet reliability or economic efficiency objectives. The Siting Council therefore must find that additional energy resources are needed as a prerequisite to approving proposed energy facilities.

In evaluating the need for new energy facilities to meet reliability objectives, the Siting Council has evaluated the reliability of supply systems in the event of changes in demand or supply or in the event of certain contingencies. With respect to changes in demand or supply, the Siting Council has found that new capacity is needed where projected future capacity available to the system is found to be inadequate to satisfy projected load and reserve requirements. Northeast Energy Associates, 16 DOMSC 335, 344-360 (1987); Cambridge Electric Light Company, supra, at 211-212; Massachusetts Electric Company, 13 DOMSC 119, 137-138 (1985); New England Electric System, 2 DOMSC 1, 9 (1977); Eastern Utilities Associates, 1 DOMSC 312, 312-314 (1977). With regard to contingencies, the Siting Council has found that new capacity is needed in order to ensure that service to firm customers

---

6/ In this discussion, "additional energy resources" is used generically to encompass both energy and capacity additions, including, but not limited to, electric generating facilities, electric transmission lines, energy or capacity associated with power sales agreements, and energy or capacity associated with conservation and load management.

can be maintained in the event that a reasonably likely contingency occurs. Middleborough Gas and Electric Department, supra, at 216-219; Boston Edison Company, 13 DOMSC 63, 70-73 (1985); Taunton Municipal Lighting Plant, 8 DOMSC 148, 154-155 (1982); Commonwealth Electric Company, 6 DOMSC 33, 42-44 (1981); Eastern Utilities Associates, supra, at 316-318.

The Siting Council also has determined in some instances that utilities need to add energy resources primarily for economic efficiency purposes. The Siting Council has found that a utility company's proposed energy facility was needed principally for providing economic energy supplies relative to a system without the proposed facility. Massachusetts Electric Company, supra, at 178-179, 183, 187, 246-247; Boston Gas Company, 11 DOMSC 159, 166-168 (1984).

2. Description of the Existing System

BELD is a summer peaking system with a peak load that reached 71 MW during the summer of 1987 (Exh. HO-N-12). The Department forecasted increasing system-wide coincident peaks that are expected to reach approximately 101 MW by the summer of 1997 (Exh. BELD-2, Table E-17).

BELD receives energy from BECo's transmission system at 115 kV interconnections (Exh. BELD-1, p. 9). External energy supplies are initially delivered to the BELD service territory at switching stations 9 and 11 (id., Appendix B, Figure 1). Energy to these stations is provided over BECo lines 478-508 and 478-502X, respectively (id.). In addition, the Department owns a 71 MW (summer rating) and an 87 MW (winter rating) oil-fired combined-cycle unit and a 4 MW diesel generating unit, both located at Potter in Braintree (id., p. 11; Exh. HO-S-14). The combined-cycle unit is dispatched by NEPOOL and normally runs during peakload periods (Exh. BELD-1, p. 11).

The Department owns a NEPOOL-dispatched, 115 kV transmission system which forms a loop between the BECo interconnections at switching stations 9 and 11 (see Figure 1, herein). Two existing substations, substations 4 and 10, transform power from 115 kV to 13.8 kV for distribution throughout the Town (id., p. 9). Substations 4 and 10 are identical in terms of transformer capacity; each substation consists of two transformers rated at 41.4 MVA apiece (id., p. 10). As shown in Figure 1, substation 10 generally serves load in the northern section of Town, while substation 4 generally serves load in the southern section of Town (id.).

The 115 kV system consists primarily of oil-filled pipe-type underground cable (id.). The single exception to the underground 115 kV system is a one-mile overhead segment between switching station 9 and substation 4 (id.). BELD stated that most of the Town's 13.8 kV distribution system consists of underground cable (id.).

3. Reliability

BELD stated that its firm power supply planning is based on single contingency design (Exh. BELD-1, pp. 6, 21, 25). The Siting Council has found consistently that if the loss of any single major component of a supply system would cause significant customer outages, unacceptable voltage levels, or thermal overloads on system components, then there is justification for additional energy resources to maintain adequate system reliability. Middleborough Gas and Electric Department, supra, at 216-219; Hingham Municipal Lighting Plant, 14 DOMSC 7, 15 (1986); Taunton Municipal Lighting Plant, supra, at 154 (1982); Middleborough Gas and Electric Department, 3 DOMSC 98, 101 (1979); Holyoke Gas and Electric Department, 3 DOMSC 1, 7 (1978).

The Department asserted that its 115-to-13.8 kV substation capability prevents BELD from ensuring single contingency reliability (Exh. BELD-1, p. 21). BELD analyzed transformer loads at substations 4 and 10 by taking the actual 1987 peak loads and projecting load growth from 1988 through 1990 due to known, new projects within the respective areas served by each substation. This resulted in the following substation load projections (Exhs. HO-N-7, HO-N-9):

	Peak Load at Substation 4	Peak Load at Substation 10
1987 (actual)	37.0 MVA	37.0 MVA
1988	39.2	41.3
1989	41.8	42.3
1990	43.4	45.3

BELD asserted, however, that based on the American National Standards Institute's standards for determining transformer capacity ratings, loads on each transformer at substations 4 and 10 are limited to a maximum of 41.4 MVA (Exh. BELD-1, pp. 22-23). The Department claimed that it already maximizes output from its substations by using methods such as forced cooling and balancing loads between substations (id., pp. 5, 22-23). Further, BELD claimed that it complies with NEPOOL's "Capacity Rating Procedures" which require that "no loss of life is to be imposed on any transformer which does not have a replacement readily available" (id., Appendix D). BELD argued that since no replacement transformers are available within the BELD system, and since transformer loadings in excess of their maximum capacity ratings reduce their useful life, the Department is effectively prohibited from operating transformers above their rated capacity (id., pp. 22-23).

Consequently, BELD asserted that beginning in 1989 load shedding would be required if a transformer outage occurs during peakload periods at either substation (id.). Based on BELD's estimated 1990 transformer loads, a transformer contingency under peakload conditions would prompt load shedding amounting to an estimated 2.0 MVA and 3.9 MVA in the sections of Town served by substations 4 and 10, respectively.[7]

7/ BELD claimed that its estimate of load shedding is conservative. For example, BELD indicated that it has noticed higher load factor consumption rates by new customers. Thus, the historical coincidence factors used to project peak loads may understate the contribution by new customers (Exh. HO-N-13; Tr. II, p. 64). In addition, BELD noted that the 1987 peak loads which form the basis for the substation load estimates were established under an emergency voltage reduction of five percent (Exhs. HO-N-9, HO-N-15).

Hence, BELD asserted that its system would be non-firm with respect to single contingency reliability standards following 1988 (Exh. HO-N-9).

Based on the foregoing, the Siting Council finds that BELD has demonstrated that its existing substation capability is inadequate to satisfy expected loads in Braintree with acceptable reliablility. Accordingly, the Siting Council finds that BELD has established that additional energy resources are needed in Braintree.

B. Comparison of the Proposed Project and Alternative Approaches

1. Standard of Review

G.L. c. 164, sec. 69H, requires the Siting Council to evaluate proposed projects in terms of their consistency with providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at lowest possible cost. In addition, G.L. c. 164, sec. 69I, requires a project proponent to present "alternatives to planned action" which may include (a) other methods of generating, manufacturing, or storing, (b) other sources of electrical power or gas, and (c) no additional electrical power or gas.[8]

In implementing its statutory mandate, the Siting Council has required a petitioner to show that, on balance, its proposed project is superior to alternative approaches in terms of cost, environmental impact, and ability to meet the previously identified need. Commonwealth Electric Company, 17 DOMSC 249, 279-288 (1988); Middleborough Gas and Electric Department, 17 DOMSC 197, 219-225 (1988); Cambridge Electric Light Company, supra, at 212-218; Massachusetts Electric Company, supra, at 141-183; Boston Edison Company, supra, at 67-68, 73-74.

8/ G.L. c. 164, sec. 69I, also requires a petitioner to provide a description of "other site locations." The Siting Council reviews the petitioner's proposed site, as well as other site locations, in Section IV, infra.

2. Need

To address the need identified in Section III.A, supra, BELD proposes to construct proposed substation 8, which is to be supplied by the proposed 115 kV transmission lines (Exh. BELD-1, p. 31). BELD contended that its proposed project would provide transformer capacity to ensure a reliable power supply in the event of a transformer outage (Exh. HO-N-20). BELD asserted that the new facilities would provide firm service beyond the ten-year forecast period; in fact, BELD projected that maximum loadings of the proposed transmission lines and substation would not be reached until about 2002 (Exh. HO-N-17).

BELD discussed three alternative approaches addressing its single contingency reliability standard -- a low-voltage alternative, a conservation and load management ("C&LM") alternative, and a cogeneration/small power production ("cogen/SPP") alternative (Exh. BELD-1, pp. 38-41; Exhs. HO-N-2, HO-N-3, HO-N-4, HO-N-12, HO-N-13, HO-N-14, HO-N-15).

The low-voltage alternative would consist of interconnecting existing substations 4 and 10, thereby utilizing all existing transformer capacity available at these substations (Exh. BELD-1, pp. 29, 39). However, BELD stated that under the low-voltage alternative, the existing transformer capacity would be fully utilized by "about 1990" and that the BELD system would fail to meet single contingency standards at that time (id., p. 29). In addition, BELD stated that the low-voltage alternative would require abandoning feeders serving Potter Station and BELD's central dispatch station due to the limited number of 13.8 kV positions at substation 10 (id., pp. 29, 40). Thus, BELD claimed that the low-voltage alternative would cause service degradation from Potter and to the central dispatch station (id.).

BELD also considered a C&LM alternative. BELD claimed that one aspect of its C&LM program, increasing the system power factor, has achieved a load reduction of 4.5 MVA since 1985, thereby forestalling the need for additional transformer capacity (Exhs. HO-N-12, HO-N-13). However, BELD stated that effects of "the remaining load management and conservation programs cannot be quantified in actuality with any degree of exactitude" (Exh. HO-N-13). BELD indicated that a C&LM approach would have to achieve reductions at least commensurate with load increases expected from new projects in order to ensure a reliable supply of power under single contingency standards (Exhs. HO-N-6, HO-D-1). Consequently, BELD concluded that this level of C&LM load reduction would be unattainable by 1989, the time by which BELD claims its system will become non-firm (Exhs. HO-N-2, HO-N-12).

Regarding the cogen/SPP alternative, BELD indicated that it has reduced load by about 1 MVA through cogeneration programs, and that it plans to develop these resources further (Exhs. HO-N-13, HO-N-15, HO-S-6). But while the Department has identified an additional 4.8 MW of potential cogeneration, 4 MW of that total may require interconnection with 115 kV transmission lines which would not help address existing substation capability problems (Exh. HO-S-6).

The Siting Council finds that the Department has demonstrated that C&LM and cogen/SPP fail to address the identified need for additional energy resources. The Siting Council also finds that the proposed project is superior to the low-voltage alternative with respect to addressing the identified need.

In reviewing the cost and environmental impacts of the proposed project, the Siting Council compares the proposal to the alternative approach of expanding the low voltage system.

3. Cost

BELD asserted that its proposed project is the least-cost option for meeting the identified need for additional energy resources in Braintree (Exh. BELD-1, pp. 43-45). In support of this assertion, BELD provided a cost analysis comparing the total capital costs of the proposed project with those of the low-voltage alternative (Exh. HO-C-6A). On the basis of this analysis, the Department estimated the proposed project would cost from $3.3 to 4.0 million while the low-voltage alternative would cost about $4.9 million (Exh. HO-C-6A).[9]

9/ BELD explained that the range of costs associated with the proposed project are due to the difference between overhead and underground construction (Exh. HO-C-6A).

Accordingly, the Siting Council finds that the proposed project is superior to the low-voltage alternative with respect to cost.

4. Environmental Impacts

With regard to environmental impacts, the proposed project approach would (1) involve land clearing for the substation site, (2) increase audible noise levels due to operations of the transformer, and (3) increase visual impacts due to the presence of structures associated with the substation. BELD asserted that mitigation measures would be employed which would reduce each of these environmental impacts to an acceptable level (Exh. BELD-1, pp. 37, 55-61).

The only environmental impacts attributable to the low-voltage alternative would involve those associated with construction -- impacts similar to those resulting from transmission line construction (id., pp. 41-42). Since the low-voltage alternative would involve no substation siting requirements, it would not generate long-term land, noise, or visual impacts.

Accordingly, the Siting Council finds that the low-voltage alternative is superior to the proposed project with respect to environmental impacts.

5. Conclusions: Weighing Need, Cost, and Environmental Impacts

The Siting Council has previously found that (1) the proposed project is superior to the low-voltage alternative with respect to addressing the identified need, (2) the proposed project is superior to the low-voltage alternative with respect to cost, and (3) the low-voltage alternative is superior to the proposed project with respect to environmental impacts. On balance, the Siting Council finds that the proposed project is superior to the low-voltage alternative.

Accordingly, the Siting Council finds that BELD has demonstrated that its proposed project is consistent with ensuring a necessary energy supply with a minimum impact on the environment at lowest possible cost.

IV. ANALYSIS OF THE PROPOSED FACILITIES

A. Standard of Review

G.L. c. 164, sec. 69I, requires a facility proponent to provide information regarding "other site locations." In implementing this statutory mandate, the Siting Council requires the petitioner to show that its proposed facilities siting plans are superior to alternatives. Specifically, a petitioner must demonstrate that its proposed facilities are sited at locations that minimize costs and environmental impacts while ensuring supply reliability.

In previous cases, once the Siting Council has determined (a) that new energy resources are needed, and (b) that the applicant has proposed a project that is, on balance, superior to alternate approaches in terms of cost, environmental impacts, and addressing identified need, the Siting Council has required the petitioner to show (1) that it has examined a reasonable range of practical facility siting alternatives, and (2) that the proposed site for the facility is superior to the alternative site(s) on the basis of a balancing of cost, environmental impact, and reliability of supply. Commonwealth Electric Company, supra, at 298-303; Middleborough Gas and Electric Department, supra, at 227-228; Northeast Energy Associates, supra, at 381-409; Cambridge Electric Light Company, supra, at 195-196, 229-237; Hingham Municipal Lighting Plant, supra, at 22-32. In past cases, in order to determine that a facility proponent has considered a reasonable range of practical facility siting alternatives, the Siting Council typically has required the proponent to establish (1) that it has developed and applied a reasonable set of criteria for identifying alternatives, and (2) that it has identified at least two practical sites with some measure of geographic diversity. Commonwealth Electric Company, supra, at 301-303; Middleborough Gas and Electric Department, supra, at 227-228; Boston Gas Company, 17 DOMSC 155, 176-181 (1988); Northeast Energy Associates, supra, at 385-388; Cambridge Electric Light Company, supra, at 228-229; Hingham Municipal Lighting Plant, supra, at 22; Massachusetts Electric Company, supra, at 190-191; Boston Edison Company, supra, at 76-77.

B. Description of the Proposed and Alternative Facilities

The Department proposes to construct substation 8, which is to be supplied by the proposed 115 kV transmission lines (Exh. BELD-1, p. 31).

1. Substation

a. Proposed Substation 8 Facilities

Proposed substation 8 would consist of one 40 MVA transformer (with accommodations for future placement of a second 40 MVA transformer) and two 115 kV breakers connected to the 115 kV transmission lines (Exh. BELD-1, p. 36). BELD provided that it would modify its original design of proposed substation 8 by utilizing "state-of-the-art" SF_6 insulated substation equipment instead of conventional 115 kV substation equipment (Exh. HO-E-40). As a result of this redesign, BELD indicated that proposed substation 8 would contain no exposed electrical devices (id.).

In addition, proposed substation 8 would contain a 13.8 kV arrangement of metalclad switchgear breakers and disconnect switches with a split bus and transfer bus arrangement housed in a prefabricated building placed on top of a concrete slab (Exh. BELD-1, pp. 36-37). The Department would connect proposed substation 8 to the existing 13.8 kV system in Lakeside Drive by means of an underground 13.8 kV ductline (id., p. 37). Finally, the height of the proposed substation's components would be a maximum of 20 feet (Exh. HO-E-37C).

b. Proposed Site

The proposed substation site is located in the northwest part of the Town on a parcel of property owned by the BWSD, which is approximately 750 feet north of Lakeside Drive and adjacent to the South Shore Plaza parking lot and the property of the Lakeside School (see

Figure 2) (Exh. BELD-1, pp. 31, 36, 38, Figure 11; Exh. HO-E-10A).[10] The property of the Lakeside School contains playing fields, the closest of which would be approximately 140 feet from the easternmost component of the proposed substation (Exhs. HO-N-5A, HO-E-37A, Plan 1).

The dimensions of the leased parcel are approximately 190 feet from north to south and 180 feet from east to west (Exh. HO-E-37A), or approximately 25,900 square feet. The entire yard area of the proposed site would be approximately 6,300 square feet, which includes the individual equipment components of proposed substation 8 (about 2,776 square feet) and an open area surrounded by a 12-foot high chain-link fence topped with protruding barbed wire (Exhs. HO-E-37C, HO-E-39). The easternmost component of the proposed substation would be located approximately 100 feet from the existing six-foot chain-link fence separating the BWSD parcel from the property of the Lakeside School (Exh. HO-37A, Plan 2). The surrounding fence would be equipped with horizontal supports at ground level, as well as in the middle and at the top (Exh. HO-E-39), and the easternmost portion of the fence would be located approximately 80 feet from the existing six-foot chain-link fence separating the BWSD parcel from the property of the Lakeside School (Exh. HO-E-37A, Plan 2). BELD indicated that on the east, south, and western sides of the proposed site, it would place 20-foot tall trees near the surrounding fence (id.). Finally, BELD provided that the proposed site would be located at the westernmost portion of the leased parcel, the site most distant from the adjacent playing fields (Exh. HO-E-37A).

BELD estimated that the total capital cost of proposed substation

---

10/ The property owned by BWSD consists of two lots (Lots 1 and 2) with a total area of approximately 96,367 square feet (Exh. HO-E-37A). Due to road salt contamination, BELD provided that BWSD has not used this property for water supply for a number of years and will no longer use it for such purposes (Exhs. HO-E-15A, HO-E-37D).

8 at the proposed site would be approximately $2,220,000 (Exh. HO-C-14).[11]

c. Alternative Sites

BELD identified two alternate sites for proposed substation 8. One site would be located in the northwest part of the Town on property owned by the developers of the South Shore Plaza off Lakeside Drive and fronted on the west by Bonnieview Road ("Bonnieview site") (Exh. BELD-1, p. 78, Figure 11; Exh. HO-E-2). The Bonnieview site is approximately 750 feet south of the proposed site (see Figure 2) (Exh. BELD-1, Figure 11).

BELD estimated that the total capital cost of proposed substation 8 at the Bonnieview site would range from $2,770,000 to $3,120,000 (Exhs. HO-C-14, HO-C-16). See Section IV.D.1, infra.

The other site considered by BELD would be located in the northwest part of the Town on land owned by the Flatley Corporation near the Grandview Office Building ("Flatley site") (Exh. HO-E-2).

2. Transmission Line Routes

a. Proposed Underground Route

The Department proposes to construct two parallel, 1.5-mile, 115 kV underground transmission lines located entirely within the Town (Exh. BELD-1, p. 31). The proposed underground route would travel in a generally east-west direction following Town streets for virtually all of its length (id., Figure 11). The proposed underground lines would consist of two underground pipe-type cables, enclosed in welded six- to eight-inch steel pipes, and immersed in non-PCB (polychlorinated biphenyl) mineral insulating oil (id., pp. 31-32). Each cable would

---

11/ BELD estimated that the total capital cost of proposed substation 8 before redesign would be about $2,135,000 (Exh. HO-C-6A). See Section IV.B.1.a, supra.

consist of three insulated aluminum conductors and would have a nominal capacity of about 125 MW (id., pp. 32-33).

As shown in Figures 2 and 3, the proposed underground route would begin at the intersection of River and Middle Streets where it would connect with existing underground 115 kV lines at a point approximately 1200 feet south of existing substation 10 (id., p. 32, Figures 11, 16). From this point, the proposed underground route would travel west on River Street for about 0.5 mile, crossing over the Monatiquot River (id., Figures 11, 16). The proposed underground route would then cross under Route 3 and the tracks of the Massachusetts Bay Transportation Authority through an abandoned Town walkway (id., p. 33, Figures 11, 16; Exh. HO-E-1). The proposed underground route would continue down an extension of River Street then briefly turn north on Washington Street before bearing west again for about 0.5 mile on Storrs Avenue (Exh. BELD-1, p. 33, Figures 11, 16). From Storrs Avenue the proposed underground route would travel north along Walnut Street, crossing Town Brook, and gradually curving to the west into Lakeside Drive (id.). At the western border of the Lakeside School property on Lakeside Drive adjacent to the South Shore Plaza parking lot, the proposed underground route would either terminate at that point (Bonnieview site) or else continue about 750 feet north to the proposed site (Exh. HO-E-10A).

BELD estimated that the total capital costs of the proposed underground route would be about $1,875,000 (Exh. HO-C-6A).

b. Alternative Routes

As an alternative to the proposed underground lines, BELD would construct two parallel, overhead, 1.5-mile, 115 kV transmission lines (Exh. BELD-1, pp. 34-35). Beginning at existing substation 10, the alternative overhead route would travel north for a short distance, and then turn west along Elm Street crossing Washington Street at the intersection with Storrs Avenue (see Figure 2) (Exh. HO-E-7). From that intersection, the remainder of the alternative overhead route would be the same as the proposed underground route, traveling along Storrs Avenue and Lakeside Drive until terminating at either the proposed or Bonnieview substation site (id.). Thus, the alternative overhead route would be the same as the proposed underground route for approximately 72 percent of its total length of 1.5 miles.

The height of the poles along the length of the route would be approximately 75 feet with 300-foot spacing between the poles (Exh. HO-E-8). BELD estimated the total capital cost of the alternative overhead route to be about $1,187,000 (Exh. HO-C-6A).

BELD indicated that it also had identified an alternative underground route (Exh. HO-E-1). This route would be the same as the alternative overhead route (id.).

C. Site Selection Process

1. Substation Sites

The Department identified three sites for constructing the proposed substation 8 facilities -- the proposed site, the Bonnieview site, and the Flatley site. BELD stated that it identified these sites based on the following criteria: (1) reliability considerations such as locating the substation near the load centers to be served and improving voltage regulation; (2) site acquisition considerations such as finding land that is feasible for construction, suitably zoned, and available at a reasonable cost; (3) other cost considerations such as minimizing the distances necessary to tie into the 115 kV and 13.8 kV systems; and (4) environmental impact considerations such as aesthetics, safety, and noise (Exh. HO-E-2).

Based on these criteria, BELD eliminated the Flatley site since the presence of ledge (i.e., bedrock) on that site would result in problems with both electrical grounding and installing underground cables (Exh. HO-E-2; Tr. II, pp. 39-42). Thus, the Department determined that the proposed site and the Bonnieview site would be practical alternatives for proposed substation 8.

The Siting Council finds that BELD has developed a reasonable set of criteria for identifying alternatives for proposed substation 8. These criteria include cost, environmental, and reliability considerations as well as site acquisition considerations. As such, BELD has developed site selection criteria that are appropriate for identifying sites that minimize the economic costs and environmental impacts of constructing and operating needed energy facilities.

The Siting Council also finds that BELD has appropriately applied its criteria for identifying alternatives. In this case, the Department has identified three sites, all located in the northern part of Town which is near the load center. The record in this case demonstrates that the Flatley site presents development disadvantages -- presence of ledge which would result in problems with both electrical grounding and installing underground cables -- which renders it impractical and justifies its elimination from further consideration.

The Siting Council also finds that BELD has identified at least two practical sites with some measure of geographic diversity. The proposed site and the Bonnieview site are approximately 750 feet apart, and are located on two distinct parcels of land. While the Department might have identified practical substation site alternatives with a greater degree of geographic diversity, the proposed site and the Bonnieview site fulfill the second requirement.

In sum, the Siting Council has found that BELD has established (1) that it has developed and applied a reasonable set of criteria for identifying siting alternatives for proposed substation 8, and (2) that it has identified at least two practical sites for proposed substation 8 with some measure of geographic diversity. Accordingly, the Siting Council finds that BELD has considered a reasonable range of practical facility siting alternatives for proposed substation 8.

2. Transmission Line Routes

The Department identified three routes for its proposed transmission facilities -- the proposed underground route, the alternative overhead route, and the alternative underground route. BELD stated that the criteria used to identify these routes included the following: (1) system design/cost considerations such as minimizing the distance from the proposed and Bonnieview substation sites to the existing underground 115 kV transmission system; (2) construction feasibility considerations such as finding routes with sufficient subsurface space for two pipe-type cables; and (3) environmental impact considerations such as minimizing construction inconveniences and ensuring adequate safety (Exh. HO-E-1).[12]

Based on these criteria, BELD eliminated the alternative underground route because (1) Elm Street, on the alternative underground route, is much more traveled than River Street, on the proposed underground route, and building on Elm Street would cause greater traffic disruption during construction; and (2) the route along Elm Street would require crossing Route 128 (Exh. HO-E-1). Thus, the Department determined that the proposed underground route and the alternative overhead route would be practical alternatives for the proposed 115 kV transmission lines.

The Siting Council finds that BELD has developed a reasonable set of criteria for identifying alternatives for the proposed 115 kV transmission lines. These criteria include system design/cost and environmental considerations, including safety concerns, as well as construction feasibility considerations. As such, BELD has developed site selection criteria that are appropriate for identifying sites that minimize the economic costs and environmental impacts of constructing and operating needed energy facilities.

The Siting Council also finds that BELD has appropriately applied its criteria for identifying alternatives. In this case, the Department has identified three routes, all of which connect BELD's existing 115 kV system to the proposed substation near the load center (id.). Further, BELD indicated that the proposed underground route is a natural extension of the existing 115 kV underground system (id.), which is also true for the alternative underground route.

However, the Siting Council cannot find that BELD has identified

---

12/ In addition, the Department identified another criterion, the merits of which the Siting Council does not address. This criterion is as follows: "It is the policy of the elected officials of the BELD Board that all 115 kV lines be placed underground for reliability, interference, safety, and aesthetic reasons. It is not BELD's policy to place 115 kV poles, 75 feet in height and 300 feet in span length in residential areas." (Exh. HO-E-6) at least two practical sites for the proposed 115 kV transmission lines with some measure of geographical diversity. After applying its criteria, the Department presented the Siting Council with the proposed underground route and the alternative overhead and underground routes -- three configurations comprising two routes.[13] These two routes are exactly the same for 72 percent of their length. Routes with such minor variations are more akin to design optimization than clear proposal alternatives. Thus, the Siting Council finds that, in this case, two routes which are exactly the same for 72 percent of their length do not constitute geographically diverse routes.[14]

Finally, the Department has failed to establish that a second practical site does not exist.[15] BELD's assertion that other streets in the area cannot be utilized because they are already overloaded with duct banks and lines (Exhs. HO-E-1, HO-E-25) remains unsubstantiated, and does not establish that other routes with more geographical diversity would not be feasible.

In sum, the Siting Council has found that BELD has established (1) that it has developed a reasonable set of criteria for identifying siting alternatives for the proposed 115 kV transmission lines, and (2) that it has applied a reasonable set of criteria for identifying siting alternatives for the proposed 115 kV transmission lines. The Siting Council also has found that BELD failed to establish that it has identified at least two practical sites for the proposed 115 kV

13/ The routes for the alternative underground route and the alternative overhead route are the same.

14/ Similarly, the Siting Council notes that the presentation of an identical route which runs overhead rather than underground does not constitute geographic diversity. While it may be important to compare an overhead route and an underground route in terms of cost and environmental impacts, the effect on the abutters to such a route is the same: they are presented with no route alternative.

15/ In cases involving proposals to construct cogeneration facilities, if the proponent can establish that a second practical facility does not exist, the Siting Council does not require the identification of two geographically diverse sites. Altresco-Pittsfield, 17 DOMSC 351, 394 (1988).

transmission lines with some measure of geographic diversity. Accordingly, the Siting Council finds that BELD has not considered a reasonable range of practical facility siting alternatives for the proposed 115 kV transmission lines.

The Siting Council's requirement that a proponent identify a reasonable range of practical facility siting alternatives is well established, and failure to comply with this standard is adequate grounds to deny an application to construct a facility. However, the Siting Council notes that its standard has evolved as a result of much consideration of these issues over a series of recent cases. See Altresco-Pittsfield, Inc., supra, at 391-394; Commonwealth Electric Company, supra, at 301-303; Middleborough Gas and Electric Department, supra, at 227-228; Boston Gas Company, supra, at 176-181; Northeast Energy Associates, supra, at 385-388. The Siting Council also acknowledges that all of these decisions were issued well after BELD filed its Occasional Supplement in April 1987, and that some of these decisions were issued after the discovery and hearing phases of this proceeding were concluded. Holding BELD to these standards without affording the Department the opportunity to amend its filing to comply with these standards would be inappropriate. While the Siting Council is empowered to require BELD or another company to amend its proposal to address recently articulated standards, in this case, such an approach would unnecessarily delay the review process.

For the purposes of this review, BELD's failure to establish that it has examined a reasonable range of practical facility siting alternatives alone shall not operate to preclude approval of BELD's facility proposal. Accordingly, the Siting Council reviews the proposed underground route and compares it to the alternative overhead route to determine whether the proposed underground route is superior to the alternative overhead route on the basis of a balancing of cost, environmental impact, and reliability of supply.

D. Cost Analysis of the Proposed and Alternative Facilities

1. Substation Costs

The Department calculated the total capital cost of substation 8 at the proposed site to be about $2,220,000 (Exh. HO-C-14). BELD has leased the proposed site from BWSD for a period of 25 years commencing on March 25, 1988 for one dollar per year (Exh. HO-C-13).[16]

BELD asserted that construction of proposed substation 8 at the Bonnieview Road site would cost about $550,000 to $900,000 more than construction at the proposed site (Exh. HO-C-16). These additional costs include $200,000 to $500,000 for land acquisition, $75,000 to $100,000 to litigate land acquisition, $250,000 due to greater length of the 115 kV transmission lines, and $25,000 due to greater length of the 13.8 kV distribution line (id.).

Regarding land acquisition, the Department asserted that the South Shore Plaza developers will not sell the Bonnieview site to BELD, and therefore the Department would have to initiate an eminent domain proceeding to acquire this site (Exh. BELD-1, p. 78; Exh. HO-E-2). However, BELD failed to present evidence supporting the additional costs associated with the 115 kV transmission lines and the 13.8 kV distribution line. In fact, based on the record, it appears that both the proposed 115 kV transmission lines and the 13.8 kV distribution line would be approximately 750 feet shorter if proposed substation 8 is built at the Bonnieview site rather than the proposed site (Exh. BELD-1, Figures 2A, 2B, 11, 14).

Thus, the Siting Council makes no findings regarding a preference for construction of proposed substation 8 at either the proposed site or the Bonnieview site on the basis of cost.

16/ On July 15, 1988, the Massachusetts Department of Environmental Quality Engineering conditionally approved the lease between BELD and BWSD (Exhs. HO-E-37D, HO-E-42).

2. Transmission Line Costs

With respect to the proposed 115 kV transmission lines, BELD calculated the total capital cost of the proposed underground lines to be about $1,875,000 (Exh. HO-C-6A). For the alternative overhead lines, BELD calculated the total capital cost to be about $1,187,000 (id.). Thus, the cost to construct the proposed underground lines would be about 58 percent more than the cost to construct the alternative overhead lines.

Accordingly, the Siting Council finds that, on the basis of cost, the alternative overhead lines are preferable to the proposed underground lines.

E. Environmental Analysis of the Proposed and Alternative Facilities

During the proceeding, BELD provided analyses of the environmental impacts, including measures to mitigate such impacts, of constructing (1) proposed substation 8 at the proposed and Bonnieview sites, and (2) the proposed 115 kV tranmission lines along the proposed underground and alternative overhead routes (Exh. BELD-1, pp. 49-79; Exhs. HO-E-1 through HO-E-36). In its review, the Siting Council first determines whether the proposals and alternatives would be acceptable in terms of their environmental impacts.[17] Commonwealth Electric Company, supra, at 316-332; Middleborough Gas and Electric Department, supra, at 229-237; Northeast Energy Associates, supra, at 391-407. The Siting Council then compares the proposals and alternatives to determine which plan is preferable in terms of having a minimum impact on the environment.

17/ Before approving proposed facilities, the Siting Council must determine that the proposed facilities are "consistent with current health, environmental protection, and resource use and development policies as adopted by the commonwealth." G.L. c. 164, sec. 69J.

1. Environmental Impacts: Substation

Potential environmental impacts of the proposed substation identified during this proceeding were related to wetlands and waterways, visual impacts, noise, and safety. The Siting Council reviews these impacts in its analysis of the proposed and alternative facilities.

a. Wetlands and Waterways

While an unnamed stream is located just north of the proposed substation site, the Department asserted that it could effectively eliminate any impacts to this stream (Exh. BELD-1, p. 69). In particular, BELD provided that all construction would be separated from this waterway by at least 100 feet, and that all access, construction, and maintenance would be from the south (id.). BELD also proposed to surround the transformer with a dike and to install a spill reservoir in order to prevent any oil leakage (Tr. II, pp. 33-35).

BELD provided no analysis addressing wetlands and waterways impacts associated with the Bonnieview site. However, the Siting Council notes that this site would be located adjacent to the north shore of Quincy Reservoir (Exh. HO-E-37E). But even so, access to the Bonnieview site is possible from Lakeside Drive, away from the reservoir. Thus, no wetlands or waterways impacts associated with siting proposed substation 8 at the Bonnieview site were identified.

Accordingly, the Siting Council finds that, with the mitigation measures proposed by the Department, construction of the proposed substation at either the proposed or Bonnieview sites would have an acceptable impact on wetlands and waterways. Further, the Siting Council finds that the proposed and Bonnieview sites are comparable with respect to wetlands and waterways impacts.

b. Visual Impacts

The area adjacent to both the proposed and Bonnieview sites is dominated by commercial development including a multi-story shopping mall, numerous adjoining commercial buildings, a multi-story parking garage, and an expansive, paved parking lot (Exh. HO-N-5A). But while BELD acknowledged that proposed substation 8 at either site would be visible from the eastern parking lot of the South Shore Plaza mall and from the western grounds of the Lakeside Elementary School, the Department argued that landscaping with tall trees would screen direct views of the substation from either of these points (Exh. BELD-1, pp. 55-56; Exhs. HO-E-3, HO-E-37D).

BELD asserted that residences would not be subjected to views of the proposed substation at the proposed site (Exh. BELD-1, p. 55). BELD also noted that the nearest residences are located about 600 feet north of the proposed substation site, separated and screened from view by a wooded area (id., p. 54). BELD claimed that, since the proposed substation's components would be a maximum of 20 feet high, the wooded area would prevent visibility from the north (id.; Exh. HO-E-37C). In contrast, the Bonnieview site would be located just off Lakeside Drive (Exh. HO-N-5A), making it difficult to achieve adequate screening.

Accordingly, the Siting Council finds that, with the mitigation measures proposed by the Department, constructing proposed substation 8 at either the proposed or Bonnieview sites would have an acceptable visual impact. Further, the Siting Council finds that the proposed site is preferable to the Bonnieview site with respect to visual impacts.

c. Noise

BELD asserted that proposed substation 8 would conform to all applicable noise regulations (Exh. BELD-1, pp. 56-62). BELD stated that the proposed substation would use a "low-noise" transformer which would produce noise at a level about 11 A-weighted decibels less than a conventional transformer (id., p. 56). BELD also stated that switchgear associated with the substation would be totally enclosed and would not emit annoying noise (id., p. 59).

By specifying such equipment, the Department claimed that the proposed substation at the proposed site would meet Massachusetts Department of Environmental Quality Engineering ("MDEQE") community noise guidelines as well as the Town's standards for noise limits in residential areas and open spaces (id., pp. 58, 60).[18] BELD claimed that residences were "much closer" to the Bonnieview site than to the proposed site and indicated that noise impacts would likely result (Exh. HO-E-37E). However, it appears that residences near Bonnieview are set back a considerable distance from the Bonnieview site (Exh. HO-N-5A), and BELD has presented no evidence that, in fact, greater noise impacts would likely result at this site.

Accordingly, the Siting Council finds that, with the mitigation measures proposed by the Department, constructing proposed substation 8 at either the proposed or Bonnieview sites would have an acceptable noise impact. Further, the Siting Council finds that the proposed and Bonnieview sites are comparable with respect to noise.

d. Safety

During the course of the proceeding, public safety concerns were raised regarding the potential for unauthorized entry into the substation. The Department addressed these concerns by stating that (1) it would take precautions to ensure that unauthorized entry would not occur, and (2) if unauthorized entry did occur, risk of injury would be reduced to a minimum (Exh. HO-E-38).

BELD stated that unauthorized entry would be prevented by surrounding proposed substation 8 with a 12-foot high, chain-link fence topped with protruding barbed wire (Exh. HO-E-39). The fence would be equipped with horizontal supports at ground level, which BELD believes would prevent access by digging (id.). BELD also contended that vegetative screening, consisting of 20-foot tall trees, would help deter unauthorized substation access (Exh. HO-E-38).

Since the Lakeside School is located next to the proposed site, BELD proposes to construct the substation on the westernmost side of the proposed site, thereby providing the greatest distance possible from the

---

18/ The Department indicated that it based its noise analysis on the assumption that the proposed substation eventually would consist of two transformers (Exh. HO-E-29).

playing fields on the school grounds (Exhs. HO-E-37, HO-E-38, HO-E-40). Under such a placement, the proposed substation's easternmost component would be located at least 100 feet from the school's property line (Exhs. HO-E-37A, Plan 2, HO-E-37D, HO-E-38B). BELD argued that this 100-foot distance would provide a sufficient "buffer zone" to minimize or eliminate the possibility of school-ground activities (e.g., stray foul balls) extending to the substation grounds (Exh. HO-E-38B).

BELD claimed that even if a person were to enter the substation yard, risk of injury would be reduced because the proposed substation would incorporate features that "completely remove the risk of electrocution" (id.). BELD stated that the proposed substation would use a "state-of-the-art" SF_6 insulation system which manifests no exposed, active electric components (Exhs. HO-E-38B, HO-E-40). Thus, BELD contended that even if unauthorized entry occured, contact with live circuits would not be possible (Exh. HO-E-38B).

BELD provided no discussion of public safety concerns associated with the Bonnieview site. However, mitigation measures similar to those at the proposed site certainly could be taken at the Bonnieview site, thereby achieving a similar level of safety.

Accordingly, with the safety measures proposed by BELD, the Siting Council finds that constructing proposed substation 8 at either the proposed or Bonnieview sites would have an acceptable safety impact. Further, the Siting Council finds that the proposed site and the Bonnieview site are comparable with respect to safety.

e. Conclusions on Environmental Impacts: Substation

The Siting Council has found that, with the environmental mitigation proposed by the Department, the environmental impacts of constructing proposed substation 8 at either the proposed or Bonnieview sites would have an acceptable impact on wetlands and waterways, visual effects, noise levels, and safety.

The Siting Council has found that (1) the proposed and Bonnieview sites are comparable with respect to wetlands and waterways impacts, noise, and safety, and (2) the proposed site is preferable to the Bonnieview site with respect to visual impacts. Accordingly, the Siting

Council finds that, on balance, the proposed site is preferable to the Bonnieview site on the basis of environmental impact.

2. Environmental Impacts: Transmission Lines

Potential transmission line environmental impacts identified during this proceeding were related to wetlands and waterways, visual impacts, and electrical effects. The Siting Council reviews these impacts in its analysis of the proposed and alternative facilities.

a. Wetlands and Waterways

BELD identified three wetlands and waterways located along the proposed underground route -- the Monatiquot River, Town Brook, and Quincy Reservoir (Exh. BELD-1, p. 68; Exhs. HO-E-35, HO-E-20). In addition, the Department indicated that a fourth wetlands may exist along Storrs Avenue (Exh. HO-E-20). However, the Department contended that specific construction techniques would avert impacts to these wetlands and waterways (Exh. BELD-1, p. 68; Exhs. HO-E-35, HO-E-20).

Where the proposed underground lines cross the Monatiquot River, BELD proposes to attach the lines to an existing bridge (Exh. BELD-1, p. 68). Thus, BELD claimed that the Monatiquot River would be crossed without disruption of the stream bed, river bank, and immediate area, thereby avoiding erosion and sedimentation effects (id.).[19]

In order to cross Town Brook, the Department proposes to tunnel beneath the Town Brook culvert crossing Walnut street (Exh. HO-E-35). By tunnelling, the Department claimed adverse impacts to Town Brook would be eliminated (id.). Specific construction precautions planned by BELD during the Town Brook crossing include leaving construction equipment on the Walnut Street roadway, keeping excavated material out

19/ BELD indicated that the River Street bridge is set above 10-year and 50-year flood profiles, but that a 100-year flood profile would reach the street level, while a 500-year flood profile would exceed it (Exh. HO-E-21).

of the stream, and halting construction during periods of rain (id.).

Regarding Quincy Reservoir, BELD asserted that the proposed underground lines would not affect the reservoir since construction would be located entirely on the Lakeside Drive roadway, and both equipment and excavated material would be kept away from the reservoir (Exh. HO-E-20).

Finally, BELD's witness, Ms. Mohrman, stated that, although a culverted stream or other wetlands may exist in the Storrs Avenue area east of Bestick Avenue, BELD conducted a visual investigation and found no evidence of any wetlands (Tr. II, p. 37). BELD indicated that it would review Town records prior to construction to determine whether a culvert crosses Storrs Avenue in this area (Exh. HO-E-20). If so, BELD stated that it would mitigate construction impacts by employing tunnelling techniques similar to those planned for Town Brook (id.).

BELD provided no analyses addressing wetlands and waterway impacts associated with the alternative overhead lines. However, the alternative overhead route would not cross the Monatiquot River (Exh. HO-E-7), and potential impacts to Town Brook and the Storrs Avenue wetlands could be mitigated by careful pole placements.

Accordingly, the Siting Council finds that with the mitigation techniques proposed by the Department, both the proposed underground and alternative overhead route would have an acceptable impact on wetlands and waterways. Further, the Siting Council finds that the alternative overhead route is preferable to the proposed underground route with respect to wetlands and waterways impacts.

b. Visual Impacts

BELD stated that, since it proposes to place transmission lines underground, long-term visual impacts would be avoided (Exh. BELD-1, p. 55). In addition, Ms. Mohrman stated that placement of the lines beneath Town streets would result in minimal damage to tree root systems, thereby protecting an important visual resource in the area (Tr. II, pp. 43-44).

With respect to the alternative overhead lines, BELD identified three long-term visual impacts (Tr. II, pp. 25, 42; Exh. BELD-1, p.

35). First, BELD stated that the 75-foot high poles would be twice the height of poles existing in Town residential neighborhoods (Exh. BELD-1, pp. 51, Figure 12). BELD claimed that these poles would be seen from greater distances and would cause greater visual impacts on abutters (Tr. II, p. 25). Second, BELD claimed that trees along the alternative overhead route would be adversely impacted, since pole and conductor installation would require tree removal and pruning (Exh. BELD-1, p. 75). Also, in order to pour foundations for corner poles, BELD would need excavations 4-to-5 feet wide and 15-to-25 feet deep in areas where major tree root systems may be located (Tr. II, pp. 25-26, 42-44; Exh. BELD-1, p. 74). Finally, BELD claimed that the alternative overhead lines would create adverse visual effects by mixing wood poles and either steel or concrete poles (Exh. BELD-1, pp. 35-36, 73).

While BELD identified a number of visual impacts of the alternative overhead lines, BELD's failed to address factors such as the scope and magnitude of incremental and cumulative visual impacts, or the sensitivity of each discrete route segment to visual effects. Further, the Department failed to address mitigating measures which might offset the visual effects of the alternative overhead lines. Nonetheless, the Siting Council has concerns with placing 115 kV or higher voltage overhead lines in developed residential areas when not on an existing utility right-of-way. See Hingham Municipal Lighting Plant, supra, at 30.

Accordingly, the Siting Council finds that the proposed underground lines would have acceptable visual impacts.[20] Further, the Siting Council finds that the proposed underground route is preferable to the alternative overhead route with respect to visual impacts.

20/ In that the Siting Council does not address the merits of BELD's policy not to place overhead 115 kV transmission lines in residential areas (see footnote 12, supra), the Siting Council does not consider whether the alternative overhead lines would have acceptable visual impacts.

c. Electrical Effects

BELD asserted that underground construction would eliminate electric fields and, given conductor spacing and cable shielding, would result in negligible magnetic fields (Exhs. HO-RR-6, HO-RR-7). The Department provided a letter from the Okonite Company, a supplier of underground electrical cable, stating that "neither electric field nor magnetic field effects are a consideration" in underground cable design (Exh. HO-RR-7). While the Department did not substantiate the Okonite Company's assertion, the record nevertheless indicates that underground lines would reduce electric and magnetic fields substantially below the level of such fields induced by overhead lines.

For the alternative overhead lines, BELD calculated maximum electric field levels in kV per meter ("kV/m") at varying distances from the centerline under nominal voltage conditions (Exh. HO-RR-6). BELD's calculations indicated that these lines would produce a maximum electric field of about 0.157 kV/m at a distance of 30 feet from the conductor nearest to residences (id.). BELD also estimated that maximum magnetic fields would reach about 23.7 milligauss ("mG") at a distance of 30 feet from the conductor nearest to residences (id.).

BELD offered no analyses of these expected electric and magnetic field levels. However, in the past the Siting Council notes that it has accepted maximum edge-of-ROW electric field levels of 1.8 kV/m and maximum edge-of-ROW magnetic field levels of 85 mG. Massachusetts Electric Company, supra, at 228-242. In the instant case, the alternative overhead lines would induce electric and magnetic fields below these levels (Exhs. HO-RR-6, HO-RR-7).

Accordingly, the Siting Council finds that the proposed underground route and the alternative overhead route would have acceptable electrical effects. The Siting Council further finds that the proposed underground route is preferable to the alternative overhead route with respect to electrical effects.

d. Conclusions on Environmental Impacts: Transmission Lines

The Siting Council has found that, with the environmental mitigation proposed by the Department, the environmental impacts of constructing the proposed underground lines would have an acceptable impact on wetlands and waterways, visual effects, and electrical effects, while the alternative overhead lines would have an acceptable impact on wetlands and waterways and electrical effects.

Further, the Siting Council has found that (1) the alternative overhead route is preferable to the proposed underground route with respect to wetlands and waterways impacts, (2) the proposed underground route is preferable to the alternative overhead route with respect to visual impacts, and (3) the proposed underground route is preferable to the alternative overhead route with respect to electrical effects. Accordingly, the Siting Council finds that, on balance, the proposed underground route is preferable to the alternative overhead route on the basis of environmental impact.

F. Reliability Analysis of the Proposed and Alternative Facilities

The only reliability issue raised during this proceeding relates to the length of time necessary to obtain land for the proposed substation.

For the proposed site, the Department already has an MDEQE-approved lease for a term of 25 years at an annual rent of one dollar (Exh. HO-C-13). According to BELD, acquiring the rights to use the Bonnieview site would require an eminent domain proceeding of perhaps two years or more (Exhs. HO-E-2, HO-E-41). The Department indicated that given the need for the proposed facilities beginning in 1989 (see Section III.A, supra), such a delay could threaten BELD's supply reliability.

In addition, the proposed site is zoned as a Highway Business District which would allow construction of the proposed substation (Exhs. HO-E-2, HO-E-37B). However, the Bonnieview site, despite its ownership by a commercial enterprise, is zoned for Residential B development (Exh. BELD-1, p. 78; Exh. HO-E-37E).[21]

Accordingly, the Siting Council finds that, on balance, the proposed substation site is preferable to the Bonnieview site on the basis of reliability of supply.

G. Conclusions on the Proposed Facilities

1. Substation

The Siting Council has found that BELD has considered a reasonable range of practical facility siting alternatives for its proposed substation. In addition, the Siting Council has found that the proposed substation site is preferable to the Bonnieview site on the basis of environmental impact and reliability of supply.

Based on the foregoing, the Siting Council finds that, on balance, constructing proposed substation 8 at the proposed site is superior to constructing it at the Bonnieview site.

2. Transmission Lines

The Siting Council has found that BELD failed to consider a reasonable range of practical facility siting alternatives for its proposed 115 kV transmission lines.[22] In addition, the Siting Council has found that (1) the alternative overhead route is preferable to the proposed underground route on the basis of cost, and (2) the proposed underground route is preferable to the alternative overhead route on the basis of environmental impact.

21/ The Department did not indicate whether a zoning variance would be required for the Bonnieview site.

22/ For the purposes of this review, BELD's failure to establish that it had examined a reasonable range of practical facility siting alternatives alone shall not operate to preclude approval of BELD's facility proposal. See Section IV.C.2, <u>supra</u>.

Pursuant to G.L. c. 164, secs. 69H and 69I, to reach decisions on facility proposals, the Siting Council is required to balance cost, environmental impact, and reliability. In cases involving proposals to construct underground and overhead transmission lines, the Siting Council has addressed the balance between cost and environmental impact. See, e.g., Hingham Municipal Lighting Plant, supra; Boston Edison Company, 3 DOMSC 44 (1978).

In the instant case, the estimated capital cost of underground construction is approximately $688,000 (58 percent) more than the estimated capital cost of overhead construction. At the same time, the environmental impacts of overhead construction are significantly greater than the environmental impacts of underground construction. Indeed, the record in this proceeding has demonstrated that the alternative overhead route would have significant visual impacts. The construction of the alternative overhead route would involve placing 75 foot poles, 300 feet apart along Town streets in dense residential areas for almost all of its length. The environmental impacts of the proposed underground route are less substantial. While the Siting Council recognizes the cost difference between the proposed underground route and the alternative overhead route, the Siting Council has concerns with placing 115 kV or higher voltage lines in developed residential areas when not on existing utility rights-of-way. See Hingham Municipal Lighting Plant, supra. In this case, the Siting Council finds that the environmental advantages of the proposed underground route outweigh the cost advantages of the alternative overhead route.[23]

Accordingly, the Siting Council finds that the proposed underground route is superior to the alternative overhead route.

23/ As indicated above, BELD, a municipally-owned utility, has a policy of placing all 115 kV transmission lines underground. This policy, in conjunction with the fact that BELD's service territory is limited to Braintree, is germane to our balancing of cost and environmental impact. In addition, we note that in the course of this proceeding, no one came forward to voice any opposition to placing the proposed transmission lines underground.

V. DECISION AND ORDER

The Siting Council hereby APPROVES the supply plan of Braintree Electric Light Department.

The Siting Council ORDERS Braintree Electric Light Department to to file its next demand forecast and supply plan on September 1, 1989.

Further, the Siting Council finds that construction of proposed substation 8 at the proposed site as described herein, and two parallel 1.5-mile, 115 kilovolt underground transmission lines along the proposed route as described herein is consistent with providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. The Siting Council further finds that proposed substation 8 and the two parallel 1.5-mile, 115 kilovolt underground transmission lines are consistent with the Department's most recently approved forecast.[24]

Accordingly, the Siting Council hereby APPROVES the petition of Braintree Electric Light Department to construct a 115 kilovolt-to-13.8 kilovolt substation located at the proposed site described herein, and two parallel 1.5-mile, 115 kilovolt electric underground transmission lines along the proposed route described herein, subject to the following CONDITIONS:

24/ In this case, the Department's "most recently approved forecast" comprises the demand forecast approved in Massachusetts Municipal Wholesale Electric Company, 16 DOMSC 95 (1987), and the supply plan approved in Section II, supra.

(1) The Department shall (a) locate the proposed site at the westernmost portion of the parcel of land leased by Braintree Electric Light Department from the Braintree Water and Sewer Department, (b) place the easternmost fence enclosing the proposed site at a minimum of 80 feet from the existing six-foot chain-link fence separating the Braintree Water and Sewer Department parcel from the property of the Lakeside School, and (c) place the easternmost component of proposed substation 8 at a minimum of 100 feet from the existing six-foot chain-link fence separating the Braintree Water and Sewer Department parcel from the property of the Lakeside School.

(2) The Department shall install and maintain a chain-link fence at least 12 feet in height surrounding the proposed site, and trees at least 20 feet in height along the south, east, and west sides of the fence. Such trees shall provide full visual screening of the proposed site, and shall be in place at the time of commercial operation of proposed substation 8.

(3) The Department shall utilize SF_6 insulated 115 kilovolt substation equipment at proposed substation 8.

(4) In the event that additional transformers are installed at the proposed site, the Department shall utilize SF_6 insulated 115 kilovolt substation equipment at proposed substation 8.

Frank P. Pozniak

Frank P. Pozniak
Hearing Officer

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of September 8, 1988 by the members and designees present and voting: Chairperson Sharon M. Pollard (Secretary of Energy Resources); Paul McNally (for Joseph D. Alviani, Secretary of Economic and Manpower Affairs); K. Scott Colby (for James S. Hoyte, Secretary of Environmental Affairs); Joseph W. Joyce (Public Member Labor); Stephen D. Umans (Public Member Electricity). Absent: Barbara Anthony (for Paula W. Gold, Secretary of Consumer Affairs and Business Regulation); Madeline Varitimos (Public Member Environment); Dennis J. LaCroix (Public Member Gas).

Sharon M. Pollard

Sharon M. Pollard
Chairperson

Dated this 8th day of September 8, 1988

TABLE 1

Braintree Electric Light Department
Consolidated Demand Forecast and Supply Plan
Summer and Winter Peaks (MW)

Year	Estimated Capability Respons. Summer	Total Supply	Surplus (%)	Estimated Capability Respons. Winter	Total Supply	Surplus (%)
1988	88.8	91.7	2.9 (3.3)	88.8	99.7	10.9 (12.3)
1989	92.8	113.1	20.3 (21.9)	92.8	120.6	27.8 (30.0)
1990	97.9	117.8	19.9 (20.3)	97.9	120.1	22.2 (22.7)
1991	100.3	123.7	23.4 (23.3)	100.3	125.4	25.1 (25.0)
1992	102.8	123.5	20.7 (20.1)	102.8	125.4	22.6 (22.0)
1993	105.4	123.3	17.9 (17.0)	105.4	125.4	20.0 (19.0)
1994	108.1	123.3	15.2 (14.1)	108.1	125.4	17.3 (16.0)
1995	110.8	138.0	27.2 (24.5)	110.8	136.0	25.2 (22.7)
1996	113.5	134.9	21.4 (18.9)	113.5	136.0	22.5 (19.8)
1997	116.4	132.4	16.0 (13.7)	116.4	133.0	16.6 (14.3)

Source: Exh. BELD-2, Table E-17

TABLE 2

Braintree Electric Light Department
Short-Run Contingency Analysis
Summer Peak Load (MW)

Cancellation or Delay of Seabrook 1[a]

Year	Base Case[b] Surplus (Deficit)	Loss of Seabrook 1	Contingency Surplus (Deficit)
1989	20.3	(7.06)	13.24

Notes:

a. The Department assumed it would begin receiving its Seabrook 1 entitlement of 7.06 MW in Summer 1989.

b. See Table 1 for short-run base case surplus/deficit.

Source: Exh. BELD-2, Table E-17

TABLE 3

Braintree Electric Light Department
Fuel Diversity

FUEL TYPE	1987	1992	1997
Hydro	4.7%	11.6%	7.1%
Nuclear	30.0	19.2	17.0
Coal	0.0	9.3	8.2
Natural Gas	8.5	19.3	37.0
#6 Oil	52.7	40.6	30.8
#2 Oil	1.6	0.0	0.0
System	.3	0.0	0.0
SOS/UOS/DEF	2.3	0.0	0.0

Source: Exh. HO-S-5

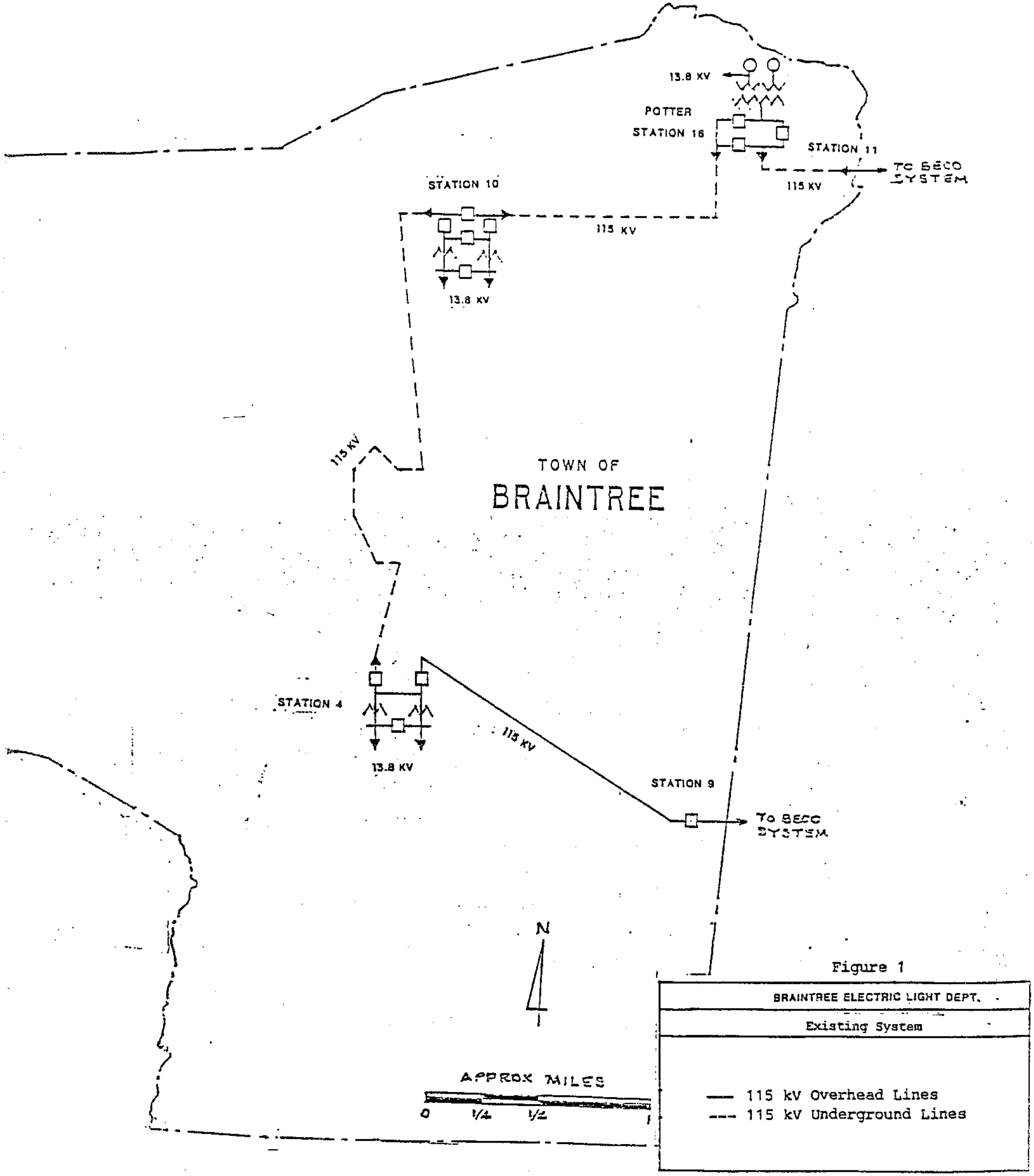
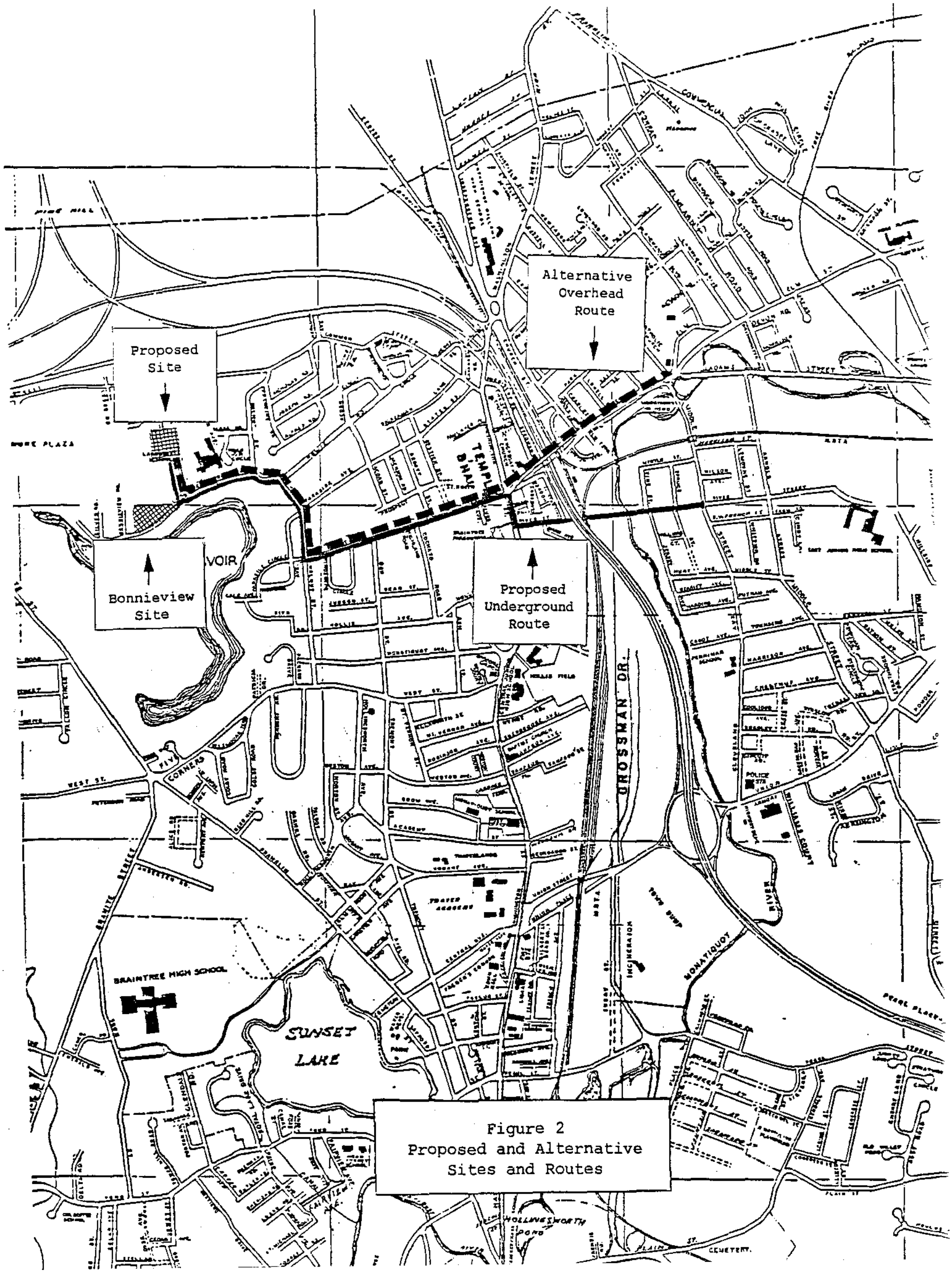

13.8 KV
POTTER
STATION 16
STATION 11
TO BECO
SYSTEM
115 KV
STATION 10
115 KV
13.8 KV
115 KV
TOWN OF
BRAINTREE
STATION 4
13.8 KV
115 KV
STATION 9
TO BECO
SYSTEM
N
APPROX MILES
0
1/4
1/2
1
BRAINTREE ELECTRIC LIGHT DEPT.
Existing System
115 kV Overhead Lines
115 kV Underground Lines

Figure 1


Alternative
Overhead
Route
Proposed
Site
Bonnieview
Site
Proposed
Underground
Route
BRAINTREE HIGH SCHOOL
SUNSET
LAKE
GROSSMAN DR.
FIVE CORNERS
WEST ST.
HOLLINGSWORTH
POND
MONATIQUOT
RIVER
CEMETERY
Figure 2
Proposed and Alternative
Sites and Routes

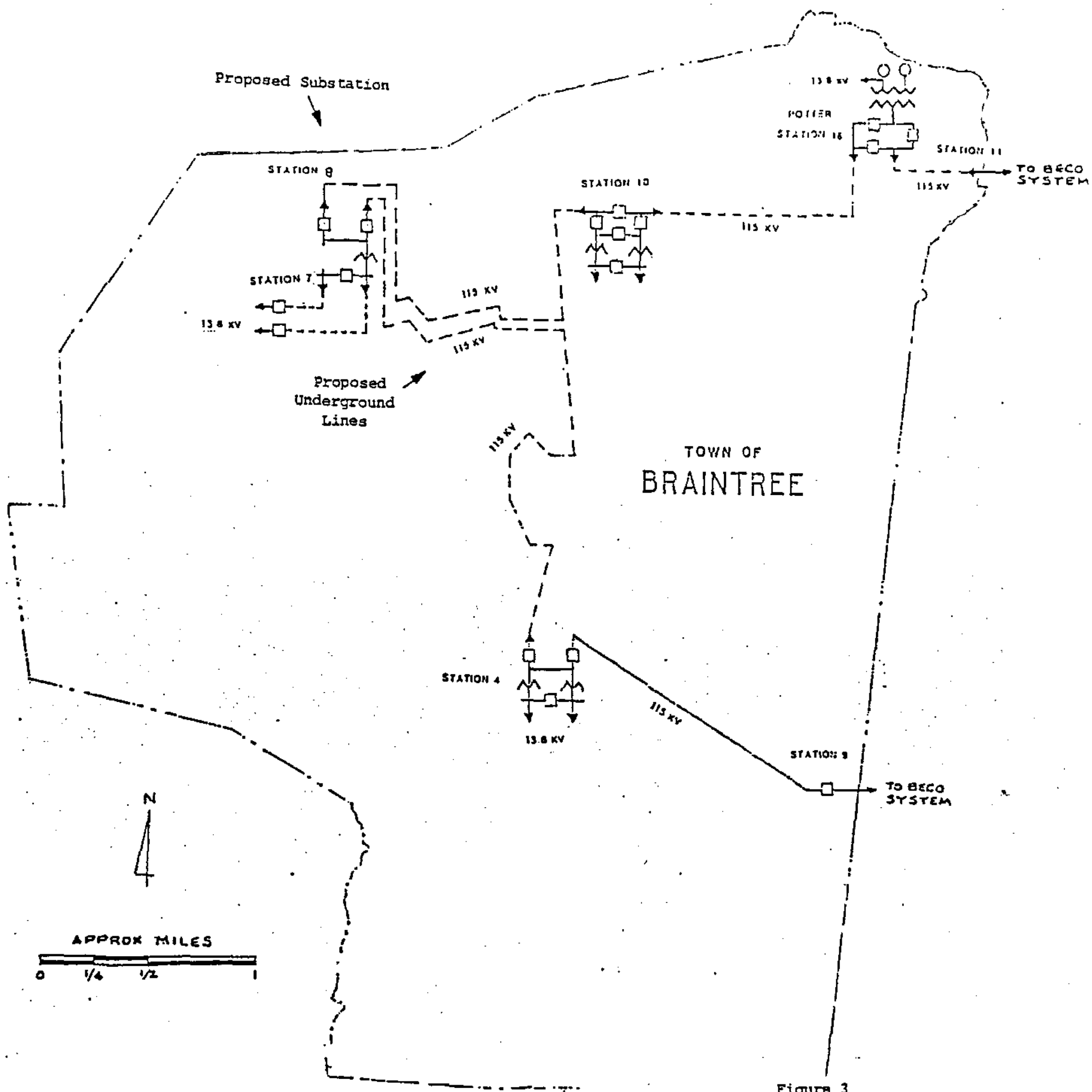


Figure 3

BRAINTREE ELECTRIC LIGHT DEPT.

Proposed Transmission System

—— 115 kV Overhead Lines
---- 115 kV Underground Lines

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 twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said Court (Sec. 5, Chapter 25, G.L. Ter. Ed., as most recently amended by Chapter 485 of the Acts of 1971).

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

Proposed Rulemaking Regarding Exemption of Certain Gas Manufacturing and Storage Facilities from Requirement for Energy Facilities Siting Council Approval	Docket No. 88-RM-100

FINAL ORDER

Sue Munis
Hearing Officer
September 8, 1988

On the Order:

Stephen Klionsky
Brian Hoefler

I. BACKGROUND

On May 26, 1988, the Energy Facilities Siting Council ("Siting Council") issued a Notice of Proposed Rulemaking and Public Hearing regarding the exemption of certain gas storage and manufacturing facilities from the requirement to obtain Siting Council approval as planned facilities. The current Siting Council regulations provide, at 980 CMR 7.07(8), that modifications to existing gas storage and manufacturing facilities are exempt from the requirement to obtain Siting Council approval if they do not increase the "gross capacity of the whole manufacturing or storage facility by more than 10 percent (10%)...." The Siting Council staff, in a May 16, 1988 memorandum to the Siting Council, stated that this exemption was too narrow and that it would lead to lengthy and unnecessary Siting Council reviews of many minor modifications to existing facilities (none of which involves a new site). At the recommendation of the Siting Council staff, the Siting Council proposed revisions to 980 CMR 7.07(8).

The regulation proposed by the Siting Council would require approval only if the changes

> (1) increase the capacity of the storage component of the facility by more than fifty percent (50%) or fifty thousand (50,000) barrels or (2) increase the capacity of the manufacturing component of the facility by more than fifty percent (50%) or twenty-five thousand (25,000) MMBtu per day....

On June 29, 1988, the Siting Council held a public hearing on the proposed rulemaking at which representatives of several gas companies were present. In addition, after notice to all parties that attended the June 29, 1988 public hearing, the Siting Council staff conducted site visits to several gas manufacturing and storage facilities. The Siting Council also received written comment on the proposed regulation from the Boston Gas Company ("Boston Gas") and joint comments from the Bay State Gas Company and the Fitchburg Gas and Electric Light Company ("Bay State").

Bay State generally supports the Siting Council's proposed change to 980 CMR 7.07(8), but recommends that subsection (2) be amended as follows: "increase the capacity of the manufacturing component of the facility by the greater of fifty percent (50%) or twenty-five thousand (25,000) MMBtu per day." Bay State states that this change would allow for the "reasonable upsizing of small, supplemental gas supply facilities" that otherwise would require approval under the Siting Council's proposed rules. Bay State further states that the proposed regulation, by requiring a capacity change to meet both a percentage and an MMBtu standard, is an undue limitation on the expansion of smaller gas plants and is thus counter to the purpose of the proposed rule, which is to allow small-scale capacity increases.

Boston Gas also generally supports the Siting Council's proposed regulation, as modified by Bay State. Boston Gas suggests further amending the proposed regulation by changing subsection (1) as follows: "increase the capacity of the storage component of the facility by the greater of fifty percent (50%) or fifty thousand (50,000) barrels." If this change is not made, according to Boston Gas, the proposed regulation will be more restrictive than the existing regulation in the case of Boston Gas' Commercial Point LNG facility. Because Boston Gas calculates ten per cent of the storage capacity at Commercial Point to be 62,100 barrels, the proposal to require Siting Council approval for any capacity increase in excess of 50,000 barrels would be more restrictive than the present requirement. According to Boston Gas this is contrary to the intent of the proposed regulation.

II. <u>DISCUSSION AND FINDINGS</u>

1. After reviewing the comments of Bay State, the Siting Council acknowledges that employing a percentage increase test without qualification for manufacturing facilities could be contrary to the intent of the proposed regulation because small existing facilities would be unduly constrained in the amount of

additional capacity permitted. The Siting Council, therefore, revises the proposed regulation to include a provision that all manufacturing capacity increases of 10,000 MMBtu per day or less do not constitute construction of a facility under 980 CMR 7.07(7).

2. At the same time, Boston Gas objects to that portion of the proposed regulation relating to gas storage because the exemption from Siting Council review at one of its storage facilities would be tightened somewhat. The Siting Council, nonetheless, finds that limiting the exemption for storage facilities to 50 percent or 50,000 barrels is a reasonable standard. Cases where additions to storage exceed those amounts represent the class of projects which the Siting Council should review to determine whether they are consistent with ensuring a necessary energy supply for the Commonwealth at the least cost and with the least environmental impact.

ORDER

Accordingly, after due notice, hearing and consideration, it is hereby

ORDERED: That 980 CMR 7.07(8)(a) shall be deleted and in place thereof shall be inserted the following:

> (a) modification, addition to, or replacement of equipment at an existing site which is a component part of an existing facility capable of the manufacture or storage of gas, unless such modification, addition or replacement:
>
> > (1) increases the capacity of the storage component of the facility by more than fifty percent (50%) or fifty thousand (50,000) barrels; or
> >
> > (2) increases the capacity of the manufacturing component of the facility by more than fifty percent (50%) or twenty-five thousand (25,000) MMBtu per day, provided that increases of ten thousand (10,000) MMBtu per day or less do not constitute the construction of facilities under 980 CMR 7.07(7);

Sue Munis

Sue Munis
Hearing Officer

Dated this 8th day of September, 1988

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of September 8, 1988 by the members and designees present and voting: Chairperson Sharon M. Pollard (Secretary of Energy Resources); Paul McNally (for Joseph D. Alviani, Secretary of Economic and Manpower Affairs); K. Scott Colby (for James S. Hoyte, Secretary of Environmental Affairs); Joseph W. Joyce (Public Member Labor); Stephen D. Umans (Public Member Electricity). Absent: Barbara Anthony (for Paula W. Gold, Secretary of Consumer Affairs and Business Regulation); Madeline Varitimos (Public Member Environment); Dennis J. LaCroix (Public Member Gas).

Sharon M. Pollard
Chairperson

Dated this 8th day of September 8, 1988

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 twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said Court (Sec. 5, Chapter 25, G.L. Ter. Ed., as most recently amended by Chapter 485 of the Acts of 1971).

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Eastern Edison Company and Montaup Electric Company, Subsidiaries of Eastern Utilities Associates, for Approval of Their 1987 Long-Range Forecast of Electric Requirements and Resources	EFSC 87-33

FINAL DECISION

Frank P. Pozniak
Hearing Officer
November 15, 1988

On the Decision:

Michael P. Aronson
Brian G. Hoefler

TABLE OF CONTENTS

The Energy Facilities Siting Council hereby APPROVES the 1987 demand forecast of the Eastern Edison Company, and hereby REJECTS the 1987 supply plan of the Montaup Electric Company.

I. INTRODUCTION

A. Background

Eastern Utilities Associates ("EUA" or "Company") is a public utility holding company and the parent company of the EUA System ("System") (Exh. HO-58). The System includes two retail electric companies, Eastern Edison Company ("Eastern Edison" or "EECo") operating in southeastern Massachusetts, and Blackstone Valley Electric Company operating in Rhode Island (id.). Eastern Edison distributes electricity to approximately 167,000 customers in southeastern Massachusetts (id.). The System also includes a wholesale electric company, Montaup Electric Company ("Montaup"), which is a generation and transmission company supplying electricity for resale to Eastern Edison, Blackstone, and three unaffiliated utilities (id.).

The System also includes another electricity generation company, EUA Power Corporation ("EUA Power") whose principal asset is a 12.13 percent share (139 megawatts ("MW")) of the Seabrook generating station ("Seabrook I") (id.; Exh. HO-1, p. II-78). The System anticipates that EUA Power will sell wholesale power to other utilities within New England (Exh. HO-1, p. II-78). Finally, the System includes EUA Ocean State Corporation, which owns 25 percent of a proposed 235 MW natural gas-fired generating station planned for construction in Burrillville, Rhode Island ("Ocean State") (id.;

Exh. HO-58).[1] The System expects to receive power from the Ocean State facility beginning in the winter of 1990-91 (Exh. HO-52, p. 2).

Eastern Edison distributes electricity in two geographically separate areas within southeastern Massachusetts. In its Brockton division, Eastern Edison serves 17 communities in and around the City of Brockton; in its Fall River division, Eastern Edison serves five communities in and around the city of Fall River (Exh. HO-1, p. I-1). Total energy output requirements for Eastern Edison during 1987 were 2,447,900 megawatthours ("MWH"), while peak demand reached a record of 467 MW during the winter of 1987-88 (id., pp. IV-9 to IV-11).

Montaup supplies almost all of the electricity distributed by Eastern Edison (Exh. EUA-1, p. I-2). Montaup owns all of the System's generating facilities and arranges to purchase power from other sources as required (id.). Montaup's total energy output requirements during 1987 were 4,140,575 MWH, while peak demand reached a record of 768 MW in the summer of 1987 (Exh. HO-1, pp. V-6 to V-10).

The Energy Facilities Siting Council ("Siting Council") reviews the 1987 demand forecast of EECo and the 1987 supply plan of Montaup.[2]

1/ In addition, the System includes EUA Cogenex Corporation, an energy management and cogeneration company; EUA Energy Investment Corporation, a new subsidiary established to invest in cogeneration and small power production facilities; and EUA Service Corporation, which provides various management services to the System (Exh. HO-58).

2/ Eastern Edison buys a small fraction of its power directly from third-party small power producers (Tr. I, p. 13). In addition, Eastern Edision develops demand-side management resource options (Exh. HO-1, p. II-63). See Section III.E.1, infra. For the purposes of the review of the supply plan in this proceeding, the Siting Council considers these EECo initiatives as Montaup supply resources. See Section III, infra.

B. Procedural History

On March 24, 1987, EUA filed its 1987 demand forecast and supply plan ("1987 forecast") (Exhs. EUA-1, EUA-3).[3] On July 6, 1987, EUA filed its technical supplement to the 1987 forecast (Exh. EUA-2). On July 24, 1987, the Hearing Officer issued a Notice of Adjudication and directed EUA to publish and post the Notice in accordance with 980 CMR 1.03(2). EUA subsequently submitted confirmation of publication.

Evidentiary hearings were held on July 12 and July 29, 1988. EUA presented five witnesses: Michael P. DiBenedetto, director of power management; Michael J. Hirsh, director of resource planning; Edward M. Kremzier, senior engineer; Donald C. Ryan, senior analyst; and Carol S. White, senior analyst. The Siting Council entered 81 exhibits into the record, largely composed of EUA's responses to information and record requests. EUA offered three exhibits into the record.

3/ Since Siting Council jurisdiction extends to Eastern Edison and Montaup, two subsidiaries of EUA, the Siting Council reviews those portions of EUA's 1987 forecast that pertain to EECo and Montaup.

During the course of the proceeding, EUA provided its 1988 demand forecast and supply plan (Exh. HO-1). While not the subject of the review in this proceeding, the Siting Council uses the 1988 demand forecast and supply plan to assist in its evaluation of the 1987 demand forecast of EECo and the 1987 supply plan of Montaup.

II. ANALYSIS OF THE DEMAND FORECAST

A. Standard of Review

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

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

B. Previous Demand Forecast Conditions

In Eastern Utilities Associates, 14 DOMSC 41, 93 (1986) ("1986 EUA Decision"), the Siting Council approved Eastern Edison's demand forecast subject to two conditions:[4]

1. That [Eastern Edison] attempt to become an active participant in the study by several Massachusetts

---

4/ The numbers preceding each condition correspond to the numbers assigned in the 1986 EUA decision.

electric utilities to directly meter appliance use in residential customer homes, and to report to the Siting Council on efforts to do so. [Eastern Edison] shall incorporate the results of the study into its next filing. Should [Eastern Edison] fail to participate in the study, it shall present in its next filing: (1) the reasons for such failure to participate, and (2) a plan for a study that would provide information on appliance use within its own service territory.

2. That [Eastern Edison] proceed with the development of a long-term econometric model for demand forecasting and verification of NEPOOL [New England Power Pool] elasticity estimates. [Eastern Edison] must demonstrate the applicability of the NEPOOL elasticities to the EUA System territory in light of this study and other relevant studies or implement appropriate changes. [Eastern Edison] must include in its next filing a plan with a time schedule for developing and conducting such a model.

In response to Condition One, EECo joined with five other Massachusetts utilities[5] in the Joint Utility Monitoring Project ("JUMP"), a study to meter appliance use by residential customers (Exh. EUA-3). This study is intended to provide state-specific average use estimates for frost-free refrigerators, uncontrolled electric water heaters, electric ranges, and electric clothes dryers (id.). The six utilities collected data from December 1986 through December 1987, and hired a consultant to analyze the data and prepare state-specific and service-area-specific average use estimates (id.). Eastern Edision expects that its next forecast will reflect the results of JUMP (Tr. I, p. 10).

In response to Condition Two, Eastern Edison submitted a "Plan for EUA Long Range Econometric Model of Annual Energy Requirements" (Exh. EUA-3). Under this plan, Eastern Edison

---

5/ The other five utilities are Massachusetts Electric Company, Western Massachusetts Electric Company, Boston Edison Company, Commonwealth Electric Company, and Massachusetts Municipal Wholesale Electric Company (Exh. EUA-3).

would develop, over a three-year period, a long-range econometric model by (1) conducting a literature search, (2) collecting and verifying econometric data, (3) specifying, estimating, and evaluating a model, (4) evaluating price elasticities, and (5) either demonstrating the applicability of the current elasticity estimates or else implementing appropriate changes to those estimates (id.). Eastern Edison's time schedule indicates that all work, including implementation of elasticity estimates if necessary, should be completed by March 31, 1990 (id.).

Accordingly, the Siting Council finds that Eastern Edison has complied with Conditions One and Two of the 1986 EUA Decision.

C. Energy Forecast

Eastern Edison forecasted annual energy requirements by first preparing economic and demographic forecasts and an electric price forecast, then applying those forecasts in a detailed end-use model (Exh. EUA-1, pp. II-1 to II-50). In separate projections for its Brockton and Fall River divisions, Eastern Edison forecasted energy requirements for the residential, commercial, and industrial sectors, and for streetlighting, internal use, miscellaneous use, and losses (id.).

The results of EECo's energy forecast are contained in Table 1.

1. Economic and Demographic Forecasts

Eastern Edison retained the services of Data Resources, Inc. ("DRI") to forecast key economic and demographic factors for the Brockton and Fall River divisions (Exh. EUA-1, p. II-4). Eastern Edison has used DRI in the past for these services. See 1986 EUA Decision, 14 DOMSC at 53-58. Factors forecasted by DRI include per capita income, population, households, commercial and industrial sector employment, fuel prices, the Consumer Price Index ("CPI"), and the Producer Price Index (Exhs. EUA-1, p. II-4, EUA-2, pp. II-1 to II-12).

For purposes of this review, the Siting Council accepts Eastern Edison's methodologies for forecasting economic and demographic factors.

2. Electricity Price Forecast

a. Description

To forecast electricity prices for each customer class, EUA forecasted the cost of electricity generation, calibrated this cost to existing prices, then used these prices as inputs to the energy forecast (Exh. EUA-1, pp. II-12 to II-15; Exh. EUA-2, Sec. VIII). If, at the completion of the energy forecast, electric prices varied significantly from those predicted by the electricity price forecast, EUA iterated this procedure until the price differences were negligible (Exh. EUA-1, p. II-12).

EUA projected electric costs for Montaup, Eastern Edison, and Blackstone by summing projections of energy and demand costs (id., pp. II-12 to II-13). EUA defined energy costs as Montaup's fuel costs (id.). The Company projected fuel costs based on DRI's fuel price forecast and on estimated fuel use as determined by a production costing model (id., p. II-12). In the 1988 demand forecast and supply plan ("1988 forecast"), EUA began using a new electric utility planning software package, The Electric Utility Planning System ("UPLAN"), to estimate fuel use (Exh. HO-1, pp. II-13 to II-14A, II-73). According to EUA, UPLAN calculates the most economical way for Montaup to generate enough electricity to supply a given load from a particular set of generating units (id.). The resulting annual fuel costs were allocated to Eastern Edison based on its respective proportion of Montaup's forecasted energy requirments (Exh. EUA-1, p. II-12).

The Company considered all non-fuel costs to be demand costs (id.). EUA divided demand costs into generation and transmission costs, which are attributable to Montaup, and distribution costs, which are attributable to Eastern Edison (id.).

EUA projected each of these demand cost components by assuming that they would retain their historical relationship with DRI's forecast of the CPI (Exh. EUA-2, p. VIII-2). As justification for this assumption, EUA stated that "no extraordinary change in expenses was forecasted" (id.). EUA established this historical relationship based on data from 1975 through 1986 which indicated that annual aggregate demand costs grew at a compound rate that was approximately 93.5 percent of the annual compound growth rate of the CPI (id.).

Montaup's generation and transmission demand costs were allocated to EECo based on its proportion of average peak demand (id.). EECo's distribution demand costs were allocated to each customer class based on their respective proportions of historical costs (id., p. VIII-6).

b. Analysis

The Siting Council finds that the basic structure of the Company's electricity price forecast -- forecasting electric costs, calibrating electric costs to existing prices, and balancing forecasted prices with the energy forecast -- is an appropriate methodology for Eastern Edison. The Siting Council also finds that disaggregating costs into energy and demand (generation, transmission, and distribution) components, provides an intuitive and practical basis for determining electricity costs. Further, the Siting Council finds that forecasting the energy component of electric costs by forecasting fuel prices, calculating the optimum use of each fuel through use of a production costing model, and allocating these costs to retail companies based on proportional consumption levels is appropriate for a company of the size and resources of Eastern Edison.

The Siting Council notes, however, that one weakness in Eastern Edison's electricity price forecast is its reliance on the CPI to forecast growth in demand costs. The Company assumed that demand costs would increase at a rate that is 93.5 percent of the CPI growth rate without sufficient justification. Given the CPI's grounding in a broad cross section of consumer goods, its relationship to the price of generation, transmission, and distribution of electricity has not been established, and the use of the CPI to forecast demand costs could lead to an unreliable electricity price forecast.

Nonetheless, the Siting Council finds that, on balance, Eastern Edison's methodology for forecasting electricity prices is reviewable, appropriate, and reliable. In its next forecast filing, however, the Siting Council ORDERS EECo (a) to demonstrate that it has reviewed other methodologies or indices for forecasting electricity demand costs, and (b) to demonstrate that the CPI-based methodology is appropriate, or to implement a different methodology deemed appropriate in light of the Siting Council's concerns.

3. Residential Energy Forecast

Eastern Edison based its residential energy forecast on the assumption that total class consumption is the sum of consumption of 19 residential appliance types (Exh. EUA-1, pp. II-16 to II-30).[6] The basic premise behind this forecast

---

6/ Eastern Edison disaggregated its residential forecast into 19 types of appliances: electric ranges, frost-free refrigerators, standard refrigerators, frost-free freezers, standard freezers, dishwashers, clothes washers, electric clothes dryers, controlled electric water heaters, uncontrolled electric water heaters, microwave ovens, color televisions, black and white televisions, lighting, room air conditioners, central air conditioners, electric space heating, fossil-fuel auxiliaries, and miscellaneous (Exh. EUA-1, p. II-16).

is that annual energy consumption by an appliance type is the product of the number of appliances and the average use per appliance (id., p. II-17).

Although Eastern Edison has enhanced some of the methodological details of its residential energy forecast, the basic structure of the residential energy forecast remains largely the same as the one approved by the Siting Council in the past. 1986 EUA Decision, 14 DOMSC at 57-66; Eastern Utilities Associates, 11 DOMSC 61, 71-79 (1984) ("1984 EUA Decision"); Eastern Utilities Associates, 8 DOMSC 192, 205-214 (1982) ("1982 EUA Decision").

a. Number of Appliances

For the years 1987 to 1997, Eastern Edison forecasted the number of appliances in each of the 19 appliance types in its service territory. The number of appliances for each appliance type was determined by multiplying the forecasted number of customers (which was assumed to be equal to the number of households in the service territory) by the average number of each respective appliance per household (Exh. EUA-1, pp. II-18 to II-22). The number of customers in each EECo division was determined from (1) regressions of the historical number of customers in each EECo division against state-wide historical household data, and (2) DRI's projections of households (Exhs. EUA-1, p. II-17, EUA-2, pp. II-1 to II-11).[7]

EECo assumed that the average number of each respective appliance per household was equal to appliance saturations which were developed primarily from a 1985 residential customer survey (Exh. EUA-1, pp. II-18 to II-22). Eastern Edison forecasted saturation levels for: (1) 11 appliance types based

---

7/ Eastern Edison used regression analysis to compare the relationship between the number of customers in the service territory, the dependent variable, and the number of households, the independent variable.

on territory-specific saturation-income functions; (2) two appliance types based on NEPOOL saturation trend data; (3) two appliance types based on the assumption of 100 percent saturation; and (4) four appliance types based on various methods of adjusting current saturation levels for predicted appliance addition or attrition (id., p. II-19). In order to compute the saturation-income functions, EECo estimated per capita income in each division for seven income ranges for each year of the forecast period (id., p. II-18).

The 1988 forecast included three changes from the 1987 forecast with respect to Eastern Edison's estimation of appliance saturation levels. These changes include (1) development of territory-specific saturation-income functions for three additional appliance types -- frost-free refrigerators, standard refrigerators, and microwave ovens, (2) development of territory-specific saturation-income functions based entirely on the 1985 residential survey instead of either the 1982 residential survey or 1970 U.S. Census data, and (3) elimination of the disaggregations for single-family versus multiple-family dwellings and rented versus owned dwellings (Exh. HO-1, pp. II-2, II-19 to II-23).

The Siting Council finds that the changes included in the 1988 forecast are reasonable. The Siting Council further finds that Eastern Edison's methodology for forecasting the number of appliances is appropriate.

b. Average Use Per Appliance

To estimate average use per appliance, Eastern Edison multiplied connected load for an appliance (i.e., appliance wattage ratings) by hours per year of appliance operation (Exh. EUA-2, p. III-27). Based on NEPOOL estimates, the methodology assumed that hours per year of appliance operation would be constant throughout the forecast period, and accounted for changes over time in average use per appliance by adjusting connected load (id., pp. III-27 to III-35).

Eastern Edison assumed 1980 to be its base year, and used 1980 NEPOOL data for its estimate of connected load for this year (id.). The base year connected-load estimate was adjusted for five types of changes -- price changes, appliance efficiency trends, family-size changes, income changes, and energy use changes due to substituting microwave ovens for electric ranges (id., pp. III-36 to III-46). For each appliance type, Eastern Edison forecasted: (1) price changes by developing a price elasticity adjustment based on NEPOOL data; (2) appliance efficiency trends based on 1983 U.S. Department of Energy estimates; (3) family-size effects (for appliances dependent on family size) by developing equations from NEPOOL data for estimating changes in the number of people per household since 1980; (4) income changes by developing income elasticities; and (5) use changes due to substitution of microwave ovens for electric ranges based on microwave oven saturations and the average use of electric ranges with and without microwave ovens (id., pp. III-33 to III-50; Exh. EUA-1, pp. II-23 to II-27). In its 1988 forecast, Eastern Edison updated its forecast of appliance efficiency trends based on NEPOOL data which accounted for efficiency standards specified in recent federal and state legislation (Exh. HO-1, p. II-27).

Although the Siting Council has approved Eastern Edison's methodology in past decisions, the Siting Council has cautioned EECo against the use of regional NEPOOL data because EECo's service territory may exhibit different appliance-related characteristics than that reflected in NEPOOL data. See, e.g., 1986 EUA Decision, 14 DOMSC at 61-66; 1984 EUA Decision, 11 DOMSC at 76-79; Eastern Utilities Associates, 5 DOMSC 10, 18-19 (1980). That is, regionally-based estimates of hours per year of appliance operation, connected load, and price elasticity may not accurately reflect Eastern Edison's service territory.

Nonetheless, the Siting Council acknowledges Eastern Edison's efforts to develop service-territory-specific data. By participating in JUMP, Eastern Edison has made considerable progress in developing end-use data which accurately reflect consumption in its service territory (see Section II.B, supra). Eastern Edison's witness, Mr. Ryan, indicated that the next forecast would reflect the results of the JUMP (Tr. II, p. 10). In addition, EECo is developing a long-range econometric model for either demonstrating the applicability of the current elasticity estimates or implementing appropriate changes to those estimates (see Section II.B, supra). According to EECo, this project should be completed by March 31, 1990 (Exh. EUA-3).

Based on the record in this proceeding, the Siting Council finds that Eastern Edison's methodology for forecasting average use per appliance for the 19 identified residential appliance types is appropriate.

In its next forecast filing, the Siting Council ORDERS Eastern Edison either to reflect the results of the JUMP in its forecast of average use per appliance or else to demonstrate why incorporation of the JUMP results would not be appropriate. The Siting Council FURTHER ORDERS Eastern Edison to file an update on the development of its long-range econometric model in its next forecast filing.

c. Conclusions on the Residential Energy Forecast

The Siting Council has found that Eastern Edison's methodology for forecasting the number of appliances and the average use per appliance for the 19 identified residential appliance types is appropriate. Accordingly, the Siting Council finds that Eastern Edison's methodology for forecasting residential energy requirements is reviewable, appropriate, and reliable.

4. Commercial Energy Forecast

Eastern Edison based its commercial energy forecast on the assumption that total sector consumption is the product of total commercial sector employment and average annual energy intensiveness (i.e., average annual energy consumption per employee) (Exhs. EUA-1, pp. II-30 to II-34, EUA-2, Sec. IV).

The basic structure of the commercial energy forecast remains largely unchanged from past forecasts, although Eastern Edison has enhanced some of the model details. See 1986 EUA Decision, 14 DOMSC at 66-68; 1984 EUA Decision, 11 DOMSC at 79-80; 1982 EUA Decision, 8 DOMSC at 214-216. In the 1982 EUA decision, the Siting Council approved the structure of this model because, in part, "the model is theoretically plausible and appropriate to [Eastern Edison's] service areas and resources" (p. 215). The Siting Council already has accepted Eastern Edison's forecast of total commercial sector employment which was prepared by DRI (see Section II.C.1, supra).

To forecast average annual energy intensiveness for each division, Eastern Edison forecasted base energy intensiveness trends, which were then adjusted for price effects (Exh. EUA-1, p. II-32). Eastern Edison's forecast of base energy intensiveness trends for each forecast year was developed by regressing annual aggregate commercial consumption, assuming constant prices, for each division versus time for the period 1978-1985 (id.). Thus, Eastern Edison based its regression equations on eight observations.[8] For the Fall River division, this regression yielded an equation that EECo accepted as reliable (Exh. EUA-2, p. IV-7). For the Brockton division, however, EECo rejected the base energy intensiveness trends because the regression statistics indicated a poor correlation between the variables (id.). Instead, EECo assumed a constant base energy intensiveness over the forecast period equal to the average actual energy intensiveness from

---

8/ In its 1988 forecast, Eastern Edison added 1986 consumption data to its database (Exh. HO-1, p. II-32). Thus, the 1988 forecast relied on nine data points.

1983 through 1985 (id.). Eastern Edison accounted for changes in base energy intensiveness resulting from electricity price changes by applying a price elasticity adjustment using essentially the same methodology as that used for the residential sector average use per appliance forecast (Exhs. EUA-1, pp. II-32 to II-33, EUA-2, pp. IV-1 to IV-2).

The Siting Council reiterates its concerns about price elasticity estimates based on non-territory-specific sources (see Section II.C.3, supra). EECo has stated, however, that is has begun a long-term plan for improving its price elasticity estimates (see Exh. EUA-3), and the Siting Council accepts at this time the current methodology given the scheduled implementation of Eastern Edison's long-range econometric model by March 31, 1990 (see Section II.C.3, supra).

However, the Siting Council has consistently criticized Eastern Edison's commercial forecast model because it is too highly aggregated and lacks a sufficient historical database. In its 1982 EUA decision, the Siting Council suggested that Eastern Edison "expand its commercial customer database with more end-use specific information" (p. 216). In the 1984 EUA decision, the Siting Council cited the limitations of the commercial forecast model due to its attempt "to explain consumption in the commercial sector by examining historical usage trends over all building types and all end uses .... The EUA forecast could be significantly improved with a more appropriate data base" (p. 80). In that same decision, the Siting Council also encouraged Eastern Edison "to uphold [its] previously expressed goal to disaggregate all commercial class accounts according to two-digit SIC code" which would help capture the diversity of energy use patterns present in the commercial class (p. 80). The Siting Council repeated these concerns in its 1986 EUA decision and "strongly urged" Eastern Edison to proceed with disaggregation of the commercial class by two-digit Standard Industrial Classification ("SIC") code (p. 67).

Eastern Edison's 1987 demand forecast indicates that virtually no progress has been made in disaggregating the commercial class database. Eastern Edison's inability to develop a commercial forecast model useful in explaining historical energy intensiveness trends in commercial consumption within the Brockton division is a clear indication that further disaggregation of data must be considered. Further, the Siting Council notes that inclusion of one additional year of data for the Fall River division reduced the base energy intensiveness regression equation's adjusted R-squared statistic from 72.7 percent in the 1987 forecast to 58.5 percent in the 1988 forecast (Exh. EUA-2, p. IV-7; Exh. HO-1, p. II-32).[9] Such a dramatic reduction in the adjusted R-squared statistic given the addition of only one year of data raises questions about the stability of the base energy intensiveness projections.

Based on the foregoing, the Siting Council finds that Eastern Edison has failed to establish that its methodology for forecasting commercial energy requirements is appropriate and reliable.

5. Industrial Energy Forecast

Eastern Edison based its industrial energy forecast on the assumption that total class consumption is the sum of consumption by the types of industries designated by two-digit SIC codes (Exhs. EUA-1, pp. II-35 to II-45, EUA-2, Sec.

9/ The R-squared statistic, also termed the coefficient of determination, is a measure of the change in one variable explained by a change in another. The R-squared statistic calculated here measures the correlation between commercial consumption in each division and time for the period 1978-1985.

V).[10] The basic premise behind this forecast is that annual energy consumption by each industry is the product of industry employment and average annual energy intensiveness (Exhs. EUA-1, p. II-35).

The basic structure of the industrial energy forecast remains largely the same as the one approved by the Siting Council in 1982, although Eastern Edison has enhanced some of the model details. 1986 EUA Decision, 14 DOMSC at 68-69; 1984 EUA Decision, 11 DOMSC at 81; 1982 EUA Decision, 8 DOMSC at 217-218. The Siting Council has already accepted Eastern Edison's industrial sector employment forecast which was prepared by DRI (see Section II.C.1, supra).

To forecast energy intensiveness for each division, Eastern Edison forecasted base energy intensiveness trends, which were then adjusted for price effects (Exh. EUA-1, p. II-35). Base energy intensity trends were established from regressions of annual energy intensity assuming constant prices for each industrial category versus time for the period 1978-1985 (id.). Although several of the equations incorporated the use of 'dummy' variables for certain years (Exh. EUA-2, pp. V-45 to V-52), Eastern Edison did not explain its theoretical basis for including such variables. Eastern Edison rejected the results of three of the 13 regression

---

10/ For its Brockton division, Eastern Edison modeled 13 types of industries: Food and Kindred Products (SIC code 20); Textiles and Finished Apparel (22, 23); Lumber and Wood/Furniture (24, 25); Paper and Printing (26, 27); Chemicals and Petroleum (28, 29); Rubber and Plastics (30); Leather (31); Stone, Clay, Glass, and Concrete (32); Primary/Fabricated Metals (33, 34); Nonelectrical Machinery (35); Electrical Machinery (36); Transportation and Miscellaneous (37, 39); and Scientific Instruments (38) (Exh. EUA-1, pp. II-41 to II-42). For its Fall River division, Eastern Edison modeled nine types of industries: Textiles (SIC code 22); Finished Apparel (23); Chemicals (28); Nondurables Except Tobacco, Textiles, and Chemicals (20, 24, 25, 26, 27, 29); Rubber and Plastics (30); Leather and Leather Products (31); Primary/Fabricated Metals (33, 34); Electrical Machinery (36); and Durables (32, 35, 37, 38, 39) (id.).

analyses for the Brockton division and four of the nine regression analyses run for the Fall River division because these results indicated weak correlations between base energy intensiveness and the predictor variables (id.). In cases where Eastern Edison rejected the regression analyses, it used constants calculated from the most recent one to three years of data (id.). The Siting Council notes that using as little as one year of data could lead to unreliable estimates of base energy intensiveness. Eastern Edison accounted for changes in base energy intensiveness trends resulting from electricity price changes by applying a price elasticity adjustment employing essentially the same methodology as that used for the residential and commercial sectors (Exhs. EUA-1, pp. II-40 to II-43, EUA-2, p. V-1).

The Siting Council reiterates its concerns about price elasticity estimates based on non-territory-specific sources (see Section II.C.3, supra). However, EECo has commenced a long-term plan for improving its price elasticity estimates (see Exh. EUA-3), and the Siting Council accepts the current methodology given the scheduled implementation of Eastern Edison's long-range econometric model by March 31, 1990 (see Section II.C.3, supra).

Eastern Edison's methodology for forecasting energy intensiveness is, on the whole, reasonable for a company of its size and resources. Accordingly, the Siting Council finds that Eastern Edison's methodology for forecasting industrial energy requirements is reviewable, appropriate, and reliable. However, the Siting Council ORDERS Eastern Edison to document all industrial energy forecast assumptions, including rationales for eliminating data or adding dummy variables, in its next forecast filing.

6. Other Energy Forecasts

Eastern Edison projected energy consumption in each division for four additional classes -- streetlighting, internal use, miscellaneous use, and losses (Exh. EUA-1, pp. II-45 to II-49).[11]

EECo forecasted streetlighting consumption in each division as the product of the number of residential customers and average annual streetlighting energy intensiveness (id., pp. II-45 to II-46).[12] Energy intensiveness was derived from regressions of historical streetlighting use, assuming constant prices, versus time, over the period 1970-1985 (id.). EECo adjusted its projections of energy intensiveness for price effects (id.).

For the Brockton division, Eastern Edison projected that internal use would grow each year at a compound annual growth rate of 2.7 percent,[13] while, in the Fall River division, EECo forecasted that internal use would remain constant (id., p. II-49). However, EECo did not provide the basis of the internal use forecast.

Miscellaneous use in each division, primarily sales to fringe customers, was forecast by extrapolating historical trends (id., p. II-46).

Finally, EECo forecast losses by assuming a constant loss rate throughout the forecast period for each division equal to the average loss rate during the three-year period 1984-1986 (id., p. II-49). The forecasted loss rates are 5.3 percent for the Brockton division and 4.7 percent for the Fall

---

11/ All sales for resale in the System are made by Montaup (Exh. EUA-1, pp. I-2 to I-3). In addition to selling bulk power to Eastern Edison and Blackstone, Montaup sells power to three other electric systems, the Middleborough Gas and Electric Department in Massachusetts, the Newport Electric Corporation in Rhode Island, and the Pascoag Fire District in Rhode Island (id.).

12/ For a discussion of the forecast of the number of residential customers, see Section II.C.3.a, supra.

13/ This growth rate is adjusted to compensate for the addition of Eastern Edison's new West Bridgewater facility (Exh. EUA-1, p. II-49).

River division (id.).

The methodologies for forecasting energy requirements for streetlighting, internal use, miscellaneous use, and losses are the same as those approved by the Siting Council in its 1986 EUA decision. Although EECo failed to describe its methodology for forecasting internal-use energy requirements, the Siting Council finds, for purposes of this review, that Eastern Edison's methodologies for forecasting energy requirements for streetlighting, internal use, miscellaneous use, and losses are reviewable, appropriate, and reliable. However, the Siting Council ORDERS Eastern Edison to describe fully its methodolgy for forecasting internal-use energy requirements in its next forecast filing.

7. Conclusions on the Energy Forecast

The Siting Council has accepted Eastern Edison's methodology for forecasting economic and demographic factors. The Siting Council has found that Eastern Edison's methodology for forecasting electricity prices is reviewable, appropriate, and reliable.

The Siting Council also has found that Eastern Edison's methodologies for forecasting energy requirements for the residential sector, the industrial sector, streetlighting, internal use, miscellaneous use, and losses are reviewable, appropriate, and reliable. However, the Siting Council has found that Eastern Edison has failed to establish that its methodology for forecasting commercial energy requirements is appropriate and reliable.

For purposes of this review, however, the Siting Council finds that, on balance, Eastern Edison's methodology for forecasting energy requirements is reviewable, appropriate, and reliable.

D. Peak-Load Forecast

Eastern Edison derives summer and winter coincident peak-load forecasts from the energy forecast by considering load factors and load management (Exhs. EUA-1, p. II-50, EUA-2, Sec. VII). EECo calculated peak load for each division as the average hourly energy consumption during a year (i.e., total annual energy consumption divided by 8760, the number of hours in a year) divided by the expected load factor (Exh. EUA-2, p. VIII-1).[14]

EECo defined the expected load factor as the average load factor for the summer and winter periods during the three most recent years for which reliable data was available (id.). These years were 1983, 1984, and 1985 for the summer peak, and 1983, 1985, and 1986 for the winter peak (id.). The period used for the winter load factor was the month of December, while EECo did not indicate the month(s) it used for its summer load factor (id., p. VII-2). EECo assumed the expected load factor to be constant over the forecast period (id., p. VIII-1).

The Siting Council has approved this methodology in the past. See 1986 EUA Decision, 14 DOMSC at 71; 1984 EUA Decision, 11 DOMSC at 82; 1982 EUA Decision, 8 DOMSC at 219. Therefore, for purposes of this review, the Siting Council finds that Eastern Edison's methodology for forecasting peak load requirements is reviewable, appropriate, and reliable.

The Siting Council notes, however, that this methodology has significant limitations because of its failure to capture any of the underlying factors that cause peak load. For instance, EECo's peak-load forecast was not disaggregated into customer classes or end uses, and did not account for important peak-load determinants such as weather effects and varying consumption patterns during different months, days, and hours.

14/ See Section II.C, supra, for the Siting Council's review of Eastern Edison's energy forecast.

Companies are required to file forecasts with the Siting Council that are based on substantially accurate historical information and reasonable statistical projections. G.L. c. 164, sec. 69J. In determining whether a statistical projection method is reasonable, the Siting Council may consider the size of the company, the state of art of forecasting, and the extent to which forecast methodology requirements are met. See 980 CMR 7.02(9)(b)(2).

Considerable advances in peak-load forecasting methodologies have been made in recent years. See, e.g., Northeast Utilities, 8 DOMSC 62, 108-109 (1982). Despite these advances, Eastern Edison has made virtually no progress towards improving this critical forecast since the Siting Council's 1982 EUA Decision. Accordingly, the Siting Council ORDERS Eastern Edison to present in its next forecast filing a plan for improving its peak-load forecasting methodology. This plan shall include (a) a comparative analysis identifying the strengths and weaknesses of the present methodology versus alternative methodologies, and (b) a time schedule for implementing methodological enhancements.

E. Conclusions on the Demand Forecast

The Siting Council has found that Eastern Edison has complied with Conditions One and Two of the 1986 EUA decision.

The Siting Council also has found that Eastern Edison's methodologies for forecasting energy requirements and peak-load requirements are reviewable, appropriate, and reliable.[15]

Accordingly, the Siting Council hereby APPROVES Eastern Edison's 1987 demand forecast.

In approving this forecast, the Siting Council notes two concerns. First, Eastern Edison indicated that, in addition to its long-range forecast, it prepared short-range energy and peak-load forecasts for forecasting periods up to three years (Exh. EUA-1, p. II-50; Tr. II, p. 8). As an example of its rationale for preparing a separate short-range forecast, EECo stated that "energy consumption in the short range is influenced by business cycles and specific weather conditions, factors that a long-range model cannot be expected to consider" (Exh. EUA-1, p. II-50). To capture such short-range influences, EECo developed an econometric model for forecasting energy consumption in each division and service class (Exh. HO-59). This model typically incorporates variables for customer numbers, previous electricity sales, electricity prices, weather, income, retail sales, and an industrial production index (id.). Eastern Edison also calculated load factors and peak allocation factors for determining short-range peak loads (id.).

In light of the questions raised in the Siting Council's review of Montaup's supply plan to meet its capability responsibility under a reasonable range of contingencies in the

---

15/ The Siting Council notes that EECo's initial forecast filing (Exh. EUA-1) did not contain sufficiently explicit and complete information to allow the Siting Council to review the forecast. While the initial forecast filing served as an adequate summary document, many of the details required to understand EECo's forecasting methodologies were contained in a technical supplement (Exh. EUA-2) filed several months after the initial forecast. In the past, the Siting Council has held that a company's filing must be self-contained and supported by sufficient documentation. Bay State Gas Company, 11 DOMSC 283, 307 (1987); 1984 EUA Decision, 11 DOMSC at 65. See also 980 CMR 7.03(5)(c). The Siting Council directs Eastern Edison to file a complete and reviewable forecast in all future forecast proceedings.

short run (see Section III.D.1, infra), it is critical that Eastern Edison file a forecast that is accurate and reliable for the short-run period. Accordingly, to the extent Eastern Edison continues to perform short-range energy and peak-load forecasts, the Siting Council ORDERS Eastern Edison to file its short-range energy and peak-load forecasts, including a description of the methodology used to develop those forecasts, in all future forecast filings.

Second, Eastern Edison provided no analysis of demand forecast sensitivity to major assumptions and parameters.[16] In particular, EECo provided no indication of whether, or how, changes in assumptions and parameters such as the economic, demographic, or electricity price forecasts would result in significant changes in the demand forecast. The Siting Council has implemented standards for reviewing supply plans 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. Cambridge Electric Light Company, 15 DOMSC 125, 134-135 (1986) ("1986 CELCo Decision"). Given the uncertainties inherent in energy and peak-load forecasts and their roles as key inputs in the supply planning process, utilities must provide a quantitative basis for analyzing the effects of forecast uncertainties on supply planning.

Accordingly, the Siting Council ORDERS Eastern Edison to provide in its next forecast filing, tests of the sensitivity of the energy and peak-load forecasts to major assumptions and parameters including (a) a quantitative analysis of uncertainties including forecasts of high-growth and low-growth scenarios, and (b) a description of the methodology used to prepare such forecasts.

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

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

The adequacy of supply is a utility's ability to provide sufficient capacity to meet its peak loads and reserve requirements throughout the forecast period. Cambridge Electric Light Company, 12 DOMSC 39, 72 (1985); Boston Edison Company, 10 DOMSC 203, 245 (1984). The diversity of supply measures the relative mixture of supply sources and facility types. The Siting Council's working principle is that a more diverse supply mix, like a diversified financial portfolio, offers lower risks. 1987 BECo Decision, 15 DOMSC at 350. The Siting Council also evaluates whether a supply plan minimizes the cost of power subject to trade-offs with adequacy, diversity, and the environmental impacts of construction and operation of new facilities. Nantucket Electric Company, 15 DOMSC 363, 384-390 (1987) ("1987 Nantucket Decision"). The Siting Council's evaluation 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. Finally, the Siting Council determines whether utilities treat all resources -- including demand management, conventional power plants, and purchases from cogeneration and small power projects and from other utility and non-utility suppliers -- on the same basis when attempting to develop an adequate, diverse and least-cost supply plan.[17] 1987 BECo Decision, 15 DOMSC at 315-323; 1986 CELCo Decision, 15 DOMSC at 133-135, 151-155, 166.

Further, the Siting Council reviews the supply planning processes utilized by utilities. Recognizing that supply planning is a dynamic process undertaken under evolving circumstances, the Siting Council requires utilities to identify, evaluate, and choose from a variety of supply options based on reasonable, appropriate, and documented criteria. A company's consistent and systematic application of such criteria to supply planning decisions indicates that a company is evaluating new supply options in a manner that ensures an adequate supply of least-cost, least-environmental-impact power. These processes and criteria take on added importance when the dynamic nature of the energy generation market and the inherent uncertainty of projections make it difficult for a company to identify with exactitude all the power resources it plans to rely upon in the latter years of its long-range forecast. 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 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

---

17/ In 1986, the Massachusetts Legislature amended the Siting Council's statute to require the Siting Council to approve a company's forecast only if the Siting Council determines that a company has demonstrated that its forecast "include[s] an adequate consideration of conservation and load management." G.L. c. 164, sec. 69J.

reasonable range of contingencies. If a company cannot establish that it has adequate supplies in the short run, that company must then demonstrate that it operates pursuant to a specific action plan guiding it in being able to rely upon alternative supplies should necessary projects not develop as originally planned. 1987 BECo Decision, 15 DOMSC at 309-322; 1986 CELCo Decision, 15 DOMSC at 134-135, 144-150, 165-166. The Siting Council has defined the short run as the period of time necessary to place into service sufficient resources obtainable from the shortest-lead-time resource option under a given company's control in a timely and cost-effective manner. The short run may vary from company to company. 1987 BECo Decision, 15 DOMSC at 297, 307-308.

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

In reviewing a company's resource identification process, the 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 resource evaluation process to all of its identified resource options.

B. Previous Supply Plan Conditions

In its 1986 EUA decision, 14 DOMSC at 93-94, the Siting Council approved Montaup's supply plan subject to two conditions (numbers 3 and 4, overall):

> 3. That [Montaup] monitor the "Teaming Up" program in Rhode Island, and evaluate the cost effectiveness of implementing such a program, or an analagous program in Massachusetts; and
>
> 4. That [Montaup] submit in its 1987 forecast filing a detailed description of all efforts to continue studying controlled water heaters as a load management option.

In response to Condition Three, Montaup submitted an evaluation of Blackstone Valley Electric Company's "Teaming-Up" program (Exh. EUA-2, Section XII). This evaluation showed that the only component of the "Teaming-Up" program that successfully reduced revenue requirements was the electric water heater conservation program (id.; Exh. HO-36). Montaup indicated that, as a result, the electric water heater conservation program will be the only component of the "Teaming-Up" program to be incorporated in Montaup's demand-side management ("DSM") program (Exh. HO-36). Finally, Montaup indicated that other components of the "Teaming-Up" program are still being evaluated (id.; Exh. EUA-1, pp. II-63 to II-67, II-72 to II-73).

In response to Condition Four, Montaup provided a study entitled "Optimization of Controlled Electric Water Heater Time Clock Settings" (Exh. EUA-2, Section X). The study identified an optimal five-hour seasonal control scheme (id.). The costs and benefits of the five-hour seasonal control scheme were examined in detail for the 20-year period of 1986 through 2005 (id.). The study also identified an optional four-hour seasonal control scheme which maintains maximum peak load reductions but is sensitive to various inputs (id.). Finally, the study made four specific recommendations, one of which was that Montaup should immediately implement the four-hour seasonal control scheme (id., p. 3).

Accordingly, the Siting Council finds that Montaup has complied with Conditions Three and Four in the 1986 EUA Decision.

C. Supply Planning Process

In its 1987 forecast, Montaup stated that its supply planning objective is to determine the mix of supply strategies which best meets its planning criteria (Exh. EUA-1, p. II-51). These criteria include:

1. Maintaining capacity adequate to meet the projected load requirements of [Montaup's] customers plus [Montaup's] share of total NEPOOL reserves necessary to maintain pool reliability;

2. Providing sufficient flexibility and diversity in power sources to insure minimal future risk to [Montaup's] ability to meet demand levels; and

3. Providing the level of service and reliability consistent with criteria Nos. 1 and 2 at the lowest cost to the customer (id.).

In determining this "optimal supply mix," Montaup considered new utility generating units, energy and capacity purchases, qualifying facilities ("QF"), independent power producers

("IPP"), and DSM (id.).

Montaup indicated that its supply planning process consisted of three "related activities:" load forecasting, generation planning, and DSM planning (id., p. II-53).[18] Generation planning consisted of identifying feasible generation resource options, developing expansion plans, calculating production costs of each expansion plan over a 30-year period, determining revenue requirements of each expansion plan, and ranking expansion plans based on the net present value of revenue requirements (id., pp. II-53 to II-55). The generation expansion plan with the lowest present value of revenue requirements was designated as the benchmark plan (id.). All other resource options were compared to this benchmark plan (id.).

Montaup began its DSM planning process by identifying alternatives then screening them based on their applicability to the System's service territory and their potential to reduce revenue requirements (id., p. II-55). Montaup stated that, since DSM programs tend to be service-territory specific, its analysis of DSM programs considered factors such as market penetration and load-shape impacts (id.). Once these individual characteristics were evaluated, Montaup compared DSM programs to generation resource options by determining the net present value of revenue requirements to implement each DSM program less fuel and capacity cost benefits over a 20-year period (id.). Montaup used a 20-year period rather than the 30-year period used to evaluate generation resource options due to "the lower level of certainty of the long-range impacts

---

18/ For an evaluation of the Eastern Edison's forecasts of energy and peak-load requirements, see Section II, C and D, supra.

of [DSM] programs" (id.).[19]

D. Adequacy of the Supply Plan

1. Adequacy of the Supply Plan in the Short Run

a. Definition of the Short Run

A company's short-run planning period is defined as the time required for a company to place into service resources under its direct control in sufficient quantities to meet the projected need for new capacity. Montaup asserted that its shortest-lead-time resource, a combustion turbine, would require 3.5 to 4 years to place into service (Tr. I, pp. 13-15; Tr. II, pp. 33-34; Exh. HO-54).[20]

Accordingly, the Siting Council finds that Montaup's short-run period is four years, extending from the summer of 1988 through the winter of 1991-92.[21]

19/ The 1988 forecast reflects a slightly different supply planning process (Exh. HO-1, pp. II-50 to II-78). For instance, the 1988 forecast indicated that Montaup's supply planning objective is to develop an economic and balanced mix of supply resources which will meet the long-term energy and peak-load requirements of the System (id., p. II-50). In addition, rather than dividing its planning process into generation and DSM planning, the 1988 forecast is based on an "integrated planning process" (id.). Nonetheless, the 1987 and 1988 forecasts are based on substantially the same methodology. In reviewing Montaup's supply planning methodology, the Siting Council evaluates the 1987 forecast as updated by the record in this proceeding.

20/ Montaup has retained Stone & Webster Corporation to study the feasibility of siting such a combustion turbine at three locations (Tr. I, pp. 14-15). This study is scheduled to be completed by November 1988 (id.).

21/ In this and future Siting Council proceedings, the short-run period shall commence (1) at the time the final discovery or record response is submitted, or (2) at the time the final hearing is held, whichever is latest. If no discovery or record responses are submitted and no hearings are held, then the short-run period shall commence at the time the forecast is filed.

b. Base Case Supply Plan

The data shown on Table 2 compares Montaup's projected resource capability to its peak-load capability responsibility through the forecast period. This table indicates that Montaup is projecting a short-run capability surplus of 2.1 percent to 22.7 percent during the summer, and a surplus of 0.1 percent to 22.5 percent during the winter.

Accordingly, the Siting Council finds that Montaup 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. To evaluate the adequacy of Montaup's short-run supply plan, the Siting Council analyzes four contingencies: (1) higher than expected load growth; (2) the delay of re-opening the Pilgrim generating station ("Pilgrim") beyond winter 1991-92; (3) the double contingency of high load growth and the delay of re-opening Pilgrim beyond winter 1991-92; and (4) the double contingency of the delay of re-opening Pilgrim and the cancellation or delay of Seabrook I beyond winter 1991-92.[22]

22/ During the proceeding, Montaup filed a high load growth forecast (Exh. HO-52). However, Eastern Edison did not provide any analysis documenting demand forecast sensitivity to key assumptions which might lead to a growth scenario that is higher than its base case forecast. The Siting Council addresses this issue in Section II.E, supra. For purposes of this review, the Siting Council evaluates Montaup's supply plan given the high load growth scenario as filed in Exh. HO-52.

i. <u>High Load Growth Contingency</u>

Under its high load growth scenario, Montaup assumed that its total system load would grow in the summer from 762 MW in 1987 to 873 MW in 1991, a compound annual growth rate of 3.5 percent, and would grow in the winter from 737 MW in 1987-88 to 838 in 1991-92, a compound annual growth rate of 3.3 percent (Exh. HO-52). If all resources in its base case supply plan remain available, Montaup would not realize a resource deficiency under its high load growth scenario (see Table 3).

Accordingly, the Siting Council finds that Montaup has established that it has adequate resources to meet its forecasted capability responsibility in the short run in the event of high load growth.

ii. <u>Pilgrim Re-Opening Contingency</u>

Montaup expects Pilgrim, shut down since April 1986, to re-open by summer 1989, supplying the System with an estimated 70.3 MW in summer and 70.7 MW in winter for the remainder of the forecast period (Exh. HO-52). If all other resources in its base case supply plan remain available to Montaup, a delay beyond the winter of 1991-92 in re-opening Pilgrim would not cause a resource deficiency (see Table 3).

Accordingly, the Siting Council finds that Montaup has established that it has adequate resources to meet its forecasted capability responsibility in the short run in the event of a delay in re-opening Pilgrim.

iii. <u>Double Contingency of High Load Growth and Delay in Re-Opening Pilgrim</u>

One possible combination of short-run contingencies would be the occurrence of high load growth along with the continued shutdown of Pilgrim. If all other resources in its base case supply plan remain available to Montaup, this double contingency would cause a resource deficiency in the summer of 1989 of approximately 3.6 MW (0.4 percent) (see Table 3).

In the event of high load growth and the continued shut down of Pilgrim, Montaup identified an action plan involving increased implementation of existing DSM programs such as additional interruptible contracts and direct load control (Exhs. HO-54, HO-61; Tr. I, pp. 41-42). Montaup's witness, Mr. Hirsh, for example, asserted that Montaup could obtain additional capacity by offering incentives for the right to interrupt customers (Tr. II, pp. 41-42). Given the relatively small resource deficiency that Montaup would realize under this double contingency, this action plan is reasonable.

Accordingly, the Siting Council finds that Montaup has established that it has an action plan to meet any resource deficiencies in the summer of 1989 in the event of both high load growth and a delay in re-opening Pilgrim.

iv. Double Contingency of Delay in Re-Opening Pilgrim and Cancellation or Delay of Seabrook I

Montaup expects Seabrook I to begin operation by January 1990, supplying 33.3 MW of energy to Montaup in both summer and winter (Exhs. HO-1, p. II-59, HO-52).[23] If all other resources in its base case supply plan remain available to Montaup, this contingency along with a delay in re-opening Pilgrim would not cause a resource deficiency in the short run (see Table 3).

Accordingly, the Siting Council finds that Montaup has established that it has adequate resources to meet its capability responsibility in the short run in the event of both

---

23/ In the 1987 forecast, Montaup estimated that Seabrook I would open by January 1988 (Exh. EUA-1, p. II-57). However, in the 1988 forecast, Montaup revised that estimate to January 1990 (Exh. HO-1, p. II-59).

a delay in re-opening Pilgrim and cancellation or delay of Seabrook I.

v. Conclusions on Short-Run Contingency Analysis

The Siting Council has found that Montaup has established that it has (1) adequate resources to meet its forecasted capability responsibility in the short run in the event of high load growth, (2) adequate resources to meet its forecasted capability responsibility in the short run in the event of a delay in re-opening Pilgrim, (3) an action plan to meet any resource deficiencies in the summer of 1989 in the event of both high load growth and a delay in re-opening Pilgrim, and (4) adequate resources to meet its forecasted capability responsibility in the short run in the event of both a delay in re-opening Pilgrim and cancellation or delay of Seabrook I.

Accordingly, the Siting Council finds that Montaup has established that its supply plan is adequate to meet its capability responsibility in the short run under a reasonable range of contingencies.

2. Adequacy of the Supply Plan in the Long Run

Montaup's long-run planning period is the remaining forecast horizon beyond the short run, from summer 1992 through winter 1996-97. Montaup's base case supply plan would satisfy capability responsibility and sales agreements until the winter of 1996-97 (see Table 2).

As previously discussed in Section III.A, *supra*, 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 Montaup'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, infra.

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

3. Conclusions on the Adequacy of the Supply Plan

The Siting Council has found that Montaup has established (1) that its base case supply plan is adequate to meet requirements in the short run, and (2) that its supply plan is adequate to meet its capability responsibility in the short run under a reasonable range of contingencies. The Siting Council also has found that Montaup 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 Montaup's base case supply plan would satisfy capability responsibility and sales agreements until the winter of 1996-1997 of the long-run planning period (see Section III.D.2, supra).

Accordingly, the Siting Council finds that, on balance, Montaup has established that its supply plan ensures adequate resources to meet projected requirements.

E. Least-Cost Supply

The Siting Council reviews Montaup's processes for identifying and fully evaluating resource options.

1. Identification of Resource Options

Montaup identified generation and DSM resource options for both the short run and the long run.[24] The Siting Council focuses its review of Montaup's resource identification process on whether Montaup 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.

a. Available Resource Options

In order to determine whether Montaup compiled a comprehensive array of available resource options, the Siting Council must first determine whether Montaup compiled adequate sets of available resource options for each type of resource identified during this proceeding. The sets of resources identified during this proceeding include: (1) short-run capacity purchases, (2) short-run DSM programs, (3) new Montaup-owned generation, (4) life extension of existing Montaup-owned generating units, (5) long-run utility purchases, (6) long-run QF purchases through EECo's request for proposals ("RFP") process, (7) long-run QF and IPP purchases outside of EECo's RFP process, and (8) long-run DSM programs.

i. Description

Montaup's witness, Mr. DiBenedetto, testified that Montaup identifies short-run capacity purchases whenever Montaup perceives a capability responsibility deficit (Tr. II, pp. 37-38). To identify short-run capacity purchases, Mr. DiBenedetto indicated that Montaup maintains on-going contact

---

24/ The Siting Council has determined that Montaup's short-run planning period is the four-year period from summer 1988 through winter 1991-92. See Section III.D.1.a, *supra*. Montaup's long-run planning period is the remaining years of the forecast period, from summer 1992 through winter 1996-97.

with any New England utility offering to sell excess capacity (id., pp. 37-38). In addition, Montaup typically contacts utilities outside of New England that have excess capacity such as Hydro Quebec in Canada and Niagara Mohawk in New York (Exh. HO-54). Thus, Montaup's set of available short-run capacity purchases consists of utilities, whether inside or outside of New England, offering to sell excess capacity.

Montaup did not indicate how it compiled its set of available short-run DSM programs. However, Montaup asserted that this set includes an interruptible contract program which presently provides about 2.74 MW of interruptible capacity (Tr. I, p. 40; Exh. HO-54, p. 5). Montaup indicated that it is pursuing additional interruptible contracts which Montaup estimates would yield summer and winter peak load reductions of 6.0 MW to 6.2 MW during the short run (Exhs. HO-1, p. II-65, HO-54, p. 5). In addition, EUA commissioned a study of available short-run capacity in the form of a load management cooperative within the EUA service area (Tr. I, pp. 40-41). Other short-run DSM programs include direct load control and customer self-generation (Tr. II, pp. 41-43; Exh. HO-61).

Although Montaup did not explain how it compiled its set of new Montaup-owned generation, Montaup noted that this set includes combustion turbines, combined-cycle plants, fluidized-bed coal plants, and nuclear plants (Tr. I, pp. 127-131).

With respect to life extension, Montaup owns all or part of eight generating plants that are currently on line including Somerset station (100 percent ownership), Canal 2 (50 percent), Massachusetts Yankee (4.5 percent), Connecticut Yankee (4.5 percent), Maine Yankee (3.6 percent), Vermont Yankee (2.25 percent), Millstone 3 (4.0 percent), and Wyman 4 (2.0 percent) (Exh. EUA-1, p. V-13). In its April 1, 1988 "NEPOOL Forecast Report of Capacity, Energy, Loads and Transmission" ("1988 CELT

Report"),[25] NEPOOL indicated that "guideline retirement dates" for the Somerset station units are 1991 for Somerset 5, 1999 for Somerset 6, 2000 for Somerset jet 1, and 2001 for Somerset jet 2. However, Montaup's witness, Mr. Kremzier, testified that Montaup assumes none of the Somerset units actually will be retired prior to 2005 (Tr. I, pp. 134-135). Of the remaining plants, none are scheduled for retirement within the Siting Council's 10-year forecast horizon (1988 CELT Report). Thus, Montaup maintains that it has no candidates for generating unit life extension.

Montaup did not explain how it compiled its set of long-run utility purchases, but indicated that this resource set includes a purchase from Potter 2 (Exh. EUA-1, p. V-13).

With respect to the set of available long-run QF purchases, Eastern Edison issued an RFP to purchase QF power pursuant to Massachusetts Department of Public Utilities ("MDPU") regulations 220 CMR 8.00 (Exhs. HO-1, p. II-60, HO-31C).

Although Montaup did not explain how it compiled its set of available long-run QF and IPP purchases outside of EECo's RFP process, Montaup indicated that this resource set includes at least 13 potential purchases (see Section III.E.1.b.i, _infra_).

To develop a set of long-run DSM programs, Montaup stated that it reviewed DSM literature, researched DSM markets, and contacted other utilities (Exh. HO-56, p. 1). Montaup's sources of available programs included Electric Power Research Institute ("EPRI") reports, contacts with New England and California utilities, and the "Power to Spare" report (Tr. I, pp. 111-112). Although Montaup did not provide a set of available long-run DSM programs, Montaup indicated that this

---

25/ The Siting Council takes administrative notice of the 1988 CELT Report pursuant to an agreement with Montaup, as reflected in a letter from the Hearing Officer to Montaup dated October 28, 1988.

resource set includes eight programs: efficient light rebates ("ELITE"), emergency generator assistance ("EGAP"), water heating conservation ("WRAP"), water heating load management ("WAT41"), air conditioner conservation ("AIRCON"), swimming pool load management ("FILTER"), interruptible contracts, and streetlighting conservation (Exh. HO-1, pp. II-62 to II-68; Tr. I, p. 109).

ii. Analysis

Montaup has provided evidence of compiling adequate sets of available resource options for only two types of resources -- short-run capacity purchases, and long-run QF purchases through EECo's RFP process. For short-run capacity purchases, Montaup maintains contact with utilities both inside and outside of New England that are offering to sell excess capacity. For long-run QF purchases through EECo's RFP process, EECo does not maintain a set of available QF purchases, perhaps an unmanageable task given the size and dynamics of the QF marketplace. Instead, EECo issued an RFP announcing its intention to add QF purchases.

The Siting Council finds that these two methods are appropriate, and therefore finds that Montaup has compiled adequate sets of available resource options for short-run capacity purchases, and long-run QF purchases through EECo's RFP process.

In regard to life extension of Montaup-owned generating units, Montaup maintains that none of its generation is scheduled for retirement until after the Siting Council's 10-year planning horizon. Although Montaup did not explain the difference between its assumed Somerset station retirement date and NEPOOL's guideline retirement date, for purposes of this review, the Siting Council accepts Montaup's assumption that it has no available life extension options.[26]

However, the Siting Council finds that, for all of the remaining types of resources -- short-run DSM programs, new Montaup-owned generation, long-run utility purchases, QF and IPP purchases outside of EECo's RFP process, and long-run DSM programs -- Montaup failed to indicate how it compiled sets of available resource options. None of these sets are sufficiently large to indicate that they represent the broad spectrum of resource options available to the electric industry. For instance, in developing its set of available long-run DSM programs, Montaup reviewed both utility and non-utility sources, but reported only eight available programs during this proceeding. Such a limited number clearly omits a wide variety of DSM programs.

Accordingly, the Siting Council finds that, on balance, Montaup has failed to establish that it compiled a comprehensive array of available resource options.

b. Development and Application of Screening Criteria

To determine whether Montaup 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 Montaup's seven resource sets.[27]

26/ In future proceedings, Montaup should document carefully guideline retirement dates for all generating units in which Montaup has equity or joint ownership and any programs necessary to extend generating unit lives beyond their guideline retirement dates.

27/ In Section III.E.1.a.ii, supra, the Siting Council accepted Montaup's assumption that one of its eight original resource sets, life extension of existing Montaup-owned generating units, does not contain any resource options. Therefore, Montaup has seven sets of available resource options.

i. Description

Mr. DiBenedetto stated that Montaup screens available short-run capacity purchases based on estimates of demand costs and production costing analyses of energy costs (Tr. II, p. 38). However, Montaup did not provide the demand-cost or energy-cost criteria used to screen its set of available short-run capacity purchases, nor did Montaup identify the purchases which met these criteria. Nevertheless, Montaup's supply plan included short-run capacity purchases from Northeast Utilities ("NU") "slice of system", NU gas turbines/Millstone 3, Hydro Quebec, Stony Brook, Middletown 4, Montville 6, Cleary 9, and NU jet turbines (Exh. HO-61A).

Montaup did not explain how it developed and applied criteria for screening available short-run DSM programs. However, Mr. Hirsh provided that, of the four programs available in this set, only the interruptible contract program proceeded to full evaluation (Tr. I, p. 40).[28]

In regard to new Montaup-owned generation, Montaup established the following criteria for screening the resource options available in this set: (1) construction feasibility, (2) fuel type (natural gas, oil, or coal) and availability, (3) plant sizes that are 100 MW or smaller, (4) stage of technology development, and (5) environmental impacts (Tr. I, pp. 127-131; Exh. HO-1, p. II-53). Mr. Kremzier asserted that these criteria resulted in the identification of combustion turbines, combined-cycle plants, and fluidized-bed coal plants as new long-run Montaup-owned generation options that qualify for further evaluation (Tr. I, pp. 127-131).

With respect to long-run utility purchases, Mr. Kremzier stated that Montaup does "a quick analysis of whether [revenue

---

28/ Although Montaup indicated that six other DSM programs would yield small amounts of short-run capacity (Exh. HO-1, p. II-65), Montaup did not identify those programs as short-run programs.

requirements] will be at or below our base case resource plan" for every such potential purchase (Tr. I, p. 128). The only long-run utility purchase that Montaup indicated met this criterion was the purchase from Potter 2.

To screen available QFs compiled from EECo's RFP process, EECo specified minimum bidder criteria or "threshold values" for purchase prices,[29] payment schedules, contract terms, financial coverage, site-acquisition status, thermal-use status, fuel availability, and interruptibility (Exh. HO-31C, pp. 9-10).[30] The MDPU approved Eastern Edison's RFP on October 1, 1987 (Exh. HO-31B). EECo issued its RFP on October 8, 1987, and, as a result of the screening criteria, identified a total of 170 MW of available QF purchases (Exh. HO-1, p. II-60).

Although Montaup did not provide its criteria for screening its set of long-run purchases from available QFs and IPPs outside of EECo's RFP process, Mr. Kremzier noted that Montaup screens cogenerators by determining whether the purchase price would be at or below a ceiling price schedule developed from Montaup's benchmark supply plan revenue requirements (Tr. I, p. 128). As a result, Montaup identified available long-run QF and IPP purchases outside of EECo's RFP process including Northeast Energy Associates Phases I and II, Ocean State Power Phases I and II, Applied Energy Services, Altresco, FEDCO, Fall River cogeneration, Tamal, Oxford cogeneration, Cumberland cogeneration, a hydroelectric facility, and a wood-waste burning facility (Exh. HO-1,

---

29/ EECo indicated that purchase prices must be less than or equal to a ceiling price schedule developed from its supply plan revenue requirements (Exh. HO-31C, pp. 9-10).

30/ EECo's RFP specified that certain other threshold values, including QF status, interconnection standards, and operating standards, must be met prior to the actual in-service date (Exh. HO-31C, p. 10). However, these criteria were not applied at the initial screening stage.

pp. II-59 to II-62; Exhs. HO-33, HO-52).

For available long-run DSM programs, Montaup applied two types of screening criteria -- an "intuitive matrix" and economic potential (Tr. I, pp. 109-117). An intuitive matrix, a concept developed by EPRI, categorizes programs based on non-economic factors such as types of DSM strategies (e.g., load shedding, load shifting, strategic conservation) and targeted classes of service (id.; Exh. HO-56, p. 2). In order to apply its intuitive matrix to screen available resource options, Montaup developed resource priorities which were, in order, (1) reducing peak load in the summer, (2) reducing peak load in the winter, and (3) reducing baseload energy requirements (Exh. HO-56, p. 2; Tr. I, p. 113). In support of these priorities, Montaup cited planning studies and system load shape characteristics (Exh. HO-56, p. 2).

Economic screening of long-run DSM programs consisted of collecting information about available program costs and benefits through methods such as saturation surveys, customer contacts, and the experiences of other utilities (Tr. I, pp. 109-117). Montaup screened out programs that it believed would fail to result in net benefits (id.). For instance, Mr. Hirsh stated that "pure conservation where it doesn't reduce peak in either peak time has to be very cheap for us to consider it" (id., p. 113).

Montaup identified eight long-run DSM programs which met these screening criteria: ELITE, EGAP, WRAP, WAT41, AIRCON, FILTER, interruptible contracts, and streetlighting conservation (Exh. HO-1, pp. II-62 to II-68; Tr. I, p. 109).

ii. Analysis

Montaup provided no evidence of developing screening criteria and consistently applying such criteria to its set of available short-run DSM programs. Given Montaup's screening of short-run DSM programs to only one program, the interruptible contract program, Montaup's failure to develop and apply objective screening criteria may have resulted in elimination of feasible programs that would be economically beneficial in meeting short-run capability responsibility obligations. In fact, the screening of a broad spectrum of short-run DSM programs is especially important given Montaup's assertion that it would respond to certain contingencies by obtaining up to 20.4 MW of additional DSM capacity by winter 1988-89 (Exh. HO-61A). Yet the record demonstrates that the only short-run DSM resource option that Montaup identified was its interruptible contract program which Montaup estimated would yield only about 6.0 MW of load reduction by winter 1988-89 (Exh. HO-1, p. II-65). Therefore, the Siting Council finds that Montaup has failed to establish that it developed and applied appropriate criteria for screening its set of available short-run DSM programs.

With respect to purchases from existing generating units, both short-run capacity purchases and long-run utility purchases, Montaup applied an initial revenue requirements test for a preliminary indication of whether purchases would result in net benefits. While a revenue requirements test may be appropriate, Montaup did not demonstrate how it screened available options to reach the eight short-run capacity purchases and one long-run utility purchase included in the supply plan. Therefore, the Siting Council finds that Montaup has failed to establish that it developed and applied appropriate criteria for screening its sets of available short-run capacity purchases and long-run utility purchases.

In regard to new generation resources -- new Montaup-owned generation, long-run QF purchases through EECo's RFP process, and long-run QF and IPP purchases outside of EECo's RFP process -- Montaup failed to apply consistent screening criteria to these three resource sets. For instance, EECo's RFP specified both revenue-requirements and non-revenue-requirements criteria -- i.e., prices at or below EECo's ceiling price schedule, payment schedules, contract term, financial coverage, site-acquisition status, thermal-use status, fuel availability, and interruptibility -- for prospective QF bidders. At the same time, for new Montaup-owned generation, Montaup screened available resource options based entirely on non-revenue-requirements criteria including construction feasibility, fuel type and availability, plant size, technology development, and environmental impacts. Finally, in screening purchases from QFs and IPPs outside of EECo's RFP process, the only criterion that Montaup stated it considered was the price of available purchases relative to its ceiling price schedule developed from benchmark supply plan revenue requirements.

The Siting Council accepts, for the purposes of this review, Montaup's screening criteria for the set of long-run QF purchases through EECo's RFP process. However, Montaup provided no justification for developing and applying inconsistent screening criteria to new Montaup-owned generation and long-run QF and IPP purchases outside of EECo's RFP process. Arguably, every revenue-requirements and non-revenue-requirements screening criteria developed and applied within EECo's RFP process could be applied to purchases from new QFs and IPPs outside of the RFP process. The criteria for new Montaup-owned generation might also include some of those from the RFP process such as site-acquisition status or a revenue requirements comparison. If Montaup perceives differences between types of new generation then it should develop a consistent set of core criteria and, if necessary, specialized criteria to accommodate those differences. Given these inconsistent screening criteria, the Siting Council finds that Montaup has failed to establish that it developed and applied appropriate criteria for screening its sets of available new Montaup-owned generation and long-run QF and IPP purchases outside of EECo's RFP process.

In regard to long-run DSM programs, the overall structure of Montaup's screening process is reasonable for a company of Montaup's size and resources: Montaup determines resource objectives, applies an intuitive matrix to search for the types of programs that address those objectives, and applies an economic screening process to rank those programs based on expected net benefits. However, Montaup provided no further details of the process used to screen available long-run DSM programs to the eight identified. Virtually none of the criteria used to classify types of DSM resource options within the intuitive matrix process were provided. Neither did Montaup provide evidence that it specified reasonably objective economic criteria. Montaup's example of specifying a criterion that conservation measures which do not reduce peak load must be "very cheap" is entirely subjective and could result in screening out programs with favorable benefits.

Regardless of whether this process demonstrates that Montaup developed appropriate criteria for screening long-run DSM programs, Montaup's witness, Ms. White, testified that Montaup applied markedly different screening criteria:

> The initial screening that we have done with the programs that we have were basically to depend on other companies' experience and to try to get into quickly programs that we knew would be cost effective and provide benefits both to the Company and to our customers (Tr. I, p. 110).

Thus, while Montaup described a reasonable process for screening long-run DSM programs -- determining resource objectives, applying an intuitive matrix, and ranking programs economically -- Montaup clearly failed to apply that process.

The Siting Council acknowledges Montaup's progress toward establishing a process for identifying long-run DSM programs. Montaup even expedited its analyses of eight long-run DSM programs known to have net benefits so as to avoid delay in implementing those programs. The fact remains, however, that Montaup screened out all but those eight long-run DSM programs before full evaluation. Rejecting all potentially beneficial long-run DSM programs except eight in advance of complete evaluation precluded a reasonable assessment of potential DSM benefits to the System. The only reason cited for this rejection was a staffing constraint on implementing programs (Tr. I, pp. 121-124). However, integrating staffing constraints into a revenue requirements analysis would be a more appropriate means to consider them. Thus, Montaup's identification process may have prevented cost-effective long-run DSM programs from providing energy and capacity benefits to the System.

Therefore, the Siting Council finds that Montaup has failed to establish that it developed and applied appropriate criteria for screening its set of long-run DSM programs.

Accordingly, based on the foregoing, the Siting Council finds that Montaup has failed to establish that it 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 Montaup has failed to establish (1) that it compiled a comprehensive array of available resource options, and (2) that it developed and applied appropriate criteria for screening its array of available resource options.

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

2. Evaluation of Resource Options

The Siting Council reviews Montaup's resource evaluation process to determine whether Montaup (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 the resource options identified in Section III.E.1, supra.

a. Description

Montaup evaluated short-run capacity purchases by calculating the revenue requirements of each potential purchase and then signing contracts for those that reduced revenue requirements (Exh. HO-1, pp. II-53 to II-55). If none of the identified purchase options reduced revenue requirements, and Montaup required capacity to remain adequate, Montaup asserted that it purchased the most economic capacity available (id.). As inputs to the revenue requirements analysis, Mr. DiBenedetto testified that Montaup estimated purchase demand costs and used a production costing model to calculate purchase energy costs (Tr. II, pp. 37-38).

The only short-run DSM program identified by Montaup was its program for contracting interruptible capacity (see Section III.E.3.a.ii, supra). Mr. Hirsh described Montaup's evaluation process for interruptible contracts as an analysis of short-run capacity purchases in order to establish the incentives necessary to attract interruptible load (Tr. I, p. 58).

Montaup stated that its objective in evaluating long-run resource options was to establish the resource plan that resulted in the lowest present value of expected revenue requirements over a wide range of contingencies (Exh. HO-1, p. II-53). For each identified resource option, Montaup estimated energy costs using UPLAN, and estimated capital costs using the Resource Planning Ancost program ("Ancost") (Exh. HO-40). To calculate the revenue requirements associated with capital costs, Montaup used an in-house model (Exh. HO-1, pp. II-53, II-62).

For new Montaup-owned generation, long-run utility purchases, and long-run QF and IPP purchases outside of EECo's RFP process, Montaup's capacity cost analysis evaluated capital costs, return on investment, taxes, depreciation, fixed operation and maintenance ("O&M") costs, and administrative costs (Exh. HO-40). Montaup did not indicate whether these capital-cost estimates included transmission, distribution, and siting costs. For long-run DSM programs, Montaup evaluated equipment costs, promotional expenses, incentive payments, and incremental administrative costs (id.). Evaluation of DSM benefits were based on avoided capacity costs and marginal energy benefits (Exh. HO-45, p. 2). Montaup's evaluation of long-run DSM programs did not consider effects on reserve requirements, system losses, and transmission and distribution capacity requirements (Tr. I, pp. 98-100, 105-107; Tr. II, pp. 108-114).

Montaup established a long-run benchmark generation expansion plan by calculating the lowest present value of expected revenue requirements over a 30-year planning horizon for the existing supply plan with new Montaup-owned generation additions as necessary to meet forecasted requirements (Exhs. HO-1, pp. II-53 to II-55, HO-63, p. 7). Montaup designed the benchmark plan to meet System requirements over a range of values for load growth, customer generation, and fuel costs (Exh. HO-1, pp. II-53 to II-55). This plan determined a benchmark ceiling price against which Montaup compared all alternative resource options (id.).

To evaluate each identified long-run utility purchase, long-run purchase from QFs and IPPs outside of EECo's RFP process, and long-run DSM program, Montaup (1) adjusted the benchmark plan for each added purchase or DSM program, (2) re-computed the capital and energy costs of the adjusted benchmark plan, (3) compared the adjusted benchmark plan's expected revenue requirements to the benchmark plan's expected revenue requirements over the purchase period or, for DSM programs, the expected life of a program's benefits, and (4) updated the benchmark plan to include all purchases and DSM options that reduced expected revenue requirements (Tr. I, pp. 96-97; Exhs. HO-1, p. II-62, HO-57).

EECo evaluated the 170 MW of qualifying bids received from its RFP based on (1) net economic benefit to ratepayers over the life of the contract, (2) impact to ratepayers during the initial years of the contract term, (3) ability of the proposed facility to meet EECo operational criteria, and (4) the likelihood of project success (Exh. HO-31C, p. 13). To evaluate bids, EECo ranked each bid on the basis of price, security, and quality (id., pp. 13-15). The price factor was based on the avoided costs of Montaup-owned generation, transmission, and distribution; the security factor was based on such factors as the amount and duration of contract payment front-loading, and the developer's ability to cover projected operating costs; the quality factor was based on non-price factors such as dispatchability, fuel type, and project design (id., Appendix A, p. 2). Although EECo specified that its supply block would be 29.2 MW (id., p. 4), the two winning bids, Duro Finishing and Wood Energy, totaled about 40 MW (Exhs. HO-1, pp. II-50 to II-60, HO-61). Montaup included these two projects in its benchmark supply plan (id.).

b. Analysis

In regard to short-run resource options, the Siting Council finds that Montaup did not treat all of its identified resource options on an equal footing. As shown in Table 4, Montaup offered substantially lower incentives to acquire interruptible capacity than Montaup paid to acquire generation capacity. For example, Montaup estimated that the revenue required to place interruptible capacity in service is $27.23 per kilowatt ("KW").[31] In comparison, Montaup's least expensive demand charge for a short-run capacity purchase during summer 1988, 25 MW of jet (peaking) capacity from NU, cost $30.00/KW. Not only did Montaup pay an additional $2.77/KW for the NU jet purchase over its interruptible contract price, but Montaup also paid 5.4 cents per

---

31/ For load management programs such as interruptible contracts, Montaup calculated levelized revenue requirements as a demand cost (Exh. HO-65). Thus, the interruptible contract program does not have an energy cost.

kilowatthour ("KWH") of NU jet energy purchased. All other short-run purchases set forth in Table 4 carry even greater demand charges, as well as energy charges. Montaup's largest capacity purchase in 1989, the NU "slice of system" purchase,[32] will cost $175.00/KW (demand and transmission charges) and carry a 2.2¢/KWH energy charge. Thus, the interruptible contract price offered by Montaup during the short run is substantially below the price offered for utility purchases.

At this reduced price, Montaup expects to contract for only 6.2 MW of interruptible capacity by 1991 (see Table 4). At the same time, Montaup signed a contract with NU to purchase additional "slice of system" capacity of 147.0 MW in 1990 for a combined generation and transmission demand charge of $180/KW. In 1991, this charge escalates to $191/KW for 166.7 MW. These NU "slice of system" purchases are roughly six to seven times more expensive than the interruptible contracting cost before the inclusion of energy charges. In a case where price offers

---

32/ Montaup's 1989 NU "slice of system" purchase consists of the following (Exhs. HO-57, HO-62E, HO-63):

Unit	Capacity	Demand Cost
Millstone 1	8.0 MW	$220.76/KW
Millstone 2	8.0	231.01
Millstone 3	13.2	534.42
Middletown 3	3.9	71.38
Middletown 4	6.4	39.48
Montville 6	6.6	51.14
Norwalk Harbor 1	2.6	71.75
Norwalk Harbor 2	2.8	72.55
South Meadow	2.9	16.48
Cos Cob	1.3	11.68
Middletown 10	0.8	12.69
Cogeneration	7.0	0.00
Northfield	11.5	29.14
Total/Average	73.5	$164.00/KW

Average energy costs are 2.2¢/KWH; transmission costs are about $11/KW.

for short-run capacity purchases are so much higher than offers for interruptible contracts, it is not surprising that a company attracts 160 MW of capacity purchases, but only 6.1 MW of interruptible capacity.

The record demonstrates that Montaup has failed to treat its short-run interruptible contracting program on an equal footing with its short-run capacity purchases, despite Mr. Hirsh's assertion that the 1989 peak generation capacity costs were the determinant of interruptible contract incentives. As a result of the substantially lower prices offered for interruptible contracts, Montaup has not realized the full potential of this program and may have failed to acquire interruptible contracts that not only would have been less costly to its customers on a capacity cost basis, but would have avoided the energy costs associated with generation purchases. Therefore, given the substantially lower prices offered for interruptible contracts and Montaup's identification of only one short-run DSM program, the Siting Council finds that Montaup has failed to demonstrate that its short-run capacity purchases of NU "slice of system," NU gas turbines/Millstone 3, Hydro Quebec, Stony Brook, Middletown 4, Montville 6, Cleary 9, and NU jet turbines are least cost.

Based on the foregoing, the Siting Council finds that Montaup has failed to treat short-run DSM programs on an equal footing with short-run capacity purchases. Accordingly, the Siting Council finds that Montaup has failed to (1) develop a resource evaluation process which fully evaluates all short-run resource options, and (2) apply a resource evaluation process to all of the identified short-run resource options.

With regard to long-run resource options, the Siting Council accepts Montaup's use of (1) UPLAN's production costing sub-module to evaluate energy costs, (2) Ancost to estimate capital costs, and (3) the in-house model to calculate the revenue requirements associated with capital costs. In addition, for the purposes of this review, the Siting Council accepts the additions of Duro Finishing and Wood Energy to

Montaup's benchmark plan. See Section III.E.1.b.ii, supra.

However, while Montaup's use of production costing, capital-cost estimating, and revenue requirements models is a logical approach to evaluating potential resource options, Montaup neglected several key factors in its analysis. First, Montaup did not establish that its evaluation of new Montaup-owned generation, long-run utility purchases, and long-run QF and IPP purchases outside of EECo's RFP process included the costs associated with transmission, distribution, or siting. If these costs were not incorporated into revenue requirements analyses, Montaup may have underestimated the cost of its benchmark plan or any potential purchases outside of the RFP process.

Next, despite Montaup's observation that DSM programs could reduce overload on its transmission system, it failed to attribute any economic value to DSM programs for deferring transmission investments (Tr. I, pp. 103-106; Tr. II, pp. 113-117). For example, Montaup indicated that load growth in the Eastern Edison service territory may overload Montaup's P-11 transmission line by 1990, thereby requiring transmission reinforcement (Exh. HO-1, p. II-82; Exh. EUA-1, p. II-84). Montaup expects this reinforcement to cost about $2.25 million, or $25/KW for a 90,000 KW increase in transmission capacity (Exh. HO-66). Yet even though Montaup correlated this transmission investment directly to load growth, Montaup does not credit any transmission capacity deferral to DSM programs that could mitigate load growth effects (Tr. II, pp. 103-109).

Finally, even though Mr. Hirsh observed that any reduction in load reduces transmission and distribution losses resulting in economic benefits for Montaup (Tr. II, p. 117), Montaup excluded these economic benefits from its evaluation of DSM programs.

Therefore, the Siting Council finds that Montaup's evaluation process has failed to incorporate all the economic benefits of DSM programs into its economic analyses resulting in an inaccurate assessment of the costs and benefits of DSM programs relative to generation resource options. Therefore, the Siting Council finds that Montaup has failed to treat long-run DSM programs on an equal footing with long-run generation resource options. Accordingly, the Siting Council finds that Montaup has failed to (1) develop a resource evaluation process which fully evaluates all long-run resource options, and (2) apply a resource evaluation process to all identified long-run resource options.

Based on the foregoing, the Siting Council finds that Montaup has failed to evaluate fully a reasonable range of short-run and long-run resource options.

3. Conclusions on Least-Cost Supply

The Siting Council has found (1) that Montaup has failed to establish that it identified a reasonable range of resource options, and (2) that Montaup has failed to evaluate fully a reasonable range of short-run and long-run resource options.

In the past, the Siting Council has required companies to consider and treat DSM programs on an equal footing with generation resource options. Braintree Electric Light Department, EFSC 87-32, pp. 8-10, 14-18 (1988); Middleborough Gas and Electric Department, 17 DOMSC 197, 205-207, 211-214 (1988); Northeast Utilities, 17 DOMSC 1, 19-21, 26-41 (1988); Massachusetts Municipal Wholesale Electric Company, 16 DOMSC 95, 109-111, 127-137 (1987); 1987 BECo Decision, 15 DOMSC at 300-302, 339-349; 1986 CELCo Decision, 15 DOMSC at 133-135, 151-155, 158-164; 1986 EUA Decision, 14 DOMSC at 73-92; Cambridge Electric, Canal Electric, Commonwealth Electric Companies, 12 DOMSC 39, 79-91 (1985); 1984 EUA Decision, 11 DOMSC at 84-108. In fact, in 1986, the Massachusetts Legislature amended the Siting Council's statute to require the Siting Council to approve a company's forecast only if the Siting Council determines that a company has demonstrated that its forecast "include[s] an adequate consideration of conservation and load management." G.L. c. 164, sec. 69J. Thus, while the equal footing standard has been clarified here, the Siting Council has applied this same standard consistently in the past.

Accordingly, the Siting Council finds that Montaup has failed to establish that its supply plan ensures a least-cost energy supply.

F. Diversity of Supply

In 1988, Montaup projected that oil would provide 46.9 percent of Montaup's primary energy requirements (Exh. HO-1, p. II-56). In the same year, Montaup projected that coal and nuclear fuels would provide 29.6 percent and 20.7 percent of EUA System's primary energy, respectively (id.). By 1992, Montaup expected to diversify its primary fuel sources by increasing its reliance on natural gas, hydro power, nuclear fuel, and non-differentiated cogeneration fuels, and decreasing its reliance on oil (id.). Over the forecast period, Montaup intends to add 154.8 MW of natural gas capacity, 54.5 MW of hydroelectric power capacity, 33.3 MW of nuclear capacity, 18 MW of coal capacity, and 42 MW of cogeneration capacity of an unspecified fuel type (Exh. HO-52, p. 3).

Accordingly, the Siting Council finds that Montaup has established that its primary fuel supply is adequately diversified.

G. Conclusions on the Supply Plan

The Siting Council has found that Montaup complied with Conditions Three and Four in the 1986 EUA Decision.

The Siting Council also has found (1) that Montaup has established that its supply plan ensures adequate resources to meet projected requirements, (2) that Montaup has failed to establish that its supply plan ensures a least-cost energy supply, and (3) that Montaup has established that its primary fuel supply is adequately diversified.

Accordingly, the Siting Council hereby REJECTS the 1987 supply plan of the Montaup Electric Company.

IV. DECISION AND ORDER

The Siting Council hereby APPROVES the 1987 demand forecast of the Eastern Edison Company, and hereby REJECTS the 1987 supply plan of the Montaup Electric Company.

The Siting Council ORDERS Eastern Edison Company in its next forecast filing:

(1) (a) to demonstrate that it has reviewed other methodologies or indices for forecasting demand costs, and (b) to demonstrate that the CPI-based methodology is appropriate, or to implement a different methodology deemed appropriate in light of the Siting Council's concerns;

(2) to reflect the results of the JUMP in its forecast of average use per appliance or to demonstrate why incorporation of the JUMP results would not be appropriate;

(3) to file an update on the development of its long-range econometric model;

(4) to document all industrial energy forecast assumptions, including rationales for eliminating data or adding dummy variables;

(5) to describe fully its methodology for forecasting internal-use energy requirements; and

(6) to present a plan for improving its peak-load forecasting methodology. This plan should include (a) a comparative analysis identifying the strengths and weaknesses of the present methodology versus alternative methodologies, and (b) a time schedule for implementing methodological enhancements.

The Siting Council FURTHER ORDERS Eastern Edision Company in all future forecast filings:

(7) to file its short-range energy and peak-load forecasts including a description of the methodology used to develop those forecasts; and

(8) to provide tests of the sensitivity of the energy and peak-load forecasts to major assumptions and parameters including (a) a quantitative analysis of uncertainties including forecasts of high-growth and low-growth scenarios, and (b) a description of the methodology used to prepare such forecasts.

The Siting Council FURTHER ORDERS Eastern Edison Company and Montaup Electric Company to file their next forecast on April 1, 1990.

Frank P. Pozniak

Frank P. Pozniak
Hearing Officer

APPROVED by a majority of the Energy Facilities Siting Council at its meeting of November 15, 1988 by the members and designees present and voting. Voting for approval of the Tentative Decision as amended: Sharon M. Pollard (Secretary of Energy Resources); Stephen Roop (for James S. Hoyte, Secretary of Environmental Affairs); Barbara Anthony (for Paula W. Gold, Secretary of Consumer Affairs and Business Regulation); Jeanette Willett (for Joseph D. Alviani, Secretary of Economic Affairs); Madeline Varitimos (Public Environmental Member); and Joseph Joyce (Public Labor Member). Voting against approval of the Tentative Decision as amended: Stephen D. Umans (Public Electricity Member). Absent: Dennis J. LaCroix (Public Gas Member).

Sharon M. Pollard
Chairman

Dated this 15th day of November, 1988

TABLE 1

Eastern Edison Company
Demand Forecast by Customer Class

EECo	Annual Energy Requirements (GWH) 1988	1996	Average Annual Compound Growth Rate 1988-1996
Residential:			
Heating	120	146	2.5%
Non-Heating	889	1070	2.3%
Commercial	1004	1230	2.6%
Industrial	367	430	2.0%
Streetlighting and Miscellaneous	17	18	0.7%
Losses/Internal Use	135	163	2.4%
Total	2533	3056	2.4%

	Peak-Load Requirements (MW) 1988	1996	Average Annual Compound Growth Rate 1988-1996
EECo Summer	492	593	2.4%
EECo Winter	482	582	2.4%

Note:

a. Totals may not add due to rounding. Statistics for EECo include the Fall River and Brockton divisions before load management.

Source: Exh. HO-1

TABLE 2

Montaup Electric Company
Consolidated Base Case Demand Forecast and Supply Plan

Summer and Winter Peaks
(MW)

Year	Capability Responsibility[a]	Existing Capability[b]	Additional Capability[c]	Base Case Surplus
S 1988	932.6	940.3	11.5	19.2 (2.1%)
W 1988-89	938.4	926.3	13.5	1.4 (0.1%)
S 1989	959.6	1000.1	15.9	56.4 (5.9%)
W 1989-90	1050.1	1059.6	74.9	84.4 (8.0%)
S 1990	1018.8	1110.7	59.3	151.2 (14.8%)
W 1990-91	1058.7	1090.9	206.2	238.4 (22.5%)
S 1991	1069.8	1054.8	257.7	242.7 (22.7%)
W 1991-92	1077.4	948.4	291.5	162.5 (15.1%)
S 1992	1082.8	925.3	293.9	136.4 (12.6%)
W 1992-93	1098.6	923.6	293.7	118.7 (10.8%)
S 1993	1096.3	910.5	296.0	110.2 (10.1%)
W 1993-94	1121.2	993.9	295.8	168.5 (15.0%)
S 1994	1117.2	910.5	298.1	91.4 (8.2%)
W 1994-95	1151.5	883.9	297.7	29.5 (2.6%)
S 1995	1142.8	870.5	300.1	27.8 (2.4%)
W 1995-96	1183.8	884.1	299.8	0.1 (0.0%)
S 1996	1168.6	866.7	302.1	0.2 (0.0%)
W 1996-97	1211.5	884.1	301.8	(25.6)(-2.1%)

Notes:

a. Includes peak-load reduction attributable to existing demand-side management programs.

b. Includes existing firm generation and purchases less firm sales. Assumes Pilgrim is not available during summer 1988 and winter 1988-89.

c. Includes incremental demand-side management programs.

Sources: Exhs. HO-52, HO-61A

TABLE 3

Montaup Electric Company
Short-Run Contingency Analysis
(MW)

1. High Load Growth

Year	High Load Growth Forecast	Estimated Capability Respons	Total Base Case Resources	Contingency Surplus
S 1988	790.0	932.6	951.8	19.2
W 1988-89	766.8	938.6	939.8	1.4
S 1989	821.7	959.6	1016.0	56.4
W 1989-90	791.1	1059.8	1134.5	74.7
S 1990	845.0	1028.3	1170.0	141.7
W 1990-91	818.4	1088.5	1297.1	208.6
S 1991	873.1	1100.1	1312.5	212.4
W 1991-92	837.6	1114.0	1239.9	125.9

2. Pilgrim Re-Opening Contingency

Year	Base Load[a] Capability Respons	Total[b] Base Case Resources	Loss of[c] Pilgrim	Contingency Surplus
S 1988	932.6	951.8	0	19.2
W 1988-89	938.5	939.8	0	1.3
S 1989	925.6	1016.0	(70.0)	20.4
W 1989-90	1009.1	1134.5	(70.4)	55.0
S 1990	977.8	1170.0	(70.0)	122.2
W 1990-91	1058.7	1297.1	(70.4)	168.0
S 1991	1069.8	1312.5	(70.0)	172.7
W 1991-92	1077.4	1239.9	(70.4)	92.1

3. High Load Growth and Pilgrim Re-Opening Contingencies

Year	High Load[a] Capability Respons	Total[b] Base Case Resources	Loss of[c] Pilgrim	Contingency Surplus
S 1988	932.6	951.8	0	19.2
W 1988-89	938.5	939.8	0	1.3
S 1989	949.6	1016.0	(70.0)	(3.6)
W 1989-90	1018.1	1134.5	(70.4)	46.0
S 1990	986.2	1170.0	(70.0)	113.8
W 1990-91	1088.5	1297.1	(70.4)	138.2
S 1991	1100.1	1312.5	(70.0)	142.4
W 1991-92	1114.0	1239.9	(70.4)	55.5

TABLE 3 (Con't)

4. Pilgrim Re-Opening and Seabrook Delay Contingencies

Year	Base Load[a] Capability Respons	Total[b] Base Case Resources	Loss of[c] Pilgrim and Seabrook	Contingency Surplus
S 1988	932.6	951.8	0	19.2
W 1988-89	938.5	939.8	0	1.3
S 1989	925.6	1016.0	(70.0)	20.4
W 1989-90	981.0	1134.5	(103.7)	49.8
S 1990	949.3	1170.0	(103.3)	117.4
W 1990-91	1058.7	1297.1	(103.7)	134.7
S 1991	1061.3	1312.5	(103.3)	147.9
W 1991-92	1077.4	1239.9	(103.7)	58.8

Notes:

a. Capability responsibility calculations are adjusted for the loss of NEPOOL capacity credit of Pilgrim and/or Seabrook.

b. Montaup's base case resource plan assumes Pilgrim is not available during summer 1988 and winter 1988-89.

c. Montaup's entitlement of Pilgrim is 11 percent of total capacity which results in NEPOOL capacity credit of 73.3 MW in summer and 73.7 MW in winter (Exhs. HO-33, HO-52). Montaup sells about 3.35 MW of this capacity to Newport Electric Company (id.).

Sources: Exhs. HO-52, HO-61A

TABLE 4

Montaup Electric Company
Economic Comparison of Short-Run Generation and
Demand-Side Management Resource Options

Resource Option	Amount Purchased or Implemented (Summer MW) 1988	1989	1990	1991	Annual[a] Demand Cost ($/KW)	Energy Cost (¢/KWH)
Generation (Purchases):[b]						
NU Jets	25.0	1.4			30.00	5.451
Cleary 9	33.4				35.00	3.141
Montville 6	10.0				45.00	2.319
Middletown 4	10.0				45.00	2.602
Stony Brook	9.3	9.3			75.41	3.000
Hydro Quebec	26.0	26.0	1.4		74.23	2.200
NU Gas Turb/Mill 3	20.0	50.0			100.00	4.992
NU "Slice of System"		73.5	147.0	166.7	175.00	2.200
Demand-Side Management:[c]						
Interruptibles	6.0	6.1	6.2	6.2	27.23	None
WAT41[d]	0.6	1.1	1.6	2.1	32.48	None
EGAP	3.0	3.0	3.1	3.1	34.36	None
FILTER	0.4	0.4	0.4	0.4	52.55	None
ELITE	1.4	4.9	6.3	7.7	None	0.274
WRAP	0.0	0.0	0.0	0.0	None	1.489
AIRCON	0.2	0.4	0.6	0.8	None	6.810

Notes:

a. Includes transmission costs for generation options.

b. The demand cost for the NU "slice of system" purchase, including transmission costs, is $180/KW in 1990 and $191/KW in 1991. All other demand costs are assumed constant.

c. The demand-side management revenue requirements analysis was based on program costs and benefits levelized over 20 years with expenses amortized over five years. Load management programs are estimated as demand costs; conservation programs are estimated as energy costs.

d. Includes only incremental capacity and energy.

e. Although Montaup indicated that WAT41, EGAP, FILTER, ELITE, WRAP, and AIRCON would yield short-run capacity, Montaup did not identify those programs as short-run programs.

Sources: Exhs. HO-1, HO-57, HO-61A, HO-61B, HO-63, HO-65

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

Such petition for appeal shall be filed with the Siting Council within twenty days after the date of service of the decision, order or ruling of the Siting Council or within such further time as the Siting Council may allow upon request filed prior to the expiration of twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said Court. (Sec. 5, Chapter 25, G.L. Ter. Ed., as most recently amended by Chapter 485 of the Acts of 1971).

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Turners Falls Limited Partnership for Approval of its Occasional Supplement to Construct a Single Circuit 1.2-Mile, Overhead 115 Kilovolt Electric Transmission Line	EFSC 88-101

FINAL DECISION

Frank P. Pozniak
Hearing Officer
December 8, 1988

On the Decision:

William S. Febiger

TABLE OF CONTENTS

FIGURES:

The Energy Facilities Siting Council hereby CONDITIONALLY APPROVES the petition of the Turners Falls Limited Partnership to construct a single circuit 1.2-mile, overhead 115 kilovolt electric transmission line along the proposed route described herein.

I. INTRODUCTION

A. Summary of the Proposed Project and Facilities

Turners Falls Limited Partnership ("TFLP"), an Illinois limited partnership, has proposed to construct a single-circuit, 1.2-mile overhead 115 kilovolt ("kV") electric transmission line in Turners Falls in the Town of Montague ("Montague"), which would interconnect a 20-megawatt ("MW") coal-fired cogeneration plant, currently under construction in Turners Falls, with existing 115 kV transmission lines of the New England Power Company ("NEPCo") ("proposal") (Exh. TFLP-1, pp. I-1, I-7).[1] The total capacity of the cogeneration plant would be wheeled over the existing 115 kV transmission grid to the UNITIL Power Corporation ("UNITIL"), a New Hampshire public utility (id.).[2]

Construction of the cogeneration plant began in September, 1987, and it is expected to be in-service by

---

1/ Indeck Energy Services Inc. of Turners Falls, an Illinois corporation and general partner of TFLP, has retained the Harza Engineering Company to construct the proposed 115 kV transmission line (Exh. TFLP-1, pp. 1, I-1; Exh. HO-16). Once the proposed 115 kV transmission line is completed, Indeck Energy Services Inc. of Turners Falls will own and maintain the line (Exh. HO-16).

2/ On November 4, 1986, Indeck Energy Services Inc. of Turners Falls and UNITIL executed a 20-year purchased power contract for the entire 20 MW from the cogeneration plant (Exh. TFLP-2, Exhibit 2).

June, 1989 (id., pp. 2, I-5; Exh. HO-40; Tr. I, p. 25). Indeck Energy Services Inc. of Turners Falls ("Indeck") is constructing the cogeneration plant (Exh. TFLP-1, p. 1, I-1). As well as generating 20 MW of electricity, the cogeneration plant will provide up to 50,000 pounds per hour ("pph") of process steam to the Strathmore Paper Company ("Strathmore") (id., pp. I-5, I-7; Tr. I, p. 183; Exh. HO-RR-7).[3] Although TFLP has provided no evidence that the cogeneration plant has been designated as a qualifying facility ("QF") by the Federal Energy Regulatory Commission ("FERC"), it appears to meet FERC QF criteria based on the expected supply of process steam to Strathmore (Tr. I, pp. 182-184). Finally, Strathmore is located adjacent to the cogeneration plant.

TFLP's proposed project consists of the proposal and alternatives for the construction of the proposed 115 kV transmission line (or "proposed 115 kV tie line") interconnecting the 20 MW cogeneration plant with an existing 115 kV transmission grid (Exh. TFLP-1, pp. I-15 to I-39). As shown in Figure 1, the route of the proposal ("proposed route") originates at the cogeneration plant and crosses over the power canal[4] in a southerly direction to a point aligned with Second Street in Turners Falls (id., pp. I-7, I-15). From this point, the proposed route runs parallel to the power canal until it connects with the existing 115 kV transmission lines of NEPCo (id.). The proposed route extends along property owned by the Western Massachussets Electric Company ("WMECo")

3/ On October 6, 1986, Indeck and Strathmore executed an agreement for the sale and purchase of steam (Exh. HO-RR-7).

4/ The power canal is a 2.1-mile long man-made canal that diverts water from the Connecticut River to generate electricity at two hydropower stations located along the power canal (Exh. TFLP-1, pp. I-3 to I-5). The power canal and the two hydropower stations, Station No. 1 and Cabot Station, are owned by the Western Massachusetts Electric Company (id., p. I-3). Station No 1 generates 5.6 MW of electricity, while Cabot Station generates 51 MW of electricity (id.).

and the Boston and Maine ("B&M") Railroad (id., pp. I-15, I-17).[4A] The width of the right of way of the proposed route is approximately 10 to 20 feet from Second Street to Fifth Street (Exh. TFLP-9; Tr. I, pp. 134-135), and approximately 40 to 80 feet for the remainder of the proposed route (Exh. TFLP-9).

TFLP identified four alternatives for the construction of the proposed 115 kV tie line: Alternative 1, Alternative 2, Alternative 3, and Alternative 4 (Exh. TFLP-1, pp. I-26 to I-39). See Figure 2. Under Alternative 1, TFLP would construct a 1.6-mile overhead 115 kV electric transmission line following the proposed route entirely and continuing approximately one-half mile beyond the termination point of the proposal to connect with the existing 115 kV transmission lines of WMECo (id., pp. I-26 to I-28).

Under Alternative 2, TFLP would construct a one-mile overhead 115 kV electric transmission line which would follow the proposed route until Seventh Street in Turners Falls, where it would then cross back over the power canal and extend to a connecting point with existing 115 kV transmission lines of NEPCo on that side of the power canal (id., pp. I-30, I-31, III-6).

Under Alternative 3, TFLP would construct a 1.1-mile overhead 115 kV electric transmission line along a route that would originate at the cogeneration plant, but would proceed in a northerly direction crossing the Connecticut River, ascending

---

4A/ TFLP expects to acquire (1) an easement from WMECo for the portion of the proposed route between Second and Fifth Streets and between Seventeenth Street and the interconnection point, (2) a fee interest in the portion of the proposed route between Sixth and Seventeenth Streets now owned by the B&M Railroad, and (3) an easement from Esleeck Manufacturing Company for the portion of the proposed route between Fifth and Sixth Streets, now owned by the B&M Railroad but under contract for sale to Esleeck Manufacturing Company (Exhs. TFLP-1, p. I-18, TFLP-9; Exhs. HO-RR-2, HO-RR-3, HO-39).

Canada Hill, crossing State Route 2, and extending just off Adams Street until reaching the connection point with existing 115 kV transmission lines of NEPCo off Adams Street in the Town of Greenfield ("Greenfield") (id., pp. I-33, I-34, III-7; Exh. HO-26).

Finally, under Alternative 4, TFLP would construct a 1.2-mile partial overhead and underground 115 kV electric transmission line following the proposed route entirely (Exh. TFLP-1, pp. I-36 to I-38). Alternative 4 would be placed underground from Second Street to a point 400 feet west of Seventh Street along the proposed route (id., p. I-37).[5]

This is the first transmission line facility presented to the Energy Facilities Siting Council ("Siting Council") by a non-utility developer. This is also the first transmission line project for either TFLP or Indeck (Exh. HO-16).

B. Procedural History

On April 14, 1988, TFLP filed an Occasional Supplement with the Siting Council requesting approval to construct the proposed 115 kV transmission line. On June 9, 1988, the Siting Council conducted a public hearing in Montague. In accordance with the directions of the Hearing Officer, TFLP provided confirmation of publication, posting, and mailing of the Notice of Public Hearing and Adjudication.

The Siting Council conducted evidentiary hearings on August 17 and 18, 1988.[6] TFLP presented four witnesses:

5/ See Section III.B. and Figures 1 and 2 infra, for a further description of the proposal and alternatives.

6/ TFLP requested that certain portions of the August 17, 1988 hearing receive protective treatment (Tr. I, pp. 192, 198). The Hearing Officer granted this request (id.). Consequently, pages 192 through 194 and 198 through 200 of the Transcript of the August 17, 1988 hearing received protective treatment.

Prem Babu, manager of electrical engineering for Indeck; Victor Bhatia, environmental and regulatory consultant for Indeck; John T. Gillick, project manager; and Michael P. Polsky, president of Indeck.

The Hearing Officer entered 95 exhibits in the record, largely composed of TFLP's responses to information and record requests.[7] TFLP offered 11 exhibits into the record. Finally, TFLP filed a brief on October 11, 1988.

C. Jurisdiction

TFLP's Occasional Supplement is filed in accordance with G.L. c. 164, sec. 69H, which requires the Siting Council to ensure a necessary energy supply for the Commonwealth with minimum impact on the environment at the lowest possible cost, and G.L. c. 164, sec. 69I, which requires electric companies to obtain Siting Council approval for construction of proposed or alternative facilities at proposed or alternative sites before a construction permit may be issued by any other state agency.

TFLP's proposal to construct a single-circuit, 1.2-mile overhead 115 kV electric transmission line, as well as to construct all alternatives, falls squarely within the second definition of "facility" set forth in G.L. c. 164, sec. 69G:

> (2) any new electric transmission line having a design rating of sixty-nine kilovolts or more which is one mile or more in length except reconductoring or rebuilding of existing transmission lines at the same voltage.

The construction of the 20 MW cogeneration plant does

7/ TFLP requested that certain documents (Exhs. HO-RR-1, HO-RR-7, HO-RR-8, and HO-RR-18) receive protective treatment. In letter orders dated September 13 and October 18, 1988, the Hearing Officer granted this request.

not fall within the first definition of "facility" set forth in G.L. c. 164, sec. 69G. This definition provides that a facility is "any bulk generating unit, including associated buildings and structures, designed for, or capable of operating at a gross capacity of one hundred megawatts or more." Further, the 20 MW cogeneration plant does not fall within the third definition of facility set forth in G.L. c. 164, sec. 69G. The third definition provides that a facility is "any ancillary structure including fuel storage facilities which are an integrated part of the operation of any electric generating unit or transmission line which is a facility." In Commonwealth Electric Company, 17 DOMSC 249, 259-265 (1988) ("1988 ComElec Decision"), the Siting Council established a two part standard for determining whether a structure is a facility for the purposes of the third definition. A structure is a facility under G.L. c. 164, sec. 69G, if (1) the structure is subordinate or supplementary to a jurisdictional facility, and (2) the structure provides no benefit outside of its relationship to the jurisdictional facility. Id. Here, the 20 MW cogeneration plant is not subordinate or supplementary to the jurisdictional facility.[8]

In accordance with G.L. c. 164, sec. 69H, before approving an application to construct facilities, the Siting Council requires applicants to justify facility applications in three phases. First, the Siting Council requires the applicant to show that the facilities are needed (see Section II.A, infra). Next, the Siting Council requires the applicant to present plans that satisfy the previously identified need and that are superior to alternative plans in terms of cost and environmental impact (see Section III.B, infra). Finally, the

8/ While the 20 MW cogeneration plant is not a jurisdictional facility, certain information regarding the cogeneration plant is necessary for determining whether additional energy resources are needed in the New England region and Massachusetts. See Section II.A and B, infra.

Siting Council requires the applicant to show that the proposed site for the facility is superior to alternate sites in terms of cost, environmental impacts, and reliability of supply (see Section III, infra).

II. ANALYSIS OF THE PROPOSED PROJECT

A. Need Analysis

1. Standard of Review

In accordance with G.L. c. 164, sec. 69H, the Siting Council is charged with the responsibility for implementing energy policies to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

In carrying out this statutory mandate with respect to proposals to construct energy facilities in the Commonwealth, the Siting Council evaluates whether there is a need for additional energy resources to meet reliability or economic efficiency objectives.[9] The Siting Council therefore must find that additional energy resources are needed as a prerequisite to approving proposed energy facilities.

In evaluating the need for new energy facilities to meet reliability objectives, the Siting Council has evaluated the reliability of supply systems in the event of changes in demand or supply or in the event of certain contingencies. With respect to changes in demand or supply, the Siting Council has found that new capacity is needed where projected future capacity available to the system is found to be inadequate to satisfy projected load and reserve requirements. Altresco-Pittsfield, Inc., 17 DOMSC 351, 359-369 (1986) ("Altresco"); Northeast Energy Associates, 16 DOMSC 335, 344-360 (1987) ("NEA"); Cambridge Electric Light Company,

---

9/ In this discussion, "additional energy resources" is used generically to mean both energy and capacity additions, including, but not limited to, electric generating facilities, electric transmission lines, energy or capacity associated with power sales agreements, and energy or capacity associated with conservation and load management.

15 DOMSC 187, 211-212 (1986) ("1986 CELCo Decision"); Massachusetts Electric Company, 13 DOMSC 119, 137-138 (1985) ("1985 MECo Decision"); New England Electric System, 2 DOMSC 1, 9 (1977). With regard to contingencies, the Siting Council has found that new capacity is needed in order to ensure that service to firm customers can be maintained in the event that a reasonably likely contingency occurs. Middleborough Gas and Electric Department, 17 DOMSC 197, 216-219 (1988) ("Middleborough"); Boston Edison Company, 13 DOMSC 63, 70-73 (1985) ("1985 BECo Decision"); Taunton Municipal Lighting Plant, 8 DOMSC 148, 154-155 (1982) ("Taunton"); Commonwealth Electric Company, 6 DOMSC 33, 42-44 (1981); Eastern Utilities Associates, 1 DOMSC 312, 316-318 (1977).

The Siting Council also has determined in some instances that utilities need to add energy resources primarily for economic efficiency purposes. The Siting Council has found that a utility's proposed energy facility was needed principally for providing economic energy supplies relative to a system without the proposed facility. 1985 MECo Decision, 13 DOMSC at 178-179, 183, 187, 246-247; Boston Gas Company, 11 DOMSC 159, 166-168 (1984).

While G.L. c. 164, sec. 69H, requires the Siting Council to ensure an adequate supply of energy for Massachusetts, the Siting Council has interpreted this mandate broadly to encompass not only evaluations of specific need within Massachusetts for new energy resources (1988 ComElec Decision, 17 DOMSC at 266-279; Middleborough, 17 DOMSC at 216-219; 1985 BECo Decision, 13 DOMSC at 70-73), but also the consideration of whether proposals to construct energy facilities within the Commonwealth are needed to meet New England's energy needs. Altresco, 17 DOMSC at 359-365; NEA, 16 DOMSC at 344-354; Massachusetts Electric Company, 15 DOMSC 241, 273, 281 (1986); 1985 MECo Decision, 13 DOMSC at 129-131, 133, 138, 141. In so doing, the Siting Council has fulfilled the requirements of G.L. c. 164, Sec. 69J, which recognizes that Massachusetts' generation and transmission system is interconnected with the region's and that reliability and economic benefits flow to Massachusetts from Massachusetts' utilities' participation in the New England Power Pool ("NEPOOL").

Pursuant to the standards set forth above, the Siting Council first determines if there is a regional need for the facility; we then determine if the facility provides Massachusetts benefits.

In cases in which a non-utility developer seeks to construct a jurisdictional cogeneration facility, regional need is established by showing that the power to be transported is needed on either economic efficiency or reliability grounds. This can be done in one of two ways. First, a showing that a significant portion of the output of the generating plant is under contract, and that such contract (or contracts) has all necessary state and federal regulatory approvals, establishes economic efficiency and/or reliability. Second, in cases in which a significant portion of the output of the generating plant is not under contract, economic efficiency or reliability can be shown by presenting a regional forecast that establishes that additional energy resources are warranted.

In determining whether a non-utility developer can demonstrate Massachusetts benefits, the Siting Council looks to the identity of the ultimate recipients of the power generated by the cogenerator. If a significant portion of the cogenerator's output is under contract to a utility for distribution to Massachusetts customers and the contract has been approved by the Massachusetts Department of Public Utilities or federal regulators, then Massachusetts benefits are clearly demonstrated. If, however, the purchasers are unknown or known but the contract is not yet approved, or if the purchasers will distribute within retail service territories outside Massachusetts, the non-utility developer must show that the proposed additional energy resources benefit the Commonwealth -- that is, that they offer reliability, economic efficiency or environmental benefits to the Commonwealth in sufficient magnitude so that the construction of an energy facility in the state is consistent with the energy needs, resource use and development policies of the Commonwealth. Altresco, 17 DOMSC at 369.

Here, for the first time, the Siting Council is presented with a proposal by a non-utility developer to construct a jurisdictional transmission line, that would connect a non-jurisdictional cogenerating plant constructed by the same non-utility developer to the regional transmission system. To the extent that the jurisdictional facility is a transmission line, this case is similar to the Siting Council's review of a utility's proposal to construct a transmission line. To the extent that the proponent of the facility is a non-utility developer, this case is akin to the two recent Siting Council reviews of non-utility generating facilities.

In areas that the Siting Council's review of the need for non-utility facilities differs from that for utility transmission facilities, however, the review here will parallel the review of non-utility facilities. Whether the jurisdictional facility in question is a cogeneration facility or a transmission line, the question presented to us is similar because in both cases we are reviewing whether additional energy resources are needed. In the case of a cogeneration facility, the Siting Council reviews the need for a power generating plant, in the latter case it is the need for a transmission line that would carry the generated power. In each case, if additional generated energy supplies are not needed, then the facility is not warranted.[10]

In our review of the proposed project in this case, we must, to some degree, review various aspects of the

---

10/ In setting out this standard, the Siting Council notes that the issue is not whether a physical connection is necessary in order to connect the non-jurisdictional cogeneration plant to the electric transmission grid and end-users. Addressing the need issue here so narrowly would be inconsistent with our analysis of other utility and non-utility facilities, as well as with our statutory mandate.

non-jurisdictional cogeneration plant. This review is not premised on jurisdiction over the cogeneration plant; we acknowledge that the plant is non-jurisdictional and the developer can construct it without our approval. Instead, our review is exclusively focused upon the need for the power generated by the non-jurisdictional generating facility because this power constitutes additional energy resources to be carried by the proposed 115 kV transmission line.

2. Status of Indeck's Power Sales Agreements

TFLP stated that the proposed project is required to interconnect a cogeneration plant with the regional 115 kV transmission system (Exh. TFLP-1, p. 1).[11] The cogeneration plant is currently under construction, and it is expected to be in-service by June 1989 (id., pp. 2, I-5; Exh. HO-40; Tr. I, p. 25).

UNITIL, which operates as a bulk power purchaser for two retail electric companies in New Hampshire, has contracted with Indeck to purchase the total capacity of 20 MW from the cogeneration plant (Exh. TFLP-1, p. 2). TFLP further stated that, based on UNITIL's representation to TFLP and accompanying documentation, UNITIL's power purchase agreement with Indeck is part of a supply planning approach approved by the New Hampshire Public Utilities Commission (id., pp. II-10 to II-23; Exh. HO-42). The cogeneration plant will provide a portion of UNITIL's NEPOOL capability responsibility, and also will be available for NEPOOL dispatch (Exh. TFLP-1, pp. 2, II-1).

11/ Low voltage transmission and distribution lines operated by WMECo are present in the vicinity of the cogeneration plant. As part of its review of the proposed project, the Siting Council considered the alternative of interconnecting the cogeneration plant to the existing 115 kV transmission system with low-voltage lines. See Section II.B, infra.

3. New England's Need for Additional Energy Resources

New England's need for the proposed 115 kV transmission line, which would carry power to a retail service territory outside Massachusetts, can be established by showing that the power to be transported is needed on either reliability or economic efficiency grounds. Altresco, 17 DOMSC at 359-365; NEA, 16 DOMSC at 344-354. The Siting Council previously has found that the existence of a signed and approved power sales agreement between a cogeneration plant and a utility constitutes a *prima facie* showing of the need for the power for economic efficiency reasons. NEA, 16 DOMSC at 358. Further, where the power sales agreement contains a capacity charge, a *prima facie* case is made that the reliability ground is met. Id. In this case, there is a signed power sales agreement between Indeck and UNITIL, which includes a capacity charge (Exh. TFLP-2, Exhibit II). In addition, the New Hampshire Public Utilities Commission, while apparently not utilizing a formal contract approval process, has indicated its approval of the power sales agreement (Exhs. TFLP-1, II-5 to II-30, TFLP-2, Exhibits IV to VI; Exh. HO-42).

Accordingly, based on the record in this proceeding, the Siting Council finds that TFLP has established New England's need for the additional energy resources.

4. Benefits to Massachusetts

Because all of the generated power that would be transported over the proposed 115 kV tie-line would be provided to UNITIL for utilities with retail service territories located exclusively in New Hampshire, the Siting Council must determine if the proposed project provides economic efficiency, reliability, or environmental benefits to Massachusetts.

a. Electricity Supply

In Altresco, 17 DOMSC at 366-399, and NEA, 16 DOMSC at 354-360, the Siting Council found that Massachusetts utility ratepayers were likely to receive reliability and economic efficiency benefits from the addition of cost-effective QF resources to their utilities' supply mixes. Here, with all generated power under contract to UNITIL for resale in New Hampshire, the supply mixes of Massachusetts utilities would not be directly affected by the addition of the proposed 115 kV transmission line.

Although Massachusetts utilities would not be directly affected, TFLP asserted that the proposed 115 kV transmission line and cogeneration plant would provide reliability or economic efficiency benefits to Massachusetts in three ways: (1) based on TFLP's analysis of approved QF solicitations to date, pursuant to 220 CMR 8.00 et seq., certain Massachusetts utilities may be dependent, at least in the short term, on NEPOOL deficiency service that would be supported in part by the proposed project; (2) based on favorable fuel price expectations for coal relative to oil, the coal-fired cogeneration plant is likely to be dispatched in the long term to provide at least some economy savings through NEPOOL to Massachusetts utilities; and (3) based on the location of the power supply and prospective points of interconnection to the regional transmission system, the proposed project (a) may provide needed voltage support to the regional transmission system during pumping operations at the Bear Swamp pumped storage facility, and (b) under certain high load situations, may provide needed power support on the regional transmission system serving eastern Masachusetts (Exh. HO-1, Part 1-b). According to TFLP, transmission shortages on the so-called Northern New England/Massachusetts transmission interface could be relieved (id.).

In support of its first argument, concerning possible NEPOOL deficiency service, TFLP provided listings of the responses to QF solicitations in Massachusetts to date, and stated that construction had not commenced on any projects for which contracts had been awarded (id.). With respect to NEA's Bellingham project, approved by the Siting Council, TFLP asserted that the planned 1990 on-line date of that project now appears unlikely (id.).

As indicated by TFLP's analysis, it is possible, although by no means certain, that some Massachusetts utilities may have capacity deficiencies in 1990 or other future years that could require NEPOOL support in order to meet the capability responsibilities of such utilities. However, the Siting Council already has found that New England needs the additional capacity that TFLP's proposed project would provide. See Section II.A.3, supra. Some level of reliability benefits for Massachusetts already is implicit in that finding. TFLP's showing with respect to possible future capacity deficiencies for some Massachusetts utilities does little to strengthen the expectation that Massachusetts actually would realize benefits from the proposed project beyond the basic pooling capability already implicit in the earlier finding on regional need.

In support of its second point, TFLP maintained that the cogeneration plant and the proposed 115 kV transmission line would provide benefits to Massachusetts because the cogeneration plant would provide NEPOOL with coal-fired capacity at a time when the Commonwealth is heavily dependent on oil-fired power (Exhs. HO-1, HO-RR-6). TFLP contended that Massachusetts utilities would benefit through economy savings with NEPOOL (id.).

The Siting Council agrees that the coal-fired cogeneration plant, if it is dispatched before another generating plant, presumably will provide economic benefits to New England. While UNITIL will be a certain recipient of these benefits, more evidence is needed to demonstrate that Massachusetts utilities and their customers also would benefit to a significant degree. On this record, the Siting Council declines to find that TFLP has demonstrated that the energy produced by this coal-fired cogeneration plant constitutes a significant benefit to Massachusetts.

In support of its argument concerning regional transmission benefits, TFLP provided correspondence from UNITIL discussing the identified regional transmission problems (Exh. HO-42). TFLP also itself addressed whether the siting of the cogeneration plant and the proposed project is beneficial from the point of view of regional transmission transfer constraints, and transmission operating requirements relating to reactive power (Exh. HO-1). TFLP contends that there are specific and direct potential benefits, including reactive power support for the nearby Bear Swamp pumped storage facility and the support of load in eastern Massachusetts without the constraint of the Northern New England/Massachusetts interface (id.). TFLP submitted a letter from Paul T. Harnett, Assistant Manager of the Rhode Island - Eastern Massachusetts - Vermont Energy Control ("REMVEC") (a division of NEPOOL concerned with energy supply in the three states listed), who indicated that there are times when only one of the two Bear Swamp pumping units can be operated due to low voltage and that TFLP's proposed generator would improve reliability (Exh. HO-RR-23).

The Siting Council has not specifically considered such indirect transmission benefits previously and in our view any such benefits need to be significant and carefully documented. While the TFLP's position and REMVEC's letter indicate that some transmission-related benefit might be expected, there is nothing in the record which carefully analyzes and quantifies this claimed benefit. Accordingly, without additional information, we cannot find that these indirect transmission benefits will be a significant benefit for Massachusetts.

Based on the foregoing, TFLP has not demonstrated that Massachusetts is likely to receive sufficient reliability or economic efficiency benefits related to electricity supply as a result of the proposed project.

b. Process Steam Benefits

The cogeneration plant will be capable of producing up to 50,000 pph of process steam, representing 35 percent of the cogeneration plant's total thermal output (Tr. I, pp. 182-185). Based on the signed contract between Indeck and Strathmore, the cogeneration plant will provide steam to meet Strathmore's current requirement of approximately 30,000 pph, and also allow for possible future expansion up to the cogeneration plant's design capacity of 50,000 pph (id.; Exh. HO-RR-7). As a result of its planned steam supply to Strathmore, TFLP asserted that the cogeneration plant would provide economic benefits and allow more efficient control of air emissions in the Turners Falls area (Tr. I, pp. 185-206).

With respect to economic benefits, TFLP maintained that the cogeneration plant would enable Strathmore to avoid investing $5 million to $10 million in modernizing its own steam boilers to burn coal (id., pp. 185-186). In addition, Indeck and Strathmore contractually agreed to a steam sales price discounted from Strathmore's prior oil-based cost, with future price changes linked to trends in the price of coal (id., pp. 187-194). TFLP stated that Strathmore sought such a steam supply arrangement to allow it to remain competitive in its Turners Falls operations, where it employs about 100 persons (id., pp. 185-187, 189; Exh. HO-RR-23).

With respect to environmental impacts, TFLP asserted that the cogeneration plant will cause significantly fewer air emissions than separate plants producing equivalent amounts of electricity and process steam (Tr. I, pp. 201-204). In support of its position, TFLP provided calculations of the expected emissions from the cogeneration plant as compared with those for two hypothetical coal-fired facilities that would meet the needs of Strathmore and UNITIL separately (Exh. HO-RR-10). Further, with respect to Strathmore's existing oil-fired boilers, TFLP stated that retirement of these units had been considered as a "credit" in the Department of Environmental

Quality Engineering's ("DEQE") air quality permit review for the cogeneration plant (Tr. I, pp. 203-204). In the case of sulfur dioxide ("SO_2"), for example, TFLP calculated that the expected emissions of 300-350 tons per year from the cogeneration plant would be partially offset by the "credit" for avoiding emissions of 100 to 150 tons per year from Strathmore's existing boilers which would be retired (id.).

The Siting Council previously has found that a cogeneration plant may provide both economic and environmental benefits to Massachusetts as a result of its expected steam sales. Altresco, 16 DOMSC at 367-369. The Siting Council based its findings in that case on evidence of substantial expected reductions in per unit steam costs and in SO_2 emissions. Id.

In this case, TFLP has cited expected savings in per unit steam costs, based on an initial per unit discount and favorable price expectations for coal relative to oil. TFLP also cited uncertainties about Strathmore's ability to justify and finance the estimated capital expenditure for modernizing its boilers.

The Siting Council again notes TFLP's arguments as to the possible long-term economic advantage of coal as a fuel for cogeneration development (see also Section II.B.4.a, supra). While there is no guarantee that Strathmore's steam costs actually would be lower as a result of the use of coal as the fuel source for the cogeneration plant, the Siting Council recognizes the signed contract between Indeck and Strathmore, itself, as evidence of an economic advantage to Strathmore, an employer of about 100 persons in the Turners Falls area. Further, the significant amount of process steam to be supplied to Strathmore, representing up to 35 percent of the cogeneration plant's thermal output, is consistent with current resource use and development policies of the Commonwealth supporting cogeneration plants. Accordingly, the Siting Council finds that TFLP has demonstrated that Massachusetts is likely to receive economic benefits related to the significant process steam supply of the cogeneration plant, which is an indirect benefit of the proposed project.

With respect to environmental impacts, the record demonstrates that the cogeneration plant will not reduce SO_2 emissions below the level of the existing steam user's boilers, as was the case in Altresco. Further, TFLP has not shown that there will be a net benefit with respect to any other air quality parameter nor any other environmental concern.

TFLP did indicate that the cogeneration plant would produce a lower level of emissions for all pollutants than two hypothetical facilities which would produce equivalent amounts of process steam and electricity separately (Exh. HO-RR-10). However, TFLP provided insufficient evidence to show that Strathmore would necessarily modernize its steam plant in the absence of the cogeneration plant, or, even if it did modernize the existing plant, that it would use coal. Thus, in this case, the Siting Council rejects TFLP's position that the expected emissions from the cogeneration plant can be compared with the emissions from the hypothetical facilities to demonstrate the environmental benefits of the cogeneration plant.

Based on the foregoing, the Siting Council finds that TFLP has not demonstrated that there will be environmental benefits for the Commonwealth as a result of the steam sales component of the cogeneration plant.

c. Community Benefits

TFLP argues that under the proposal, Indeck has tentatively agreed to share the right of way for the proposed 115 kV tie line with the Montague Economic Development Industrial Corporation ("MEDIC") and the Massachusetts Department of Environmental Management (DEM), for purposes of constructing a recreational bikeway and footpath, known as the Franklin County Bikeway, thereby providing an important land use and community benefit (Brief, p. 34). TFLP stated that

Indeck has tentatively agreed to grant an easement to MEDIC with the approval of DEM, for shared use of the right of way at a cost of one dollar (Exhs. HO-15B, HO-RR-23, HO-39).[11A] TFLP asserted that, in the absence of such an arrangement, the acquisition cost to DEM for the same right of way would be $157,761 (Exhs. HO-14C, HO-15A, HO-RR-23).

TFLP has acknowledged that, along a portion of the proposed route, the already narrow space for bicycling may be further constricted by the proposed 115 kV transmission line structures (Exh. TFLP-1, p. I-39) (see Section III.E.2, infra). The possible visual impacts of the proposed 115 kV transmission line along the proposed route are an additional concern for the Franklin County Bikeway (see Section III.E.3, infra).

In NEA, the Siting Council found that a non-utility developer must demonstrate reliability or economic efficiency benefits to the Commonwealth (p. 349). In Altresco, the Siting Council found that a non-utility developer also may demonstrate benefits to the Commonwealth based on economic grounds apart from a power sales agreement or based on environmental grounds (p. 369). In this case, we find that a non-utility developer also may demonstrate benefits to the Commonwealth based on community benefits that are connected to the proposed project. Here, the Siting Council determines whether the prospective easement is a community benefit.

The economic value of the prospective easement is considerable, and the record shows that DEM has shown a continuing interest in sharing the right of way with TFLP (Exhs. HO-15, HO-15B, HO-39). Accordingly, based on the

---

11A/ The easement would apply to the portion of the proposed route between Sixth and Seventeenth Streets, which TFLP expects to acquire in fee from the B&M Railroad (Exhs. HO-15B, HO-39). However, the bikeway is planned to extend along the entire proposed route, including those portions owned by WMECO and prospectively by Esleeck Manufacturing Company.

proposed agreement between Indeck, MEDIC, and DEM, the Siting Council finds that TFLP has demonstrated that Massachusetts is likely to receive community benefits in the form of recreational use of the proposed 115 kV transmission line right of way under the proposal.[12]

d. Conclusions on Benefits to Massachusetts

The Siting Council has found that (1) TFLP has not demonstrated that Massachusetts is likely to receive sufficient reliability or economic efficiency benefits related to electricity supply as a result of the proposed project, (2) TFLP has demonstrated that Massachusetts is likely to receive economic benefits related to the significant process steam supply of the cogeneration plant, which is an indirect benefit of the proposed project, (3) TFLP has not demonstrated that there will be environmental benefits for the Commonwealth as a result of the steam sales component of the cogeneration plant, and (4) based on the proposed easement between Indeck, MEDIC, and DEM, TFLP has demonstrated that Massachusetts is likely to receive community benefits in the form of recreational use of the proposed 115 kV transmission line right of way under the proposal.

Accordingly, on balance, the Siting Council finds that TFLP has established that Massachusetts is likely to receive economic and community benefits as a result of the additional energy resources.

12/ We note that the same right of way would be used under Alternative 4, and portions of this right of way would be used under Alternatives 1 and 2. If the Siting Council were to approve any of these alternatives, we would expect TFLP to grant a similar easement for shared use of the right of way.

5. Conclusions on Need

The Siting Council has found that (1) TFLP has established New England's need for additional energy resources, and (2) TFLP has established that Massachusetts is likely to receive economic and community benefits from the additional energy resources. Accordingly, the Siting Council finds that additional energy resources are needed.

B. Comparison of the Proposed Project and Alternate Approaches

1. Standard of Review

G.L. c. 164, sec. 69H, requires the Siting Council to evaluate proposed projects in terms of their consistency with providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at lowest possible cost. In addition, G.L. c. 164, sec. 69I, requires a project proponent to present "alternatives to planned action" which may include (a) other methods of generating, manufacturing, or storing, (b) other sources of electrical power or gas, and (c) no additional electrical power or gas.[13]

In implementing its statutory mandate, the Siting Council has required a petitioner to show that, on balance, its proposed project is superior to alternative approaches in terms of cost, environmental impact, and ability to meet the previously identified need. Braintree Electric Light Department, EFSC 87-32, p. 24 (1988) ("Braintree"); 1988 ComElec Decision, 17 DOMSC at 279-288; Middleborough, 17 DOMSC

13/ G.L. c. 164, sec. 69I, also requires a petitioner to provide a description of "other site locations." The Siting Council reviews the petitioner's proposed site, as well as other site locations, in Section III, *infra*.

at 219-225; 1986 CELCo Decision, 15 DOMSC at 212-218; 1985 MECo Decision, 13 DOMSC at 141-183; 1985 BECo Decision, 13 DOMSC at 67-68, 73-74.

2. Project Approaches to the Identified Need

TFLP's proposed project consists of the construction of the proposed 115 kV tie line to interconnect the 20 MW cogeneration plant with an existing 115 kV transmission grid. TFLP indicated that the proposed 115 kV tie line would be dedicated to transmitting the gross output of the cogeneration plant (Tr. I, pp. 258-260). Electricity used by the cogeneration plant would be provided over low-voltage lines owned by WMECo (id.).

TFLP asserted that the proposed 115 kV tie-line has a rated capacity matched to the maximum 20 MW power output of the cogeneration plant (Exh. HO-8).[14] TFLP further contended that the cogeneration plant is intended to be dispatchable and that, by being interconnected at 115 kV, the cogeneration plant could be readily controlled by NEPOOL with respect to reactive power output, thereby allowing improved control of regional transmission voltages for regional reliability purposes (Exh. HO-2, Part 2a).

TFLP considered one alternate approach for transmitting the 20 MW of power to an existing transmission grid -- direct interconnection of the cogeneration plant to WMECo's low-voltage transmission lines in the Turners Falls area ("low-voltage alternative") (Exh. TFLP-1, pp. I-44 to I-47). TFLP analyzed the low-voltage alternative in the context of a "no-build" alternative, and asserted that the existing

14/ TFLP indicated that the rated power output of the cogeneration plant is 19.84 MW at a 0.8 power factor, while the proposed 115 kV tie line is rated to transmit 20 MW at a 0.8 power factor (Exh. HO-8).

4/0-conductor, 13.8 kV transmission line located near the cogeneration plant, which connects with the 115 kV transmission grid two miles from the cogeneration plant at the Cabot substation, has insufficient capacity to carry the cogeneration plant's maximum power output (id.). TFLP also asserted that, if the existing 13.8 kV transmission line was upgraded to a larger conductor size, a 1,000 kcmil conductor would be required to transmit the 20 MW power output of the cogeneration plant alone, and a 1,300 kcmil conductor would be required if this line was to accommodate additional load from existing local distribution needs and electricity use by the cogeneration plant (Exh. HO-10).[15] TFLP noted that, regardless of conductor size, use of these low-voltage lines as interconnecting lines could subject the local distribution/transmission system to load swings because of NEPOOL dispatch requirements, and inhibit the prospective ability of NEPOOL to control reactive power output from the cogeneration plant for purposes of improved supply reliability on the regional transmission system (Exh. HO-2, Part 2a).

Based on the foregoing, the Siting Council finds that the proposed project is superior to the low-voltage alternative with respect to meeting the identified need.

3. Cost

TFLP contended that a low-voltage alternative would result in substantially greater line losses than the proposed project (Exh. TFLP-1, pp. I-46 to I-47; Exh. HO-10, Part 10a). TFLP also indicated that utility charges for interconnecting a cogeneration plant and wheeling power under various capacity

---

15/ TFLP provided correspondence from WMECo indicating that in order to transmit the maximum output of the cogeneration plant, WMECo would have to construct a new 13.8 kV transmission line dedicated to interconnecting the cogeneration plant with the existing 115 kV transmission grid (Exh. HO-2A).

and voltage situations favor the proposed project relative to the low-voltage alternative (Exh. HO-11).

In support of its contention concerning relative line losses, TFLP provided calculations showing that interconnection line losses valued at $86,577 per year could be expected under the low-voltage alternative, compared with interconnection line losses valued at just over $2,000 per year under the proposed project (Exh. TFLP-1, p. I-47; Exh. HO-10, Part 10a, Tr. I, p. 221).

With respect to utility charges, TFLP indicated that WMECo would charge an interconnection fee of approximately $224,000,[16] and annual wheeling costs of $1,240,000 under the low-voltage alternative (Exhs. HO-2A, HO-11).[17] By comparison, NEPCo would charge an interconnection fee of $274,094 and annual wheeling costs of $82,500 under the proposed project (id.).[18]

Based on the foregoing, the Siting Council finds that the proposed project is superior to the low-voltage alternative with respect to cost.

16/ In a 1985 correspondence with Indeck, WMECo estimated a cost of $224,000 for interconnecting a cogeneration plant of 4-12 MW on its 13.8 kV system (Exh. HO-2A). Therefore, the interconnection costs for a 20 MW cogeneration plant may be greater than $224,000.

17/ TFLP could not clarify whether the WMECo wheeling charge would include the cost of initial improvements or annual line losses associated with a new dedicated low-voltage line (Exh. HO-11).

18/ The Siting Council notes that, although Indeck is generally responsible for the cost of providing the contracted power at the interconnection point without risk to the purchasing utilities or their ratepayers, the purchased power contract does provide for Indeck and UNITIL to share wheeling costs (Exh. TFLP-2, Exhibit II, pp. 50-52).

4. Environmental Impacts

In discussing the low-voltage alternative as a "no-build" alternative, TFLP acknowledged that this alternative would avoid certain visual impacts and land use conflicts associated with the proposed project (Exh. TFLP-1, p. I-45).[19] However, TFLP failed to address possible environmental impacts of any improvements that might be required to upgrade the low-voltage transmission lines in the Turners Falls area to carry the maximum output from the cogeneration plant to the 115 kV transmission grid.

TFLP did state that a single dedicated 13.8 kV transmission line, with 1,000 kcmil conductors measuring 1.151 inches in diameter, would be required to transmit the 20 MW output from the cogeneration plant (id., pp. I-45 to I-46; Exh. HO-2A). In addition, a step-up transformer would be required to interconnect the dedicated 13.8 kV transmission line to the existing 115 kV transmission lines at Cabot substation (id.). By contrast, the proposed project would require only 336.4 kcmil conductors for the proposed 115 kV tie line, and a step-up transformer would not be required at any interconnection point (Exh. TFLP-1, p. I-7).

The proposed project would require higher transmission structures than a typical low-voltage transmission line, with structures of up to 85 feet in height (Exh. TFLP-10). Nonetheless, given WMECo's position that a dedicated low-voltage tie line would be required to carry the maximum output of the cogeneration plant under a low-voltage alternative (Exh. HO-2A), a new transmission line would be required under either the proposed project or the low-voltage

---

19/ Under the proposal and Alternatives 1, 2, and 4, the proposed 115 kV tie line would traverse the Turners Falls Historic District, and utilize a right of way to be shared with the planned Franklin County Bikeway. See Section III.B.2. and E.2, infra.

alternative. As noted by TFLP, there are numerous existing lines in the vicinity of the cogeneration plant (Tr. II, pp. 51-52). Thus, any new transmission line would increase the cumulative visibility of wires and poles in the immediate vicinity of the cogeneration plant. However, on balance, the proposed project would cause greater visual impacts over a wider area than the low-voltage alternative.

The low-voltage alternative and the proposed project may differ as to other environmental impacts, including possible electrical effects and siting impacts on trees, wetlands or other natural resource values. However, there is no evidence that any such environmental impacts of the low-voltage alternative would be of any significance, either alone or relative to the impacts identified in TFLP's analysis of the proposed project.

On balance, neither project approach offers substantial environmental advantages over the other. However, the Siting Council finds that, based on relative visual impacts, the low-voltage alternative is superior to the proposed project with respect to environmental impacts.

5. Conclusions: Weighing Need, Cost, and Environmental Impacts

The Siting Council has found that (1) the proposed project is superior to the low-voltage alternative with respect to meeting the identified need, (2) the proposed project is superior to the low-voltage alternative with respect to cost, and (3) the low-voltage alternative is superior to the proposed project with respect to environmental impacts. On balance, the Siting Council finds that the proposed project is superior to the low-voltage alternative.

Accordingly, the Siting Council finds that TFLP has demonstrated that its proposed project is consistent with ensuring a necessary energy supply with a minimum impact on the environment at the lowest possible cost.

III. ANALYSIS OF THE PROPOSED FACILITIES

A. Standard of Review

G.L. c. 164, sec. 69I, requires a facility proponent to provide information regarding "other site locations." In implementing this statutory mandate, the Siting Council requires the petitioner to show that its proposed facilities siting plans are superior to alternatives. Specifically, a petitioner must demonstrate that its proposed facilities are sited at locations that minimize costs and environmental impacts while ensuring supply reliability.

In previous cases, once the Siting Council has determined (a) that new energy resources are needed, and (b) that the applicant has proposed a project that is, on balance, superior to alternate approaches in terms of cost, environmental impacts, and addressing identified need, the Siting Council has required the petitioner to show (1) that it has examined a reasonable range of practical facility siting alternatives, and (2) that the proposed site for the facility is superior to the alternative site(s) on the basis of a balancing of cost, environmental impact, and reliability of supply. Braintree, EFSC 87-32 at 28; 1988 ComElec Decision, 17 DOMSC at 298-303; Middleborough, 17 DOMSC at 227-228; NEA, 16 DOMSC at 381-409; 1986 CELCo Decision, 15 DOMSC at 195-196, 229-237; Hingham Municipal Lighting Plant, 14 DOMSC 7, 22-32 (1986) ("Hingham"). In past cases, in order to determine that a facility proponent has considered a reasonable range of practical facility siting alternatives, the Siting Council typically has required the proponent to establish (1) that it has developed and applied a reasonable set of criteria for identifying alternatives, and (2) that it has identified at least two practical sites with some measure of geographic diversity. Braintree, EFSC 87-32 at 28; 1988 ComElec Decision, 17 DOMSC at 301-303; Middleborough, 17 DOMSC at 227-228; Boston Gas Company, 17 DOMSC 155, 176-181 (1988); NEA, 16 DOMSC at 385-388; 1986 CELCo Decision, 15 DOMSC at 228-229; Hingham, 14 DOMSC at 22; 1985 MECo Decision, 13 DOMSC at 190-191.

B. Description of the Proposed and Alternate Facilities

1. Proposed Facility

TFLP's proposal consists of a single-circuit 1.2-mile overhead 115 kV transmission line to be constructed along the proposed route which extends across, and then runs parallel to WMECo's power canal in Turners Falls (Exh. TFLP-1, pp. I-2 to I-3). After crossing the power canal from the cogeneration plant in Turners Falls, the proposed route would run for a distance of 1.11 miles along segments of abandoned railroad right of way owned by WMECo and the B&M Railroad on the southeast side of the power canal, and then continue for a distance of 0.08 miles through a wooded area owned by WMECo to the proposed interconnection point with a NEPCo 115 kV tap line known as the B-128 line ("NEPCo line") (id., pp. I-7, IV-46 to IV-47).[20] The proposed route would extend through the Turners Falls Historic District, as designated by the Massachusetts Historical Commission ("MHC"), from Second Street to a point aligned with Ninth Street (id., pp. IV-16 to IV-18). See Figure 1.

The proposal would consist of (1) 21 corten steel structures ranging from 55 to 85 feet in height, with all arms and hardware mounted to one side, and (2) 3 conductors of 336.4 kcmil steel-reinforced aluminum ("ACSR") (id., pp. I-7 to I-9; Exh. TFLP-10).

20/ Although Indeck has been negotiating for the rights to own or use the property along the proposed route, TFLP had not acquired property from the B&M Railroad nor obtained an easement from WMECo as of the close of the proceeding (Exhs. HO-14B, HO-14C). See Footnote 4A, supra.

Total installation cost for the proposal would be \$1,238,560 (Exh. TFLP-1, p. III-3; Exh. HO-RR-21).[21]

2. Alternate Facilities

TFLP identified four alternatives, which are described herein.

a. Alternative 1

Alternative 1 would fully overlap the proposed route, but would extend beyond the termination point of the proposal to an interconnection point with a WMECo 115 kV transmission line known as the Montague-Fairmount line ("WMECo 115 kV line"), rather than with the NEPCo line (Exhs. TFLP-1, pp. I-26 to I-28, TFLP-2, Exhibit XXV). Alternative 1 would be 1.6 miles in length, and would traverse additional land owned by WMECo in order to reach the alternate interconnecting point (id.). The additional 0.4 mile segment beyond the terminus of the proposed route would extend a short distance parallel to the canal and the NEPCo line, but then would veer through a wooded area and some wetlands to the WMECo 115 kV line (id.).

Total installation cost of Alternative 1 would be \$1,299,860 (Exh. TFLP-1, p. III-4; Exh. HO-RR-21).

b. Alternative 2

Alternative 2 would overlap the proposed route for nearly half its length, from the cogeneration plant to a point near Canal and Seventh Streets (Exh. TFLP-1, pp. I-30 to I-31). At

21/ Total installation costs for the proposal and alternatives include construction, right of way acquisition, interconnection charges, and environmental mitigation measures in the downtown area of Turners Falls. See Footnote 22 and Section III.D, infra.

this point, Alternative 2 would parallel existing WMECo low-voltage lines crossing back over the power canal and WMECo's nearby water power holding pond area, and then extend along the east bank of the Connecticut River to the point of interconnection with the NEPCo line (id.). Alternative 2 would be 1.0 miles in length and, after leaving the holding pond area, would traverse wooded land also owned by WMECo to the interconnection point (id., pp. I-32 to I-33, III-6).

Total installation cost of Alternative 2 would be $1,283,360 (id., p. III-6; Exh. HO-RR-21).

c. Alternative 3

Alternative 3 would overlap no portion of the proposed route, and instead would cross the Connecticut River directly from the cogeneration plant and extend along new right of way in Greenfield to the NEPCo line (Exh. TFLP-1, pp. I-33 to I-36). After crossing the river, Alternative 3 would would ascend Canada Hill, a wooded slope of 150 feet, then cross Route 2 and extend through an industrial park area on the east side of Adams Street to the interconnection point (id., p. III-7; Exhs. HO-28, HO-29C). Alternative 3 would have an installation cost of $2,015,500, the most expensive of all the alternatives (Exh. TFLP-1, p. III-8). However, it offers a total route deviation, with associated environmental differences and trade-offs relative to the proposal. The total length of Alternative 3 is 1.1 miles (id., p. III-7).

d. Alternative 4

Alternative 4 would fully mirror the proposed route, but, after crossing the power canal from the cogeneration plant, would extend underground along the railroad right of way from Second Street to just beyond Seventh Street, and then proceed overhead to the interconnection point (id., pp. I-36 to I-37). The underground segment, representing 43 per cent of the route, would avoid the placing of new overhead 115 kV transmission lines near the downtown area of Turners Falls[22] and within most of the Turners Falls Historic District (id., pp. III-7 to III-9).

TFLP stated that either oil-filled or solid dielectric cable would be used for the underground segment (id., p. I-37). TFLP indicated that, at both of the underground-overhead transfer points, dead-end poles with up to 9 arms would be required (Tr. I, pp. 123-125; Exh. TFLP-6). Oil storage and pumping equipment would be required at one of the transfer points if oil-filled cable is used (Exh. TFLP-1, p. I-37).

Total installation cost of Alternative 4 would be $1,562,300 (id., p. III-10).

C. Site Selection Process

TFLP identified five sites for the proposed 115 kV tie line -- the proposed route and Alternatives 1 through 4. TFLP indicated that the criteria used in selecting the proposed route and alternatives for detailed analysis, included (1) length of route, (2) cost, (3) environmental impacts, (4) difficulty in obtaining rights of way, and (5) obstacles in obtaining construction and interconnection approvals (Tr. II, pp. 98-100).

TFLP indicated that the proposed route and the alternatives were filed as, and are, practical facility siting alternatives (Tr. I, pp. 95-102, 248-249). TFLP nevertheless asserted that, with the passage of time, some of the identified alternatives had become less practical from an economic standpoint, based on what TFLP perceived to be increasingly apparent difficulties in its ability to implement such

---

22/ The downtown area of Turners Falls located near the proposed 115 kV tie line under the proposal and Alternatives 1, 2, and 4, generally extends from Second Street to Seventh Street. See Figure 1.

alternatives within financially critical time periods (id., pp. 249-250; Tr. II, pp. 117-119) (see Section III.D, infra). Nonetheless, TFLP did not withdraw any alternatives, and maintains that the proposed route and all the alternatives represent practical facility siting alternatives (Tr. I, pp. 248-249).

TFLP identified two additional routes that had been considered but rejected as part of the initial site selection process based on above criteria, including (1) a route that would cross the Connecticut River and extend northward through the Town of Gill ("Gill") along an existing WMECo right of way to interconnect with a regional transmission line owned by NEPCo, and (2) a route that would extend upstream along the Montague side of the Connecticut River, in the opposite direction from the proposed route and alternatives, to interconnect with the WMECo 115 kV line east of Turners Falls (Tr. II, pp. 99-100). TFLP stated that it rejected the additional route across the river, based on the length and visibility of the span across the river, uncertainties about using the WMECo right of way, and uncertainties about interconnecting with NEPCo's regional 115 kV transmission line as opposed to a tap line (Tr. I, pp. 16-18, 42-46, 51-53). TFLP stated that it rejected the route upstream along the Montague side of the Connecticut River based on land use and environmental factors (Tr. II, pp. 101-102).

The Siting Council finds that TFLP developed a reasonable set of criteria for identifying alternatives for the proposed 115 kV tie-line. These criteria include cost, environmental and system reliability/design considerations, as well right of way acquisition considerations. As such, TFLP has developed site selection criteria that are appropriate for identifying sites that minmize the economic costs and environmental impacts of constructing and operating needed energy facilities.

The Siting Council also finds that TFLP appropriately applied its criteria for identifying alternatives for the proposed 115 kV tie line. Specifically, TFLP identified a proposed route and four alternatives for the proposed 115 kV tie line including (1) an alternative that deviates in whole (Alternative 3) and an alternative that deviates in significant part (Alternative 2) from the proposed route, (2) an alternative (Alternative 1) that offers a choice with respect to the interconnecting utility,[23] and (3) an alternative (Alternative 4) that offers the option of underground construction. Further, the proposed route and the four alternatives meet the stated purpose of connecting the 20 MW cogeneration plant with an existing 115 kV transmission system. Finally, based on its criteria, TFLP rejected two other possible alternatives.

The Siting Council also finds that TFLP identified at least two sites for the proposed 115 kV tie line with some measure of geographic diversity. In particular, Alternative 3 deviates in whole from the proposed route.

In sum, the Siting Council has found that TFLP has established (1) that it developed and applied a reasonable set of criteria for identifying facility siting alternatives for the proposed 115 kV tie-line, and (2) that it identified at least two practical sites with some measure of geographic diversity for the proposed 115 kV tie-line. Accordingly, the Siting Council finds that TFLP has considered a reasonable range of practical facility siting alternatives for the proposed 115 kV tie-line.

Notwithstanding the above findings, the Siting Council focuses its further review on the proposal, Alternative 3, and Alternative 4, and, for the reasons stated below, substantially limits its further consideration of Alternatives 1 and 2.

Alternative 1 would involve a higher installation cost than the proposal, and higher annual regional transmission costs

---

23/ TFLP estimated that annual costs for dispatching power would be $592,500 for the proposal and Alternatives 2, 3 and 4 (which would be interconnected with NEPCo), and $970,000 for Alternative 1 (which would be interconnected with WMECo) (Tr. II, pp. 90-92; Exh. HO-11).

as well (Exh. TFLP-1, pp. III-2 to III-4; Exh. HO-11). Because Alternative 1 would fully overlap the proposed route and then extend across wooded areas with wetlands, it also would have greater environmental impacts than the proposal. Thus, Alternative 1 would provide no advantages relative to the proposal.

Alternative 2 would be slightly more costly than the proposal, based on TFLP's expectation that Alternative 2 would involve more difficult site preparation and construction (Exh. TFLP-1, pp. I-32, III-6). Further, Alternative 2 deviates from the proposed route only outside the Turners Falls Historic District and downtown area in Turners Falls (id., pp. I-30 to I-31). Thus, a predominant environmental concern in the review of the proposed route -- possible visual impacts on the Turners Falls Historic District and downtown area of Turners Falls (see Section III.E.3, infra) -- would not be avoided by Alternative 2. In addition, the segment of Alternative 2 that deviates from the proposed route would pass near a two-block residential street, traverse extensive wooded areas, and generally parallel a nearby section of the Connecticut River under consideration for inclusion in the federal wild and scenic rivers program (id., pp. I-32 to I-33). In sum, Alternative 2 would not be advantageous with respect to cost, and would involve certain environmental disadvantages relative to the proposal.

D. Cost Analysis of the Proposed and Alternate Facilities

TFLP argues that, based on estimated installation costs as well as expected annual regional transmission charges, the proposed route is the least-cost alternative (Brief, pp. 28-29).[24] TFLP estimated that total installation costs, including construction, right of way acquisition, interconnection charges, and environmental mitigation measures

---

24/ TFLP also argues that, based on the construction schedule and expected commercial operation by June 1989 for the cogeneration plant, approval by the Siting Council of the proposed route is an "absolute necessity to the financial good health of petitioner" (Brief, p. 39). TFLP stated that, since filing its petition, it had committed itself to the purchase of transmission structures for the proposal, in order to be in a position to commence construction by November, 1988 (Tr. I, p. 23). At the same time, TFLP asserted that approval by the Siting Council of certain alternatives would leave inadequate lead time to meet the planned commercial in-service date of the cogeneration plant given the necessity (1) to order underground cable and seek FERC approval to allow underground construction across WMECo property considered to be a part of WMECo's water power projects, as necessary for Alternative 4 (id., pp. 14-15, 104-106, 159), and (2) to seek federal and other agency approvals to allow construction across the Connecticut River, as necessary for Alternative 3 (id., pp. 15-16, 46-51).

Citing interest costs and possible penalty payments to the contractor of the cogeneration plant, J. A. Jones, TFLP asserted that a delay of about six months in implementing the proposed project would be "devastating" for the overall cogeneration project (Tr. I, pp. 20, 25, 70-71; Exhs. HO-RR-1, HO-RR-18). In past reviews, the Siting Council has recognized implementation and timing considerations, such as site acquisition, condemnation, and permitting requirements, as potentially legitimate factors in comparing proposed and alternate facilities with respect to cost and reliability. NEA, 17 DOMSC at 388-390, 408; 1988 ComElec Decision, 17 DOMSC at 339-343. In this case, however, the asserted financial consequences of a delay in implementing the proposed project stem more from TFLP's management of project scheduling then from legitimate differences among alternatives with respect to implementation and timing considerations. Indeed, given the tightness of the project construction schedule, the record fails to demonstrate that even the proposal can be implemented without some measure of adverse financial consequences of the type cited by TFLP. Accordingly, the Siting Council rejects TFLP's arguments that scheduling and related financial concerns should be considered as part of the Siting Council's cost analysis in this review.

in the downtown area of Turners Falls,[25] would be $1,238,560 for the proposal, $2,015,500 for Alternative 3, and $1,562,300 for Alternative 4 (Exh. TFLP-1, pp. III-1 to III-10; Exh. HO-RR-21). Thus, based on TFLP's estimates, Alternatives 3 and 4 would be 63 per cent and 26 per cent more costly than the proposal, respectively.

TFLP estimated that annual costs for maintaining the proposed 115 kV tie-line would be $5,000 (Exh. TFLP-1, p. III-12). TFLP estimated much larger annual costs for dispatching of power over regional transmission lines, amounting to $592,500 in wheeling and line loss charges under the proposal (Tr. II, pp. 90-91). TFLP estimated that these annual dispatching costs also would be $592,500 for Alternatives 3 and 4, which like the proposal would be interconnected with NEPCo (id.).

Accordingly, based on TFLP's analysis of expected installation costs, the Siting Council finds that the proposal is preferable to both Alternatives 3 and 4 with respect to cost.

E. Environmental Analysis of the Proposed and Alternate Facilities

During the proceeding, Commonwealth provided analyses of the expected environmental impacts of the proposal and alternatives and possible measures to mitigate such impacts (Exhs. TFLP-1, pp. IV-1 to IV-76; TFLP-2, Exhibit XVI to Exhibit XXIV; TFLP-10; Exhs. HO-26, HO-32). In its review, the

---

25/ TFLP indicated that WMECo has agreed to relocate certain distribution circuits in the downtown area of Turners Falls in order to allow Indeck to lower expected pole heights under the proposal as an environmental mitigation measure (Exh. HO-RR-21; Exh. TFLP-11). Indeck would pay WMECo an estimated $61,860 to lower the poles (Exh. HO-RR-21; Exh. TFLP-1, pp. III-1 to III-10). The Siting Council includes this cost as part of the overall installation costs estimated by TFLP for the proposal.

Siting Council first determines whether the proposal and Alternatives 3 and 4 would be acceptable with respect to expected environmental impacts. Braintree, EFSC 87-32 at 39-48; 1988 ComElec Decision, 17 DOMSC at 316-332; Middleborough, 17 DOMSC at 229-237; NEA, 16 DOMSC at 391-407. The Siting Council then compares the proposal and Alternatives 3 and 4 to determine which plan is preferable in terms of having a minimum impact on the environment.

1. Water and Land Environments

TFLP provided comparative estimates of wetland impacts and forest clearing under the proposal and the alternatives (Exh. HO-32). Other issues raised by TFLP included the presence of endangered species in the project area, special concerns related to the Connecticut River, and special concerns related to underground construction (Exhs. TFLP-1, pp. I-39, IV-22 to IV-24, TFLP-2, Exhibits XVII, XVIII and XIX).

TFLP indicated that direct construction in wetlands would not be required under the proposal, Alternative 3, or Alternative 4 (Exh. HO-32). However, TFLP noted that each route would involve construction across or along the edge of waterways in the project area, including the Connecticut River and the power canal, thereby necessitating review of possible wetland or waterway impacts by the Montague Conservation Commission (Exh. TFLP-1, p. I-36; Tr. II, pp. 33-35).

TFLP asserted that underground construction under Alternative 4 would require more excavation work than the proposal, and thus increased risk of erosion of sediment into the power canal (Exh. TFLP-1, p. I-39). TFLP provided that Alternative 3 would affect environmentally sensitive terrain on the opposite and undeveloped side of the Connecticut River (id., pp. I-35, IV-22 to IV-24). TFLP further noted that a segment of the river extending from Turners Falls to a point approximately 9 miles downstream is under consideration for inclusion in the federal wild and scenic river program (id.).

With respect to forests, TFLP indicated that Alternative 3 would require the clearing of 2.7 acres of woodlands, while the proposal and Alternative 4 each would require the clearing of only 0.4 acres (Exh. HO-32).

TFLP acknowledged that it may be possible, under Alternative 3, to span the conductors across the Connecticut River from the cogeneration plant to near the top of the 150-foot rise of Canada Hill on the opposite side, thereby potentially reducing the number of transmission structures and associated right-of-way impacts extending up the slope from the river bank to the top of Canada Hill (Tr. II, pp. 28-32).

In sum, displacement of water and land resources would be minimal under the proposal and Alternatives 3 and 4, and environmental mitigation measures and design options appear to be available to minimize environmental impacts. The Siting Council finds that the proposal, Alternative 3 and Alternative 4 all would be acceptable with respect to impacts on water and land environments.

TFLP's analysis shows that, based on terrain differences, Alternative 3 nevertheless would be potentially more disruptive to water and land environments than the proposal. Further, the partial-underground alignment under Alternative 4, although following a relatively level abandoned rail bed, would require more excavation than the proposal potentially resulting in additional erosion. Accordingly, the Siting Council finds that the proposal is preferable to Alternative 3 and slightly preferable to Alternative 4, with respect to water and land environments.

2. Land Use and Community Development

a. Local Community Impacts

TFLP provided a zoning map of Montague, and described existing land use and zoning provisions affecting the proposal and Alternative 3 (Exh. TFLP-1, pp. IV-5 to IV-7; Exh. HO-26).

With respect to the proposal, TFLP indicated that there are three single family residences and an apartment building within 100 feet of the right of way, but that actual and zoned land use along the route is primarily industrial (Exh. TFLP-1, p. IV-5). The proposed route would traverse a parking lot, without requiring pole placement therein (Tr. I, pp. 92-93, 116-119), and otherwise would not traverse any developed land parcels.

TFLP stated that Alternative 3 would traverse predominantly industrially zoned land, including a gravel pit and an expanding industrial park, but noted the presence of some residences in the vicinity of the route (Exhs. HO-26, HO-RR-12; Tr. II, pp. 23-28). TFLP sugested that it might encounter resistance or incur unexpected costs in assembling the necessary rights of way across undeveloped parcels, but did not indicate any need to displace existing developed land uses (Tr. II, pp. 80-83).

TFLP asserted that Montague has no adopted land use plan (Exh. TFLP-1, p. IV-7). TFLP also asserted that, in issuing a special permit for construction of the cogeneration plant, the Montague Planning Board explicitly acknowledged the proposal as part of the overall project approval for the cogeneration plant (Exh. HO-38; Tr. I, p. 48).

TFLP acknowledged that construction of the proposed 115 kV tie-line requires certain variances from Montague's zoning provisions in order to exceed pole height restrictions and, for a portion of the proposed route, to avoid adopted use restrictions (Exh. TFLP-1, p. IV-7). Indeed, TFLP reported that the Montague Board of Zoning Appeals initially rejected Indeck's request for a variance, based in part on Indeck's failure to adequately consider alternatives (Exh. TFLP-10; Tr. 1, pp. 7-11). When Indeck later agreed to lower the height of pole 4 from 75 to 65 feet, pole 5 from 85 to 76 feet, and pole 6 from 95 to 78 feet, with all such poles located along the proposed route in the area of Fifth and Sixth Streets, the Montague Board of Zoning Appeals granted the variance requests (Exh. TFLP-11).

b. State and Federal Concerns

TFLP identified a number of additional potential land use or special area concerns related to regional, state and federal programs affecting Turners Falls (Exh. TFLP-1, pp. IV-7, IV-14 to IV-16, IV-35 to IV-39). TFLP stated that (1) the Turners Falls Historic District encompasses the entire downtown area of Turners Falls, including areas along the power canal from Second to Ninth Streets that would be traversed by the proposal or Alternative 4; (2) the Franklin County Bikeway, which would extend through a number of local communities, is planned by MEDIC and DEM and would run along the entire proposed route and thus, prospectively shares the proposed 115 kV tie-line right of way under either the proposal or Alternative 4; (3) a state heritage park, under the auspices of DEM, is planned to be operational in 1990 adjacent to the power canal opposite the cogeneration plant; and (4) a segment of the Connecticut River passing Turners Falls and extending 9 miles downstream, which segment would be traversed by Alternative 3, is under consideration by the U.S. Department of Interior for designation as a wild and scenic river (id.).

TFLP maintains that Turners Falls derives its historical significance from its origins as an early industrial community formed to take advantage of available water power (Brief, p. 33). TFLP argues that the proposed route near downtown Turners Falls would be sited in what still is a primarily industrial area, and that modern intrusions such as electrical lines already abound in the area (id.). With respect to the planned bikeway, TFLP argues that Indeck has tentatively agreed with MEDIC and DEM to grant an easement, at a cost of one dollar, to allow the bikeway to be constructed as a shared use of the proposed right of way (id., p. 34). Finally, TFLP maintains that, unlike the proposal, Alternative 3 would adversely affect the planned heritage park, which will overlook the prospective Connecticut River crossing, as well as intrude into the area of the proposed wild and scenic river designation along the

Connecticut River near Turners Falls, which would encompass the same river crossing area (id., pp. 33-35).

The record demonstrates that the proposed route is within a short distance of a number of historical properties within the Turners Falls Historic District, including the power canal itself, mill buildings on the opposite side of the power canal from the proposed route, and two residences and a church within one to two blocks of the proposed route near Sixth Street (Exh. TFLP-2, Exhibit XVI; Exh. HO-57). However, numerous other identified properties in the historic district are either two or more blocks from the proposed route, or separated from the proposed route by a substantial difference in elevation (id.; Exh. HO-43; Tr. II, p. 41).

TFLP provided evidence that it had consulted with WMECo about possible effects of the proposed 115 kV tie-line on the structural integrity of the canal wall, and had addressed these concerns to the satisfaction of WMECo (Exh. TFLP-2, Exhibit XV; Exh. HO-RR-19). Further, the record shows that MHC issued a "determination of no adverse effect" with respect to the siting of the proposal (Exh. TFLP-1, p. IV-19; Exh. HO-39).

With respect to the planned Franklin County Bikeway, TFLP has acknowledged that, in the WMECo-owned segment between Second and Fifth Streets, the proposed route is narrow and that possible further constriction of the limited bikeway space by the proposed transmission structures is a disadvantage of the proposal (id., p. I-39). However, the record demonstrates that DEM, Indeck, and WMECo consulted and agreed to relocate certain pole locations along the proposed route to minimize possible interference with the Franklin County Bikeway (Exh. HO-39).[26]

In regard to the planned state heritage park, TFLP

26/ The record indicates that DEM, as an agency of the Commonwealth, has first refusal rights to acquire for its sole use the portions of the abandoned railroad right of way now owned by the B&M Railroad (Exh. TFLP-1, p. I-15).

asserted that a representative of DEM objected to Alternative 3 based on its likely visual impact on the planned heritage park (Tr. I, pp. 15-16). While the evidence suggests that the state heritage park will indeed afford visitors a view of the affected reach of the river (Exh. TFLP-1, p. IV-15), there is insufficient evidence to conclude that this view is so central to the purposes of such a park as to establish that siting a power line crossing the Connecticut River several hundred feet from the park would constitute an unacceptable land use conflict.

With respect to the possible wild and scenic river designation, the record indicates that the opposite bank of the Connecticut River from Turners Falls features the 150-foot high slope to the top of Canada Hill with no apparent developmental intrusions (Tr. 1, pp. 47-48; Exhs. HO-54, HO-55). However, the record also demonstrates that there are existing power line crossings of the Connecticut River in the general area, including the WMECo low-voltage line to Gill a short distance upstream, and the NEPCo line approximately one mile downstream (Exh. TFLP-2, Exhibit XXV). Thus, while the Alternative 3 crossing of the Connecticut River would detract from the scenic quality of the river valley, there is insufficient evidence to conclude that the transmission line crossing would result in an unacceptable conflict with the possible wild and scenic river designation.[27]

c. Conclusions on Land Use and Community Development

Based on the foregoing, the Siting Council finds that the proposal, Alternative 3, and Alternative 4 all are acceptable with respect to impacts on land use and development.

In balancing the numerous potential land use impacts of

27/ The Siting Council further considers the visual impacts of Alternative 3 in Section III.E.3, *infra*.

the proposal and Alternatives 3 and 4, predominant concerns under the proposal include routing overhead 115 kV tranmission lines near the downtown area of Turners Falls, through the Turners Falls Historic District, and along the route of the planned Franklin County Bikeway. Under Alternative 3, predominant concerns pertain to acquiring new right of way in Greenfield and intruding on the Connecticut River valley. Alternative 4, however, would substantially avoid these concerns. Accordingly, the Siting Council finds that Alternative 4 is preferable to the proposal and Alternative 3 with respect to impacts on land use and development.

3. Visual Impacts

TFLP provided an assessment of expected visual impacts of the proposal on a segment-by-segment basis (Exh. TFLP-1, pp. IV-39 to IV-47). TFLP also assessed by segment the visibility of each alternative facility plan, and compared the relative overall visual impacts of the proposal and alternatives (id., pp. IV-70 to IV-77, Exh. TFLP-2, Exhibit XXI).

In assessing visual impacts, TFLP indicated that, for each segment, it considered the scenic quality of the area to be traversed and the visibility of the proposed 115 kV tie-line in that area (Exh. TFLP-1, p. IV-39). TFLP stated that it based its assessment of scenic quality on (1) topographic, vegetative and water features, (2) human activity, and (3) developed land use features compatible with transmission facilities (id., pp. IV-42 to IV-43). TFLP provided that visibility is a function of whether the view is open or screened, and additional modifying factors such as the number of potential viewers of the proposed 115 kV tie line, the distance between viewers and the proposed 115 kV tie line, and the background of the view (id., IV-43 to IV-45).

TFLP argues that Alternative 3 would have more severe visual impacts than the proposal, based largely on the impact of Alternative 3 crossing the Connecticut River and ascending the wooded Canada Hill across from the cogeneration plant (Brief, p. 36). TFLP acknowledges that Alternative 4 is the "mitigation alternative" for visual impacts, and maintains that this alternative should have superior visual characteristics (id.).

Nonetheless, TFLP maintains that any visual impacts of the proposal would be minimized by use of a route used in the past for rail transport, and still largely separated from adjacent land uses by grade differences and vegetation (id., p. 36-37). In addition, TFLP argues that its proposed use of weathering corten steel poles, free standing without support wires, would further mitigate aesthetic concerns (id., p. 37).

TFLP agreed that, under Alternative 3, a direct span of conductors from the cogeneration plant to the top of Canada Hill appears possible as a means of minimizing the need to clear a right of way and locate poles up the slope of Canada Hill (Tr. II, pp. 28-32). Outside of the Connecticut River crossing area, TFLP's visual assessment of Alternative 3 was scant, and rated visual concerns along the entire route as medium to high without explanation (Exh. TFLP-2, Exhibit XXI). TFLP indicated that it had not pursued the possibility of an alignment behind existing industrial buildings along the east side of Adams Street, rather than directly paralleling the street (Tr. 1, pp. 244-246).

With regard to TFLP's arguments as to the desirability of selecting the B&M Railroad corridor as the proposed route, the Siting Council indeed has supported such an approach as one means of acceptably siting transmission facilities in built-up areas. Hingham, 14 DOMSC at 30; Taunton, 8 DOMSC at 162. The Company demonstrated that the proposed route by and large abuts industrial land uses or, where other developed uses exist, is significantly separated from such uses by grade differences or vegetation (Exh. TFLP-1, p. IV-5; Exhs. HO-43, HO-46, HO-48, HO-50; Tr. II, pp. 41). At the same time, the Siting Council notes some areas of potential concern with respect to the visibility of the proposal (Tr. II, pp. 41-60). In particular, between Fifth and Seventh Street, an area containing a number of residences, the proposed route abuts Canal Street nearly at grade, without any screening, and is also directly visible from the Fifth Street Bridge approach to Turners Falls crossing the Connecticut River (id., pp. 41-50). Between Seventh and Eleventh Streets, the proposal would pass two abutting residences, one as close as 30 feet, and would be visible from numerous other residences across the power canal (id., pp. 47, 54-59).

TFLP maintained that the area of Fifth and Sixth Streets is not scenic, and that numerous existing electrical wires minimize the degree of incremental impact of the proposal (id., pp. 43-52). TFLP also provided evidence that, as part of obtaining its variance from the Montague Zoning Board of Appeals (see Section III.E.2, supra), it had agreed to significantly lower the heights of its proposed poles in that area (Exh. TFLP-11). With these changes, the proposal would be no higher than 85 feet at any point along the proposed route, and generally would be 65 feet or less in height along major portions of the proposed route where clearance obstructions are not present (Exh. HO-7A).

Accordingly, the Siting Council finds that the proposal, Alternative 3, and Alternative 4 all are acceptable with respect to visual impacts.

Alternative 4 would avoid the visual impacts of the proposal in the downtown area of Turners Falls and in the Turners Falls Historic District, including the area with some nearby residences between Fifth and Seventh Streets. Alternative 4 also would avoid the significant visual impact of Alternative 3 in crossing the Connecticut River and ascending Canada Hill. Accordingly, the Siting Council finds that Alternative 4 is preferable to the proposal and Alternative 3 with respect to visual impacts.

4. Electrical Effects

TFLP provided analyses of the expected electrical effects of the proposal, including eight categories of effects relating to possible safety, health, noise, and radio/television interference concerns (Exh. TFLP-1, pp. IV-50 to IV-67). TFLP stated that the results of its analysis show that all such effects of the proposal would be well below guidelines established in Massachusetts as well as in any other state (id., p. IV-64).

With regard to field levels, TFLP indicated that the maximum electric field would be 1.31 kV per meter ("kV/m") within the proposed right of way and 0.31 kV/m at the edge of the right of way (id., p. IV-51).[28] TFLP calculated that the maximum magnetic field would be 56 milligauss (mG) under the line (id., p. IV-55).

TFLP stated that the nearest residence, located in the area of Seventh and J Streets, would be about 30 feet from the centerline of the proposed 115 kV tie line (Tr. II, p. 111). TFLP noted that, while its calculations of electric and magnetic fields were based on a minimum conductor height of 25 feet expected along relatively open portions of the proposed route, the conductors in the vicinity of Seventh and J Streets actually would be at least 45 feet above the ground (id., p. 110).

In the past, the Siting Council has accepted maximum edge-of-right-of-way electric field levels of 1.8 kV/m and maximum edge-of-right-of-way magnetic field levels of 85 mG. 1985 MECo Decision, 13 DOMSC at 228-229, 241. In the instant case, the proposal would induce electric and magnetic fields below these levels.

TFLP did not provide separate calculations of electric effects for the alternatives. However, TFLP indicated that the Department of Public Utilities requires a minimum conductor height of 25 feet for the type of transmission line TFLP is proposing to construct (Tr. II, p. 109). Thus, centerline field

---

28/ This assumes that the right of way edge is approximately 9 meters from the centerline of the proposed 115 kV tie line (Exh. TFLP-1, p. IV-52).

levels for the alternatives would not be expected to exceed those for the proposal.

With regard to Alternative 4, TFLP did not contend that an underground alignment would induce measurable fields at any distance from the conductors, and in fact acknowledged that Alternative 4 may have less impact than the proposal with respect to electrical effects (Brief, p. 38).

Accordingly, the Siting Council finds that the proposal, Alternative 3 and Alternative 4 all would be acceptable with respect to electrical effects. The Siting Council makes no findings as to preference of the proposal or Alternatives 3 and 4 with respect to electrical effects.

5. Conclusions on Environmental Analysis of the Proposed and Alternate Facilities

The Siting Council has found that the proposal, Alternative 3 and Alternative 4 all would be acceptable with respect to all of the environmental concerns raised in this proceeding.

The Siting Council has found that (1) the proposal is preferable to Alternative 3 and slightly preferable to Alternative 4 with respect to water and land environments, (2) Alternative 4 is preferable to the proposal and Alternative 3 with respect to land use and community development, and (3) Alternative 4 is preferable to the proposal and Alternative 3 with respect to visual impacts. The Siting Council made no findings as to the preference of the proposal or Alternatives 3 and 4 with respect to electrical effects.

Accordingly, the Siting Council finds that, on balance, Alternative 4 is preferable to the proposal and Alternative 3 with respect to environmental impacts.

F. Conclusions on the Analysis of the Proposed Facilities

The Siting Council has found that TFLP considered a reasonable range of practical facility siting alternatives for the proposed 115 kV tie line. In addition, the Siting Council has found that (1) the proposal is preferable to Alternative 3 and Alternative 4 with respect to cost, and (2) Alternative 4 is preferable to the proposal and Alternative 3 with respect to environmental impact. Thus, the Siting Council determines whether the proposal is superior to Alternative 4.

Pursuant to G.L. c. 164, secs. 69H and 69I, in reaching decisions on facility proposals, the Siting Council is required to balance cost, environmental impact, and reliability of supply. In cases involving proposals to construct underground and overhead transmission lines, the Siting Council has addressed the balance between cost and environmental impact. See, e.g., Braintree, EFSC 87-32 at 49-50; Hingham, 14 DOMSC at 7; Boston Edison Company, 3 DOMSC 44 (1978).

In the instant case, the estimated installation cost for Alternative 4 is approximately $324,000 (26 per cent) more than the proposal. Meanwhile, the portion of the proposal for which underground construction has been considered under Alternative 4 traverses the Turners Falls Historic District, overlaps the route of the planned Franklin County Bikeway, and passes near some residences.

While recognizing the higher costs of underground construction as opposed to overhead construction, the Siting Council in the past has stated its concerns with placing 115 kV or higher voltage transmission lines through residential areas when not on existing separate rights of way used for utility purposes. Id. Indeed, the Siting Council found in Braintree that, despite cost differences at least as large as those in the instant case, more costly underground construction was warranted to avoid constructing 75-foot poles along residential streets (pp. 49-50).[28] Further, in that case, the underground construction was consistent with the policy of the Town of Braintree.

A number of additional factors, however, are critical in the instant case. First, the proposed route near the downtown area of Turners Falls does not follow public streets, but rather follows an abandoned railroad right of way in which Indeck would acquire ownership and easement interests. Second, the MHC has determined that the proposal would have no effect on the Turners Falls Historic District. Third, the Montague Board of Zoning Appeals has accepted the proposal. Fourth, regarding portions of the right of way of the proposed route still owned by the B&M Railroad, DEM to date has elected to negotiate for shared use of such right of way for the planned Franklin County Bikeway, rather than excercise its right to acquire the right of way outright.

Finally, as a step to mitigate any visual impacts of the proposal, TFLP would use corten weathering steel structures.[29] In addition, a majority of the structures would be 65 feet or less in height, and the facility centerline would

---

28/ In Braintree, the proposed underground line was $688,000, or 58 percent more expensive than the alternative overhead line -- a larger differential than in the instant case. However, the proposed underground line extended along the entire proposed underground route; in contrast, Alternative 4 in the instant case would provide for underground construction along 43 percent of the route.

29/ While accepting TFLP's position in this case that weathering steel structures help mitigate visual impacts, the Siting Council has in a past case approved use of wooden structures over weathering steel structures based on the preference of abutters. See Hingham, 14 DOMSC at 25-26, 32.

be sited at least 30 feet from all existing residences.[30]

In light of the higher cost of underground construction under Alternative 4, and the additional mitigating factors noted above with respect to the proposal, the Siting Council finds that, on balance, the proposal is superior to Alternative 4.

However, in order to further mitigate the potential impact of the proposed 115 kV transmission line structures between Second and Fifth Streets along the proposed route, with particular reference to the prospective shared use of right of way with the planned Franklin County Bikeway, the Siting Council ORDERS TFLP:

(1) to install fenders or padding of aesthetically acceptable material to protect bicyclists or other users of the planned Franklin County Bikeway from accidentally colliding with proposed 115 kV transmission line structures identified as poles 1, 2, 3, 4 and 5; and

(2) to consult with responsible officals of MEDIC and DEM in the design, and choice of materials, for such fenders or padding.

30/ While providing a buffer from residences, TFLP nevertheless maintained that the proposed 115 kV tie line would be designed to avoid any noise or known health concerns related to electrical effects within as well as outside of the right of way.

IV. DECISION AND ORDER

The Siting Council finds that the construction of a single circuit 1.2-mile, overhead 115 kilovolt electric transmission line along the proposed route described herein is consistent with providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

Accordingly, the Siting Council hereby APPROVES the petition of Turners Falls Limited Partnership to construct a single circuit 1.2-mile, overhead 115 kilovolt electric transmission line along the proposed route described herein, subject to the following conditions:

(1) TFLP shall generally limit the height of the proposed 115 kV transmission line structures to no greater than 65 feet, except that, in order to locally provide adequate clearance for obstructions, TFLP shall construct the proposed 115 kV transmission line structures that conform to the following heights for identified poles: poles 2, 3, 10 and 11 shall be 70 feet; pole 13 shall be 71 feet, pole 5 shall be 76 feet; pole 6 shall be 78 feet; and pole 7 shall be 85 feet.

(2) TFLP shall locate the proposed 115 kV transmission line such that the centerline of the proposed 115 kV transmission line is at least 30 feet from all existing residences.

(3) TFLP shall finalize an agreement, consistent with this decision, that would allow the Montague Economic Development Industrial Corporation and the Department of Environmental Management to utilize the proposed route from Sixth Street to Seventeenth Street for the Franklin County Bikeway at a cost of one dollar, and provide a copy of the finalized agreement to the Siting Council.

(4) TFLP shall (a) install fenders or padding of aesthetically acceptable material to protect bicyclists or other users of the planned Franklin County Bikeway from accidentally colliding with the proposed 115 kV transmission line structures identified as pole numbers 1, 2, 3, 4 and 5; and (b) consult with responsible offícals of the Montague Economic Development Industrial Corporation and the Department of Environmental Management in the design, and choice of materials, for such fenders or padding.

Frank P. Pozniak

Frank P. Pozniak
Hearing Officer

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of December 8, 1988 by the members and designees present and voting. Voting for approval of the Tentative Decision as amended: Sharon M. Pollard (Secretary of Energy Resources); Stephen Roop (for James S. Hoyte, Secretary of Environmental Affairs); Timothy Gailey (for Paula W. Gold, Secretary of Consumer Affairs and Business Regulation); Jeanette Willett (for Joseph D. Alviani, Secretary of Economic Affairs); and Madeline Varitimos (Public Environmental Member). Ineligible to vote: Dennis J. LaCroix (Public Gas Member). Absent: Joseph Joyce (Public Labor Member).

Sharon M. Pollard
Chairperson

Dated this 8th day of December, 1988

Figure 1

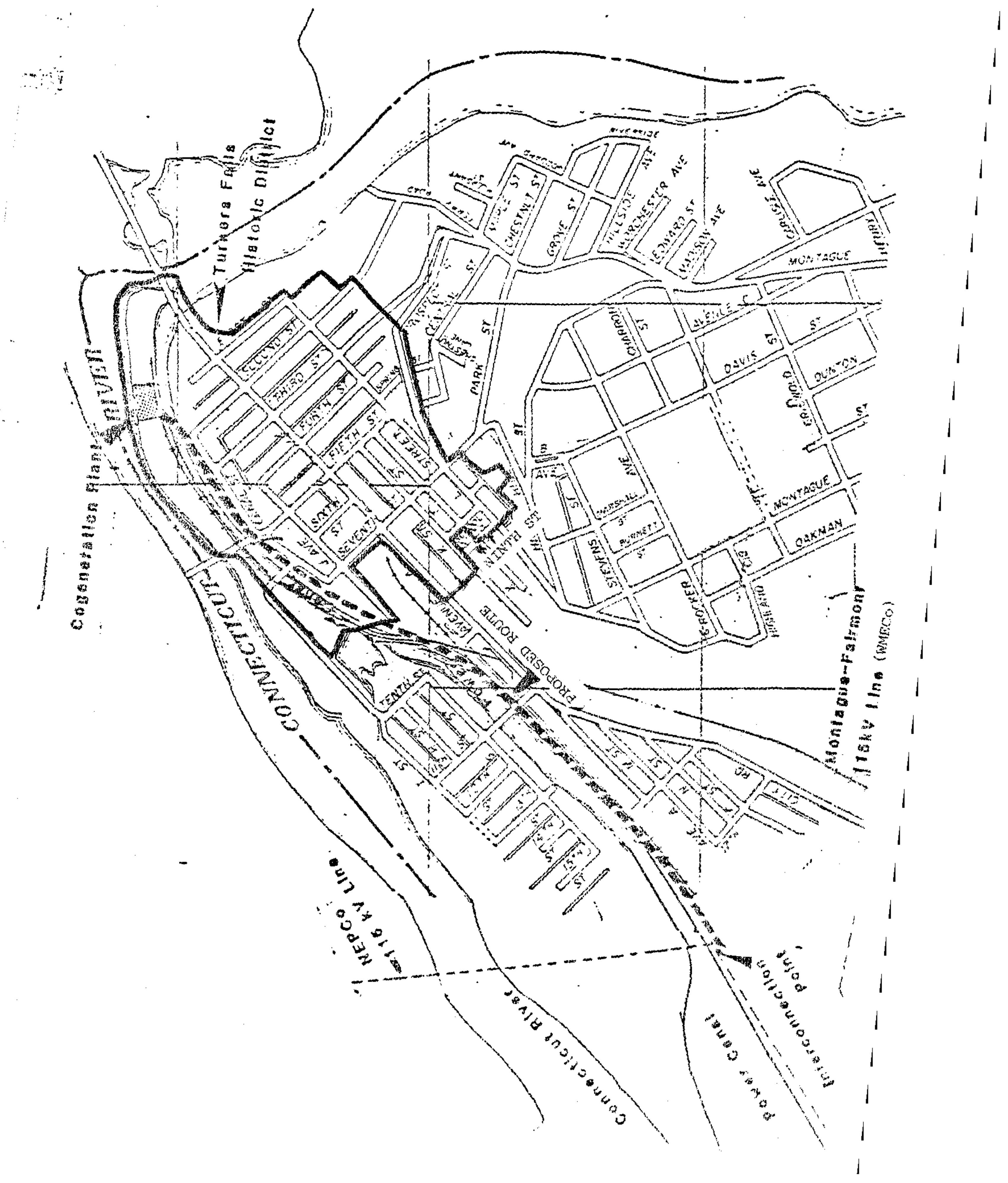
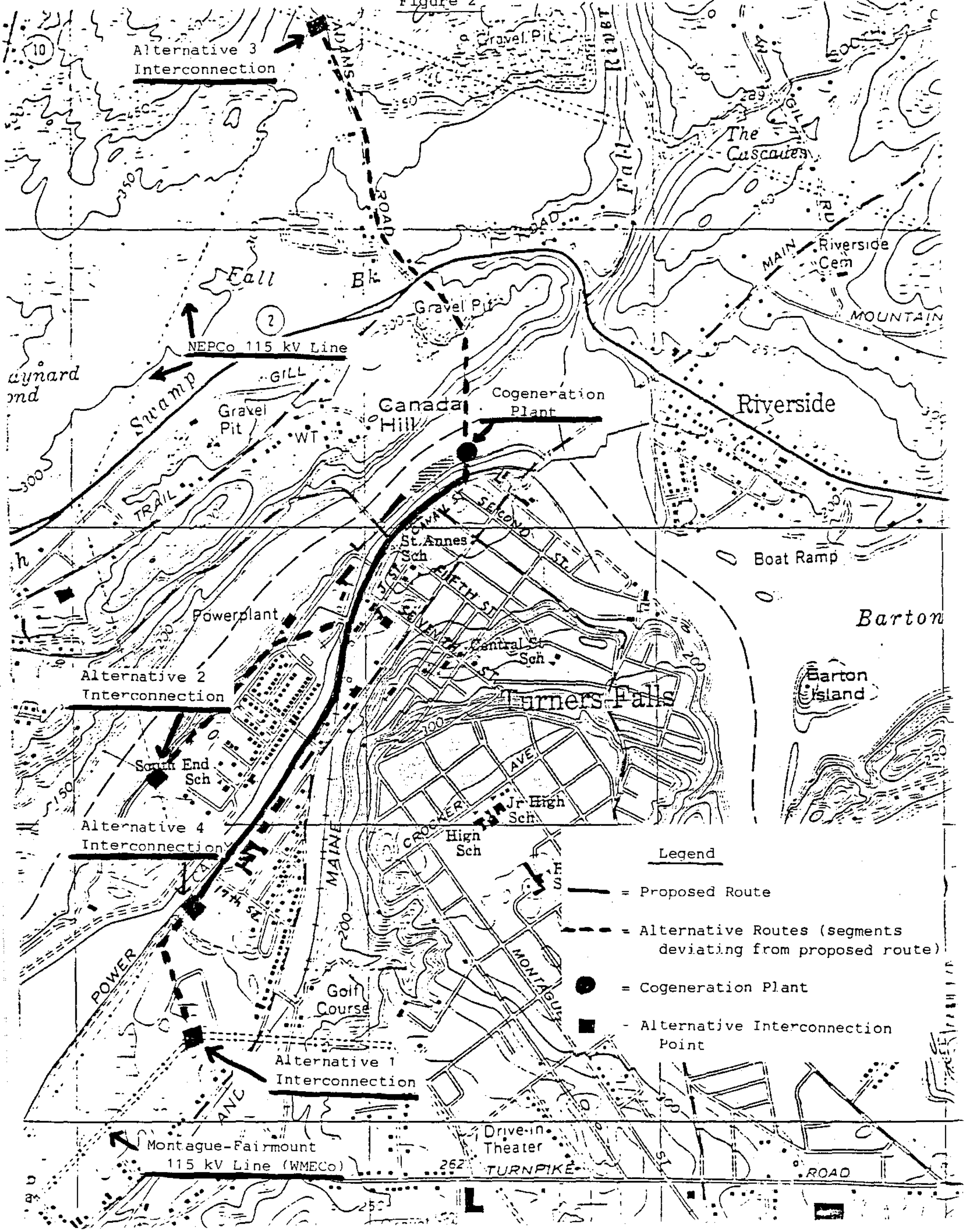

Turners Falls
Historic District
Cogeneration Plant
CONNECTICUT RIVER
PROPOSED ROUTE
Montague-Palmony
115kV Line (WMECo)
NEPCo Line
115 kV Line
Connecticut River
Power Canal
Interconnection point
SECOND ST
THIRD ST
FOURTH ST
FIFTH ST
SIXTH ST
SEVENTH ST
NINTH ST
TENTH ST
PARK ST
CHESTNUT ST
GROVE ST
HILLSIDE AVE
DORCHESTER AVE
LEONARD ST
MADISON AVE
MONTAGUE
AVENUE C
DAVIS ST
DUNTON
CHARRON ST
GRISWOLD
MARSHALL
BURNETT
STEVENS
CROCKER
HIGHLAND
OAKMAN
RIVERSIDE

Figure 2


Alternative 3
Interconnection
Gravel Pit
ADAMS
ROAD
The
Cascades
Riverside
Cem
MAIN
MOUNTAIN
Fall
Bk
Gravel Pit
NEPCo 115 kV Line
Swamp
GILL
Gravel
Pit
WT
Canada
Hill
Cogeneration
Plant
Riverside
TRAIL
CANAL ST
SECOND ST
St.Annes
Sch
FIFTH ST
Boat Ramp
Barton
Powerplant
SEVENTH ST
Central St
Sch
Alternative 2
Interconnection
Turners Falls
Barton
Island
South End
Sch
AVE
Jr High
Sch
Alternative 4
Interconnection
MAINE
CROCKER
High
Sch
Legend
= Proposed Route
= Alternative Routes (segments
deviating from proposed route)
= Cogeneration Plant
- Alternative Interconnection
Point
POWER
MONTAGUE
Golf
Course
Alternative 1
Interconnection
Montague-Fairmount
115 kV Line (WMECo)
Drive-in
Theater
TURNPIKE
ROAD

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

Such petition for appeal shall be filed with the Siting Council within twenty days after the date of service of the decision, order or ruling of the Siting Council or within such further time as the Siting Council may allow upon request filed prior to the expiration of twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said Court. (Sec. 5, Chapter 25, G.L. Ter. Ed., as most recently amended by Chapter 485 of the Acts of 1971).

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Boston Edison Company for Approval of its 1988 Long-Range Forecast of Electric Requirements and Resources	EFSC 88-12

FINAL DECISION

Stephen Klionsky
Hearing Officer
February 16, 1989

On the Decision:

Michael P. Aronson
Brian G. Hoefler

APPEARANCES:

William S. Stowe, Esq.
Mary Elizabeth Stanton-Cotter, Esq.
800 Boylston Street
Boston, Massachusetts 02199
FOR: BOSTON EDISON COMPANY
Petitioner

Allan Nogee
29 Temple Place
Boston, Massachusetts 02111
FOR: MASSACHUSETTS PUBLIC INTEREST RESEARCH GROUP
Intervenor

TABLE OF CONTENTS

TABLE OF CONTENTS (Cont.)

The Energy Facilities Siting Council hereby APPROVES the 1988 demand forecast and APPROVES the 1988 supply plan of Boston Edison Company.

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 1986, Boston Edison provided retail service to 40 cities and towns in the greater Boston metropolitan area (Exh. BE-2, p. A-1) and wholesale service to 19 customers (Exh. BE-3, pp. E-1 to E-3), primarily municipal light boards.1 Total electricity sold in 1986 was 11,685 gigawatthours ("GWH"); peak load during 1986 was 2,254 megawatts ("MW") (Exh. BE-2, pp. A-1, A-8). BECo's sales account for about 30 percent of the retail electricity sold in Massachusetts. Boston Edison services a largely urbanized area with a summer-peaking load (id., pp. A-8, A-9).

In its review of Boston Edison's previous filing, the Siting Council approved the Company's demand forecast and rejected the Company's supply plan. Boston Edison Company, 15 DOMSC 287 (1987) ("1987 BECo Decision"). In that decision, the

---

1/ Two municipally-owned electric utilities, the Concord Municipal Light Plant ("Concord") and the Electric Division of the Wellesley Board of Public Works ("Wellesley"), receive almost all of their power requirements from Boston Edison (Exh. BE-2, p. H-1). Given the Company's obligation to supply virtually all of Concord's and Wellesley's power needs (id., p. H-6), their annual requirements and peak demands are included in the Company's forecast of total system demand. (As of July 1985, these municipals also purchase a small portion of their annual energy requirements, approximately 22 GWH, from the New York Power Authority (id., p. H-1).)

Siting Council ordered the Company to: (1) develop a plan for the possibility of losing Pilgrim capacity credit; and (2) develop a plan for minimizing the risk and extent of disconnecting firm customer load in the City of Boston for all summers prior to the expected in-service date of the Company's proposed 345 kV Mystic-Downtown transmission line. The Company complied with these orders, as discussed in Section III.B, infra.

B. Procedural History

On February 5, 1988, the Company filed its Integrated Planning Process, Energy and Peak Load Forecast, and Resource Plan (Exhs. BE-1, BE-2, and BE-3, respectively). On March 30, 1988, the Hearing Officer issued a Notice of Adjudication and directed Boston Edison to publish and post the Notice in accordance with 980 CMR 1.03(2). Boston Edison subsequently submitted confirmation of publication.

On May 6, 1988, the Massachusetts Public Interest Research Group ("MASSPIRG") filed a Motion to Intervene in the proceeding. On May 13, 1988, the Company filed its Opposition to MASSPIRG's Motion to Intervene. The Hearing Officer, on July 7, 1988, allowed MASSPIRG's Motion to Intervene.

Evidentiary hearings were held on September 15, September 16, and October 4, 1988. BECo presented seven witnesses: William P. Killgoar, Manager of the Energy Resources Planning and Forecasting ("ERP&F") Department; Paul D. Vaitkus, Division Head of Supply Planning Division in the ERP&F Department; Robert J. Cuomo, Division Head of the Forecasting and Market Analysis Division of the ERP&F Department; Gregory R. Sullivan, Head of the Distribution and Planning Section of the Electrical Engineering and Station Operations Department; Kathleen A. Kelly, Division Head of the Demand Planning Division of the ERP&F Department; Philip DiDomenico, Performance and Reliability Coordinator in the Production Operations Department; and Elaine D. Robinson, Division Head of the Nuclear Information Division of the Corporate Relations Organization. The Siting Council entered 150 exhibits into the record, largely composed of BECo's responses to information and record requests. BECo entered 18 exhibits into the record, and MASSPIRG entered five exhibits into the record.

Pursuant to a briefing schedule established by the Hearing Officer, MASSPIRG filed its initial brief on November 4, 1988 ("MASSPIRG Brief"), and the Company filed its brief on November 18, 1988 ("BECo Brief"). MASSPIRG filed its reply brief on November 28, 1988 ("MASSPIRG Reply Brief").

II. ANALYSIS OF THE DEMAND FORECAST

A. Standard of Review

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

A demand forecast is reviewable if it contains enough information to allow full understanding of the forecasting methodology. A forecast is appropriate if the methodology used to produce that forecast is technically suitable to the size and nature of the utility that produced it. A forecast is reliable if the methodology provides a measure of confidence that its data, assumptions, and judgments produce a forecast of what is most likely to occur. 1987 BECo Decision, 15 DOMSC at 294.

B. Previous Demand Forecast Orders

The Siting Council approved the previous Boston Edison demand forecast without orders or conditions. 1987 BECo Decision, 15 DOMSC at 294-299.

C. Energy Forecast

Boston Edison forecasted annual energy requirements by first preparing electricity price, demographic, and employment forecasts, then applying those forecasts in a detailed end-use/econometric model (Exh. BE-II, pp. A-1 to A-6). Boston Edison forecasted energy requirements individually for the residential, commercial, and industrial sectors, as well as for three other classes -- streetlighting, municipal sales, and losses and internal use.

The results of BECo's energy forecast are presented in Table 1.

1. Electricity Price Forecast

The Company forecasted electricity prices as the sum of a base component and a fuel component (Exh. BE-2, pp. B-1 to B-5). The base component is essentially a simplified cost-of-service model; the fuel component is estimated from the Company's production costing model (id.). Boston Edison reported that its electricity price forecast methodology was unchanged since the previous Siting Council review, but that certain assumptions had been updated (id.; Exh. BE-8; Tr. I, p. 179).

MASSPIRG asserts that the price forecast is likely to be too low (MASSPIRG Brief, p. 3). MASSPIRG argues that two of the Company's assumptions about Pilgrim costs that would flow through to electricity price support this assertion: first, the assumption about Pilgrim's future operations and maintenance ("O&M") and capital costs are greatly underestimated; second, the assumption of a 70 percent capacity factor for Pilgrim compared to the unit's historical capacity factor of 49 percent leads to an underestimate of cost of future replacement power (id.).

Boston Edison responds that its assumed O&M escalation rate of 7.9 percent was based on a composite of nuclear and fossil-fuel O&M cost escalation rates derived from national indices provided by Wharton Econometric Forecasting Associates ("WEFA") (BECo Brief, pp. 64-65). The Company asserts that this escalation rate is "very close to the Company's average of the previous two years" (id.). But, regardless of the Pilgrim assumptions behind the electricity price forecast, BECo contends that Pilgrim is just one element in the calculation of electricity price which in turn is just one element affecting electricity demand (id.).

Concerns about uncertainties in the Company's electricity price forecast have been raised in the past. See Boston Edison Company, 7 DOMSC 93, 124 (1982) ("1982 BECo Decision"). Given Pilgrim's historical performance (see Section III, infra), MASSPIRG's concerns about the Company's Pilgrim assumptions in the electricity price forecast are warranted -- the assumptions may be overly optimistic, resulting in an electricity price forecast which is low. BECo has not demonstrated either the validity of a particular set of Pilgrim cost assumptions or how alternative cost assumptions would affect the electricity price forecast and, in turn, the demand forecast.

As part of BECo's 1988 forecast filing, however, the Company developed high and low energy forecasts which considered high and low electricity prices (Exh. BE-2, pp. K-1 to K-13). Alternative Pilgrim cost assumptions may be captured within the Company's high electricity price scenario which relies on, among other assumptions, a high O&M escalation rate (id., p. K-3). Even so, the base electricity price forecast should reflect the most likely price scenario, while high and low forecast bandwidths should reflect sensitivity testing of the major assumptions and parameters affecting electricity price.

BECo's electricity price forecasting methodology is basically sound, and has been approved by the Siting Council in the past. Although questions remain regarding input assumptions, the Siting Council finds that, on balance, Boston Edison's methodology for forecasting electricity prices is reviewable, appropriate, and reliable. However, in its next forecast filing the Company should provide an explicit accounting of effects on the base, high, and low electricity price forecasts of Pilgrim costs, including those due to O&M, capital investments, and capacity factors, and should justify the Pilgrim cost assumptions affecting each of these forecasts.[2]

2. Demographic Forecast

To generate a projection of residential customers, the Company first forecasted population growth and average household size, then divided the total population by the average household size for each year of the forecast (Exh. BE-2, pp. C-1 to C-6). Although the Company did not change its demographic forecast substantially since the Siting Council approved the methodology in its previous decision, BECo updated its forecast based on more current data, including the respecification of the net migration equation (id.; Exh. BE-8; Tr. I, pp. 177-179).

In forecasting population growth, the Company assumed that the population at the beginning of a particular year equals population at the start of the previous year adjusted for births, deaths, and net migration during that year (Exh. BE-2, pp. C-1 to C-6).

MASSPIRG criticizes the Company's net migration equation because it fails to consider the high cost of housing in the Boston area, thus resulting in a "highly suspect" equation (MASSPIRG Brief, p. 2).

Boston Edison, however, asserts that the record does not support this criticism (BECo Brief, pp. 62-63). BECo observes that, while housing prices were not directly considered,

---

2/ Developing appropriate methodologies and assumptions for forecasting base, high, and low electricity prices, energy requirements, and peak loads are clearly important aspects of an integrated resource planning process. A closely related and perhaps equally important aspect is developing an appropriate methodology for assigning probabilities to these alternative forecasts. For a description and discussion of the probabilities assigned to base, high, and low demand (i.e., load growth) forecasts, see Sections III.C.3.b and III.E.2.b.ii, infra.

another housing variable, namely housing starts, was considered (id.). Although Boston Edison agrees with MASSPIRG's position that housing costs influence migration behavior, the Company argues that its research resulted in no direct measures of housing costs which passed the tests of statistical reliability and forecast reasonableness, and that there is no reliable source of forecasted housing costs for either the BECo service territory or the Boston area (id.). As an alternative, the Company submits that the employment and wage and salary disbursement variables capture the housing price dynamic (id.).

The record indicates that BECo forecasted net migration as a function of the annual change in U.S. wage and salary disbursements, the annual change in Massachusetts employment, the annual change in the U.S. civilian labor force, and a variable for the 1974-1975 year (Exh. BE-2, pp. C-1 to C-6). The Company attempted to incorporate a variable related to housing costs in its migration equation, but the equation yielded counter-intuitive statistics (Exh. HO-50).

The Siting Council has been concerned about the Company's specification of its migration equation in the past. In our 1982 BECo Decision, we stated that the equation "provides only a rough proxy for variables that explain the behavior that results in net migration" which "may not produce a plausible forecast if the values of the independent variables are outside a narrow range of values" (p. 116). Yet over time the Company has made considerable improvements in its migration model. For instance, in our 1984 Boston Edison decision, we acknowledged the Company's tests of a variety of model specifications and stated that, "despite our concern over the lack of a strong theoretical basis for the migration equation, we are satisfied that the Company has selected its migration-forecasting methodology through an appropriate and acceptable process that balances theory, data availability, statistical strength, and judgment." Boston Edison Company, 10 DOMSC 203, 216 (1984) ("1984 BECo Decision"). At the same time, we directed the Company to continue to search for the best available method for forecasting migration. Id., p. 240. In our 1987 BECo Decision, we accepted a respecification of the migration model undertaken on the Company's own initiative (pp. 298-299).

The parties agree that accounting for the influence of housing costs on migration behavior would be still another improvement to the migration equation. However, BECo argues persuasively that it has researched ways to capture the housing dynamic without identifying an acceptable methodology. Thus, based on the foregoing, the Siting Council finds that BECo's respecified net migration equation is reasonable.

Based on the record, the Siting Council finds that the Company's methodology for forecasting demographic factors is reviewable, appropriate, and reliable. Even so, as methodological improvements become available, the Company should continue to implement cost-effective enhancements to its net migration equation as well as to the remainder of its demographic forecast.

3. Employment Forecast

Boston Edison's employment forecast was derived using econometric techniques based on territory-specific employment data for the years 1967 through 1985 (Exh. BE-2, pp. D-1 to D-6). Territory-specific data available for the projections included average employment, wage, and population figures (id.). In addition, BECo incorporated economic effects external to the Boston Edison service territory by using macroeconomic data supplied by WEFA that reflected state and national trends (id.). Because the Company uses the employment forecast as an input to the commercial and industrial energy forecasts, BECo disaggregated the employment forecast into 20 categories within 12 building-types within the commercial sector and 19 two-digit standard industrial classification ("SIC") categories within the industrial sector (id., pp. D-7 to D-13).[3] The employment forecast methodology is substantially the same as that used in the Company's 1986 forecast filing (id., pp. D-1 to D-13; Exh. BE-8; Tr. I, p. 179).

MASSPIRG asserts that BECo's economic growth assumptions may be too high (MASSPIRG Brief, p. 1). As support, MASSPIRG contends that the Company's choice of WEFA as a source for its economic growth assumptions is arbitrary and differs from "the consensus of the region's utilities" as reflected by the New England Power Pool's ("NEPOOL") choice of Data Resources, Inc. ("DRI") (id., pp. 1-2). MASSPIRG argues that WEFA's GNP forecast is a full 25 percent higher than DRI's, and its unemployment rate forecast is slightly lower than DRI's, both of which may bias the demand forecast in "a high direction" (id.). Moreover, MASSPIRG, citing Exhibit HO-139, submits that there is evidence that DRI has been somewhat more accurate historically in its economic forecasts than WEFA (id.).

Boston Edison asserts that: (1) WEFA was selected as a source for economic growth assumptions from among a number of nationally-respected economic forecasting services; (2) each forecasting service was evaluated on a variety of factors; and (3) the choice of WEFA was made based largely on the quality of WEFA's regional economic forecasting service (BECo Brief, pp. 57-60). Boston Edison argues that the record establishes that its choice of WEFA was based on "considered judgment after a rational process and is the very antithesis of an arbitrary decision" (id., p. 59). BECo also argues that NEPOOL's choice of DRI for certain forecasting purposes falls short of establishing a regional consensus among utilities regarding the choice of forecasters (id.). With regard to the relative historical accuracy of the two forecasting services, the

---

3/ See Sections II.C.5 and II.C.6, infra, respectively, for the 12 commercial building-types and 19 industrial SIC categories.

Company maintains that MASSPIRG misinterpreted Exhibit HO-139, and that, in fact, this Exhibit concludes that no one economic forecasting service dominates all others in terms of accuracy (BECo Brief, pp. 57-60).

The Company's witness, Mr. Cuomo, testified regarding the Company's selection of WEFA for providing certain forecasting services used in preparation of the Company's 1988 demand forecast (Tr. I, pp. 170-177). He stated that the Company issued a request for proposals for these forecasting services, and, in response, received bids from five or six consultants including both WEFA and DRI (id., pp. 171-172). He reported that bids were evaluated based on the ability to prepare 30-year forecasts of macroeconomic and regional indicators as well as electric utility cost escalators (id.). Mr. Cuomo testified that, although WEFA and DRI were both finalists in the bid evaluation and were comparable in certain forecasting areas, the Company based its selection on the regional and local data required by the forecast -- data which BECo believed could be supplied best by WEFA (id.). Based on the record, the Siting Council finds that Boston Edison has established that its selection of WEFA to provide certain forecasting services used to prepare the Company's 1988 demand forecast was based on a reasonable process.

The Siting Council also concurs with the Company that NEPOOL's choice of DRI for certain forecasting services does not necessarily establish a regional consensus on the most appropriate forecasting service for individual utilities. Regarding MASSPIRG's submission that DRI's economic forecasts have been more accurate historically than WEFA's, Exhibit HO-139 supports BECo's position that no one economic forecasting service dominates all the others in terms of accuracy (Exh. HO-139, p. 26).

Based on the foregoing, the Siting Council rejects MASSPIRG's assertion that BECo's economic growth assumptions may be too high.

Regardless of the source, MASSPIRG maintains that the labor force productivity estimates used in BECo's employment forecast are likely to be overestimated (MASSPIRG Brief, p. 2). As evidence, MASSPIRG cites the forecast assumption noted in Exhibit BE-2 that labor force productivity would grow at a rate of 1.6 percent per year in contrast to the historical rate of 1.2 percent per year provided by WEFA in Exhibit HO-55 (id.).

BECo, however, contends that MASSPIRG does not address the reasons provided in Exhibit HO-55 that support a forecasted increase in the productivity growth rate to 1.6 percent per year (BECo Brief, p. 61).

Review of the attachment to Exhibit HO-55, a document prepared by WEFA and entitled "Key Assumptions of U.S. Long-Term Economic Outlook," indicates that the historical growth rate in labor force productivity was, in fact, 1.2 percent per year between 1981 and 1986 (id., pp. 2-3). At the same time, BECo projects a "dramatic improvement" in labor productivity over the next 30 years resulting in an annual productivity growth rate of 1.6 percent (id.). In reconciling this projection of dramatic improvement in labor productivity with the historical rate of 1.2 percent between 1981 and 1986, Exhibit HO-55 notes that in the 11-year period from 1966 to 1976 productivity grew at a rate of 1.5 percent per year, that prior to 1966 it grew at an average rate of over two percent per year, and that the factors depressing productivity over the last ten years will be neutral or work in the opposite direction over the next ten years (id.).

On this record, the Siting Council rejects MASSPIRG's assertion that labor force productivity is likely to be overestimated, and accepts BECo's projection.

Based on the record in this proceeding, the Siting Council finds that Boston Edison's methodology for forecasting employment is reviewable, appropriate, and reliable.

4. Residential Energy Forecast

Boston Edison forecasted residential energy consumption as the summation of consumption by 21 end-uses (appliance-types) (Exh. BE-2, pp. A-3, E-1 to E-21).[4]

BECo listed three changes to its residential energy forecasting methodology since the previous Siting Council review: (1) the addition of saturation-income functions for estimating the saturations of electric water heaters and portable electric space heaters; (2) the incorporation of Massachusetts state appliance efficiency standards beginning in 1988, and national appliance efficiency standards beginning in 1990; and (3) the development of territory-specific appliance consumption estimates using data collected from the Company's Household Appliance Metering Study ("HAMS") and the Massachusetts Joint Utility Monitoring Project ("JUMP") (Exh. BE-2, pp. E-1 to E-16).[5] In addition, the Company re-estimated appliance saturation equations based on new data from BECo's 1986 residential survey (id.).

MASSPIRG observes that the Company assigns a "significant price elasticity" to overall residential energy

---

4/ The 21 end-uses include electric ranges, self-cleaning electric ranges, frost-free refrigerators, standard refrigerators, second refrigerators, frost-free freezers, standard freezers, dishwashers, room air conditioners, central air conditioning, lighting, clothes washers, electric dryers, electric water heaters, microwave ovens, color televisions, black and white televisions, electric space heating, heat pumps, portable electric heaters, and miscellaneous (Exh. BE-2, p. E-1).

5/ The Company conducted HAMS itself, but conducted JUMP in conjunction with five other Massachusetts utilities -- Massachusetts Electric Company, Western Massachusetts Electric Company, Commonwealth Electric Company, Massachusetts Municipal Wholesale Electric Company, and Eastern Edison Company (Exh. BE-2, pp. E-3 to E-4). HAMS monitored frost-free refrigerators, frost-free freezers, and clothes washers; JUMP monitored frost-free refrigerators, uncontrolled electric water heaters, electric ranges, and electric clothes dryers (id.).

consumption, but assigns a price elasticity of zero to electric heating consumption (MASSPIRG Brief, pp. 2-3). MASSPIRG submits that electric heating use is price elastic because it is a major contributor to an electric heating customer's overall consumption and also is an end-use over which customers can exert considerable control (id.). Thus, MASSPIRG asserts that the Company's assumption of no price elasticity for electric heat is arbitrary and counter-intuitive (id.).

Boston Edison argues that MASSPIRG's assertions are unsubstantiated in the record (BECo Brief, pp. 63-64). In any case, the Company maintains that electric heating price elasticities have been excluded in prior forecast filings, that electric heating consumption is more weather sensitive than price sensitive, and that in the short run electric heating customers have virtually no opportunity to shift load in response to prices (id.).

The Siting Council agrees with the Company that this record does not substantiate MASSPIRG's assertion that an assumption of no price elasticity for electric space heating is arbitrary. However, MASSPIRG's concern about the theoretical basis of this assumption is valid and should be addressed in the Company's next forecast filing.

Boston Edison has demonstrated an effort to continue to update and strengthen the residential energy forecast that was approved in our 1987 BECo Decision. Accordingly, the Siting Council finds that Boston Edison's methodology for forecasting residential energy requirements is reviewable, appropriate, and reliable.

5. Commercial Energy Forecast

To forecast commercial energy consumption, the Company used an end-use model known as the Commercial Energy Demand Modeling System ("CEDMS") which was developed by Oak Ridge National Laboratory but adapted to BECo's service territory (Exh. BE-2, pp. A-4, F-1 to F-32). This model forecasts commercial energy as the summation of consumption for eight end-uses within 12 building-types (id.).[6] The commercial energy forecast also included a separate projection of master-metered apartment buildings (id.).

Boston Edison stated that its 1988 commercial energy forecast used the same methodology as that used for the Company's 1986 forecast except for five modifications. These are: (1) redefining building-types including the addition of two new building types, warehouses and other health services; (2) restructuring the floor space and employment data to reflect the redefined building-types; (3) adding two new end-uses, cooking and refrigeration, that were previously in the miscellaneous category; (4) developing territory-specific energy use indices by building-type; and (5) estimating short-run utilization elasticities (id., pp. F-6 to F-8). In addition, BECo re-calibrated the model to reflect more current data (id.).

In a manner similar to its residential methodology, the Company has continued to update and improve the commercial energy forecast that was approved in our 1987 BECo Decision. Accordingly, the Siting Council finds that Boston Edison's methodology for forecasting commercial energy requirements is reviewable, appropriate, and reliable.

6. Industrial Energy Forecast

In its 1988 forecast filing, Boston Edison introduced a new industrial forecasting methodology based on the Production

---

6/ The 12 commercial building-types are offices, restaurants, retail trade, grocery stores, warehouses, elementary and secondary schools, colleges and universities, hospitals, other health services, hotels and motels, public except office buildings, and miscellaneous (Exh. BE-2, pp. D-9 to D-13). The eight commercial end-uses are space heating, air conditioning, ventilation, water heating, cooking, refrigeration, lighting, and other (id.).

Input Decision Model ("PIDM") (Exh. BE-2, pp. A-4, G-1 to G-16). The methodology disaggregated the industrial sector into 19 SIC categories, and forecasted total consumption as the sum of the consumption in each of these 19 categories (id.).[7] BECo stated that the methodology is based on the combined costs of production inputs used in industrial processes including capital, labor, electricity, and other fuels (id.). According to BECo, PIDM calculates the share of electricity to be used in an industrial process based on historical prices and output, expected output, and expected production costs (id.).

The Company asserts this new technique of forecasting industrial energy consumption represents a significant improvement and is the first step in the development of a forecasting system that will eventually include production-oriented end-use modeling (BECo Brief, p. 16).

For the purposes of this review, the Siting Council accepts Boston Edison's methodology for forecasting industrial energy requirements.

7. Other Energy Forecasts

Boston Edison projected energy consumption in each of three other classes -- streetlighting, municipal sales, and losses and internal use (Exh. BE-2, pp. H-1 to H-4). In addition, the Company generated a short-run energy forecast to project energy consumption over the first two years of the

---

7/ The 19 SIC categories include: 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-electrical machinery (35); electrical machinery (36); transportation equipment (37); instruments (38); and miscellaneous (39) (Exh. BE-2, p. G-15).

forecast horizon (id., pp. I-1 to I-14).

For its projection of streetlighting sales, the Company stated that it expects the introduction of more efficient streetlights and the impact of a statute limiting municipalities' authority to raise property taxes (commonly referred to as Proposition 2 1/2) to offset streetlighting growth over the forecast period (id., pp. H-1 to H-3). Thus, BECo forecasts constant annual sales to the streetlighting sector over the forecast period (id.).

The Company provides wholesale electric service to the towns of Concord and Wellesley on an "as needed" basis (id.). Assuming that energy sales to each of the towns is correlated to gross national product, personal income, and/or town employment, BECo developed regression models from historical data to forecast these municipal sales (id.).

Finally, the Company assumes losses and internal use will be 9.4 percent of all other sales, an assumption reflecting the average of losses and internal use for the years 1982 through 1984 (id.).

Based on the record, the Siting Council finds that Boston Edison's methodologies for forecasting energy requirements for streetlighting, municipal use, and losses and internal use are reviewable, appropriate, and reliable.

The Company reported in its 1988 forecast filing that for the first time it directly applied its two-year short-run forecast in preparation of its energy forecast for the residential, commercial, industrial, and streetlighting sectors (id., pp. I-1 to I-14). The short-run model, based on a set of regression equations, is used to forecast the month-to-month response of energy sales to changes in the economy, company pricing and billing, and weather (id.).

For purposes of this review, the Siting Council accepts Boston Edison's methodology for forecasting short-run energy requirements.

8. Alternative Energy Forecast Scenarios

Given the uncertainties inherent in its energy forecast, the Company developed high and low bandwidths around the base case forecast (Exh. BE-2, pp. K-1 to K-13). These alternative energy forecasts were based on high and low forecasts of various inputs including energy prices, economic growth, conservation and load management ("C&LM"), time-of-use rates ("TOUR"), and packaged self-generation (id.).

For purposes of this review, the Siting Council accepts Boston Edison's methodologies for forecasting high and low bandwidth energy requirements.

9. Conclusions on the Energy Forecast

The Siting Council has found that Boston Edison's methodologies for forecasting electricity prices, demographic factors, and employment are reviewable, appropriate, and reliable.

The Siting Council also has found that the Company's methodologies for forecasting energy requirements for the residential sector, commercial sector, streetlighting, municipal use, and losses and internal use are reviewable, appropriate, and reliable. Further, the Siting Council has accepted the Company's methodologies for forecasting industrial, short-run, and high and low bandwidth energy requirements.

Accordingly, the Siting Council finds that Boston Edison's methodology for forecasting energy requirements is reviewable, appropriate, and reliable.

D. Peak-Load Forecast

Boston Edison derived its forecast of peak loads from the Hourly Electric Load Model ("HELM"), a model developed by I.C.F. Inc. for the Electric Power Research Institute ("EPRI")

(Exh. BE-2, Section J). The Company stated that it estimated hourly loads based on forecasted annual energy consumption by customer class and end-use, monthly and day-type allocators, weather response functions, and average hourly load shapes (id.).[8] In addition, BECo forecasted high and low bandwidths about its base case peak-load forecast (id., pp. K-1 to K-13). The Company projected that peak load adjusted for time-of-use rates, Company-sponsored C&LM, and self-generation would grow at an average rate over the forecast period of 0.4 percent per year during the summer and 0.8 percent per year during the winter (id., p. L-11).

The Company noted that it made two changes to the HELM methodology since the Company's 1986 filing (id., Section J). First, BECo updated HELM's weather response functions to assess the current sensitivity of load to five weather variables including average temperature, extreme temperature, wind speed, minutes of sunshine and a temperature humidity index; second, the Company re-estimated TOUR elasticities for commercial and industrial customers (id.).

For the purposes of this review, the Siting Council accepts the Company's methodology for forecasting peak load.

E. Conclusions on the Demand Forecast

The Siting Council has found that Boston Edison's methodology for forecasting energy requirements is reviewable, appropriate, and reliable. In addition, the Siting Council has accepted the Company's methodology for forecasting peak load.

Accordingly, the Siting Council hereby APPROVES Boston Edison's 1988 demand forecast.

8/ See Section II.C, supra, for the Siting Council's review of Boston Edison's energy 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.[9]

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); 1984 BECo Decision, 10 DOMSC at 245. 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, 15 DOMSC 125, 134 (1986) ("1986 CELCo Decision"). 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,

---

9/ Diversity, which in past Siting Council decisions has been discussed separately, now is treated within the discussion of cost.

165-166.[10]

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. 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 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 (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

10/ The Siting Council previously has defined the short run as a function of the time required to implement certain resource options. See 1987 BECo Decision, 15 DOMSC at 307-309. We now find it more appropriate, however, to define the short run as a time certain. Henceforth, the short run shall extend four years 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. See Eastern Edison Company, EFSC 87-33, p. 31 (1988).

identifying and evaluating a variety of supply options. In reviewing a company's resource identification process, the 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 resource evaluation process to all of its identified resource options. Eastern Edison Company, EFSC 87-33, pp. 36-55 (1988) ("1988 EUA Decision").

B. Previous Supply Plan Orders

In its 1987 BECo Decision, the Siting Council ordered Boston Edison to comply with the following Orders (referred to hereinafter as the "Pilgrim Order" and the "Transmission Order," respectively):

- to develop immediately a clear and specific plan for squarely facing the possibility of losing Pilgrim capacity credit. Such plan shall include a time schedule providing for specific actions by the Company if Pilgrim generation resumption meets any further delays. The Company is ordered to file such plan with the Siting Council by May 1, 1987 and to report all Company actions that either follow or modify that plan.

- to develop immediately a clear and specific plan for minimizing the risk and extent of disconnecting firm customer load in the City of Boston for all summers prior to the expected in-service date of the

Company's proposed 345 kV Mystic-Downtown transmission line. This plan shall identify all options available to the Company to reduce the risk and extent of load shedding in the City of Boston including consideration of an immediate and aggressive demand management strategy. Further, the plan shall provide for actions the Company will take, including a schedule for implementing those actions, to minimize the risk and extent of load shedding in each summer covered by the plan. The Company is ordered to file such plan with the Siting Council and the City of Boston by June 1, 1987 and to report all actions that either follow or modify that plan.

1. Response to Pilgrim Order

On May 1, 1987, BECo submitted a document to the Siting Council entitled "Boston Edison Company Contingency Action Plan for Pilgrim Station" (Exh. HO-149). BECo updated this document with a letter dated March 17, 1988 (Exh. BE-4). BECo provided an additional update to its action plan in July 1988 (Exh. HO-16).

MASSPIRG asserts that BECo did not comply with the Pilgrim Order by developing adequate short-run contingency plans in the event of a delay in returning Pilgrim to service (MASSPIRG Brief, p. 4). MASSPIRG contends that, while BECo listed a few options that it could employ to replace the loss of Pilgrim station, the Company did not create a true plan to respond to specific events (id.).

BECo maintains that Exhibits HO-149, BE-4, and HO-16 demonstrate its compliance with the Siting Council's Pilgrim Order and that these documents, the Company's filing in this proceeding, and the direct and cross-examination of Company witnesses demonstrate the existence of an ongoing action plan (BECo Brief, p. 66).

The Siting Council addresses here only the Company's compliance with the Pilgrim Order, not the broader question of adequacy which is addressed in Section III.D, infra. Exhibit HO-149 presented BECo's strategy under the contingency of loss of Pilgrim capacity credit (Exh. HO-149). This plan consisted of three main elements: (1) re-evaluation of C&LM programs that were not found to be cost-effective previous to loss of Pilgrim capacity credit; (2) solicitation of short-run capacity purchases; and (3) construction of new Company-owned generation (id., pp. 8-13).

In Exhibit HO-149, the Company indicated that it had updated cost data on previously reviewed and rejected C&LM programs, and that an implementation schedule would be complete by May 15, 1987 (id., p. 9). The Company also indicated that it would send a letter by May 1, 1987 soliciting short-run capacity purchases from other utilities with a response deadline of May 15, 1987 (id., p. 11). In addition, the Company stated it would seek additional QF power to be on-line in 1987 and 1988 (id.). With respect to new Company-owned generation, Boston Edison stated that it is attempting to expedite licensing of a gas-fired combustion turbine at its Walpole substation in order to shorten the lead time necessary to construct such a plant (id., pp. 11-12).

In its update of March 17, 1988, the Company detailed the results of its short-run capacity solicitation and stated that the Walpole combustion turbine could be on-line within 27 months (Exh. BE-4). Finally, in July 1988, the Company filed a plan similar to that filed in March 1988 along with a copy of the letter used to solicit additional capacity and energy for the winter 1988-89 period (Exh. HO-16).

The Company's response to the Pilgrim Order is the type of plan we envisioned. Accordingly, the Siting Council finds that Boston Edison has: (1) filed an action plan for loss of Pilgrim capacity credit on May 1, 1987; (2) provided a schedule for specific actions in the event of continued delays in returning Pilgrim to service; and (3) reported company actions following or modifying that plan.

Accordingly, the Siting Council finds that the Company has complied with the Pilgrim Order in the 1987 BECo Decision.[11]

2. Response to Transmission Order

In the 1987 BECo Decision, the Siting Council found that the Company had failed to ensure adequate transmission of electrical power to its customers in the City of Boston (pp. 332-333). The Siting Council stated that "the risk of a blackout in the City of Boston is intolerably high during the summers of 1987 and 1988 -- and in all subsequent summers if the Company has not put the new Mystic-Downtown line into service" (id., p. 334). The high risk of blackout was found to exist when both units of New Boston station go out of service during peak-load periods; on the BECo system these are generally hot summer days (id., p. 333). The Siting Council also found that the Company's transmission system planning process for the City of Boston was deficient in several respects. Two problems were the Company's failure to address the transmission problems diligently when they became apparent, and the Company's failure to integrate its transmission system planning with its overall resource planning process (id., pp. 335-336).

On May 18, 1987, the Siting Council received the Company's response to the Transmission Order, entitled "Plan for the Continuity of Electric Service, City of Boston" (Exh. HO-150). BECo's plan to address its Boston transmission

---

11/ This finding, however, does not relieve the Company of its obligation to continue to ensure an adequate supply of power in the absence of Pilgrim. The Company should provide updates to the Siting Council every six months regarding its Pilgrim action plan until either the New England Power Pool restores Pilgrim's capacity credit or the Company determines that it will no longer rely on Pilgrim as part of its supply plan.

problems had six main elements: First, the Company stated it would rely on transmission reinforcements already installed. These included additional heat exchangers, circuit switchers, capacitor banks and replaced or additional conductors. Second, the Company emphasized its reliance on preventative maintenance. In this regard, BECo planned the two New Boston units scheduled outages during off-peak periods, and took steps to ensure that all equipment necessary to maintain and cool pertinent transmission facilitites would be repaired and monitored. Third, the Company emphasized that it was acquiring new dispatching systems which allow maximum use of transmission capacity by monitoring ambient conditions at transmission equipment (id., pp. 3-4). Fourth, the Company stated that it was implementing actions that system operators could take to reduce power flows on key lines (id., p. 4). Fifth, the Company stated it was emphasizing and accelerating demand-side management measures. BECo stated that the generator assistance program, the cool storage incentive program, the fluorescent lighting rebate program, and the commercial and industrial load curtailment program provide the greatest opportunity for demand-side reductions in metropolitan Boston (id., pp. 4-5).

Finally, the Company stated that it planned to place in service elements of the full transmission reinforcement plan before the summer of 1988 (id., pp. 2-3), and that transmission reinforcements would be the "foundation to the City's supply plan" (id., pp. 5-6). The reinforcements BECo planned were the installation in 1988 of the Mystic to Golden Hills 345 kV line and the installation, also in 1988, of several phase-angle regulating transformers. These two measures, according to BECo, would reduce the flow of power on downtown Boston lines and strengthen the grid (id., pp. 5-6). The Company also stated that the installation of the Mystic to Kingston Street 345 kV line (also called the "Mystic to Downtown" line or the "Downtown" line) would complete the transmission reinforcement plan. This line is scheduled for completion in June 1989 (Exh. BE-3, p. B-3-13; Tr. II, pp. 13, 18). The Company is also installing a second utility duct to accommodate a second 345 kV line along the same route (Tr. II, p. 19). According to Mr. Sullivan, the Company's witness, this line would not be required until "some years later than 1992" (id., p. 22).

In this proceeding, the Company states that it implemented the measures described above and was successful in avoiding significant outages in 1987 and 1988 notwithstanding record temperatures in the summer of 1988 (Exh. BE-9, pp. 3-4; BECo Brief, p. 52). In addition, the Company contends that the transmission planning process in place now is integrated fully with the supply-side and demand-side planning process (id., p. 52).

MASSPIRG contends that BECo does not consider transmission and distribution investments equally with generation investments. MASSPIRG states that "transmission and distribution failures, not inadequate generation capacity, have been responsible for every interruption of service to customers for at least the last decade" (MASSPIRG Brief, pp. 13-14). According to MASSPIRG, BECo should be required to conduct an evaluation of its transmission and distribution system (id., p. 14).

Based on the record in this case, the Siting Council finds that Boston Edison has complied with the Transmission Order in the 1987 BECo Decision. The Company appears to have focused its attention on this transmission problem and has taken steps to lessen the chance of outages. The planned completion of the Mystic to Kingston Street line prior to this summer's peak usage would further lessen the risk of outages.

Although the Siting Council finds that the Company complied with the Siting Council's 1987 Order, the underlying concerns that gave rise to that Order remain. In that regard, the Company must develop a method of analyzing its transmission system to anticipate problems, identify and evaluate solutions to problems, and then implement institutional responses. The risk of outage that the Siting Council identified in its 1987 BECo Decision may have diminished, but the Company must be poised to address future transmission problems.

With respect to the measures that the Company has taken to meet the Boston transmission problems, these appear primarily to involve what the Company terms operating tools, operating procedures and transmission reinforcements. Generally, this approach amounts to operating the system more efficiently, with more sophisticated equipment, and building additional facilities. While these actions are important in addressing transmission problems, C&LM also is an important tool. Although the Company stated that it emphasized and accelerated demand management measures in response to the Siting Council's Transmission Order, it is not clear from the record how transmission system planning fully interacts with demand- and supply-side planning. This interaction is necessary to ensure that transmission reinforcements are constructed only when they are the necessary, least-cost and low environmental impact solutions to a transmission problem.

Finally, the Siting Council notes MASSPIRG's position concerning transmission and distribution investments. In the absence of a more thorough discussion and a more clear exposition of MASSPIRG's proposal, however, the Siting Council declines to require the Company to perform an evaluation relating to its transmission and distribution investment.

C. Supply Planning Process

1. Introduction

Boston Edison has changed its resource planning process substantially since the last Siting Council review. In its new resource planning process, the Company added mechanisms to integrate the evaluation of supply-side and demand-side resources. In addition, BECo included a combined contingency analysis and risk/uncertainty assessment to evaluate the balance between resource adequacy and cost (Exh. BE-3).

The Company stated that the goal of its new resource planning process, Integrated Resource Planning ("IRP"), was to create a risk-adjusted, least-cost resource plan (Exhs. BE-1, p. D-1; BE-3, p. A-1). To accomplish this goal, Boston Edison applied a two-stage process: first, developing a base case resource plan ("base case plan"); and second, managing base case plan risks.

2. Development of the Base Case Plan

a. Developing the Initial Resource Plan

Boston Edison developed an initial resource plan as a first step in the development of the base case plan (Exh. BE-3, p. A-1). To develop its initial resource plan, the Company used a computer model known as the Electric Generation Expansion Analysis System ("EGEAS") (Exh. BE-1, pp. D-1 to D-4).[12] BECo asserted that EGEAS optimizes generation expansion plans based on total revenue requirements (Exh. BE-3, p. C-4-1). EGEAS' algorithm is based on load duration curves, forced outage probabilities, fuel costs, capital costs, and various other system parameters which allow calculation of production costs, system reliability, revenue requirements, and non-time-differentiated avoided costs (Exh. BE-1, p. D-4).

BECo developed its initial resource plan from six basic inputs: (1) the natural demand forecast;[13] (2) life extension of all existing generating units; (3) signed purchase agreements; (4) committed Qualifying Facilities ("QFs") from

---

12/ EGEAS was developed under an EPRI grant by the Massachusetts Institute of Technology and Stone and Webster Engineering Corporation (Exh. BE-1, p. D-4).

13/ Consistent with the Company's definition, we refer to a natural demand forecast as the energy or peak-load demand by customers adjusted only for market-driven C&LM (Exh. BE-2, p. A-6).

the Request For Proposals ("RFP") process;[14] (5) committed conservation and load management programs;[15] and (6) time-of-use rate effects (Exhs. BE-1, pp. D-2 to D-4; BE-3, p. A-1).

The Company also employed an EGEAS feature which catalogs the parameters of generation alternatives in order to add them to the resource plan as needed (Exh. BE-3, p. C-4-18). The Company developed and cataloged parameters for six generation technologies in various size configurations (100 MW to 400 MW) for a total of 18 Company-owned generation options (id.).[16]

To compare its 18 generation options, Boston Edison used EGEAS to develop "screening curves," which the Company described as a graph of life-cycle costs as they vary with capacity factor (id., pp. C-4-3 to C-4-5, C-4-13 to C-4-16; Exh. HO-90). BECo drew several conclusions from its screening curves including the following: (1) for units designed to run at high capacity factors (baseload units), 400 MW units are the

---

14/ In its initial resource plan, and later its base case plan, Boston Edison assumed that 100 percent of the capacity now under agreement to BECo through signed purchase contracts and the RFP process would be delivered to BECo as planned (Exh. BE-1, p. E-1).

15/ Boston Edison included 14 committed C&LM programs in its initial resource plan. These programs are, by load shape strategy (see Section III.C.2.b, infra): Lite Lights, Fluorescent Replacement, Boston Housing Authority, Design Plus, Demonstrated Lighting, Encore, Easy Heating Rebate, and Calculated Rebate (strategic conservation); Generator Assistance at Peak, G-2 Air Conditioner Cycling, and Residential Central Air Conditioner Cycling (peak clipping); Time of Use Curtailment and Northeast Energy Cooperative (flexible load shape); and Cool Storage (load shifting) (Exh. BE-3, p. B-1-10; Tr. II, pp. 71-72).

16/ Although the Company did not state explicitly that the development of the initial resource plan included these 18 generation options, on several occasions BECo generally indicated that it did (see Exhs. BE-1, pp. D-1 to D-4; BE-3, pp. A-1, B-1-7, C-4-1 to C-4-5; BE-5, p. 3). Thus, we assume that the Company included these 18 generation options in the development of its initial resource plan.

most economical; (2) of the baseload units, 400 MW integrated coal-gasification combined-cycle ("IGCC") units are the most economical although 400 MW pulverized coal ("PC") units are "a very close second;" (3) for units designed to operate at low capacity factors, combustion turbines are the most economic choice; (4) for units designed to operate within a narrow range of intermediate capacity factors, oil-fired combined-cycle units are the most economical; and (5) the technology limit of about 100 MW for both atmospheric and pressurized fluidized-bed coal units render these types of units uneconomical compared to 400 MW IGCC, PC, or combined-cycle units (id.).

Thus, based on the six input assumptions and 18 generation options, BECo used EGEAS to calculate the optimum expansion plan based on total revenue requirements (Exhs. BE-1, p. D-9; BE-3, pp. A-1, B-1-1). The Company also calculated the avoided energy and capital costs of this initial resource plan to use in the screening and evaluation of C&LM programs (id.).

b. Integrating Additional Resources into the Initial Resource Plan

Once the initial resource plan was developed, the Company researched and screened, and then evaluated, available C&LM programs for integration into the initial resource plan. BECo used a three-step process to research and screen available C&LM programs, consisting of: (1) assessing system and customer needs; (2) designing programs to address those needs; and (3) screening programs based on cost-effectiveness.

To assess its system needs, BECo evaluated forecasted requirements and researched market parameters to provide customer-type load profiles and estimates of the number of appliances and end-uses on the system (Exh. BE-3, B-1-7 to B-1-9). Based on its system needs assessment, the Company asserted that its primary goal for C&LM is the reduction of summer peaks, while a secondary goal is the conservation of energy throughout the year (id.). The Company assessed customer needs through consultations with customers and energy experts, analyses of customer survey results, and interviews with manufacturers of energy efficient equipment (id.). The Company determined that one of the most important customer needs was simplicity and flexibility of C&LM programs.

Next, Boston Edison stated that it designed C&LM programs to address the identified needs. BECo identified strategic conservation, peak clipping, load shifting, and flexible load shape as the strategies of Company-sponsored C&LM programs that would address system and customer needs (id., pp. B-1-5 to B-1-6).[17] To develop conceptual designs for C&LM programs, BECo: (1) obtained information from other utilities, industry journals, and EPRI; (2) analyzed specific Company data, including such items as the number of control hours needed to achieve load management goals (id., p. B-1-7); (3) estimated the market potential of each program design; (4) estimated the demand and energy reductions attainable for each program design; (5) determined whether a program design would be feasible in the BECo service territory; and (6) estimated program design costs (id.; Exh. HO-130).

In order to screen each proposed C&LM program for cost-effectiveness, BECo used the Load Management Strategy Testing Model ("LMSTM") (Exh. HO-130).[18] Program designs that were not deemed cost-effective were eliminated from consideration. The remaining 15 cost-effective programs were

---

17/ According to BECo, strategic conservation reduces consumption over most of the day, peak clipping eliminates load during peak hours, load shifting moves load from peak to off-peak periods, and flexible load shape provides reliability needs through such programs as load interruption or curtailment (Exh. BE-3, p. B-1-5).

18/ Although BECo indicated in its filing that it used a model known as COSBEN to screen C&LM programs (Exh. BE-3, pp. B-1-8 to B-1-15), Ms. Kelly testified that the Company replaced COSBEN with LMSTM in screening C&LM programs (Tr. II, pp. 57-60).

designated as "potential" C&LM programs.[19] Potential programs were submitted to Boston Edison implementation personnel, to outside vendors of C&LM services, as well as to customers for suggestions on how to improve initial program designs to overcome market barriers to implementation (Exh. HO-130).

Once the Company revised cost estimates to include program refinements, these potential C&LM program designs were tested for their ability to reduce the Company's total cost of service over the life of the program. The eight C&LM programs that passed this test and were, in the Company's judgment, both feasible and marketable were designated as "proposed" programs and added to the initial resource plan (Exh. BE-3, p. B-1-8; Tr. II, pp. 80-82).[20]

Boston Edison then re-optimized the initial resource plan with the additional eight C&LM programs using EGEAS. From this resource plan the Company recalculated electricity price estimates and generated revised estimates of load and energy consumption. Boston Edison reiterated this procedure until the Company's demand and energy forecasts, generation plans, and C&LM plans were balanced (Exh. BE-1, p. B-7). Boston Edison

---

19/ These 15 potential programs, by load shape strategy are: Efficient Motors, Solar Film, Efficient Residential Appliances, Efficient Commercial Appliances, and Security Lighting programs (strategic conservation); G-1 and G-3 Air Conditioner Cycling, Residential Room Air Conditioner Cycling, and Commercial and Industrial Dual Fuel programs (peak clipping); Energy Management Systems, Area Targeted Conservation and Load Management, and G-1 Air Conditioner Interruption programs (flexible load shape); and Thermal Heat Storage, Swimming Pool Pump Control, Water Heater Control, and Residential Ceramic Storage programs (load shifting) (Exh. BE-3, p. B-1-11).

20/ Proposed C&LM programs include Efficient Motors, Solar Film, Efficient Residential Appliances, Security Lighting, Energy Management Systems, Area Targeted Conservation and Load Management, Thermal Storage Heat, and Control of Swimming Pool Pumps (Exh. BE-3, p. B-1-12; see also Exh. BE-3, Appendix A).

designated the resulting resource plan as its base case plan (see Table 2).

3. Management of Base Case Plan Risks

Boston Edison's methodology for managing base case plan risks[21] consisted of (1) developing a range of planning scenarios from different forecasts of key resource planning variables, (2) assigning probabilities to each scenario, (3) screening the scenarios to a representative sample for further analysis, (4) determining the balance of resource adequacy and cost, and (5) developing a risk management action plan.

a. Developing Scenarios

Boston Edison asserted that the key variables which have the greatest impact on required resources are load growth, C&LM penetration, committed capacity additions, and fuel prices (Exh. BE-3, p. C-3-1). BECo selected load growth, C&LM penetration, and committed capacity additions due to their direct impact on resource requirements; the Company selected fuel prices due to their impact on load growth, C&LM penetration, committed capacity additions, and alternative strategies for addressing resource deficiencies (id.).

To account for uncertainties, the Company developed base, high, and low forecasts for each variable (id.). BECo developed fuel price bandwidth estimates using information supplied by DRI (id., p. C-3-2). Load growth forecast bandwidths were derived by the Load Forecasting Division with

---

21/ For purposes of this review, the methodology for managing base case plan risks is also referred to as the "IDEAS process."

information supplied by both WEFA and DRI (id.).[22] The Company did not explain how it developed bandwidth estimates for the levels of C&LM penetration. To develop the high, base (medium), and low forecasts of committed capacity additions, Boston Edison surveyed personnel within its ERP&F Department to estimate the likelihood of each QF and independent power producer project reaching commercial operation. The survey, which probed individuals' expectations that currently signed contracts would come on-line, led to the setting of three possible levels of capacity additions: the highest level, 1014 MW by the winter of 1993-94 (representing all signed contracts plus those under negotiation), the base level, 507 MW, and the lowest level, 259 MW.

The combination of four variables with base, high, and low forecasts resulted in the generation of 81 possible planning scenarios. Based on these scenarios, the Company projected that its resource requirements by 2011 would be between zero and 2100 MW. The Company asserted that the 81 scenarios were reasonably representative of the range of possibilities during the forecast period (Tr. II, pp. 94-99).[23]

b. Assigning Probabilities to Scenarios

To establish the joint probability that any one of the 81 scenarios would occur, Boston Edison developed a decision

---

22/ The Siting Council reviews the Company's methodologies for forecasting energy and peak-load requirements in Section II, supra.

23/ The base case plan constituted the scenario of base forecasts of load growth, C&LM penetration, and fuel prices, but the high forecast of committed capacity additions (Exh. BE-1, p. E-1). The use of the high forecast of committed capacity additions reflects the Company's assumption that all signed contracts will come to fruition under the terms of the contracts (id., p. E-1).

tree and assigned unconditional probabilities to the base, high and low forecasts of each variable as well as conditional probabilities to combinations of variables (Exh. BE-3, pp. C-3-1 to C-3-17).[24] Personnel from Boston Edison's ERP&F Department and two outside consulting firms, WEFA and DRI, provided subjective estimates of the unconditional and conditional probabilities (id.). The scenario decision tree and assigned probabilities are summarized in Table 3.

For the fuel prices forecast, BECo assumed a 60 percent probability of base fuel prices, and a 20 percent probability for both high and low fuel prices over the forecast period (id.). These conditional probabilities were determined subjectively based on information provided by DRI (id.).

BECo assumed that load growth depended on fuel prices, and therefore developed nine conditional probabilities for each combination of load forecasts and fuel prices (see Table 3) (id.). For the estimates of load growth forecast bandwidths, the Company relied on information from its ERP&F Department, WEFA, and DRI (id.).

Boston Edison relied upon the judgment of individuals in its EPR&F Department to estimate 27 conditional probabilities for the levels of C&LM that would be attained under the nine combinations of fuel price and load growth forecasts (see Table 3) (id.). These 27 probabilities were based on assumed relationships between C&LM penetration, load growth, and fuel prices (id.).

To estimate the probability of high, medium, and low levels of capacity additions, Boston Edison surveyed personnel in its ERP&F Department to determine the likelihood that each level of committed capacity additions would be reached

---

24/ The base, high, and low forecasts for each variable remain constant throughout the risk management process. However, the "conditional probabilities" associated with a particular variable forecast vary with changes in assumptions about other variables.

irrespective of other variables (id.). In a second survey of the same population, Boston Edison generated estimates of the likelihood that each level would be reached given a particular fuel forecast (id.). Thus, the Company determined conditional probabilities for nine separate committed capacity addition scenarios (see Table 3).

c. Screening Scenarios

Boston Edison used a statistical model known as the Integrated Decision Analysis System ("IDEAS") to screen the 81 scenarios to a representative sample of 34 for detailed analysis (Exh. BE-3, p. C-1-1). To select these 34 representative scenarios, BECo grouped scenarios, ranked the groupings, then eliminated those groupings which "would ultimately add very little to the planning process" (Exh. BE-3, p. C-3-9). Of the remaining scenarios, many proved nearly identical to those within their grouping in the quantity and timing of required resources. In these cases, the Company selected the scenario with the higher probability for analysis and eliminated its companions from consideration. In this manner the Company narrowed the focus of its analysis from the set of 81 scenarios to the 33 selected in the screening process plus the base case scenario.[25]

Once the IDEAS scenario screening was complete, Boston Edison stated that it developed optimal resource plans for each

25/ Despite the fact that the base case scenario fell into a grouping eliminated from the analysis, Boston Edison decided not to eliminate it.

of the 34 remaining scenarios (Exh. BE-3, p. C-4-5).[26]

d. Balancing Resource Adequacy and Cost

In balancing resource adequacy and cost, Boston Edison attempted to define a cost-versus-reliability curve and then choose the point on the curve which, in the Company's judgment, balances cost and reliability goals (Exh. BE-3, pp. C-5-1 to C-5-9).[27] Reliability was defined in terms of the cumulative probability of meeting the energy requirements associated with the 81 scenarios; cost was defined in terms of the revenue required to meet successively higher levels of reliability (id.).

To assess reliability, Boston Edison applied a three-step process. First, the Company determined the resources required each year through the year 2011 in order to ensure that, based on cumulative probabilities of the 81 scenarios, 50 percent, 60 percent, 70 percent, 80 percent, 90 percent, and 100 percent of the scenarios would be met (id.). Second, the Company chose three points to define its cost-

---

26/ The Company used EGEAS and a standard set of assumptions, including those concerning existing unit parameters, life extension, reserve margins, O&M, and the parameters of 18 available Company-owned generation options (see Section III.C.2.a, supra), in the analysis of resource plans for each scenario (Exh. BE-3, pp. C-4-1 to C-4-19). Thus, the EGEAS model generated an optimal resource plan for each of the 34 scenarios based on minimizing revenue requirements (id., p. C-4-5). These plans vary by scenario with regard to the type, size, and timing of capacity additions over BECo's 25-year analysis horizon (id., pp. C-4-20 to C-4-22).

As far as we can determine, however, BECo did not use the 34 scenario resource plans to develop any other part of its resource plan.

27/ In the context of managing base case plan risk, BECo generally refers to adequacy as reliability. For purposes of reviewing the IDEAS process, the Siting Council uses adequacy and reliability interchangeably.

versus-reliability curve -- the 50 percent, 70 percent, and 90 percent reliability levels -- and developed optimal expansion plans to meet the respective resource requirements of each of them (id.). The resource requirements and optimal expansion plans for these three levels are summarized in Table 4. Third, Boston Edison determined the expected value of unmet energy[28] at the 50 percent, 70 percent, and 90 percent levels assuming the respective expansion plans would be implemented (id.). These expected values were derived by (1) using EGEAS to determine unmet energy for each of the 34 planning scenarios in combination with the respective expansion plans held constant at each level, and (2) weighting the 34 values of unmet energy by the probability that that scenario would occur (id.).[29]

To assess cost, Boston Edison determined the revenue required to develop the respective expansion plans for the 50 percent, 70 percent, and 90 percent reliability levels (id.). The difference in revenue requirements between two expansion plans represented the incremental cost of achieving the additional level of reliability (id.). For instance, the difference in revenue requirements between the 70 percent and 50 percent expansion plans represented the incremental cost of achieving the 70 percent reliability level.

Boston Edison reported that this analysis resulted in an estimated cost of 23 cents per kilowatthour ("¢/KWH") to

---

28/ The Company defined unmet energy as "a level of load that will not be served given load requirements and resources to meet those requirements. It is a statistical measure of reliability" (Exh. BE-3, p. C-5-3).

29/ For instance, at the 50 percent level, BECo ran EGEAS 34 times, once for each planning scenario, holding constant the 50 percent level expansion plan of a 100 MW combustion turbine in service in 1992, a 400 MW IGCC unit in service in 2001, and a 400 MW IGCC unit in service in 2008 (see Table 4). In some of the 34 planning scenarios unmet energy would result, while in others all energy requirements would be met. The average of unmet energy for these 34 scenarios, weighted by the scenario probability, is the expected value of unmet energy.

increase reliability to 70 percent from 50 percent, but 76¢/KWH to increase reliability to 90 percent from 70 percent (id.). The Company suggested that the incremental cost of reliability increased exponentially in this range of the cost-versus-reliability curve (id.). Thus, Boston Edison asserted that "[t]he results pointed to the 70% level as a reasonable balance of cost and reliability" (id., p. C-5-5).

e. Developing a Risk Management Action Plan

Boston Edison asserted that its base case plan in effect provides resources to meet the base forecasts of load growth, C&LM penetration, and fuel prices, and a high forecast of committed capacity additions (Exh. BE-3, p. C-7-1). However, BECo also asserted that, given the uncertainty surrounding the forecasts of key variables and the demonstration of a reasonable balance of resource adequacy and cost, it must take action to achieve the 70 percent reliability level (id.).[30]

The Company identified a variety of actions which it believes would attain this goal in the "most balanced and cost-effective manner" (id.). These actions include: (1) advancing the development of the Design Plus C&LM program; (2) creating an in-house QF project assistance team; (3) advancing the development of the Walpole combustion turbine, a single 85 MW unit; (4) beginning the process of pre-licensing a multiple unit site for additional combustion turbines in 100 MW increments with a targeted in-service date of 1992 for the first unit; (5) advancing the Edgar Station development process, in order to bring one of the station's two proposed 400 MW units on-line by 1997; and (6) identifying additional sites for 400 MW class units which potentially

---

30/ Based on cumulative probabilities, the base case plan achieves a reliability level of about 15 percent (Exh. BE-3, p. C-3-17).

could be placed in service by 2010 (id., pp. C-7-1 to C-7-6). In the Company's estimation, these six actions could meet the resources requirements of the 70 percent reliability level (id., p. C-7-6). See Table 5.

The Company also recommended encouraging dispatchable capacity additions from either utility or nonutility sources and bringing more expertise into the development of scenario probabilities (id., p. C-7-3). Finally, the Company indicated that it would continue to be involved in additional resource development activities such as the RFP process for QFs and would research the feasibility of installing an underwater transmission line to Nova Scotia (id.).

D. Adequacy of the Supply Plan

1. Adequacy of the Supply Plan in the Short Run

a. Definition of the Short Run

The Siting Council herein has defined a company's short-run period as four years from the date of the final hearing or from the date of the response to the final record request (see Section III.A, supra). BECo, of course, filed its forecast and supply plan under our previous definition of the short run. Accordingly, for purposes of this decision, we define the short run consistent with our previous standard: the time required to place into service the shortest-lead-time resource under a utility's direct control in sufficient quantities to meet the projected need for new capacity. See 1987 BECo Decision, 15 DOMSC at 308-309.

We accept the Company's position that a combustion turbine unit can be placed in service in approximately three years from the final hearing in this proceeding (BECo Brief, p. 19). In this proceeding, the final hearing was held in October 1988. Accordingly, BECo's short-run period extends through the summer of 1991.

b. Base Case Plan

Table 6 compares BECo's projected resource capability to its peak-load capability responsibility throughout the forecast period (see also Table 2). This table indicates that BECo is projecting a short-run capability surplus of 0.4 percent to 11.3 percent during summer periods.[31]

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 Boston Edison's short-run supply plan, the Siting Council analyzes the Company's action plan for the 70 percent planning reliability level as recommended in BECo's risk management process.[32] In addition, the Siting Council analyzes the contingency of a continuation of the Pilgrim shutdown.

i. Seventy Percent Reliability Level

Boston Edison's risk management process described in

31/ Since BECo is a summer peaking system, the Company only provided data for its summer peak period (Exh. HO-15). In future forecast filings, the Company should provide both summer and winter peak capability responsibility forecasts and should compare those forecasts to projected resources.

32/ As noted in Section III.C.3.e, supra, the base case plan provides for about the 15 percent reliability level. The risk management action plan would provide a response to base case contingencies up to about the 70 percent reliability level.

Section III.C.3, supra, identifies uncertainties surrounding certain key variables. Hence, the Company asserted that balancing resource adequacy and cost requires an action plan for achieving a reliability level of 70 percent based on the cumulative probabilities of BECo's 81 planning scenarios (see Section III.C.3.f, supra).

In scenarios up to the 70 percent reliablity level, the Company's base case plan could realize resource deficiencies of 50 MW in 1989 and 100 MW in 1990 (see Table 5). Thus, to meet the requirements prescribed by this reliability level, the Company formulated its risk management action plan to implement up to 106 MW of resources by 1989 and 134 MW by 1990 if necessary. By 1990 these resources would include 46 MW of C&LM, 3 MW of QF purchases, and 85 MW from the Walpole combustion turbine (see Table 5).

Boston Edison has developed an action plan to meet its 70 percent reliablity level which provides diversity of demand-side and supply-side resource types and sizes. This diversity should provide the Company with the flexibility to adapt to changing circumstances while ensuring that the Company's recommended 70 percent reliability level is met.

Accordingly, the Siting Council finds that Boston Edison has established that it has an action plan to meet any resource deficiencies up to a reliability level of 70 percent based on cumulative probabilities of the Company's 81 planning scenarios.[33]

ii. Continued Shutdown of Pilgrim

Boston Edison stated that it expects Pilgrim, shut down since April 1986, to re-open by summer 1989, supplying the

33/ The Siting Council reviews the least-cost nature of BECo's risk management action plan in Section III.E.2.b.v, infra.

Company with an estimated 495 MW in summer and 498 MW in winter for the remainder of the forecast period (Exh. HO-15). MASSPIRG asserts that the Pilgrim outage may extend through the summer of 1989 (MASSPIRG Brief, p. 4). If all other resources in its base case plan remain available to BECo, a delay in re-opening Pilgrim beyond the summer of 1989 would cause a resource deficiency of about 443 MW (13.3 percent) during the summer 1989 period (see Table 7). Continued shutdown beyond the short-run planning horizon would result in resource deficits of about 445 MW (13.4 percent) in the summer of 1990 and 89 MW (2.8 percent) in the summer of 1991 (see Table 7).

MASSPIRG contends that the Company does not have a specific action plan in response to this contingency, and, as a result, the Company cannot state with a high degree of confidence that it can address any resource deficiencies successfully (MASSPIRG Brief, p. 4). However, if the Pilgrim shutdown continues, Boston Edison argues that it can continue to rely on the action plan already shown to be successful in purchasing replacement capacity because many of these purchases are available over longer periods (BECo Brief, p. 67).

Indeed, the record indicates that 400 to 500 MW of the short-run capacity purchases originally solicited by BECo for the summer of 1988 would be available through 1991 (Exh. BE-4, pp. 3-6). These purchases would address most or all of the resource deficiencies anticipated in the event that the Pilgrim shutdown continues throughout the short run.

Based on the record, the Siting Council finds that BECo has established that it has an action plan to address anticipated resource deficiencies in the event of that the Pilgrim shutdown continues beyond the short run.[34]

34/ The Siting Council reviews the least-cost nature of the Company's action plan for the continued shutdown of Pilgrim in Section III.E.2.c, *infra*.

iii. Conclusions on Short-Run Contingency Analysis

The Siting Council has found that Boston Edison has established that it has action plans (1) to meet any resource deficiencies up to a reliability level of 70 percent based on cumulative probabilities of the Company's 81 planning scenarios, and (2) to address anticipated resource deficiencies in the event of that the Pilgrim shutdown continues beyond the short run.

Accordingly, the Siting Council finds 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.

2. Adequacy of the Supply Plan in the Long Run

Boston Edison's long-run planning period is the remaining forecast horizon beyond the short run, from the winter of 1991-92 through the summer of 1997. The Company's base case plan would satisfy capability responsibility and sales agreements throughout the long run (see Table 6).

As previously discussed in Section III.A, *supra*, 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 BECo'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, *infra*.

As indicated in Section III.E, *infra*, BECo has established that its supply planning process identifies and fully evaluates a reasonable range of resource options. Accordingly, the Siting Council finds that BECo has established that its supply planning process ensures adequate resources to meet forecasted requirements in the long run.

3. Conclusions on the Adequacy of the Supply Plan

The Siting Council has found that Boston Edison has established that its: (1) base case plan is adequate to meet requirements in the short run; (2) supply plan is adequate to meet its capability responsibility in the short run under a reasonable range of contingencies; and (3) supply planning process ensures adequate resources to meet forecasted requirements in the long run.

Accordingly, the Siting Council finds that Boston Edison's supply plan ensures adequate resources to meet forecasted requirements.

E. Least-Cost Supply

The Siting Council reviews Boston Edison's processes for identifying and fully evaluating resource options.

1. Identification of Resource Options

Boston Edison identified both generation and C&LM resource options for evaluation. The Siting Council focuses its review on whether Boston Edison 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 BECo compiled a comprehensive array of available resource options, the Siting Council first must determine whether BECo compiled adequate sets of available resource options for each type of resource identified during this proceeding.

i. Types of Resource Sets

During this proceeding, BECo identified five types of resource sets for consideration in its IRP process: (1) short-run capacity purchases;[35] (2) C&LM programs; (3) life extension of existing generation; (4) new Company-owned generation; and (5) long-run QF purchases (Exhs. BE-3, BE-4).

MASSPIRG asserts that BECo should have included another resource set, the cost-effectiveness, risks, and uncertainties of all existing units (MASSPIRG Brief, p. 5). MASSPIRG submits that any assumption that existing generation will operate reliably and cost-effectively is one that must be tested on a routine basis in any reasonable planning process (id.). MASSPIRG also contends that the Siting Council has a statutory obligation to ensure that energy is provided at the lowest possible cost and that in this respect the Siting Council analyzes "whether a supply plan minimizes the long-run cost of power subject to tradeoffs with adequacy, diversity, and the environmental impacts of construction and operation of new facilities." MASSPIRG Reply Brief, p. 2, citing 1987 BECo Decision, 15 DOMSC at 300 (emphasis in original). MASSPIRG further contends that it is impossible to ensure that a supply plan minimizes long-run costs of power unless there is an examination of "whether continued use of existing generating units is cost-effective relative to the construction and operation of new facilities" (MASSPIRG Brief, p. 3). There is already a statutory requirement, according to MASSPIRG, under G.L. c. 164, sec. 69I(3), for a utility to provide a description of actions affecting capacity, including "reduction

---

35/ The Company compiled its set of short-run capacity purchases as part of its action plan in response to a Pilgrim contingency (see Sections III.B.1 and III.D.1.b.ii, supra). Thus, short-run capacity purchases are not part of either the Company's base case plan or its risk management plan.

or removal of existing facilities."

MASSPIRG also argues that a particular generating unit, Pilgrim, should have been evaluated for inclusion in the least-cost plan because of its continued sub-standard performance (MASSPIRG Brief, pp. 7-8). According to MASSPIRG, BECo has not performed any economic analysis of Pilgrim's economic viability of its own volition and BECo went so far as to halt such an analysis which was to be part of a generating unit life extension study (id., p. 8).

MASSPIRG argues that even if an examination of existing generation is warranted only in exceptional circumstances, such a situation is present in the case of Pilgrim (id., p. 5). As evidence that Pilgrim should have received "special treatment" in the Company's planning process, MASSPIRG cites Pilgrim's two and one-half year shutdown, its consistent performance below target availabilities, and enormous increases in O&M and capital costs (id., p. 6).

Finally, MASSPIRG challenges certain performance assumptions that BECo applied to the Pilgrim unit.[36] MASSPIRG claims that: (1) BECo's use of a 70 percent capacity factor for Pilgrim was unreasonably high; (2) BECo's assumption that direct O&M costs would increase by five percent each year are too low; (3) BECo improperly excluded certain Pilgrim O&M overhead costs and insurance costs; and (4) BECo underestimated future Pilgrim capital additions (id., pp. 8-11). MASSPIRG states that it demonstrated the effect of Pilgrim cost-effectiveness to small changes in these assumptions (id., p. 11; MASSPIRG Reply Brief, p. 6). It contends it has illustrated that the supply plan is deficient because there has been no showing that Pilgrim is cost-effective and because unreasonble assumptions have been made for the operation of

---

36/ Although Pilgrim was not considered as a resource option, certain operating assumptions concerning its cost and operation were used in the development of the initial resource plan (see Section III.C.2.a, supra).

Pilgrim.[37]

The Company responds by stating that it is reasonable to assume that existing generation is not only more reliable than alternatives but also more economic (BECo Brief, p. 37). BECo argues that, in contrast to new generation, capital costs of existing generation are already sunk and therefore customers only pay the incremental cost of power production (id.). Thus, BECo states that, as a general rule, the incremental costs of existing generation will be less than the total costs of new generation (id.). BECo cites two studies, the study performed in response to an earlier Executive Office of Energy Resources request (Exh. MP-2), and BECo's life extension study (Exhs. MP-1, MP-1A), which it believes tend to confirm that judgment (BECo Brief, p. 37).

The Company admits, however, that there are exceptions to this rule, such as when an existing unit nears the end of its useful life and requires a substantial capital investment to remain in operation, or perhaps when oil prices escalate so dramatically that oil-fired generation is no longer practicable (id., pp. 37-38). The Company submits that these events are the exception, not the rule, and that a planning process should not require regular evaluation of the cost-effectiveness of existing generation absent extraordinary circumstances (id., p. 38). Although the Company appears to focus on life extension and sharp oil price change as extraordinary circumstances it also states that,

> [w]hile the Company's strong view is that the Pilgrim unit continues to be an economic investment for its customers, the analysis which is currently under preparation and the Company's approach to evaluating the economics of existing generation under extraordinary circumstances such as the Pilgrim outage will be available for future Council review. Id., p. 38 (emphasis supplied).

37/ MASSPIRG does not contend that it has shown Pilgrim to be uneconomic (MASSPIRG Brief, p. 12).

BECo states that even if the events surrounding Pilgrim constitute an extraordinary circumstance, the Siting Council has never required a utility to address in a long-range forecast the unavailability or economics of an existing unit (id., p. 68). If such a requirement is interposed, according to BECo, it cannot stand as a reason for rejecting its forecast which was presented under pre-existing filing requirements (id., pp. 68-69). The Company states that the IDEAS process is sufficiently flexible to model the unavailability of a unit such as Pilgim and it will "work with the Council in this regard" (id., p. 39).

Initially, the Siting Council agrees with MASSPIRG that an absolute demonstration of supply plan cost minimization would include a comparison of existing generation to new and, in fact, all other resources. However, we also agree with BECo's contention that, absent extraordinary circumstances, existing generation is generally more reliable and economic than implementing new generation. Thus, requiring ongoing analysis of existing generation indeed would be an unnecessary exercise which would increase the difficulty of developing a supply plan. Finally, the Siting Council previously has not required utilities to analyze the economics of existing generation, and we do not view G.L. c. 164, section 69I(3), as requiring such a showing. Therefore, the Siting Council rejects MASSPIRG's assertion that BECo should have considered the cost-effectiveness, risks, and uncertainties of all existing units.

At the same time, the parties agree that extraordinary circumstances warrant review of existing generation resources. In fact, as part of its IRP process, Boston Edison routinely examines the economics of life extension of existing units because life extension could require a substantial investment of new capital. The Siting Council concurs with the parties and finds that companies should evaluate existing generating units within a supply planning process when extraordinary circumstances result in questions about the reliability or economic advantages of those units when compared to other resource options. We expect such extraordinary circumstances to occur rarely.

The remaining question is whether the events surrounding the Pilgrim unit constitute such an extraordinary circumstance. Record evidence indicates that they do (Exhs. HO-9, HO-98, HO-113, HO-114, HO-120, HO-147; Exh. BE-15). Pilgrim is a nuclear unit that has suffered an outage of two and one-half years. Such an outage at such a baseload unit is in itself unprecedented and ample reason for a Company to evaluate the cost-effectiveness of the unit's continued operation. In addition, MASSPIRG has raised some trenchant issues concerning consistent Pilgrim performance below target availabilities, and enormous increases in O&M and capital costs. Further, we do not view the two studies cited by the Company as resolving the question of Pilgrim's economics. Boston Edison itself acknowledges that the Pilgrim shutdown is an extraordinary circumstance, and states that it is preparing a comprehensive analysis of Pilgrim's economics for the purposes of cost recovery and ratemaking (BECo Brief, p. 38).

Therefore, we find that the events surrounding Pilgrim constitute an extraordinary circumstance and raise ongoing reliability and cost questions. In fact, given these events, it would have been appropriate for BECo to include Pilgrim as a resource option in its supply planning process. We are mindful, however, that in the past the Siting Council has not required utilities to evaluate existing units, whether extraordinary circumstances exist or not. Therefore, under our previously established standards, we find that BECo has identified a reasonable range of resource sets. However, we ORDER the Company in its next filing 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.[38] We recognize the complexity this adds to the Company's supply planning process, but we find such an analysis necessary.

ii. Compilation of Resource Sets

As part of its action plan in response to the Pilgrim Order, Boston Edison compiled a set of available short-run capacity purchases by soliciting capacity from 27 utilities in New England, Canada, New York, New Jersey, and Ohio (Exh. BE-4, p. 3). The Company received offers from 15 of those utilities (id., p. 6; Exh. HO-25). This solicitation constituted a reasonable method for the Company to research available short-run capacity purchases. Therefore, the Siting Council finds that Boston Edison compiled an adequate set of available short-run capacity purchases.

As described in Section III.C.2.b, supra, the Company compiled its set of available C&LM programs for implementation in the short run and the long run from other utilities, industry journals, and EPRI. The Company's witness, Ms. Kelly, testified that this literature search was conducted to collect information on potential C&LM programs in all classes and end-uses (Exh. BE-10, p. 4). Compilation of this set was integrated into C&LM program design such that the set would address specific needs. This integration is logical since it helps the Company direct its research efforts toward the most beneficial programs. Accordingly, the Siting Council finds that Boston Edison compiled an adequate set of available C&LM programs.

Boston Edison established threshold criteria for generating units which constitute life-extension candidates

---

38/ The record suggests that differing assumptions concerning Pilgrim's operating and cost variables may affect the result of any analysis significantly (see, e.g., Tr. I, p. 98).

based on the length of time in service. All fossil-steam units at the end of their thirty-fifth year of operation and all combustion turbines at the end of their twenty-fifth year of operation were considered to be candidates for life extension (Exh. MP-1, pp. B-3 to B-6). Based on these criteria, BECo stated that its set of available life-extension resource options includes Mystic Station units 4, 5, and 6, New Boston Station units 1 and 2, and ten combustion turbines (id.).[39] In that the Company's set of generating units available for life extension included all units meeting the threshold criteria, the Siting Council finds that Boston Edison compiled an adequate set of available life-extension candidates.

Boston Edison asserted that its base case plan is adequate without additional Company-owned capacity until 2008 (BE-3, p. C-3-15). Nevertheless, as part of its risk management process, the Company compiled a set of 18 available Company-owned generation options which could be implemented if necessary (see Section III.C.2.a, supra). This set provided a range of options that address several types of resource requirements. For instance, the set included options which could operate at high, intermediate, or low capacity factors, options which could use coal or oil, and options which could be built in relatively large or small increments. One weakness, however, was that BECo limited fuel choices to coal and oil thus eliminating legitimate technologies which use alternative fuels such as natural gas or renewable fuels. In addition, the Company omitted a number of advanced generation technologies which potentially could contribute to a least-cost supply plan such as compressed-air storage or fuel cells. Nevertheless, for purposes of this review, the Siting Council finds that Boston Edison compiled an adequate set of new Company-owned

---

39/ The ten combustion turbines include the Company's units at Medway (3 units), Framingham (3), Edgar Station (2), Mystic Station (1), and L Street (1) (Exh. MP-1, Fig. G-1).

generation resource options.

To compile its set of available long-run QF purchases, Boston Edison issued an RFP soliciting QF purchases pursuant to Massachusetts Department of Public Utilities ("MDPU") regulations 220 CMR 8.00 (Exh. HO-5). The MDPU regulations require Boston Edison to continue to issue such RFPs as part of future resource plans (Exh. BE-7, p. 5). The Siting Council has found in the past that such solicitations serve as appropriate means for compiling a set of available QF resources. 1988 EUA Decision, EFSC 87-33 at 40. Thus, the Siting Council finds that Boston Edison has compiled an adequate set of available long-run QF purchases.

iii. Conclusions on Available Resource Options

For the reasons set forth in Section III.E.1.a.i, *supra*, the Siting Council has found that BECo has met the Siting Council's requirements for identifying resource sets. In addition, the Siting Council has found that the Company compiled adequate sets of short-run capacity purchases, C&LM programs, life-extension candidates, new Company-owned generation, and long-run QF purchases.

Accordingly, the Siting Council finds that, on balance, Boston Edison has demonstrated that it compiled a comprehensive array of available resource options. In addition to the Siting Council's ORDER set forth in Section III.E.a.i, *supra*, the Siting Council ORDERS BECo in its next forecast filings to consider for inclusion in its array of available resource options a wider range of the generation technologies which potentially could contribute to a least-cost supply plan.

b. Development and Application of Screening Criteria

To determine whether Boston Edison 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 BECo's resource sets. For three of its resource sets -- short-run capacity purchases, life extension of existing generation, and new Company-owned generation -- the Company did not screen out any of the options available. Thus, the Siting Council reviews the criteria for the two remaining sets, C&LM programs and long-run QF purchases.

As described in Section III.C.2.b, supra, Boston Edison screened C&LM programs by assessing the needs of both the system and its customers, designing programs to address those needs, and then determining the cost-effectiveness of those programs. The criteria developed and applied in each step of the process are logical and generally well-founded. The Company first identified system and customer needs so that it could direct research toward those programs which would provide the maximum benefits to the Company and its customers. In designing C&LM programs, BECo conceptualized four C&LM strategies which would address identified needs, then researched individual C&LM programs, estimated C&LM program costs and benefits, and determined C&LM program feasibility and marketability.

Finally, the Company analyzed program costs and benefits using LMSTM, a model which permits the calculation of time-differentiated avoided costs. BECo used LMSTM to eliminate those programs which were not cost-effective. With this screening process, Boston Edison identified 15 potentially cost-effective programs for final evaluation. These programs address all four of the C&LM load shape strategies and provide a reasonable range of programs for final market analysis, final program design, and implementation.

Based on the foregoing, the Siting Council finds that Boston Edison developed and applied appropriate criteria for screening its set of available C&LM programs.

To screen available long-run QF purchases compiled from BECo's RFP process, Boston Edison specified minimum bidder criteria or "threshold requirements" for purchase prices, payment schedules, project size and design, site acquisition status, permit identification, cost estimation, management plans, fuel supply, waste management, and thermal energy use (Exh. HO-5, pp. 6-9). The MDPU must approve these screening criteria prior to any purchase solicitation. See 220 CMR 8.00. Therefore, for purposes of this review, the Siting Council accepts Boston Edison's development and application of screening criteria for its set of available long-run QF purchases.

Accordingly, the Siting Council finds that Boston Edison 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 Boston Edison (1) has demonstrated that it compiled a comprehensive array of available resource options, and (2) has developed and applied appropriate criteria for screening its array of available resource options.

Accordingly, the Siting Council finds that Boston Edison has established that it has identified a reasonable range of resource options.

2. Evaluation of Resource Options

The Siting Council reviews Boston Edison's resource evaluation process to determine whether BECo (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 the resource options identified in Section III.E.1, supra. This review addresses the Company's evaluation process described in Section III.C, supra, as it was applied in developing the base case plan, managing base case plan risks, and developing action plans in the event of a Pilgrim re-opening contingency.

a. Development of the Base Case Plan

i. Developing the Initial Resource Plan

Boston Edison used EGEAS to develop its initial resource plan. The Company asserted that EGEAS selects the optimal generation expansion plan based on minimizing total revenue requirements. The Siting Council has found in the past that minimizing total revenue requirements is an appropriate basis for minimizing the economic costs of alternative resource plans. See, e.g., Middleborough Gas and Electric Department, 17 DOMSC 197, 211-212 (1988). Although the EGEAS model was not reviewed fully during this proceeding, it appears to be a reasonable model for analyzing and optimizing expansion plans based on a set of input assumptions. Thus, the Siting Council accepts the Company's assertion that EGEAS optimizes generation expansion plans by minimizing total revenue requirements.

In developing its initial resource plan, Boston Edison made six basic input assumptions. The first of these was to develop this plan based on the natural demand forecast, an obvious and logical input assumption. The five remaining assumptions involved resources that the Company deemed "committed." Four of these -- signed purchase agreements with other utilities, QFs from previous RFPs, C&LM programs that are already in the implementation stage, and TOUR effects -- are reasonable.

However, the Company's imput assumption that all existing units would be life-extended effectively eliminates one of the Company's stated resource option sets. The Siting Council has found herein that companies should evaluate existing generating units in a supply planning process when extraordinary circumstances result in questions about the reliability or economic advantages of those units compared to other resource options. See Section III.E.1.a.i, <u>supra</u>. The Company itself asserts that life extension constitutes one such extraordinary circumstance (BECo Brief, pp. 37-38). While BECo provided an extensive study of the cost-effectiveness of life extension programs (Exhs. MP-1, MP-1A), the Company did not indicate how this study shows that all life extension programs should be considered committed resources as opposed to resource options in its least-cost planning process.

For purposes of this review, the Siting Council accepts this input assumption. However, in future filings, Boston Edison either should demonstrate why life extension programs are committed resources or instead should treat these programs as available resource options for evaluation within the supply planning process on an equal footing with other available resource options.

Finally, the Company included its set of 18 new Company-owned generation options in its analysis used to develop the initial resource plan. EGEAS evaluated the various inputs and integrated new Company-owned generation options into the initial resource plan when they reduced revenue requirements. This methodology is an acceptable means for evaluating the economic costs of new Company-owned generation.[40]

Based on the record, the Siting Council finds that Boston Edison's methodology for developing its initial resource plan is appropriate.

40/ The Siting Council found in Section III.E.1.a.i, <u>supra</u>, that the Company should have identified Pilgrim for consideration in its IRP process. One method for doing so might have been through a process similar to that used for new Company-owned generation.

ii. Integrating Additional Resources into the Initial Resource Plan

In its supply planning process, Boston Edison compiled five sets of available resource options -- short-run capacity purchases, C&LM programs, life extension of existing generation, new Company-owned generation, and long-run QF purchases. See Section III.E.1, supra. However, BECo compiled its set of short-run capacity purchases in the event of a Pilgrim re-opening contingency rather than for purposes of developing the base case plan. Hence, the Siting Council reviews the Company's evaluation of short-run capacity purchases in Section III.E.2.c, infra. In addition, Boston Edison assumed life extension was a committed resource in the initial resource plan.[41] Furthermore, the Company evaluated new Company-owned generation in developing the initial resource plan. Thus, the Siting Council reviews the two remaining resource sets, C&LM programs and long-run QF purchases.

(A) C&LM Programs

With respect to C&LM programs, MASSPIRG asserts that the Company has not given these resources adequate attention or priority in its planning process (MASSPIRG Brief, p. 12). MASSPIRG argues that BECo has failed to consider non-price criteria such as environmental benefits in evaluating C&LM programs (id., p. 13). Finally, MASSPIRG maintains that "the Company's own presentation shows that [BECo's] current [C&LM] programs fall short of capturing all cost-effective C&LM opportunities" (MASSPIRG Reply Brief, p. 7). According to MASSPIRG, even though C&LM is the cheapest resource, the Company is holding back on C&LM to cover Pilgrim unavailability

---

41/ For a discussion of this assumption, see Section III.E.2.a.i, supra.

and transmission contingencies (id., p. 8). MASSPIRG also states that the Company appears to be spending far less on C&LM than what the Company had budgeted (id.).

Boston Edison responds that MASSPIRG has provided no objective standard for measuring "adequate attention or priority" in its planning process (BECo Brief, p. 73). The Company maintains that points made in MASSPIRG's supporting arguments are mistaken, misconstrued, or isolated examples and therefore do not justify MASSPIRG's broad assertion (id.). Rather, the Company submits that its C&LM evaluation process and results respond to statutory and regulatory directives by: (1) evaluating C&LM programs based on a total revenue requirements test; (2) implementing a flexible and dynamic evaluation process; (3) using the selection criteria set forth by the MDPU; and (4) instilling a strong Company commitment to achieving C&LM goals (id., pp. 39-47). Further, the Company asserts that it has addressed each of the principal findings of the 1987 BECo decision (id., p. 41).

MASSPIRG largely echoes the Siting Council's findings in the 1987 BECo Decision that the Company had not given C&LM resources adequate attention or priority in its planning process (pp. 341-349). Our criticisms included a finding that the Company treats C&LM resource options differently than supply-side options due to the failure of the Company's supply planning process to: (1) integrate supply-side and demand-side planning; (2) pursue all cost-effective C&LM programs; (3) monitor changes in the cost-effectiveness of C&LM programs as avoided costs change; (4) incorporate analytical tools that accommodate economic comparisons of C&LM options and supply-side options; (5) assess the risks of different types of resource options objectively; (6) evaluate C&LM options as a potential response to contingencies; (7) develop estimates of its short-run C&LM resources with a credible technical basis; and (8) estimate all benefits to the Company's system of C&LM resources (id.).

Boston Edison indeed has provided evidence of marked progress toward meeting most of these supply planning concerns. First, the Company developed its IRP process which Mr. Killgoar, the Company's witness, asserted has truly integrated demand and supply planning (Exh. BE-5, p. 4). We agree that the structure used to develop the base case plan and risk management plan as described in Section III.C, supra, represents a practical methodology for integrating supply-side and demand-side options for both the base case and contingency planning.

In regard to the second concern, Ms. Kelly testified that the Company includes all cost-effective C&LM programs in its resource plan (Exh. BE-10, p. 4). The Company's identification and evaluation processes for C&LM options as described in Section III.C.2, supra, support Ms. Kelly's position. The processes used to identify C&LM programs and evaluate their cost-effectiveness -- a needs assessment, program design, extensive cost/benefit analysis, market assessments and final design, and integration into the initial resource plan -- resulted in a proposal to implement eight programs (in addition to the 14 now in the implementation stage) and review seven more potential programs which deserve further evaluation. MASSPIRG contends that more than eight new programs should be implemented and the results of LMSTM do indicate that more than eight programs meet BECo's tests (Exh. HO-1, Tr. II, p. 80-82). Ms. Kelly stated that BECo's judgments on the market feasibility of a program and the difficulty of educating customers to use a program affect the decision of which programs to implement (Tr. II, pp. 80-84).

While evaluating C&LM programs may require judgment regarding certain feasibility and marketing barriers prior to program implementation, the Company should make every attempt to implement programs which its own analysis indicates are cost-effective. For instance, certain perceived barriers, such as the need to educate customers, may be simply a question of costs -- costs which can be readily considered in the Company's planning process. Therefore, if a C&LM program is cost-effective after inclusion of the cost of customer education, it should not then be subject to a subjective decisionmaking process that could operate to eliminate the program. In its next filing, we direct the Company to demonstrate why any programs which pass net present value or cost-effectiveness tests are not chosen for implementation.

Ms. Kelly responded to the third concern by stating that the Company now re-evaluates C&LM programs on an annual basis within its IRP process (Exh. BE-10, p. 9). She testified that Boston Edison evaluates C&LM programs using LMSTM and the initial resource plan which is based on the most recent forecast and supply assumptions (id.). In addition, she noted that LMSTM's dynamic design better reflects changes in avoided costs over the life of a program (id., pp. 9-10).

Mr. Killgoar stated that the Company responded to the fourth concern by filing a forecast in the instant docket which relied on full implementation of LMSTM in contrast to the forecast in EFSC 85-12 (Phase II) when LMSTM was not completely available (Exh. BE-5, pp. 4-5). He asserted that LMSTM evaluates C&LM programs based on total revenue requirements -- the same basis used by EGEAS for evaluating supply options (id.).

Although the Company did not respond directly to the fifth concern, the Company has demonstrated through the development of its IRP process, and its progress in identifying and implementing cost-effective C&LM programs, that it has re-evaluated the risks associated with demand-side options relative to supply-side options. Indeed, in this record Boston Edison has demonstrated a stronger commitment to achieving C&LM goals.

Regarding the sixth concern, Mr. Killgoar noted that LMSTM's calculation of total revenue requirements for C&LM programs allows the Company to use C&LM in contingency planning (Exh. BE-5, pp. 4-5). He cited the Company's action plan in response to continued delay in returning Pilgrim to full service as one instance where the Company has included C&LM in contingency planning (id., pp. 5-6). In addition, the Company's risk management plan includes accelerated C&LM through the Design Plus program (Exh. BE-3, p. C-7-6).

Ms. Kelly asserted that the Company has addressed the seventh concern by developing short-run estimates of available C&LM resources which reflect the Company's most recent experience with C&LM programs (Exh. BE-10, p. 5). In particular, BECo updated C&LM planning assumptions based on actual program experience and compared C&LM programs to avoided costs calculated from expansion plans based on the most current data (id.).

In response to the eighth concern, Ms. Kelly reiterated the Company's position that it is committed to evaluating C&LM and supply options on the same basis (id., pp. 10-11). She cited deferred investment in generation, transmission, and distribution and savings in energy costs as benefits the Company attributes to C&LM programs (id.). She also asserted that, even though the Company does not assign a dollar value to the reduction of risk due to decreased forecasting error of weather-sensitive end-uses, this value is captured inherently in the Company's risk analysis and contingency planning (id.).

In light of the above, we are satisfied that the Company has made progress toward addressing the Siting Council's concerns set forth in the 1987 BECo Decision. While we expect the Company to continue to refine and expand upon its C&LM efforts, we find that, at this time, Boston Edison has implemented a supply planning methodology which (1) provides for the effective integration of C&LM into its resource plan, and (2) includes an adequate consideration of conservation and load management.

(B) Long-Run QF Purchases

With respect to long-run QF purchases, the Company's witness, Mr. Vaitkus, testified that Boston Edison is seeking 400 MW of QF power to be on line by 2005 (Exh. BE-7, p. 5). He noted that MDPU regulations require Boston Edison to issue RFPs annually, soliciting long-run QF purchases for a supply block of at least five percent of the Company's peak load (id.). Further, he anticipates that these RFPs will result in additional purchase agreements (id.). However, as the Company observes, the supply plan filing excluded all uncommitted long-run QF purchases (BECo Brief, p. 49).

While this exclusion raises questions about the least-cost nature of the base case plan as well as the risk management plan, it may have as least one advantage: the supply plan may serve as a basis for calculating the ceiling price and defining non-price parameters for a QF purchase solicitation. Also, given the proper design of QF solicitation criteria, the addition of long-run QF purchases to a company's resource mix should reduce costs and risks thereby resulting in a more optimal supply plan.

Thus, for purposes of this review, the Siting Council accepts Boston Edison's decision to exclude long-run QF purchases from its base case plan. However, the Company should justify any similar decision in its next forecast filing.

(C) Conclusions on Integration of Additional Resources into the Initial Resource Plan

The Siting Council has found that (1) Boston Edison has implemented a supply planning methodology which allows effective integration of C&LM into its resource plan, and (2) that Boston Edison's supply plan includes an adequate consideration of conservation and load management. In addition, the Siting Council has accepted Boston Edison's decision to exclude long-run QF purchases from its base case plan.

Accordingly, the Siting Council finds that Boston Edison's methodology for integrating additional resources into its initial resource plan is appropriate.

iii. Conclusions on Development of the Base Case Plan

The Siting Council has found that Boston Edison's methodologies for developing its initial resource plan and for integrating additional resources into the initial resource plan are appropriate.

Based on the record in this proceeding, the Siting Council finds that Boston Edison has demonstrated that it has developed and applied a resource evaluation process to development of its base case plan which fully evaluates identified resource options.

In making this finding, the Siting Council notes two concerns. First, the Siting Council's standards for reviewing utilities' supply planning processes require it to determine whether those processes treat all resources -- including C&LM programs, conventional powerplants, and purchases from cogeneration and small power projects and from other utility and non-utility supplies -- on an equal footing when attempting to develop an adequate and least-cost supply plan. Massachusetts Municipal Wholesale Electric Company, 16 DOMSC 95, 109 (1987); 1987 BECo Decision, 15 DOMSC at 300; 1986 CELCo Decision, 15 DOMSC at 133. Boston Edison argues that its supply planning process treats all resource options on an equal footing (BECo Brief, p. 27). The Company cites its use of LMSTM as a means of ensuring that supply-side and demand-side options are compared on an equal footing (id., p. 28).

But regardless of LMSTM's modeling sophistication, the modeling results reflect scenario input assumptions, including data errors or restrictions. In this case, the Company has justified its decisions to restrict the scope of its evaluation of resource options to only two types, new Company-owned generation and C&LM programs, and to exclude other types of resource options such as life extension of existing generation or short-run (and long-run) purchases from other utilities.[42] However, the Company has not demonstrated that it compared the costs and benefits of resource options within these two sets with all alternative resource options.

Therefore, we make no findings here regarding treatment of all identified resource options on an equal footing. In future forecast filings, the Siting Council directs the Company to implement a supply planning methodology which allows the Company to apply its resource evaluation process to all of its identified resource options.

Second, while the Company's total revenue requirements test may allow a direct comparison of demand-side and supply-side options, the Company has not demonstrated that it attributes environmental impacts or benefits to resource options. For instance, in this proceeding, the Company did not show that environmental benefits associated with C&LM options were considered adequately. Our enabling statute directs us to balance economic considerations with environmental impacts in ensuring that the Commonwealth has a necessary supply of energy. G.L. c. 164, sec. 69H. 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 power. See Section III.A, supra. Therefore, the Siting Council ORDERS Boston Edison to implement a methodology in its next forecast filing which includes an adequate consideration of the environmental impacts of alternative resource options.

b. Management of Base Case Plan Risks

The Siting Council reviews the five aspects of Boston

42/ In soliciting long-run QF purchases, the RFP screening and evaluation criteria are reviewed by the MDPU (see Section III.E.1.b, supra).

Edison's plan to manage base case plan risks as described in Section III.C.3, supra.

i. Developing Scenarios

To serve as the basis of the Company's planning scenarios, Boston Edison selected four variables -- load growth, C&LM penetration, committed capacity additions, and fuel prices -- which the Company believes have direct or indirect impacts on required resources.

MASSPIRG asserts that these variables encompass only a small and selective range of forecasting and planning risks (MASSPIRG Brief, pp. 14-15). MASSPIRG suggests that other variables, such as risks surrounding existing generating units, also should be considered (id.).

However, the Company maintains that these four variables are the major variables affecting resource requirements (BECo Brief, p. 30). But while BECo concedes that more variables could be added to the analysis, it argues that to do so would not add to the information gained from the 81 scenarios and would increase modeling difficulty (id., p. 31). The Company agrees, however, that variables such as existing generating units could be added to the process if probabilities can be assigned to alternative forecasts (id., p. 80).

The Company has demonstrated that the four selected variables do in fact significantly impact resource requirements. Even so, the Company could have provided additional planning insight by considering other variables affecting resource requirements. For instance, BECo might have included variables with high, base, and low forecasts of expected capacity factors for existing generating units, NEPOOL reserve requirements, or the timing of committed capacity additions. Although additional variables may increase modeling complexity, Boston Edison already has demonstrated its ability to model a large number of scenarios -- its life extension study examined 12 different variables generating 64,000 different scenarios (Exh. MP-1, p. C-17).[43] Further, BECo also has implemented a methodology for reducing a large number of scenarios to a more manageable number of representative scenarios (see Section III.E.2.b.iii, infra). Finally, the Company has demonstrated its ability to assign probabilities to alternative forecasts for variables (see Section III.E.2.b.ii, infra).

Nevertheless, Boston Edison has analyzed four variables which provide a reasonable range of possible resource scenarios. While we urge the Company to explore additional variables for consideration in its IDEAS process, we find, for purposes of this review, that the four variables identified by Boston Edison constitute a reasonable range of variables for scenario development.

Once the Company identified the four variables, it developed high, base, and low forecasts for each variable. The combination of these four variables with three forecasts each resulted in 81 scenarios. Although the Company did not describe how it derived its forecast of C&LM penetration, the Siting Council, for purposes of this review, accepts each of these forecasts used to develop the 81 scenarios.

Based on the foregoing, the Siting Council finds that Boston Edison has established that its methodology for developing its 81 scenarios is appropriate.

43/ The variables in the life extension study included changes in: (1) environmental licensing requirements for building a new generating unit to replace New Boston and Mystic units 4, 5, and 6; (2) environmental retrofit requirements for the New Boston and Mystic units; (3) scope of life extension; (4) life extension costs; (5) availability factors of life-extended units; (6) load growth; (7) Pilgrim capacity factor; (8) fuel costs; (9) cogeneration capacity; (10) cost of new units; (11) Canadian purchase availability; and (12) Canadian purchase costs (Exh. MP-1, pp. C-15 to C-17).

ii. Assigning Probabilities to Scenarios

A critical step in the Company's IDEAS process was the assignment of unconditional and conditional probabilities within the 81-scenario decision tree.

MASSPIRG submits that this step is too subjective since it relies heavily on the subjective input of utility planners (MASSPIRG Brief, pp. 14-15). For instance, MASSPIRG asserts that BECo's Delphi survey demonstrates that BECo staff is considerably more pessimistic about committed capacity additions than the outside experts consulted in that study (id., p. 15). Thus, MASSPIRG maintains that the IDEAS process should not be relied upon for planning decisions (id., p. 14).

The Company responds that the concerns MASSPIRG raises have less to do with methodological problems than with disagreements on the data to input (BECo Brief, p. 79). As support, BECo points out that MASSPIRG's contention, that the Company's assumptions for committed capacity additions are unreasonable, is actually a disagreement over the probabilities assigned to particular variable forecasts rather than the process itself (id., p. 80).

The Siting Council agrees with the Company that MASSPIRG's concerns about assigning scenario probabilities pertain to the probabilities assigned rather than the decision-tree process itself. In fact, decision trees require unconditional and conditional forecast probabilities so that scenario joint probabilities may be calculated, an important aspect of ascertaining relative risks. In that the decision-tree analysis provides a practical means of examining useful planning information, the Siting Council rejects MASSPIRG's assertion that the Company should not rely upon the IDEAS process for planning decisions.

MASSPIRG's concern is nevertheless valid: given the inherent subjectivity of assigning probabilities, assigning them solely on the basis of utility planners' judgment could bias the resulting resource plans. The Company's survey, "Modified Delphi Project: An Assessment of Outside Perspectives on the Value of New C&LM Progams" ("Delphi survey"), indicates exactly that -- opinions of BECo staff on future resource planning events were consistently different than opinions of outside utility experts from the Boston area (Exh. HO-41, p. 14). For instance, the Delphi survey noted that "[u]tility staff were relatively more certain co-gen will fail and that failures will occur earlier than the outside panel" (id.).

In assigning probabilites within the IDEAS process for the forecasts of two variables, fuel prices and load growth, Boston Edison in fact based forecast probabilities on the combined judgment of sources both inside and outside of the Company. However, for the forecasts of C&LM penetration and committed capacity additions, Boston Edison based forecast probabilities exclusively on the judgment of in-house staff. At the same time, the Company acknowledged the need to include a wider range of perspectives in developing scenario probabilities "[i]n order to reflect the collective judgement of all stakeholders in putting together a risk adjusted least-cost resource plan" (Exh. BE-3, p. C-7-3; see also Tr. II, pp. 101-103). Thus, the Company has proposed to use a Delphi-type survey as a more formal approach of assessing unconditional and conditional probabilities based on the opinions of sources inside and outside of the Company (Exh. BE-3, p. C-7-3). BECo suggested that sources from outside the Company might include representatives from regulatory, public policy, and public interest groups (id.).

The Siting Council is satisfied that Boston Edison has made substantial progress in implementing a methodology for developing and assigning forecast probabilities for use within the IDEAS process. Accordingly, for purposes of this review, the Siting Council finds that Boston Edison has established that its methodologies for estimating unconditional and conditional probabilities of variable forecasts are appropriate. However, the Siting Council ORDERS Boston Edison in its next forecast filing 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.

iii. Screening Scenarios

The process used by Boston Edison to screen its 81 scenarios to 34 for detailed analysis was based on the innovative IDEAS model. By narrowing the planning focus to 34 of the most likely scenarios, IDEAS permitted the Company to streamline its detailed scenario analysis without significantly affecting the accuracy of the results.

Accordingly, the Siting Council finds that Boston Edison's methodology for screening scenarios is appropriate.

iv. Balancing Resource Adequacy and Cost

The Company maintains that the balance between resource adequacy and cost indicates that it was economical to plan to the 70 percent reliability level (BECo Brief, p. 32).

However, MASSPIRG argues that quantification of costs within the IDEAS process due to inadequate capacity is troubling because: (1) there is enormous imprecision and an absurdly large range of estimates of power shortage costs; (2) the relationship of such estimates to BECo planning are not clear because the cost of an outage to customers is a factor in regional planning, while the cost to the Company is a NEPOOL deficiency charge; and (3) the process does not adequately reflect the direct costs and risks of excess generating capacity or indirect risks such as construction length and financial exposure (MASSPIRG Brief, p. 15).

Except for the indirect costs which BECo asserts are too much for any model to consider, the Company maintains that these arguments are less of a condemnation of the process than an indication of areas in which the Company might seek additional research and improved consensus (BECo Brief, p. 81).

The record supports MASSPIRG's assertion that the range of estimates of power shortage costs, in terms of unmet energy, are large. For instance, the Company observed that if unmet energy is viewed as simply the cost of emergency replacement power, then the cost would be 12.5¢/KWH, the NEPOOL deficiency energy charge (Exh. BE-3, p. C-5-3). However, as the Company pointed out, if all utilities relied on NEPOOL to supply their deficiencies, it might decrease the reliability of the power pool (id.). At the other end of the spectrum, BECo cited a National Economic Research Associates ("NERA") report which concluded that, in 1981 dollars, the average societal cost of outages is at least 50¢/KWH and potentially is well over 100¢/KWH (id.). The Company asserts that its true cost of unmet energy is somewhere within the range of NEPOOL and NERA costs (id.).

Because of this wide range, BECo developed its cost-versus-reliability curve based on the Company's cost to secure enough of its own resources to meet successively higher reliabilty levels. Indeed, Boston Edison's effort to quantify these factors and to balance them rationally is commendable. While this methodology may not reflect all the costs necessary to understand the implications of incremental reliability (e.g., direct costs of excess generating capacity, societal costs of an outage), the method serves as a practical starting point for balancing resource adequacy and cost.

The Company, however, should begin researching methods to evaluate or quantify these additional costs and to integrate more consensus into its balancing of resource adequacy and cost. In addition, the record does not support BECo's suggestion that the cost of reliability increases exponentially in the range of 50 percent to 90 percent. Thus, further definition of the cost-versus-reliability curve, perhaps at 10 percent increments rather than 20 percent increments, would provide a useful increase in the resolution of this curve.

Accordingly, the Siting Council finds that Boston Edison has established that its methodology for balancing resource adequacy and cost is appropriate. Further, the Siting Council finds that the Company has established on this record that the 70 percent reliability level serves as a reasonable balance between resource adequacy and cost.

v. Developing a Risk Management Action Plan

To ensure that it could meet the 70 percent reliability level, Boston Edison provided a risk management action plan. With respect to the adequacy provided by this plan, the Siting Council found in Section III.D.1.b.i, supra, that the Company had established that it has an action plan to meet any resource deficiencies up to a reliability level of 70 percent.

With respect to the least-cost nature of this action plan, the Company asserts that, since the plan emphasizes C&LM and powerplant pre-licensing, it provides flexibility and is economic (BECo Brief, p. 32).

This plan identified six different actions including advancing C&LM programs, providing assistance to QFs, and shortening the lead times for various Company-owned generation alternatives. This plan provides resource diversity in terms of type and size (see Table 5), both of which are desirable attributes of an action plan. The Company has in fact demonstrated that this action plan provides the flexibility to respond to a range of contingencies up to the 70 percent reliability level. However, while resource diversity and flexibility certainly contribute to developing a least-cost action plan, a more systematic methodology for identifying and evaluating resource options would help demonstrate that an action plan is least-cost.

Nonetheless, the Company has shown substantial progress towards developing a plan to respond to the risks inherent in its base case plan. Accordingly, for purposes of this review, the Siting Council finds that Boston Edison has established that its risk management action plan provides for a least-cost response to meet any resource deficiencies up to a reliability level of 70 percent.

vi. Conclusions on Management of Base Case Plan Risks

The Siting Council has found that Boston Edison has established that: (1) its methodology for developing its 81 scenarios is appropriate; (2) its methodologies for estimating unconditional and conditional probabilities of variable forecasts are appropriate; (3) its methodology for screening scenarios is appropriate; (4) its methodology for balancing resource adequacy and cost is appropriate; (5) the 70 percent reliability level serves as a reasonable balance between resource adequacy and cost; and (6) its risk management action plan provides for a least-cost response to meet any resource deficiencies up to a reliability level of 70 percent.

Accordingly, the Siting Council finds that Boston Edison has established that it has a reasonable plan for managing the risks inherent in its base case plan.

c. Action Plan for Continued Shutdown of Pilgrim

In response to the potential loss of Pilgrim capacity credit, Boston Edison compiled a set of 15 available short-run capacity purchases (see Sections III.B.1 and III.E.1.a.ii, supra). If the Pilgrim shutdown continues beyond the short run, the Company would continue to rely on these short-run capacity purchases in order to provide adequate resources (see Section III.D.1.c.ii, supra). With respect to the adequacy provided by this plan, the Siting Council found in Section III.D.1.b.ii, supra, that BECo had established that it has an action plan to address anticipated resource deficiencies in the event of that the Pilgrim shutdown continues beyond the short run.

With respect to the least-cost nature of this action plan, the Company asserts that the plan is providing cost-effective power to its customers (BECo Brief, p. 25).

The record indicates that once the 15 available short-run purchases were identified, BECo evaluated each of them using price and non-price criteria (Exh. BE-4, p. 5). Price criteria included comparing the total cost of the purchase offer to NEPOOL charges for capacity deficiency and deficiency energy service; non-price criteria included service certainty, transmission availability, cancellation provisions, dispatchability, and resale potential (id.). The Company found that four of the purchase offers met or exceeded these evaluation criteria and therefore decided to pursue contracts with those four for a total of about 212 MW of capacity (id.).

The Company's May 1987 contingency action plan for the loss of Pilgrim capacity credit provided for re-evaluation of C&LM programs that were not found to be cost-effective prior to the loss of Pilgrim's capacity credit (Exh. HO-149). Although the Company did not specify further how C&LM interacted with the continued shutdown of Pilgrim, Ms. Kelly, the Company's witness, stated that Boston Edison evaluated C&LM programs annually based on the most recent forecast and supply assumptions (Exh. BE-10, pp. 9-10).

While additional specificity on the least-cost nature of the plans to deal with the Pilgrim contingency would be helpful, the record indicates that the Company considered both price and non-price factors in evaluating identified contract purchase options, and the Siting Council finds that these evaluation criteria are reasonable. The Siting Council has also found that for the purpose of this review the Company's methodology for evaluating C&LM programs is appropriate (see Section III.E.2.iii, supra). Accordingly, the Siting Council finds that Boston Edison has established that it has developed and applied a resource evaluation process for its action plan for the continued shutdown of Pilgrim which fully evaluates identified short-run capacity purchases.

d. Conclusions on Evaluation of Resource Options

The Siting Council has found that Boston Edison has established that it (1) has developed and applied a resource evaluation process for its base case plan which fully evaluates available resource options, (2) has a reasonable plan for managing the risks inherent in its base case plan, and (3) has developed and applied a resource evaluation process for its action plan for the continued shutdown of Pilgrim which fully evaluates identified short-run capacity purchases. However, the Siting Council has made no findings regarding treatment of all resource options on an equal footing.

Accordingly, the Siting Council finds that Boston Edison has established that it developed a resource evaluation process which fully evaluates all resource options, and applied its resource evaluation process to all of its identified resource options.

3. Conclusions on Least-Cost Supply

The Siting Council has found that Boston Edison has established that it (1) has identified a reasonable range of resource options, and (2) has developed and applied a resource evaluation process which fully evaluates all identified resource options.

Accordingly, the Siting Council finds that, based on the applicable standards at the time of the Company's filing, Boston Edison has established that its supply plan ensures a least-cost energy supply.

F. Conclusions on the Supply Plan

The Siting Council has found that Boston Edison complied with the Pilgrim Order and the Transmission Order in the 1987 BECo Decision.

The Siting Council also has found that (1) Boston Edison's supply plan ensures adequate resources to meet forecasted requirements, and (2) based on the applicable standards at the time of the Company's filing Boston Edison has established that its supply plan ensures a least-cost energy supply.

Accordingly, the Siting Council hereby APPROVES the 1988 supply plan of Boston Edison Company.

In approving the Company's integrated resource planning process, the Siting Council notes the significant strides made by the Company since our last decision. In particular, the supply planning process set forth in this case places a long overdue emphasis upon the integration of conservation and load management options in the Company's resource plan. Further, the development of a mechanism designed to evaluate and address resource contingencies has enabled the Company to better ensure an adequate and least-cost supply for its customers.

At the same time, the record in this case indicates that the Company must reevaluate its treatment of the Pilgrim generating unit in its resource planning process. The Company continues to base its resource plans on unsupported assumptions regarding the future operation of Pilgrim. Throughout this review, MASSPIRG highlighted a number of instances where these unsupported assumptions may have affected the validity of the entire planning process. Nowhere is this more evident than the Company's failure to subject the cost of continued operation of a facility with the extraordinary characteristics of Pilgrim to the same evaluation processes used for other resources.

In conclusion, while our last decision acknowledged that Boston Edison's resource planning process read well on paper, that same decision criticized the Company for failing to apply its planning process to analyze resource options and to make decisions regarding resource implementation. In making our decision today, we recognize the Company's important leap from establishing a planning framework to actually implementing a planning process designed to ensure adequate, least-cost supply.

IV. DECISION AND ORDER

The Siting Council hereby APPROVES the 1988 demand forecast and supply plan of Boston Edison Company.

The Siting Council ORDERS Boston Edison Company in its next forecast filing:

(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 the 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; and

(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.

The Siting Council FURTHER ORDERS Boston Edison Company to file its next forecast on February 1, 1990.

Stephen Klionsky
Stephen Klionsky
Hearing Officer

Dated this sixteenth day of February, 1989

UNAMIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of February 16, 1989, by the members and designees present and voting: Sharon M. Pollard (Secretary of Energy Resources); Barbara Anthony (for Paula W. Gold, Secretary of Consumer Affairs and Business Regulation); Jeanette Willett (for Grady Hedgespeth, Secretary of Economic Affairs); Stephen Roop (for John P. DeVillars, Secretary of Environmental Affairs); Joseph W. Joyce (Public Labor Member); and Madeline Varitimos (Public Environmental Member).

Sharon M. Pollard, Chairperson

Dated this 16th day of February, 1989

TABLE 1

Boston Edison Company
1988 Demand Forecast

Customer Class	Annual Energy Requirements (GWH)		Average Annual Compound Growth Rate 1989-1997
	1989	1997	
Residential:			
Heating	651	810	2.8%
Non-Heating	2,595	2,748	0.7%
Commercial	7,069	7,306	0.4%
Industrial	1,896	2,120	1.4%
Streetlighting	131	131	0.0%
Municipal Sales	330	406	2.6%
Losses/Internal	1,192	1,271	0.8%
Totals	13,864	14,792	0.8%

Planning Period	Peak-Load Requirements (MW)		Average Annual Compound Growth Rate 1989-1997
	1989	1997	
Summer	2,599	2,676	0.4%
Winter	2,348	2,495	0.8%

Note:

a. Energy and peak-load forecasts include the effects of market-driven C&LM, Company-sponsored C&LM, TOUR, and packaged self-generation.

Source: Exh. BE-2, pp. L-1 to L-11

Table 2

BOSTON EDISON's LONG RANGE RESOURCE PLAN

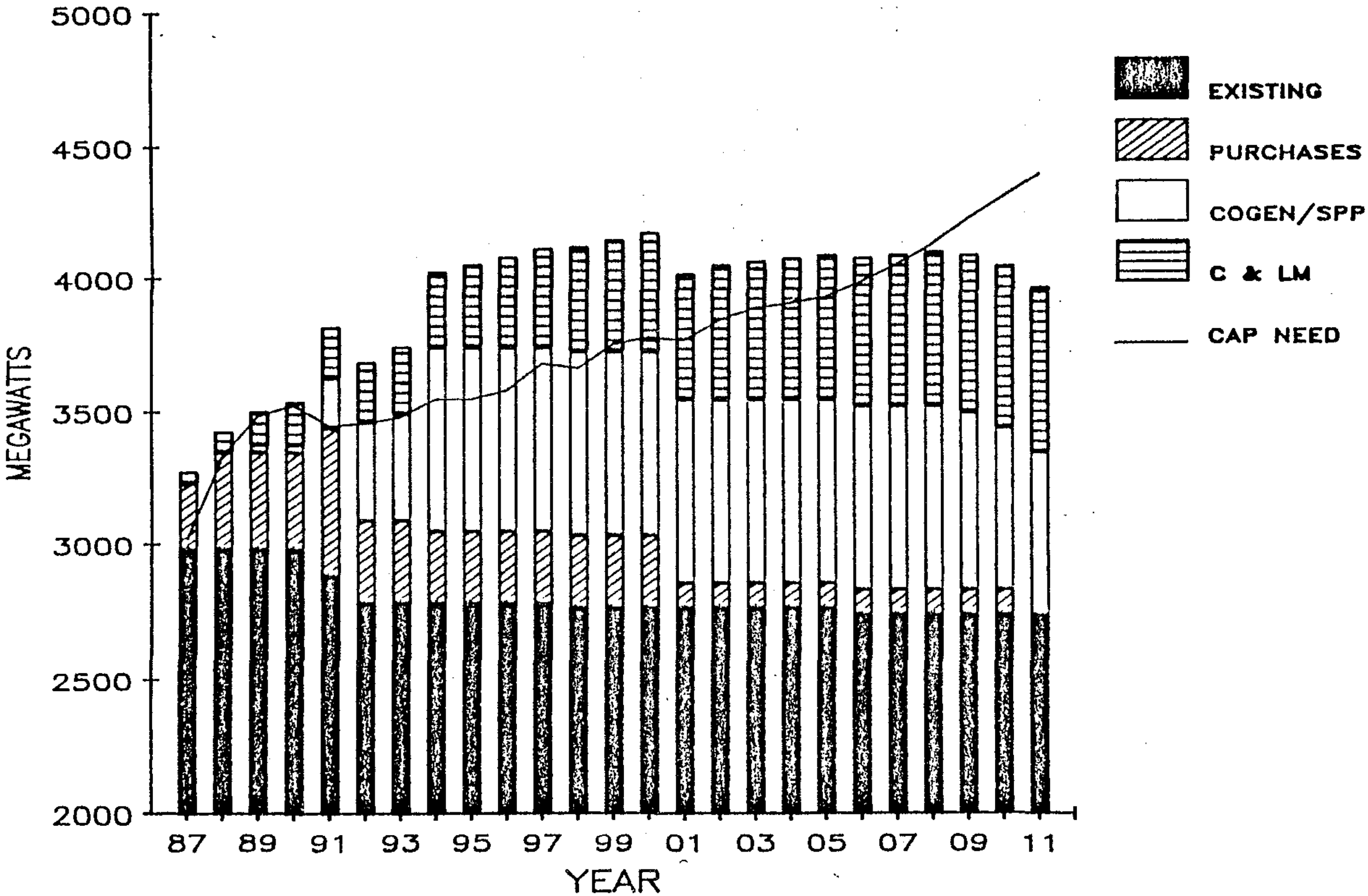


Table 3
DECISION TREE - HIGH FUEL FORECAST

FUEL FORECAST	LOAD FORECAST	C&LM FORECAST	CAPACITY ADDITIONS		SCENARIO PROBABILITY	RESOURCE REQUIRED 2011	FIRST CONTINUOUS NEED	FIRST NEED	FIRST NEED GREATER THAN 50 MWATTS
HIGH 0.20	HIGH 0.10	HIGH 0.55	0.05 HIGH	1	0.0006	(1,272)	2001	1989	1989
			0.60 MID	2	0.0066	(1,577)	1992	1989	1989
			0.35 LOW	3	0.0039	(1,729)	1989	1989	1989
		BASE 0.30	0.05 HIGH	4	0.0003	(1,426)	1999	1988	1989
			0.60 MID	5	0.0036	(1,731)	1988	1988	1989
			0.35 LOW	6	0.0021	(1,883)	1988	1988	1989
		LOW 0.15	0.05 HIGH	7	0.0002	(1,580)	1997	1988	1989
			0.60 MID	8	0.0018	(1,885)	1988	1988	1989
			0.35 LOW	9	0.0011	(2,037)	1988	1988	1989
	BASE 0.30	HIGH 0.40	0.05 HIGH	10	0.0012	(276)	2010	2010	2010
			0.60 MID	11	0.0144	(581)	2001	1992	2002
			0.35 LOW	12	0.0084	(733)	1992	1992	1992
		BASE 0.40	0.05 HIGH	13	0.0012	(430)	2008	2008	2009
			0.60 MID	14	0.0144	(735)	1997	1992	1992
			0.35 LOW	15	0.0084	(887)	1992	1989	1992
		LOW 0.20	0.05 HIGH	16	0.0006	(584)	2006	1989	2007
			0.60 MID	17	0.0072	(889)	1992	1989	1992
			0.35 LOW	18	0.0042	(1,041)	1989	1989	1992
	LOW 0.60	HIGH 0.30	0.05 HIGH	19	0.0018	98	N/A	N/A	N/A
			0.60 MID	20	0.0216	(206)	2009	2009	2010
			0.35 LOW	21	0.0126	(359)	2006	1992	2007
		BASE 0.35	0.05 HIGH	22	0.0021	(56)	2011	2011	2011
			0.60 MID	23	0.0252	(360)	2007	2007	2008
			0.35 LOW	24	0.0147	(513)	1997	1992	1992
		LOW 0.35	0.05 HIGH	25	0.0021	(210)	2010	2010	2010
			0.60 MID	26	0.0252	(514)	2003	2003	2005
			0.35 LOW	27	0.0147	(667)	1992	1992	1992

Table 3 (Continued)

DECISION TREE - BASE FUEL FORECAST

FUEL FORECAST	LOAD FORECAST	C&LM FORECAST	CAPACITY ADDITIONS		SCENARIO PROBABILITY	RESOURCE REQUIRED 2011	FIRST CONTINUOUS NEED	FIRST NEED	FIRST NEED GREATER THAN 50 MWATTS
		HIGH	0.05 HIGH	28	0.0024	(1,272)	2001	1989	1989
			0.65 MID	29	0.0312	(1,577)	1992	1989	1989
		0.40	0.30 LOW	30	0.0144	(1,729)	1989	1989	1989
	HIGH	BASE	0.05 HIGH	31	0.0021	(1,426)	1999	1988	1989
			0.65 MID	32	0.0273	(1,731)	1988	1988	1989
	0.20	0.35	0.30 LOW	33	0.0126	(1,883)	1988	1988	1989
		LOW	0.05 HIGH	34	0.0015	(1,580)	1997	1988	1989
			0.65 MID	35	0.0195	(1,885)	1988	1988	1989
		0.25	0.30 LOW	36	0.0090	(2,037)	1988	1988	1989
		HIGH	0.05 HIGH	37	0.0036	(276)	2010	2010	2010
			0.65 MID	38	0.0468	(581)	2001	1992	2002
		0.20	0.30 LOW	39	0.0216	(733)	1992	1992	1992
BASE	BASE	BASE	0.05 HIGH	40	0.0099	(430)	2008	2008	2009
			0.65 MID	41	0.1287	(735)	1997	1992	1992
0.60	0.60	0.55	0.30 LOW	42	0.0594	(887)	1992	1989	1992
		LOW	0.05 HIGH	43	0.0045	(584)	2006	1989	2007
			0.65 MID	44	0.0585	(889)	1992	1989	1992
		0.25	0.30 LOW	45	0.0270	(1,041)	1989	1989	1992
		HIGH	0.05 HIGH	46	0.0012	98	N/A	N/A	N/A
			0.65 MID	47	0.0156	(206)	2009	2009	2010
		0.20	0.30 LOW	48	0.0072	(359)	2006	1992	2007
	LOW	BASE	0.05 HIGH	49	0.0021	(56)	2011	2011	2011
			0.65 MID	50	0.0273	(360)	2007	2007	2008
	0.20	0.35	0.30 LOW	51	0.0126	(513)	1997	1992	1992
		LOW	0.05 HIGH	52	0.0027	(210)	2010	2010	2010
			0.65 MID	53	0.0351	(514)	2003	2003	2005
		0.45	0.30 LOW	54	0.0162	(667)	1992	1992	1992

Table 3 (Continued)
DECISION TREE - LOW FUEL FORECAST

FUEL FORECAST	LOAD FORECAST	C&LM FORECAST	CAPACITY ADDITIONS		SCENARIO PROBABILITY	RESOURCE REQUIRED 2011	FIRST CONTINUOUS NEED	FIRST NEED	FIRST NEED GREATER THAN 50 MWATTS
			0.10 HIGH	55	0.0042	(1,272)	2001	1989	1989
		HIGH 0.35	0.70 MID	56	0.0294	(1,577)	1992	1989	1989
			0.20 LOW	57	0.0084	(1,729)	1989	1989	1989
			0.10 HIGH	58	0.0042	(1,426)	1999	1988	1989
	HIGH 0.60	BASE 0.35	0.70 MID	59	0.0294	(1,731)	1988	1988	1989
			0.20 LOW	60	0.0084	(1,883)	1988	1988	1989
			0.10 HIGH	61	0.0036	(1,580)	1997	1988	1989
		LOW 0.30	0.70 MID	62	0.0252	(1,885)	1988	1988	1989
			0.20 LOW	63	0.0072	(2,037)	1988	1988	1989
			0.10 HIGH	64	0.0012	(276)	2010	2010	2010
		HIGH 0.20	0.70 MID	65	0.0084	(581)	2001	1992	2002
			0.20 LOW	66	0.0024	(733)	1992	1992	1992
			0.10 HIGH	67	0.0024	(430)	2008	2008	2009
LOW 0.20	BASE 0.30	BASE 0.40	0.70 MID	68	0.0168	(735)	1997	1992	1992
			0.20 LOW	69	0.0048	(887)	1992	1989	1992
			0.10 HIGH	70	0.0024	(584)	2006	1989	2007
		LOW 0.40	0.70 MID	71	0.0168	(889)	1992	1989	1992
			0.20 LOW	72	0.0048	(1,041)	1989	1989	1992
			0.10 HIGH	73	0.0003	98	N/A	N/A	N/A
		HIGH 0.15	0.70 MID	74	0.0021	(206)	2009	2009	2010
			0.20 LOW	75	0.0006	(359)	2006	1992	2007
			0.10 HIGH	76	0.0006	(56)	2011	2011	2011
	LOW 0.10	BASE 0.30	0.70 MID	77	0.0042	(360)	2007	2007	2008
			0.20 LOW	78	0.0012	(513)	1997	1992	1992
			0.10 HIGH	79	0.0011	(210)	2010	2010	2010
		LOW 0.55	0.70 MID	80	0.0077	(514)	2003	2003	2005
			0.20 LOW	81	0.0022	(667)	1992	1992	1992

Table 5

Risk Management Action Plan

RECOMMENDED ALTERNATIVE ACTIONS
70% RELIABILITY LEVEL
(MEGAWATTS)

	RESOURCE RQMT.	ADVANCE DESIGN PLUS	QF PROJECT TEAM	WALPOLE CT	FUTURE CT	EDGAR RFP	FUTURE IGCC	TOTAL ALT. ACTIONS
1987	0	0	0	0	0	0	0	0
1988	0	0	0	0	0	0	0	0
1989	50	18	3	85	0	0	0	106
1990	100	46	3	85	0	0	0	134
1991	0	51	19	85	0	0	0	155
1992	250	51	37	85	100	0	0	273
1993	200	49	40	85	100	0	0	274
1994	200	47	69	85	100	0	0	301
1995	200	43	69	85	100	0	0	297
1996	150	38	69	85	100	0	0	292
1997	300	33	69	85	100	400	0	687
1998	300	27	69	85	100	400	0	681
1999	400	20	69	85	100	400	0	674
2000	400	14	69	85	100	400	0	668
2001	400	5	69	85	100	400	0	659
2002	500	0	69	85	100	400	0	654
2003	500	0	69	85	100	400	0	654
2004	500	0	69	85	100	400	0	654
2005	500	0	69	85	100	400	0	654
2006	700	0	69	85	100	800	0	1054
2007	700	0	69	85	100	800	0	1054
2008	800	0	69	85	100	800	0	1054
2009	1000	0	67	85	100	800	0	1052
2010	1100	0	61	85	100	800	400	1446
2011	1300	0	61	85	100	800	400	1446

TABLE 6

Boston Edison Company
Consolidated Base Case Demand Forecast and Supply Plan

Summer Peaks
(MW)

Year	Capability Responsibility[a]	Existing Capability[b]	Base Case Surplus	
S 1989	3,362	3,379	17	0.5%
S 1990	3,364	3,379	15	0.4%
S 1991	3,258	3,629	371	11.3%
S 1992	3,236	3,466	230	7.1%
S 1993	3,233	3,496	263	8.1%
S 1994	3,268	3,745	477	14.6%
S 1995	3,239	3,745	506	15.6%
S 1996	3,246	3,745	499	15.3%
S 1997	3,311	3,745	434	9.3%

Notes:

a. BECo provided summer capability responsibility numbers only.

b. Includes all committed and uncommitted resources.

Source: Exh. HO-15

TABLE 7

Boston Edison Company
Short-Run Contingency Analysis[a]
(MW)

Pilgrim Re-Opening Contingency

Year	Base Load Capability Respons.[b]	Total Base Case Resources	Delay of Pilgrim	Contingency Surplus (Deficit)[c]	
S 1989	3,327	3,379	(495)	(443)	(13.3%)
S 1990	3,329	3,379	(495)	(445)	(13.4%)
S 1991	3,223	3,629	(495)	(89)	(2.8%)

Notes:

a. See Table 5 for BECo's recommended alternative actions for ensuring supply plan adequacy at the 70 percent reliability level.

b. Includes the Company's estimate of its adjustment to NEPOOL capability responsibilty if Pilgrim capacity credit is not reinstated. See Exhibit HO-15.

c. The Company stated that it has identified 400 to 500 MW of short-run purchases available through 1991. See Section III.D.1.c.ii, supra.

Sources: Exh. HO-15; Exh. BE-4.

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

Such petition for appeal shall be filed with the Siting Council within twenty days after the date of services of the decision, order or ruling of the Siting Council or within such further time as the Siting Council may allow upon request filed prior to the expiration of twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said Court. (See. 5, Chapter 25, G.L. Ter. Ed., as most recently amended by Chapter 485 of the Acts of 1971).

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Massachusetts Electric Company and New England Power Company, Subsidiaries of New England Electric System, for Approval of Their 1986 and 1987 Long-Range Forecasts of Electric Requirements and Resources	)	EFSC 86-24

FINAL DECISION

Frank P. Pozniak
Hearing Officer
March 30, 1989

On the Decision:

Robert J. Harrold

APPEARANCES: Phillip H.R. Cahill, Esq.
25 Research Drive
Westborough, Massachusetts 01582-0099
FOR: Massachusetts Electric Company
New England Power Company
Petitioner

TABLE OF CONTENTS

The Energy Facilities Siting Council hereby APPROVES the 1986 and 1987 demand forecasts of the Massachusetts Electric Company, and APPROVES the 1986 and 1987 supply plans of the New England Power Company.

I. INTRODUCTION

A. Background

The New England Electric System ("NEES") consists of retail, bulk power, construction, and planning companies (Exh. HO-C-2, vol. 1, pp. 1-2). Massachusetts Electric Company ("MECo") is its retail subsidiary serving Massachusetts, while two other retail subsidiaries, the Narragansett Electric Company and the Granite State Electric Company, serve retail customers in Rhode Island and New Hampshire, respectively (id., p. 1). The New England Power Company ("NEPCo") supplies bulk power and transmission to the NEES retail subsidiaries and to several municipal systems (id.). The other subsidiaries of NEES include the New England Electric Transmission Corporation, and the New England Hydro-Transmission Corporation, both of which are involved in Canada-to-New England transmission line construction projects (id.). The New England Power Service Company performs forecasting, power planning services, and conservation and load management ("C&LM") coordination for the NEES companies (Exh. HO-C-3, vol. 1, Section II, vol. 2, Appendix C, p. 62).

NEPCo owns 30 percent of the stock of Yankee Atomic Electric Company, and therefore receives 30 percent of the output of that Company's 165 megawatt ("MW") baseload nuclear generating plant operating in Rowe, Massachusetts (Exh. HO-C-2, vol. 1, pp. 1-2).

The MECo service territory includes most of central Massachusetts, and many other communities in diverse locations across the state (id., vol. 2, p. 112). Total energy output requirements for MECo during 1987 were 15,111,000 megawatthours

("MWH") (Exh. HO-1, vol. 3, p. 48). MECo is a winter-peaking utility with a winter peak load of 2,864 MW (id., p. 50).

NEPCo supplies almost all of the electricity distributed by MECo (Exh. HO-C-2, vol. 1, p. 1). NEPCo owns most of NEES' generating facilities and arranges to purchase power from other sources as required (id.). NEPCo's total energy output requirements during 1987 were 21,223,000 MWH while peak demand reached 3,960 MW in the winter of 1987 (Exh. HO-1, vol. 3, p. 119).

The Energy Facilties Siting Council ("Siting Council") reviews the 1986 and 1987 demand forecasts of MECo and the 1986 and 1987 supply plans of NEPCo.

B. Procedural History

On May 1, 1986, NEES filed its 1986 demand forecast and supply plan ("1986 forecast"), and on May 1, 1987, NEES filed its 1987 demand forecast and supply plan ("1987 forecast").[1] On September 23, 1987, the Hearing Officer issued a Notice of Adjudication for the 1987 forecast and directed NEES to publish

---

1/ Since Siting Council jurisdiction extends to MECo and NEPCo, two subsidiaries of NEES, the Siting Council reviews those portions of NEES' 1986 and 1987 forecasts that pertain to MECo and NEPCo.

On May 1, 1988, NEES filed its 1988 demand forecast and supply plan. In a letter order dated January 16, 1989, the Hearing Officer made this forecast part of the record in this proceeding (Exh. HO-1). While not the subject of the review in this proceeding, the Siting Council uses the 1988 demand forecast and supply plan to assist in its evaluation of the 1986 and 1987 demand forecasts of MECo and the 1986 and 1987 supply plans of NEPCo.

and post the Notice in accordance with 980 CMR 1.03(2).[2] NEES subsequently submitted confirmation of publication and posting.

Evidentiary hearings were held on February 29, March 1 and March 21, 1988. NEES presented four witnesses: Eric P. Cody, manager of load forecasting and analysis; John L. Levett, manager of alternate energy products; John F. Malley, manager of generation planning; and Lydia M. Pastuszek, director of demand planning. The Siting Council entered 73 exhibits into the record, largely composed of NEES' responses to information and record requests. NEES offered five exhibits into the record.

2/ On July 15, 1986, the Hearing Officer issued a Notice of Adjudication for the 1986 forecast, and directed NEES to publish and post the Notice in accordance with 980 CMR 1.03(2). On September 2, 1986, NEES confirmed publication and posting of this Notice. On January 15, 1987, NEES requested that review of the 1987 forecast be consolidated with the review of the 1986 forecast. In a letter order dated January 26, 1987, the Hearing Officer granted this 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" (G.L. c. 164, sec. 69H), the Siting Council determines whether "projections of the demand for electric power ... are based on substantially accurate historical information and reasonable statistical projection methods." G.L. c. 164, sec. 69J. To ensure that the foregoing standard is met, the Siting Council applies three criteria to demand forecasts: reviewability, appropriateness, and reliability.

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

B. Previous Demand Forecast Review

The Siting Council approved the previous MECo demand forecast without orders or conditions. Massachusetts Electric Company, 12 DOMSC 197 (1985) ("1985 MECo Decision").

C. Energy Forecast

MECo forecasted annual energy requirements by first preparing economic and demographic forecasts, assuming price behavior of electricity and competing fuels, and then applying these forecasts and assumptions in detailed end-use and econometric models (Exh. HO-C-2, vol. 1, pp. 10-11, 14). MECo's forecast provided separate projections of energy requirements for the residential, commercial, and industrial sectors, and for the following classes: streetlighting, sales for resale, internal use, and losses (id., p. 14). In addition, four alternative scenarios were developed to indicate the sensitivity of the forecast to changes in key variables (id., p. 161) (see Section II.C.7, infra).

The results of MECo's energy forecast are contained in Table 1.

1. Economic and Demographic Forecast

MECo retained the services of Wharton Economic Forecasting Associates ("WEFA") to provide economic and demographic forecasts for Massachusetts, as well as economic and demographic growth factors (Exh. HO-C-2, vol. 1, pp. 27, 77, 84; Exhs. HO-D-7, HO-D-11).[3] WEFA provided forecasts of commercial and industrial employment, oil and gas prices, and household size (id.; Tr. I, pp. 83, 95). WEFA also projected growth rates of personal income, state population, and state industrial production, which were used to adjust data provided by MECo (id.). For example, personal income was forecasted based on data from MECo's 1985 customer survey, which was then adjusted by annual personal income growth rates projected by WEFA (Exh. HO-D-25). Similarly, state population figures, based on the 1980 census, were adjusted by an annual state population growth rate projected by WEFA (Exh. HO-D-13).

For purposes of this review, the Siting Council accepts

3/ In the past, MECo has used Chase Econometrics for these services. See 1985 MECo Decision, 12 DOMSC at 203-205. Subsequent to the date of the filing of the 1987 forecast, Chase Econometrics merged with WEFA (Exh. HO-D-7).

MECo's methodologies for forecasting economic and demographic factors.

2. Electricity Price Forecast

MECo stated that it did not utilize an electricity price forecast (Exh. HO-D-24). Instead, MECo assumed that in the base case, electricity price would remain constant in real terms over the forecast period (id.). MECo argued that this assumption is supported by analyses of (1) price trends of the recent past, (2) anticipated additions to revenue requirements, and (3) fuel price expectations (id.). MECo stated that its analyses included historic average revenues per KWH, historic and forecasted fuel prices, company records describing capital additions, and tax reform impacts (id.).

The Siting Council finds that the basic components associated with MECo's assumption regarding a constant electricity price -- past electricity price trends, additions to revenue requirements, and fuel price forecasts -- are appropriate components to consider in price projections. However, the Siting Council notes that, although NEPCo is proposing to convert Brayton Point unit 4 to gas, and that MECo will receive energy from NEPCo's participation in the Seabrook 1 generating plant project ("Seabrook 1"), the Ocean State project, and the Hydro-Quebec Phase II project, the record in this proceeding does not indicate whether these projects were included in analyses of additions to revenue requirements (Exh. HO-D-24). As a result, it is unclear whether revenue requirements would be affected by these new projects.

For purposes of this review, the Siting Council accepts MECo's assumption of a constant electricity price. However, the Siting Council ORDERS MECo in its next forecast filing to explain in detail the methodology used to support a constant price assumption for electricity in real terms, including (a) a listing of major additions to capacity or major investments of capital planned over the forecast period with estimates of related cost impacts to MECo customers, (b) a full description of analyses performed on each of the basic components of the assumption, and a full description of the methodology used to integrate the results of these analyses, and (c) a full explanation of the methodology used by MECo to determine real prices, including sources of inflation forecasts used by MECo.

For purposes of this review, the Siting Council accepts MECo's methodology for forecasting electricity prices.

3. Residential Energy Forecast

MECo based its residential energy forecast on the assumption that total class consumption consists of the sum of consumption represented by 22 residential appliance-types (Exh. HO-C-2, vol. 1, pp. 24-25).[4] The basic premise underlying this forecast is that annual energy consumption of each appliance-type is the product of the quantity of the appliance-type and its average use per year (id., pp. 25, 55).

Although MECo has enhanced some of the methodological details of its residential energy forecast, the basic structure of the residential energy forecast remains largely the same as the one previously approved by the Siting Council. 1985 MECo Decision, 12 DOMSC at 205-213.

a. Number of Appliances

To estimate the quantity of each appliance-type in its

4/ The 22 appliance-types are: frost-free refrigerators, standard refrigerators, frost-free freezers, standard freezers, dishwashers, electric ranges, microwave ovens, room air conditioners, central air conditioners, washers, electric dryers, uncontrolled electric hot water heaters, controlled electric hot water heaters, solar assisted electric hot water heaters, unsupplemented electric heat, solar assisted electric heat, electric heat and wood stoves, fossil auxiliaries, color televisions, black and white televisions, lighting, and miscellaneous (Exh. HO-C-2, vol. 1, p. 24).

service territory, MECo multiplied its forecasted number of customers by its forecasted average number of appliance-types per customer (Exh. HO-C-2, vol. 1, pp. 21, 25). MECo assumed that the number of customers is equivalent to the number of dwelling units, which MECo defined as the sum of residential customers and the number of apartments in master-metered electrically heated buildings (id., p. 25). MECo forecasted dwelling units based on (1) the percentage of the Massachusetts population residing in the MECo service territory as determined by the 1980 census (this percentage was then treated as a constant over the forecast period), (2) WEFA's projections of population growth for the state over the forecast period, (3) household size projections, and (4) an adjustment factor based on the ratio of dwelling units to households within MECo's service territory (Exhs. HO-D-7, HO-D-29).

MECo assumed that the average number of appliance-types per dwelling unit was equal to appliance saturations which were developed from various data sources (Exh. HO-C-2, vol. 1, pp. 21, 25-26). Before forecasting appliance saturations, MECo first categorized appliance-types as necessities or luxuries, then sorted the categories according to the presence or absence of competing fuels (id., p. 33). Thus, MECo organized appliance-types into four quadrants consisting of non-competitive necessities, competitive necessities, competitive luxuries, and non-competitive luxuries (id., p. 34).[5] MECo claimed that the quadrant system provided a proper theoretical basis for forecasting appliance-type saturations (id., p. 33).

5/ Quadrant I, non-competitive necessities, consists of refrigerators, lighting, televisions, and clothes washers; Quadrant II, competitive necessities, consists of water heating, home heating, and cooking appliances; Quadrant III, competitive luxuries, consists of clothes dryers; and Quadrant IV, non-competitive luxuries, consists of diswashers, air conditioners, freezers, and microwave ovens (Exh. HO-C-2, vol. 1, pp. 34-36).

Independent of the quadrant organization, MECo forecasted appliance-type saturation levels based on: (1) a combination of simulated competition between electricity and alternate fuels, MECo survey data, NEPOOL data, and assumptions[6] for four appliance-types (water heating, space heating, cooking, clothes drying); (2) fixed saturation levels established by MECo survey data and assumptions[7] for four appliance-types (refrigerators, lighting, television, clothes washers); (3) regression equations and time trends for three appliance-types (freezers, dishwashers, central air conditioners); (4) an assumed rate of growth established by national survey data for microwave ovens; and (5) a combination of a percentage factor, growth of personal income, and electricity price for miscellaneous (Exh. HO-C-2, vol. 1, pp. 38-54; Exh. HO-D-28).

The 1987 forecast included a change from previous forecasts reviewed by the Siting Council with respect to appliance-type penetration methodology (Exh. HO-C-2, vol. 1, p. 15). Formerly, MECo used a probability scenario approach with a subjective assignment of scenario probabilities as predictors of new fuel shares of electricity and competing end-use fuels,

---

6/ MECo assumed that (1) electric water heating was 100 percent saturated in electrically heated homes, and competitive with natural gas otherwise, (2) space heating saturation was a function of key variables (prices of competing fuels, capital costs, operating costs, convenience, tax incentives, and whether the decision maker is the occupant or a developer), (3) electric cooking was 100 percent saturated in electrically heated homes, and competitive with natural gas otherwise, and (4) electric clothes dryer saturation was in competition with natural gas, and the difference between saturations of clothes dryers and washers was assumed to be decreasing at a constant rate (Exh. HO-C-2, vol. 1, pp. 38-54; Exh. HO-D-28).

7/ MECo assumed that refrigerators, lighting, and televisions were present in every household (Exh. HO-C-2, vol. 1, pp. 35-37). MECo also assumed that saturations of clothes washers were fixed, as increases in residential saturations would correspond to decreases in saturations of laundromats in the commercial sector (id., p. 37).

primarily for space heating. 1985 MECo Decision, 12 DOMSC at 208-211. MECo now predicts fuel shares with a microsimulation model which takes into account capital and operating costs, efficiencies, and sensitivities to relative cost differences between fuels (Exh. HO-C-2, vol. 1, pp. 15, 40).[8] The Siting Council finds that this change is reasonable.

The Siting Council further finds that MECo's methodology for forecasting the number of appliances is appropriate. However, MECo failed to establish a clear relationship between the quadrant system and methodologies applied to individual appliance-type saturation forecasts. Accordingly, in its next forecast filing, the Siting Council ORDERS MECo to fully explain the relationship between the quadrant system and the methodologies used to forecast individual appliance-type saturations.

b. Average Use Per Appliance

To estimate average use per appliance-type, MECo multiplied hours per year of appliance operation (i.e., an average use estimate) by connected load of an appliance (i.e., appliance wattage rating) (Exh. HO-D-26). MECo's methodology was based on logic taken from the New England Power Pool ("NEPOOL") model, but used MECo-service-territory-specific data (Exhs. HO-D-19, HO-D-26; Exh. HO-C-2, vol. 1, p. 54). The methodology assumed that hours per year of appliance operation would remain constant over the forecast period, while connected load would vary to reflect changes in key variables (i.e., income, electricity price, household size, mandated appliance

8/ The 1988 demand forecast and supply plan indicates that MECo continued to use the microsimulation model (Exh. HO-1, vol. 1, pp. 56, 58).

efficiency standards, and usage trends) (Exhs. HO-D-19, HO-D-26, HO-RR-9).[9]

In an effort to improve average use per appliance estimates for frost-free refrigerators, electric ranges, electric clothes dryers, and uncontrolled electric water heaters, MECo is participating in the Joint Utilities Monitoring Project ("JUMP"), which entails collecting and pooling appliance consumption data (Exh. HO-C-2, vol. 3, pp. 13-19; Exh. HO-D-19).[10] MECo claimed that as a result of JUMP, more detailed service-territory-specific data relating to these end-uses would be available for use in its next forecast (id.).

While MECo's estimated average use per appliance methodology is reviewable, MECo failed to provide several details of its methodology which would allow for a more complete understanding. For example, the Siting Council notes that MECo failed to identify sources and dates of data used to derive connected load and hours per year of appliance operation, and sources and dates of elasticities used in estimating appliance average use.

Based on the record in this proceeding, the Siting Council finds that MECo's methodology for forecasting average use per appliance for the 22 identified residential appliance-types is appropriate. However, the Siting Council ORDERS MECo in its next forecast filing to (a) file a complete

---

9/ MECo defined usage trends as "factors which influence annual appliance KWH consumption but are independent of both electricity price and appliance efficiency levels" (Exh. HO-RR-9). MECo identified usage trends of (1) decreased use of individual air conditioner units when multiple units are present, (2) displacement of electric range use by microwave ovens when both appliance-types are present, and (3) increased electric water heater use when dishwashers are present (id.).

10/ Other JUMP participants are Western Massachusetts Electric Company, Boston Edison Company, Commonwealth Electric Company, Massachusetts Municipal Wholesale Electric Company, and Eastern Edison Company (Exh. HO-C-2, vol. 3, p. 14).

description of its residential average use per appliance forecast methodology, including the sources and dates of all data and elasticities, and (b) explain why a forecast based on such data is appropriate.

c. Conclusions on the Residential Energy Forecast

The Siting Council has found that MECo's methodology for forecasting the number of appliances and the average use per appliance for the 22 identified residential appliance-types is appropriate. Accordingly, the Siting Council finds that MECo's methodology for forecasting residential energy requirements is reviewable, appropriate, and reliable.

4. Commercial Energy Forecast

MECo based its commercial energy forecast on the assumption that commercial floor space can be used to represent energy use (Exh. HO-C-2, vol. 1, p. 65). MECo asserted that floor space is a valid proxy for energy use since end-use systems such as heating, cooling, and lighting are designed on the basis of floor space requirements (id.). Thus, MECo forecasted commercial energy consumption as the product of (1) commercial floor space within the MECo service territory, (2) fuel shares of electricity (i.e., the fraction of commercial floor space served by electric end-uses), and (3) energy intensiveness of electric end-uses (i.e., average annual electricity consumption of the end-use per square foot) (id., pp. 65-67).

MECo used the Electric Power Research Institute ("EPRI") Commercial Sector End-Use Energy Demand Forecasting Model ("COMMEND") to forecast commercial sector energy requirements (Exh. HO-RR-1). The COMMEND model replaced econometric techniques used in previous MECo commercial forecasts that were approved by the Siting Council. See e.g., 1985 MECo Decision, 12 DOMSC at 213; Massachusetts Electric Company, 7 DOMSC 270, 294-300 (1982) ("1982 MECo Decision"). MECo provided that the COMMEND model would improve the accuracy of the commercial energy forecast by utilizing disaggregated end-use data and by modeling alternative C&LM options affecting end-uses (Tr. I, pp. 120-121).

a. Floor Space

i. Description

MECo's commercial floor space forecast was based largely on the level of commercial employment (Exh. HO-C-2, vol. 1, pp. 65-67). MECo assumed that employment stimulated floor space construction (Tr. I, p. 32). MECo's floor space forecast consisted of (1) subdividing commercial sector floor space into ten building-types (office, non-food retail, food stores, restaurants, warehouses, medical, education, large service area, hotel/motel, and miscellaneous), (2) estimating the total amount of existing commercial floor space in the MECo service territory, as of a base year, (3) distributing the estimated total amount of existing floor space to individual years by building-type, starting from the base year and extending back to 1924, (4) aging the resultant distribution of existing floor space and annually estimating the proportion which would be removed due to age, through a floor space decay function, and (5) estimating future annual additions to floor space beyond the base year on the basis of commercial employment projections (id., pp. 32, 36-38; Exh. HO-C-2, vol. 1, pp. 70-71, 85).

MECo indicated that estimates of the total amount of existing commercial floor space were obtained from a Control Group Study compiled by MECo in 1986 (Tr. I, p. 18; Exh. HO-C-2, vol. 3, Appendix B). The Control Group Study is a collection of stratified random sample data obtained from 281 commercial customers in MECo's service territory (Tr. I, p. 18; Exh. HO-C-2, vol. 3, Appendix B, p. 4; Exhs. HO-RR-2, HO-RR-17). Based on its Control Group Study, MECo updated its existing floor space estimates for all building-types except hospitals, which were estimated separately in 1985 (Exh. HO-C-2, vol. 1, p. 72, 80, 84, vol. 3, Appendix B, p. 11; Tr. I, p. 18). While the survey was performed in 1986, MECo did not indicate whether this year was the base year for commercial floor space estimation purposes.

MECo's witness, Mr. Cody, stated that MECo distributed the total amount of existing commercial floor space to past individual years by building-type starting from the base year and extending "backward in time" to 1924 (Tr. I, p. 32). MECo's methodology for distributing floor space to individual years assumed a relationship between historic employment data and commercial floor space construction, i.e., that the level of employment was a valid proxy for floor space construction over the designated time period (id.; Exh. HO-RR-1). To reflect removals of floor space due to age, estimates of existing floor space for individual years were removed by an EPRI decay function, which assumed an "S-curve" rate of decay and a 45-year average life (Exh. HO-RR-4).[11]

Estimates of annual future floor space additions for the years which followed the base year and extended over the forecast period were formulated from WEFA employment projections and an assumed ratio of floor space per employee by building-type -- a ratio that MECo assumed would remain constant over the forecast period (Tr. I, p. 39; Exh. HO-C-2, vol. 1, pp. 84-85). MECo implemented this assumption by matching five employment categories (trade; finance, insurance, and real estate; services; state and local government; and federal

---

11/ An S-curve rate of decay removes floor space slowly initially, accelerating removals in later years (Exh. HO-RR-1, p. 2.12). For example, the EPRI decay function removed only two percent of floor space during the first 20 years of life (id.). Over the next ten years, seven percent more is removed, and over the next ten years an additional 23 percent is removed (id.).

government) with the ten commercial building-types (office, non-food retail, food stores, restaurants, warehouses, medical, education, large service area, hotel/motel, and miscellaneous) (Tr. I, pp. 36-38; Exh. HO-C-2, vol. 1, pp. 70-71, 85). In support of the matching procedure, Mr. Cody stated that "there were not employment forecasts available for all of the specific building-types" selected for use in the commercial forecast (Tr. I, p. 37).[12]

ii. Analysis

In the 1985 MECo decision, the Siting Council directed MECo to reevaluate the use of major simplifying assumptions -- particularly the assumption that floor-space-per-employee ratios are constant over time. 1985 MECo Decision, 12 DOMSC at 220. In its 1986 and 1987 forecasts, as well as its 1988 demand forecast and supply plan ("1988 forecast"), MECo continued to assume constant floor space-per-employee ratios by building-type. However, while MECo indicated that the ratios were tested by comparing forecasted floor space quantities of recent years to known floor space quantities for a similar time period (Tr. I, p. 39), MECo did not state or document how closely its forecast of floor space corresponded to known amounts.

Further, a reevaluation of this assumption may not necessarily be accomplished by a simple test comparing

---

12/ MECo matched the trade category to restaurants, retail, foodstores, warehouses, and hotels/motels; the services category to offices and large service area types; and state and local and federal government categories to the medical building-type (Exh. HO-RR-16). Due to projections of stable or even declining school enrollment, floor space of the education building-type was set at a "no growth" level (id.). MECo did not explain why the finance, insurance, and real estate employment category was not assigned to a building-type, nor did MECo explain whether an employment category was matched to the miscellaneous building-type.

forecasted and actual results. Present and future economic factors, including the costs of construction, real estate, and labor, may have an impact on commercial floor space growth which a comparison of the ratios may not capture. In this proceeding, MECo has not shown that its floor space-per-employee ratios capture all pertinent economic factors that may effect its estimates of commercial floor space growth. For a company of MECo's size and resources, the Siting Council requires a showing that employment statistics represent the best available data for predicting commercial floorspace growth. Northeast Utilities, 17 DOMSC 1, 15 (1988). Here, MECo has not made that showing.

MECo stated that it uses the EPRI floor-space decay function because "historical service territory data on the decay of commercial floor space were unavailable, and thus, EPRI data represent the best available estimates" (Exh. HO-RR-4). However, the Siting Council notes that EPRI's documentation of the decay function indicated that it is "judgmentally determined for lack of specific information on commercial floor space removal" (Exh. HO-RR-1). Thus, the EPRI decay function may bear little resemblance to actual commercial decay rates, including those of commercial buildings within the MECo service territory.

In addition, while MECo described how employment categories were matched to building-types for new additions to floor space, no similar description was provided for MECo's distribution of existing floor space, which also depended on employment data. Further, MECo failed to describe its source of historic employment data, its base year for existing floor space estimation, and failed to state whether historic floor space calculations assumed constant floor-space-per-employee ratios.

Based on the foregoing, the Siting Council finds that MECo's methodology for estimating floor space is not appropriate. The Siting Council ORDERS MECo in its next forecast filing to (a) fully reevaluate its use of constant floor space-per-employee ratios including justification of the use of these ratios with respect to other reasonable methods of commercial floor space growth estimation, (b) undertake further analysis to determine whether or not the EPRI decay function reasonably reflects the rate of decay of floor space within the MECo service territory, (c) explain how it matched historic employment data to building-types, (d) identify the source of historic employment data, (e) specify the base year used in floor space estimations, and (f) explain any assumptions relating to floor space-per-employee ratios for estimates of existing floor space.

b. Fuel Shares of Electricity

i. Description

MECo estimated the fuel shares of electricity (i.e., the fraction of commercial floor space served by each electric end-use) based on (1) an assumed turnover rate for end-use equipment, determined by the age distribution of end-uses and their frequency of replacement, (2) simulated customer fuel preferences for competitive end-uses, and (3) customer ownership patterns for non-competitive end-uses (Exh. HO-1, vol. 1, pp. 82, 84; Exh. HO-C-2, vol. 1, p. 66, vol. 3, p. 11; Tr. III, pp. 61-62). Estimates of existing floor space fuel shares incorporated all of these factors; estimates of fuel shares associated with new additions to floor space consisted of the latter two factors only (id.).

Using the foregoing factors, MECo estimated the fuel shares by building-type for seven major end-uses including space heating, cooling, water heating, cooking, refrigeration, lighting, and miscellaneous end-uses (Exh. HO-C-2, vol. 1, pp. 84, 86).[13] However, MECo failed to explain the basis for its turnover rate by not describing the age distribution of existing

---

13/ MECo assumed that lighting is fueled entirely by electricity, and that the miscellaneous end-use is fueled almost entirely by electricity (Exh. HO-RR-1, p. 2.12).

end-uses and their frequency of replacement (id., p. 67; Exh. HO-1, vol. 1, pp. 82, 84).

MECo predicted customer fuel preferences for competitive end-uses largely in terms of the fuel choice for space heating (Exh. HO-RR-1, p. 2.12; Exh. HO-C-2, vol. 1, p. 77). MECo's fuel choice model assumed that a commercial customer would choose a fuel based primarily on the lowest cost space heating system, taking into account capital cost, operating cost, discount rates, energy use, and life span (Exh. HO-RR-1, p. 2.24). The model assumed that the choice of water heating fuel matched that of space heating, and that cooling was fueled entirely by electricity (id., p. 2.12). MECo did not indicate whether cooking or refrigeration were modeled competitively (id.).[14] Fuel preferences predicted by the model provided the basis for determining (1) electricity's fuel share when competitive end-uses are replaced at the end of their useful lives, and (2) electricity's fuel share when competitive end-uses are first selected for installation in new additions to floor space (Exh. HO-1, vol. 1, pp. 82-84).

MECo stated that fuel shares of non-competitive end-uses were determined by results of the Control Group Study (Exh. HO-C-2, vol. 1, pp. 84, 86, vol. 3, p. 11).[15]

ii. Analysis

Based on the record in this proceeding, the Siting Council finds that MECo's methodology for estimating fuel shares of electricity is appropriate. The use of a fuel choice model is a reasonable methodology to predict customer fuel preferences

---

14/ EPRI documentation indicated that COMMEND could model the refrigeration end-use as competitive between electricity and natural gas (Exh. HO-RR-1, p. 2.12).

15/ For a description of the Control Group Study, see Section II.C.4.a.i, supra.

for fuel competitive end-uses. In addition, the use of the Control Group Study, which consists of territory-specific data, is also a reasonable methodology to estimate fuel shares of non-competitive end-uses.

Nonetheless, the Siting Council notes that a more complete description of MECo's procedures would allow a better understanding of MECo's fuel share estimates. Accordingly, the Siting Council ORDERS MECo in its next forecast filing to explain fully (a) the basis for and source of data used to determine the age distribution of existing end-use equipment within the MECo service territory, (b) the basis for and source of data used to determine the frequency of replacement for end-use equipment within the MECo service territory, and (c) how fuel competition was accounted for in the cooking end-use fuel share estimate, and what methodology was used to determine the fuel share of the refrigeration end-use.

c. Energy Intensiveness

i. Description

MECo represented energy intensiveness by building-type for seven major electric end-uses using Energy Use Indexes ("EUIs") (Exh. HO-C-2, vol. 1, pp. 70-72, 74; Tr. I, p. 25). These seven end-uses are space heating, cooling, water heating, cooking, refrigeration, lighting, and miscellaneous end-uses (id.). MECo stated that EUIs were estimated in terms of millions of British Thermal Units ("MBTU") per square foot, and were based on survey data (Exh. HO-C-2, vol. 1, p. 74; Exh. HO-RR-17). Essentially, MECo estimated two sets of EUIs per building-type: (1) EUIs for end-uses currently operating in existing floor space; and (2) marginal EUIs for end-use replacements in existing floor space and end-use installations in new additions to floor space (Exh. HO-C-2, vol. 1, pp. 74, 76). MECo estimated EUIs for end-uses currently operating in existing floor space based on the Control Group Study, and MECo stated that these EUI's remained constant over the life of the end-use system (Exh. HO-C-2, vol. 1, pp. 67-69, 72, 77-78, 84 vol. 3, Appendix B, p. 11; Exh. HO-RR-1).

However, marginal EUIs were based on a database of nationwide commercial building characteristics provided by Xenergy Inc. (Tr. I, pp. 24-28). Xenergy has provided this service for MECo since 1985 (id., p. 27). MECo stated that Xenergy's database was used for marginal EUIs since the small sample size of the Control Group Study might have under represented consumption characteristics of new buildings (id., p. 24). Nonetheless, MECo claimed that the marginal EUIs were analyzed so as to produce the "most reasonable" approximation for the MECo service territory (id., p. 120). In addition, MECo stated that the marginal EUIs reflected recently mandated state and federal appliance efficiency standards, and changes to building code standards (id., p. 29; Exh. HO-RR-3).

Marginal EUIs were subject to change based on efficiency improvements driven by fuel price increases (Exh. HO-C-2, vol. 1, pp. 67-69, 77-78; Exh. HO-RR-1). MECo's energy intensiveness estimation procedure captured efficiency improvements through an efficiency elasticity relationship (id.).[16] Similarly, fuel price increases affected end-use utilization levels, through a utilization elasticity mechanism (Exh. HO-C-2, vol. 1, p. 65; Exh. HO-RR-1). MECo stated that efficiency and utilization elasticities are those initially established by EPRI for the COMMEND model (Exh. HO-RR-6).

Presently, MECo includes computerization and automation loads in the miscellaneous end-use category (Exh. HO-C-2, vol. 1, pp. 72, 76). MECo anticipates a significant increase in

---

16/ MECo stated that changes in appliance efficiency are determined either by economic elasticity relationships (for end-uses of lighting, water heating, cooking, refrigeration, and miscellaneous), or by a combination of engineering and cost information (for end-uses of space heating, cooling, and ventilation) (Exh. HO-C-2, vol. 1, p. 65).

commercial computerization and automation loads over the forecast period (Exh. HO-RR-5). As a result, MECo adjusted the miscellaneous end-use EUI upward to account for increases in commercial computerization and automation loads based on a study published in "Public Utilities Fortnightly" (id.; Exh. HO-RR-18).

ii. Analysis

In the 1985 MECo decision, the Siting Council criticized MECo's commercial end-use forecast because MECo used non-service-territory-specific data. 1985 MECo Decision, 12 DOMSC at 220. Here, the Siting Council notes that MECo developed service-territory-specific data for existing floor space EUIs using the Control Group Study. However, the Siting Council also notes that MECo continues to use non-service-territory-specific data with respect to efficiency elasticities, utilization elasticities, and marginal EUIs, and again, the Siting Council notes its concern over the use of non-service-territory specific data.

With respect to efficiency elasticities and utilization elasticities, EPRI COMMEND documents indicated that both of these elasticities were based on nationwide commercial sector data from the years 1968 to 1972 (Exh. HO-RR-1, pp. 3.56, 3.57). The Siting Council notes that energy consumption patterns have changed significantly since 1973, the time of the oil embargo, and therefore, pre-1973 price and consumption relationships may not accurately reflect current conditions. In addition, national estimates may not reflect energy consumption that is representative of commercial customers in MECo's service territory.

With respect to marginal EUI's, MECo relied on non-service-territory-specific data in order to estimate consumption characteristics of end-uses in new additions to floor space. However, MECo presented no evidence demonstrating that nationwide commercial data would be representative of MECo's commercial customers.

Finally, the Siting Council notes that the basis for MECo's adjustment to miscellaneous EUIs, a study published in "Public Utilities Fortnightly", was not service-territory-specific. The study cited instances of increasing computerization and automation from New York City office towers, and cited the results of a Northeast Utilities ("NU") report which focused on NU's service territory (Exhs. HO-RR-5, HO-RR-18). Again, however, MECo failed to demonstrate why consumption characteristics of these two locations would be representative of MECo's commercial sector. Further, the NU study demonstrates that an electric utility can undertake a service-territory-specific examination of the consumption characteristics of new additions to commercial floor space, and that the results of such a study may have importance to commercial load forecasting.

Based on the foregoing, the Siting Council finds that MECo's methodology for estimating energy intensiveness is not appropriate. The Siting Council ORDERS MECo in its next forecast filing to (a) use territory-specific elasticity estimates in the commercial forecast, including estimates calculated endogenously within the commercial energy forecast, or justify use of other estimates, and (b) explain how marginal EUIs were determined to be representative of consumption characteristics for new additions to floor space and end-use replacements within the MECo service territory.

The Siting Council notes that the potential impact of increased computerization and automation in the commercial sector warrants further review. By MECo's own admission, computerization and automation loads have increased and MECo anticipates that such loads will continue to increase significantly. As a result, MECo should consider a service-territory-specific analysis to determine with more precision the extent and magnitude that increases in computerization and automation might have on energy use within the MECo commercial sector. If analyses of computerization and automation loads demonstrate an increasing level of importance of this end-use to MECo's commercial customers, MECo's end-use forecast might be further improved by modeling computerization and automation as a separate end-use, as opposed to increasing the miscellaneous end-use EUIs. Thus, the Siting Council ORDERS MECo in its next forecast filing to (a) model computerization and automation as a separate end-use with territory-specific data, or (b) justify continued use of increases to the miscellaneous end-use EUI as a methodology to reflect increasing computerization and automation loads in MECo's commercial sector.

d. Conclusions on the Commercial Energy Forecast

The Siting Council has found that MECo's methodologies for forecasting floor space and energy intensiveness are not appropriate. The Siting Council also has found that MECo's methodology for forecasting fuel shares of electricity is appropriate. In previous decisions, the Siting Council, recognizing the heterogeneous composition of the commercial sector, has encouraged use of commercial forecasting methodologies which employed more end-use specific data, and criticized those methodologies which were too highly aggregated. Eastern Edison Company, EFSC 87-33, pp. 15-16 (1988) ("1988 EUA Decision"); Massachusetts Municipal Wholesale Electric Company, 16 DOMSC 95, 106-107 (1987); Eastern Edison Company, 14 DOMSC 41, 63-65, 72 (1986). In addition, the Siting Council has consistently directed companies to utilize service-territory-specific data in developing forecasting methodologies, and criticized those companies which have not done so. Massachusetts Municipal Wholesale Electric Company, 16 DOMSC 95, 106-107 (1987); Eastern Edison Company, 14 DOMSC 41, 63-65, 72 (1986); 1985 MECo Decision, 12 DOMSC at 220.

In this case, the Siting Council recognizes that MECo has selected a disaggregated commercial forecasting methodology which can adequately reflect the heterogeneous composition of the commercial sector and its end-uses. The COMMEND model appears to be a reasonable model with which MECo can improve the accuracy of the MECo commercial sector forecast. In addition, the COMMEND model should provide the impetus for MECo to further refine the numerous disaggregate data inputs which are a prerequisite to an effective use of COMMEND. However, the Siting Council notes that while MECo has undertaken some refinement of disaggregate data inputs required by COMMEND, primarily through the Control Group Study, the record indicates that MECo continues to utilize significant portions of non-service-territory-specific data, and has not fully explained major assumptions bearing on the commercial sector forecast. Thus, while MECo's framework for forecasting commercial energy consumption -- specifically the COMMEND model -- appears to be reasonable, MECo has not demonstrated that its commercial energy forecast is based on substantially accurate historical data, and is supported with adequate documentation of its major assumptions. Accordingly, on balance, the Siting Council finds that MECo's methodology for forecasting commercial energy requirements is not reviewable, appropriate, and reliable.

5. Industrial Energy Forecast

MECo based its industrial energy forecast on the assumption that total class consumption is the sum of consumption by 25 types of industries as designated by two-and three-digit Standard Industrial Classification ("SIC") codes (Exh. HO-C-2, vol. 1, p. 101; Tr. I, p. 67).

The basic structure of the industrial energy forecast remains largely the same as the one approved by the Siting Council in 1985, although MECo has enhanced some of the model details. 1985 MECo Decision, 12 DOMSC at 222-224. The Siting Council already has accepted MECo's industrial sector employment forecast (see Section II.C.1, supra).

In a change from previous forecast filings, MECo stated that its energy forecast equations now use both national and state economic indicators (Exh. HO-C-2, vol. 1, p. 101). MECo claimed that state industrial indicators obtained from WEFA correlate to energy consumption better than national indicators (Tr. I, pp. 65-66, 83). As a result, MECo noted that its energy consumption equations included a national indicator for just one SIC group, Fabricated Metals (id., p. 71).

MECo provided energy consumption equations for 20 SIC groups (Exh. HO-C-2, vol. 1, pp. 107-108).[17] These equations were based on regressions of SIC energy consumption as a function of combinations of the state industrial index, the industrial employment index, a national industrial index, the real price of electricity for the industrial sector, or a time trend (id., pp. 107-108). In certain equations, MECo also included "dummy" variables to capture extraordinary events, although it did not explain the theoretical basis for use of such variables (id.).

For four of the remaining five SIC groups, (Textile Manufacturing (SIC 22); Lumber Products (24); Furniture (25); and Paper Mills (262)), MECo stated that it rejected the regression equations developed from the various indices due to weak statistical results (Tr. I, pp. 67-70).[18] Thus, for these four groups, MECo determined energy consumption by assuming a relationship between energy consumption and state industrial production growth rates (id.). In support of this assumption, Mr. Cody stated that the relationship between state industrial production growth rates and energy consumption is

---

17/ The 20 SIC groups are: Food (SIC 20); Apparel (23); Paper (26); Printing (27); Chemicals (28); Industrial Inorganic Chemicals (281); Petroleum (29); Rubber and Plastic (30); Miscellaneous Plastic Products (307); Leather (31); Stone, Clay, and Glass (32); Primary Metals (33); Fabricated Metals (34); Non-electric Machinery (35); Computer (357); Electrical Machinery (36); Communication (366); Electronic Components (367); Instruments (38); and Miscellaneous (39) (Exh. HO-C-2, vol. 1, pp. 107-108).

18/ MECo stated that these four SIC groups would represent about six percent of total industrial sales in 1996 (Exh. HO-C-2, vol. 1, p. 119).

"very strong" and generally easy to observe at the aggregate level (id., p. 68). Further, Mr. Cody argued that any lack of statistical significance attributed to the regressions for these four SIC groups is more likely caused by faulty data than by the lack of a relationship between industrial production growth rates and energy consumption (id., pp. 68-69). However, MECo did not describe the quantitative relationships assumed between any of the four SIC groups' consumption and state industrial production growth rates.

Finally, for the remaining category, Transportation (SIC 37), MECo estimated base energy consumption through projected changes in real national defense spending (Exh. HO-C-2, vol. 1, p. 106).[19] However, MECo provided neither the relationship between energy consumption for this category and real national defense spending growth rates, nor the premise for that relationship.

For all SIC categories, MECo based electricity price on a five-year moving average which essentially became a constant price as the forecast moved through time (Tr. I, pp. 92-93). MECo stated that the effect of price is reflected in the estimates of energy consumption for these categories through either (1) equation coefficients associated with the electric price variable, or (2) a "specific adjustment" of SIC groups which did not include the electric price variable and associated coefficients (id., p. 75). Since equations for only five SIC groups (Apparel, Printing, Petroleum, Fabricated Metals, and Instruments) contained an electric price variable and associated coefficients, MECo applied the specific adjustment to the other 20 SIC groups (Exh. HO-C-2, vol. 1, pp. 107-108). However, MECo did not describe how the specific adjustment was accomplished

---

19/ MECo indicated that the Transportation category would represent about five percent of the total industrial sales in 1996 (Exh. HO-C-2, vol. 3, p. 40).

and what theory it was based on.

MECo stated that the structure of its industrial forecast was premised on a continuation of past levels of energy intensiveness (id., p. 106). Nonetheless, MECo adjusted the outputs of the forecast downward, assuming that significant reductions in energy intensiveness would occur throughout the industrial sector, mainly due to technological improvements (id., p. 111; Exh. HO-RR-8; Tr. I, p. 73; Tr. III, p. 63). Mr. Cody argued that the adjustments were justified because equations based on historical data exhibited "no precedent" for technology improvement "like what we will see over the next 15 years" (Tr. I, p. 72).

However, MECo presented no survey data or other service-territory-specific evidence demonstrating that a forthcoming reduction in energy intensiveness would be representative of its industrial customers (Exh. HO-RR-8).[20] Further, MECo did not explain why its industrial customers would be motivated to reduce energy intensiveness, given expectations of a stable electricity price over the forecast period, and why energy intensiveness reductions would occur in all SIC groups.[21]

While the assumptions contained in the industrial

20/ MECo provided excerpts from an Office of Technology Assessment document discussing the outlook for reduced energy intensiveness in the industrial sector (Exh. HO-RR-8). The document was based on studies of four industries (pulp and paper, petroleum refining, chemicals, and unknown) from unspecified locations (id.).

21/ MECo stated that beginning in 1987, an industrial load shape pilot project was initiated in conjuction with EPRI (Exh. HO-1, vol. 3, pp. 8-10). The pilot project will examine consumption patterns of four industrial customers -- representing Plastic Products (SIC 307), Frozen Foods (209), Metal Products (335), and Electric Equipment (364) -- within the NEES service territory, with two of these customers eligible for more detailed analyses (id.). However, results of the project are not expected until well into 1989 (id.).

forecast are reasonable, MECo has failed to support these assumptions with adequate documentation. Indeed, MECo's assumption that significant reductions in energy intensiveness would occur throughout the industrial sector is largely unsupported, as well as MECo's assumptions regarding the levels of energy consumption of the five SIC groups of Textile Manufacturing, Lumber Products, Furniture, Paper Mills, and Transportation. Further, MECo has failed to fully document and describe the effect of price on 20 of the 25 SIC categories.[22]

Despite serious flaws in MECo's documentation of the industrial forecast, for purposes of this review, the Siting Council accepts MECo's methodology for forecasting industrial sector energy requirements. However, the Siting Council ORDERS MECo in its next forecast filing to (a) explain in detail the use of dummy variables, (b) explain in detail the relationship assumed between energy consumption and industrial production growth rates, for SIC groups forecasted on this basis, (c) explain in detail the relationship between the Transportation SIC and real national defense spending, and the premise for that relationship, (d) explain how the specific adjustment was implemented to incorporate price effects in the forecasts of SIC groups without electric price variables and associated coefficients, (e) identify the key factors which determine energy intensiveness of MECo's industrial customers, and establish a logical relationship between these key factors and any future changes in industrial energy intensiveness, and (f) justify in detail any projected reductions in energy intensiveness in the industrial sector that are independent of MECo's industrial model structure, and explain in detail why that reduction is representative of MECo's industrial customers.

22/ In its previous decision, the Siting Council directed MECo to review the role of price in the industrial forecast. 1985 MECo Decision, 12 DOMSC at 224.

6. Other Energy Forecasts

MECo projected energy consumption for four other classes -- streetlighting, sales for resale, internal use, and losses (Exh. HO-C-2, vol. 1, p. 121). MECo stated that streetlighting sales account for approximately one percent of total energy sales (id.). MECo assumed that streetlighting sales would remain constant, despite increasing total energy sales, largely due to effects of streetlighting conservation programs (id; Exh. HO-1, vol. 1, p. 135).

MECo stated that the sales for resale class consists of wholesale sales of bulk power to municipally and privately-owned systems within and adjacent to the service territory (Exh. HO-C-2, vol. 1, pp. 121-122). MECo indicated that about 5,000 MWH would be sold annually for resale over the forecast period (Exh. HO-1, vol. 3, p. 48).

MECo stated that internal use has been estimated as approximately one percent of total sales, but offered no description of the methodology used to calculate this percentage (id., vol. 1, p. 137). MECo reported that internal use has averaged between one and 1.4 percent of total sales per year (id.).

MECo stated that losses have been projected as a percentage of total sales, but MECo did not provide the forecasted percentage (id.). MECo only stated that the percentage of losses has been declining slowly (id.).

MECo has failed to fully document its methodologies for forecasting streetlighting, sales for resale, internal use, and losses. While each of these classes individually represent a small portion of MECo's energy forecast, collectively they represent approximately five percent of the energy forecast. Thus, MECo is required to fully document the forecasts for each of these classes. In the past, the Siting Council has held that a company's filing must be supported by sufficient documentation. Bay State Gas Company, 11 DOMSC 283, 307 (1987); Eastern Utilities Associates, 11 DOMSC 61, 65 (1984). See also

980 CMR 7.03(5)(c). Here, the assumptions contained in each of these forecasts require more complete documentation.

Nonetheless, for purposes of this review, the Siting Council finds that MECo's methodologies for forecasting energy requirements for streetlighting, sales for resale, internal use, and losses are reviewable, appropriate, and reliable. The Siting Council ORDERS MECo to file forecasts of streetlighting use, sales for resale, internal use, and losses in a form that is fully reviewable in its next forecast filing.

7. Alternative Energy Forecasts

Given the uncertainties inherent in its energy forecast, MECo developed four alternative energy forecasts in addition to the base case forecast (Exh. HO-C-2, vol. 1, pp. 161-164). MECo stated that the alternative forecasts indicated (1) the range over which forecasted energy requirements could reasonably vary, and (2) the sensitivity of the forecasting model to changes in key inputs (id.). The four alternative forecasts -- the technically feasible conservation case, the low case, the high case, and the contingency high load growth case -- were developed using the base case model structure, but with modifications to key inputs (id.). By modifying key input values, including electricity price, population growth, electric heat saturation, state manufacturing employment growth, appliance efficiency standards, and C&LM program implementation, MECo identified annual energy growth rates which ranged from a low of 1.3 percent to a high of 3.3 percent (id.). MECo claimed that the results of the alternative energy forecasts were useful for strategic energy planning, and for contingency planning (id.).

For purposes of this review, the Siting Council accepts MECo's methodologies for forecasting high and low energy requirements.

8. Conclusions on the Energy Forecast

The Siting Council has accepted MECo's methodology for forecasting economic and demographic factors, electricity prices, industrial sector energy requirements, and high and low energy requirements. The Siting Council has found that MECo's methodologies for forecasting energy requirements for the residential sector, streetlighting, sales for resale, internal use, and losses are reviewable, appropriate and reliable. The Siting Council also has found that MECo's methodologies for forecasting energy requirements for the commercial sector is not reviewable, appropriate, and reliable.

Accordingly, on balance, the Siting Council finds that MECo's methodologies for forecasting energy requirements is reviewable, appropriate, and reliable.

D. Peak-Load Forecast

MECo's methodology for forecasting peak load is based on three components: (1) disaggregating the sector energy forecasts into customer groups; (2) developing a system-wide load profile; and (3) applying a set of econometrically-derived peak-load factors to determine monthly peaks (Exh. HO-C-2, vol. 1, pp. 125-135).[23]

23/ As a fourth component, MECo stated that it adjusted its peak-load forecast for the effects of C&LM programs (Exh. HO-C-2, vol. 1, pp. 136-138). We review the effects of MECo's C&LM programs as part of our review of other resource options in Section III.E, infra. The C&LM programs of MECo included in the forecast of peak load are those incorporated in MECo's forecast of energy requirements -- certain MECo electric heat conservation policies, appliance efficiency standards, and industrial sector technology improvements (id.).

1. Customer Groups

In the peak-load forecast, MECo disaggregated its commercial sector energy forecast into eight commercial building-types, and its industrial sector energy forecast into 14 industrial SIC groups (id.).[24] MECo has a load research program for these commercial building-types and industrial SIC groups which includes collecting data at 15-minute intervals at a total of about 370 randomly selected, statistically representative customer locations (id.). MECo provided that it has been collecting such consumption data since 1981 and thus has a "rich, service area-specific data base" (id., p. 132).

For the residential class, MECo stated that, although it has collected similar load research data by rate-type, the peak-load forecast uses aggregated data (id., pp. 127, 131). However, MECo added that as JUMP data become available it will disaggregate the residential class by appliance-type (id.).[25]

In the past, the Siting Council has supported and, in fact, encouraged utilities to disaggregate their customer energy and demand forecasts to a level appropriate for capturing the diversity of energy and demand patterns that underlie such forecasts. See, e.g., 1988 EUA Decision, EFSC 87-33, pp. 15-16,

---

24/ The eight commercial building-types are wholesale trade, retail trade, food stores, restaurants, offices, large area services, medical services, educational services (Exh. HO-C-2, vol. 1, p. 129). The 14 industrial SIC groups are food & kindred products, textile mill products, paper & allied products, chemicals & allied products, rubber & miscellaneous plastics, stone, clay, glass, and concrete, primary metal industries, fabricated metal products, machinery except electrical, computer manufacturers, electrical & electronic equipment, transportation equipment, instruments, and miscellaneous manufacturing (id., p. 130).

25/ In its 1988 forecast, MECo stated that, although JUMP data was applied in the residential energy forecast, disaggregation of the peak-load forecast was still in the planning stage (Exh. HO-1, vol. 1, pp. 34-35).

21-22; 1985 MECo Decision, 12 DOMSC at 213, 224. MECo has demonstrated substantial progress in disaggregating its peak-load forecast into customer groups. MECo's load research program for commercial building-types and industrial SIC groups provides a sound resource for understanding the underlying characteristics that drive peak load. Further, JUMP data should provide a basis for disaggregating at least 50 percent of residential load into end-uses which should assist MECo in its residential peak-load analysis (Exh. HO-1, vol. 1, p. 35). MECo should continue to report its progress on disaggregation of the residential peak-load forecast. The remaining customer groups, streetlighting, sales for resale, internal use, and losses -- particularly transmission and distribution losses, are sufficiently homogeneous that further disaggregation appears unwarranted at this time.

Therefore, the Siting Council finds that MECo disaggregated its peak-load forecast into appropriate customer groups.

2. Load Profiles

MECo developed a system-wide hourly load profile from customer group hourly load profiles (Exh. HO-C-2, vol. 1, pp. 125-135). To develop customer group load profiles, MECo allocated its forecast of annual energy consumption for each customer group to hours of the year based on the "expected fraction" of annual consumption expected during each particular hour (id., p. 127). Mr. Cody stated that MECo obtained expected fractions from hourly patterns of use across the year (Tr. I, p. 110). Applying a customer group's expected fractions to its energy forecast for a particular year results in that group's hourly load profile for the year (Exh. HO-C-2, vol. 1, 125-135). The system-wide load profile is simply the sum of all customer group load profiles (id., p. 127).

In developing expected fractions and hourly load profiles for the commercial, industrial, and residential customer groups, MECo defined 1152 hour-types based on 24 hours per day for each of four day-types and for each of the 12 months (24 times 4 times 12 equals 1152) (id., pp. 125-135). MECo identified the four day-types as Mondays, weekdays (Tuesday-Friday), Saturdays, and Sundays (id., p. 127). MECo developed individual load profiles for each of the eight commercial building-types and 14 industrial SIC groups based on expected fractions that were derived from the load research data (id.). For the residential class, although MECo noted that it relies on an aggregated sector-wide load profile (id.), MECo did not provide the basis for developing the expected fractions which define this profile.

Regarding streetlighting load profiles, MECo defined four seasons -- December-February, March-May, June-August, and September-November -- and based streetlighting expected fractions on the average number of daylight hours during each season (id., p. 132).

Transmission and distribution losses were allocated to each of the 8760 hours in a year based on two functions (id.). MECo assumed that 25 percent of these losses were unrelated to load and therefore distributed this portion of losses evenly throughout the year (id.). Expected fractions for the remaining 75 percent of these losses were based on the "ratio of squared demand in that hour to squared peak demand for that calendar year" (id.). MECo did not explain its theory for defining this function.

For other losses and internal use, MECo assumed that the peak contribution would be proportional to the sum of all other sectors' contributions, excluding losses associated with these sectors (id.).

Finally, MECo assumed the load profile for other energy, consisting primarily of sales for resale, would be proportional to the load profile of the rest of the system (id.).

In general, MECo's methodologies for developing customer group load profiles are appropriate. First, MECo used its energy forecast in combination with expected fractions as the basis for the peak-load forecast for each customer group.[26] Combining expected fractions with the energy forecast ensures that changes in total requirements over the forecast period will flow through to the peak-load forecast. Next, MECo developed reasonably dependable expected fractions for its various customer groups. In the cases of the eight commercial and 14 industrial customer groups, these fractions were developed from detailed load research data collected directly from customers. For the residential sector, MECo proposes to disaggregate its sector-wide profile into end-uses as soon as JUMP data is available allowing the development of more dependable expected fractions. The use of a sector-wide profile in this forecast serves as an adequate interim methodology. The remainder of the customer groups are relatively small and therefore warrant less sophisticated methodologies. Finally, the system-wide hourly load profile is clearly the sum of the customer group hourly load profiles. For these reasons, the Siting Council finds that MECo has developed an appropriate system-wide load profile.

One weakness in developing expected fractions and hence load profiles was that MECo failed to explain whether, and if so how, it projected naturally-occuring or market-based changes in customer group consumption patterns.[27] While the disaggregated energy forecast can indicate how total requirements for a customer group change relative to other groups, it does not forecast changes in the expected fractions. The Siting Council ORDERS MECo in its next forecast filing to explain whether, and if so how, it projected naturally-occuring

---

26/ The Siting Council already has found that MECo's energy forecast is reviewable, appropriate, and reliable. See Section II.C, supra.

27/ Although the Siting Council considers MECo-sponsored C&LM programs in its supply plan review (see Section III.E, infra.), naturally-occuring or market-based changes in demand patterns are considered in the demand forecast review.

or market-based changes in customer group consumption patterns, as well as to provide complete descriptions of load-profile development.

3. Monthly Peak-Load Factors

MECo forecasts peak load for each month of the forecast period from the system-wide load profile and an econometrically-derived set of monthly peak-load factors (Exh. HO-C-2, vol. 1, pp. 133-134). Mr. Cody testified that these peak-load factors were developed from time series data and are used to construct relationships between average loads and peak loads (Tr. I, p. 109).

With these peak-load factors, MECo attempts to capture weather sensitivity. Thus, MECo derived two sets of monthly peak-load factors -- one for typical peaks expected to occur in any given year, and one for "extreme" peaks expected to occur on average once every five years (id., pp. 106-107; Exh. HO-C-2, vol. 1, pp. 133-134). MECo asserted that five of its 14 industrial SIC groups (about 30 percent of annual industrial energy) along with the commercial, residential, and other classes are weather sensitive (Exh. HO-C-2, vol. 1, p. 131). Thus, MECo stated that applying the "extreme" set of peak-load factors provides a greater understanding of the sensitivity of peak loads to weather conditions (id., p. 134).

To a large extent, MECo's justification for these sets of factors, the methodology used to derive them, and their relationship to the remainder of the peak-load forecast methodology is undocumented. However, for purposes of this review, the Siting Council accepts MECo's application of these factors. The Siting Council ORDERS MECo in its next forecast filing to document carefully the use of the sets of monthly peak-load factors.

4. Conclusions on the Peak-Load Forecast

The Siting Council has found that MECo disaggregated its peak-load forecast into appropriate customer groups and developed an appropriate system-wide load profile. In addition, the Siting Council has accepted MECo's application of monthly peak-load factors.

Accordingly, the Siting Council finds that MECo has established that its peak-load forecasting methodology is reviewable, appropriate, and reliable. However, in its next forecast filing, the Siting Council ORDERS MECo to document and describe peak-load forecasting in detail, including a full description of peak-load and econometric models, theoretical assumptions, and logical relationships represented in the peak-load methodology.

E. Conclusions on the Demand Forecast

The Siting Council has found that MECo's methodologies for forecasting energy requirements and peak-load requirements are reviewable, appropriate, and reliable.

The Siting Council notes that MECo did not provide adequate documentation for many of the assumptions contained in the energy and peak-load forecasts. In the past, the Siting Council has held that a company's filing must be self-contained and supported by sufficient documentation. Bay State Gas Company, 11 DOMSC 283, 307 (1987); Eastern Utilities Associates, 11 DOMSC 61, 65 (1984). See also 980 CMR 7.03(5)(c). A forecast filing not supported by sufficient documentation could lead to a rejection of that forecast. The Siting Council directs MECo to file a complete and fully documented forecast in its next forecast filing.

The Siting Council hereby APPROVES MECo's 1986 and 1987 demand 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.[28]

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. Cambridge Electric Light Company, 15 DOMSC 125, 134 (1986) ("1986 CELCo Decision"). 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,

---

28/ Diversity, which in past Siting Council decisions has been discussed separately, now is treated within the discussion of least-cost. See Section III.E, infra.

15 DOMSC at 134-135, 144-150, 165-166.[29]

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. 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

29/ The Siting Council previously has defined the short run as a function of the time required to implement certain resource options. See 1987 BECo Decision, 15 DOMSC at 307-309. In Boston Edison Company, EFSC 88-12 (1989), however, the Siting Council defined the short run as four years (pp. 21n, 41). The four year period was 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. Id., see also 1988 EUA Decision, EFSC 87-33, p. 31.

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. Boston Edison Company, EFSC 88-12, pp. 46-76 (1989) ("1989 BECo Decision"); 1988 EUA Decision, EFSC 87-33, pp. 36-55.

B. Previous Supply Plan Review

The Siting Council approved the previous NEPCo supply plan without orders or conditions. 1985 MECo Decision, 12 DOMSC at 226-241.[30]

C. Supply Planning Process

1. Introduction

NEPCo stated that the goal of its resource planning process is to develop a risk-adjusted resource plan that would remain low cost across a range of scenarios (Exh. HO-C-3, vol. 2, Appendix C, pp. 19-25). A supply plan that exhibited risk-adjusted, low-cost characteristics was termed a 'balanced plan' by NEPCo (Exh. HO-1, vol. 1, p. 4). To develop a balanced

---

30/ In that decision, the Siting Council made no findings as to whether NEPCo's supply plan was a least-cost supply plan. 1985 MECo Decision, 12 DOMSC at 241.

plan, NEPCo employed a three-stage process consisting of: (1) cost analysis of resource options; (2) risk management of resource options; and (3) balancing of additional costs of resource options against reductions in risk (id., pp. 6-17).

NEPCo approached balanced planning largely through consideration of diversity of resource options. The range of resource options considered by NEPCo in developing its balanced plan included C&LM programs, alternate energy ("AE") purchases, unit life extension and conversion of units to more efficient fuels, new NEPCo-owned generation, and purchases of power from other utilities (Exh. HO-C-3, vol. 2, pp. 21, 26-60). Implementation goals for each of these resource options are established by NEPCo's NEESPLAN II (Exh. HO-1, vol. 1, pp. 8-10).[31] NEPCo indicated that NEESPLAN II provides a least-cost supply planning strategy for NEPCo for the next 15 years (Exh. HO-C-3, vol. 2, Appendix C, p. 4).

2. Cost

NEPCo asserted that all resource options -- both supply-side and demand-side -- were subjected to a uniform cost analysis based on a consistent set of economic criteria (Exh. HO-1, vol. 1, p. 12). The objective of the cost analysis was to rank resource options in terms of a cost/benefit ("C/B") ratio (Exh. HO-C-3, vol. 2, Appendix B, p. 4; Tr. II, p. 33).[32]

31/ NEESPLAN II was set forth in April, 1985, superceding NEESPLAN which had been in effect since 1979 (Exh. HO-C-3, vol. 2, Appendix C, pp. 1-3). According to NEPCo, NEESPLAN II replaced NEESPLAN because of strong regional economic growth, higher than anticipated load growth, and the accompanying potential for generating capacity shortfalls in the late 1990's (id., p. 3).

32/ NEPCo defined the C/B ratio as discounted revenue requirements divided by discounted capacity and energy benefits (Exh. HO-C-3, vol. 2, Appendix B, p. 4; Tr. II, p. 33).

NEPCo derived resource option cost and benefit data from its 'Least Cost Model' (Exh. HO-C-3, vol. 2, Appendix B, p. 4). Costs were determined by a standard revenue requirements methodology, while benefits were determined from (1) capacity benefits (KW benefits as measured by the value of deferring construction of gas turbine capacity for one year),[33] and (2) energy benefits (KWH benefits as measured by the value of NEPCo's marginal energy cost) (id.).[34] The Least Cost Model utilized a 20-year time period in its calculations, and was capable of analyzing resource options at a level as small as one KW (Tr. II, pp. 18-19, 32). Transmission costs and line losses were not included in the Least Cost Model (id., pp. 104-106). NEPCo plans to add a production costing submodel to the Least Cost Model, to assist in the determination of an appropriate mix of generating units necessary to meet forecasted capacity and energy requirements (Exh. HO-C-3, vol. 1, Section III).

In this filing, unlike previous NEPCo filings reviewed by the Siting Council, NEPCo analyzed the economic attributes of

---

33/ NEPCo asserted that if new generation is required to meet reliability requirements prior to the year 2001, gas turbines are the least expensive capacity available with the shortest lead-time (Exh. HO-C-3, vol. 2, Appendix C, p. 20). To compute the value of deferring gas turbine capacity for one year, NEPCo first calculated the revenue requirements of a series of 100 MW gas turbines, installed over 20-year intervals (Tr. II, pp. 102-103). Next, NEPCo calculated the revenue requirements of an identical series of 100 MW gas turbines, with this series being installed exactly one year later than the preceding series (id.). The present value of the revenue requirements of each series was calculated, then one was subtracted from the other, yielding the difference between the two cost streams, which represented the value of deferring gas turbine capacity for one year (id.).

34/ Marginal energy cost was evaluated in terms of NEPCo's marginal fuel, which NEPCo stated was oil (Tr. I, p. 97). NEPCo calculated marginal energy cost using a production cost model, which yielded on-peak and off-peak marginal energy costs over a 20-year period (id.). Inputs into the model included operating characteristics of existing units, existing commitments, fuel price and escalation assumptions (id., pp. 93, 96-97).

C&LM programs (Exh. HO-C-3, vol. 2, p. 19; Exh. HO-D-3).[35] Previously, certain C&LM programs were assumed to be cost-effective and included in NEPCo's balanced plan independent of supporting analysis (Exh. HO-D-3).

3. Risk Management

NEPCo addressed two aspects of risk management regarding resource options. These were: (1) the risk posed by modifications to base case assumptions (i.e., risk as to whether the base case assumptions will materialize, and how alternative assumptions would affect economic performance); and (2) the risk that forecasted energy requirements would not be met by NEPCo's balanced plan, (i.e., risk that supply would not meet forecasted demand) (Exh. HO-1, vol. 1, pp. 12-17).

Modifications to base case assumptions were established by: (1) identifying key variables (load growth, economic growth, fuel price, and availability of major resource options); (2) using the key variables to develop 15 plausible scenarios; and (3) subjecting five of the 15 scenarios to further analysis (id., pp. 4-5, 13).[36] According to NEPCo, the potential cost impacts of the five scenarios were used, in part, to determine the composition of the balanced plan, thereby minimizing risks represented by the scenarios (id.).

Using statistical techniques, NEPCo projected the

35/ Although NEPCo stated that C&LM programs contributed to more efficient use of existing generation, transmission and distribution facilities, the Least Cost Model did not credit C&LM programs for these benefits (Exh. HO-C-3, vol. 2, Appendix C, p. 7).

36/ The five scenarios subject to further analysis are high economic growth, capacity constraints, high C&LM penetration, oil interruption, and industrial bypass (Exh. HO-1, vol. 1, pp. 4-5, 13). In addition to these five scenarios, the base case scenario also was subject to further analysis (id.).

likelihood of a supply excess or deficiency at three confidence levels: 50 percent, 80 percent, and 90 percent (id., p. 16). Based on its projections, NEPCo asserted that forecasted energy requirements during the forecast period would be met by the balanced plan at probabilities ranging from a low of 50 percent to a high of 80 percent (id., p. 15).

In addition, NEPCo addressed short-term uncertainty for the period 1988-1992 with a short-term contingency plan (id., pp. 20-21). The contingency plan addressed high load growth by accelerating C&LM programs, particularly standby generation and interruptible rate programs, and by supplementing short-term capacity purchases (id., p. 21).

4. Balancing of Costs and Risks

As a final step in development of its balanced plan, NEPCo balanced additional cost against reduction in risk (Exh. HO-D-4(b), p. 2). NEPCo stated that its balanced plan must exhibit relative cost stability over the range of risks identified in some of the scenarios (id., pp. 6, 10).

NEPCo's balanced plan weighed cost but also relied on criteria other than cost (Exh. HO-C-3, vol. 2, p. 24). NEPCo asserted that additional costs which achieved reductions in risk were reasonable (id., Appendix B, p. 15). Diversity as a means to achieve reduction in risk was a criteria considered, and NEPCo stated that NEESPLAN II goals ensured that a diverse mix of resource options would be available for selection (id., vol. 2, p. 24). No explicit guidelines were established by NEPCo which quantified the extent to which additional costs and reduction in risk would be balanced, but NEPCo claimed that it strived to keep costs low (Tr. II, pp. 68-69, 78; Exh. HO-D-4(b), pp. 9-10).

NEPCo stated that the balanced plan would "probably not" be the lowest cost plan under any single scenario, but it would be structured to achieve a "reasonable cost" across all scenarios (Exh. HO-D-4(b), p. 2; Tr. II, p. 66). For example, under base case assumptions, the cost of the balanced plan for 1986 was about 10 percent higher than the absolute lowest cost, non-risk adjusted plan (id., pp. 15-17). NEPCo claimed that this was a "relatively modest" level of additional costs (id., p. 17).

D. Adequacy of the Supply Plan

1. Adequacy of the Supply Plan in the Short Run

a. Definition of the Short Run

The short run in this proceeding is four years. NEPCo submitted its filing under the Siting Council's previous definition of short run (see Section III.A, supra; 1989 BECo Decision, EFSC 88-12, pp. 21n, 41. That definition established the short run as the time required to place into service the shortest-lead-time resource under a utility's direct control in sufficient quantities to meet the projected need for new capacity. See 1987 BECo Decision, 15 DOMSC at 308-309. In this case, we accept NEPCo's position that a gas turbine unit can be placed in service in approximately four years (Exh. HO-S-19).[37] This four-year period runs from the date of the final hearing or from the date of the response to the final record request. See 1989 BECo Decision, EFSC 88-12, pp. 21n, 41; 1988 EUA Decision, EFSC 87-33, p. 31. In this proceeding, the short run extends from the summer of 1988 through the winter of 1991-1992.

37/ The Siting Council has determined that henceforth the short run simply will be defined as four years (1989 BECO Decision, EFSC 88-12, p. 21n). In this case, therefore, the short run would be four years under either the new or old standard.

b. Base Case Supply Plan

The data shown in Table 2 compares NEPCo's projected resource capability to its peak-load capability responsibility over the forecast period. This data indicates that NEPCo is projecting a short-run capability surplus of 1.7 to 12.5 percent during the summer peak period, and a deficiency of 0.4 percent to a surplus of ten percent for the winter peak period.

NEPCo's base case supply plan indicates that without the addition of new resources, it will experience short-run deficiencies of 21 MW (0.4 percent) during the winter of 1989-1990. NEPCo has stated that it would address this short-term deficiency with accelerated C&LM programs and short-term utility purchases (Exh. HO-1, vol. 1, p. 21). NEPCo indicated that 12 C&LM programs are currently being implemented, several of which could be expanded and accelerated to address a supply deficiency (Exh. HO-C-2, vol. 1, pp. 151-156; Exh. HO-1, vol. 1, p. 7). For example, NEPCo's standby generation program, which is currently scheduled to reduce summer peak load by 19.9 MW in 1989, 27.4 MW in 1990, and 34.9 MW thereafter, could be expanded and accelerated to achieve higher levels of load reduction (Exh. HO-C-3, vol. 1, Section V; Exh. HO-1, vol. 1, p. 21). In addition, NEPCo stated that its interruptible rate program, currently expected to reduce summer peak load by nine MW in 1989, 12 MW in 1990, and 15 MW thereafter, could also be expanded and accelerated (id.). Finally, NEPCo indicated that it could expand its purchases of power from other utilities to address short-run deficiencies. NEPCo stated that it has already signed agreements for short-run power purchases with Long Island Lighting Company, Niagara Mohawk Company, and NU representing a minimum of 225 MW (Exh. HO-1, vol. 1, pp. 8, 20; Tr. III, p. 25).

The Siting Council finds that it is appropriate for NEPCo to rely on the resource options identified to meet capability responsibility, and thereby avoid base-case deficiencies in the short run. By calling on these resource additions, NEPCo would have sufficient resources to meet its requirements in the short run, assuming no contingencies occur. Therefore, the Siting Council finds that NEPCo has established that it has sufficient options to meet its base-case deficiencies 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 NEPCo's short-run supply plan, the Siting Council analyzes the following contingencies: (1) cancellation or delay of Seabrook 1, (2) the one-year delay of Hydro Quebec Phase II, and (3) the double contingency of cancellation or delay of Seabrook 1 and a one-year delay of Hydro Quebec Phase II.

i. Cancellation or Delay of Seabrook 1

If Seabrook 1 is unavailable in the short-run, and if all other resources remain available to NEPCo, the data presented indicate that NEPCo would experience a resource deficiency in the winter of 1989-1990 of 14.0 MW (0.3 percent) (Exh. HO-C-2, vol. 2, Table E-17) (see Table 3). In the event of such a cancellation or delay, NEPCo identified an action plan involving accelerated implementation of C&LM programs and utility power purchases (Exh. HO-C-2, vol. 1, p. 9; Exhs. HO-D-4(e), HO-S-9(c)). See Section III.D.1.b, *supra*.

Accordingly, the Siting Council finds that NEPCo has established that it has an action plan to meet the resource deficiencies in the winter of 1989-1990 in the event of a cancellation or delay of Seabrook 1.

ii. Delay of Hydro Quebec Phase II

NEPCo stated that it expects Hydro Quebec Phase II to provide 162 MW of power beginning in the winter of 1990-1991 and continue to provide that level of power throughout the forecast period (Exh. HO-C-2, vol. 2, Table E-17). If all other resources in its base case supply plan remain available to NEPCo, NEPCo would not realize a resource deficiency in the short run due to a one-year delay in the operation of Hydro Quebec Phase II (see Table 3).

Accordingly, the Siting Council finds that NEPCo has established that it has adequate resources to meet its forecasted capability responsibility in the short run in the event of a one-year delay in the operation of Hydro Quebec Phase II.

iii. Double Contingency of Cancellation or Delay of Seabrook 1 and Delay of Hydro Quebec Phase II

One possible combination of short-run contingencies would be the cancellation or delay of Seabrook 1 and a one-year delay of Hydro Quebec Phase II. If all other resources in its base case supply plan remain available to NEPCo, this double contingency would produce a short run resource deficiency of 14.0 MW (0.3 percent) in the winter of 1989-1990 (see Table 3).

In the event of a cancellation or delay of Seabrook 1 and a one-year delay in Hydro Quebec Phase II, NEPCo identified an action plan involving accelerated implementation of C&LM programs, increased AE purchases, and purchases of power from other utilities (Exh. HO-C-2, vol. 1, p. 9; Exhs. HO-D-4(e), HO-S-9(c)). See Section III.D.1.b. and c.i, *supra*.

Accordingly, the Siting Council finds that NEPCo has established that it has an action plan to meet any resource deficiencies in the winter of 1989-1990 in the event of a cancellation or delay of Seabrook 1 and a one-year delay of Hydro Quebec Phase II.

iv. Conclusions on the Short-Run Contingency Analysis

The Siting Council has found that NEPCo has established that it has: (1) an action plan to meet any resource deficiencies in the winter of 1989-1990 in the event of a cancellation or delay of Seabrook 1; (2) adequate resources to meet its forecasted capability responsibility in the short run in the event of a one-year delay in operation of Hydro Quebec Phase II; and (3) an action plan to meet any resource deficiencies in the winter of 1989-1990 in the event of a cancellation or delay of Seabrook 1 and a one-year delay of Hydro Quebec Phase II.

Accordingly, the Siting Council finds that NEPCo has established that its supply plan is adequate to meet its capability responsibility in the short run under a reasonable set of contingencies.

2. Adequacy of the Supply Plan in the Long Run

NEPCo's long-run planning period is the remaining forecast horizon beyond the short run; this extends from the summer of 1992 through the winter of 1996-1997. NEPCo's base case supply plan would satisfy its capability responsibility through winter of 1996-1997 (see Table 2).

As previously discussed in Section III.A, *supra*, 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 NEPCo'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, *infra*.

As indicated in Section III.E, *infra*, NEPCo has established that its supply plan ensures a least-cost energy supply. Accordingly, the Siting Council finds that NEPCo 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 NEPCo has established that: (1) it has sufficient options to meet its base-case deficiencies in the short run; (2) its supply plan is adequate to meet its capability responsibility in the short run under a reasonable set of contingencies; and (3) its supply planning process ensures adequate resources to meet requirements in the long run. Accordingly, the Siting Council finds that NEPCo has established that its supply plan ensures adequate resources to meet projected requirements.

E. Least-Cost Supply

The Siting Council reviews NEPCo's processes for identifying and fully evaluating resource options.

1. Identification of Resource Options

NEPCo identified generation and C&LM resource options. The Siting Council focuses its review on whether NEPCo 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 NEPCo compiled a comprehensive array of available resource options, the Siting Council must determine whether NEPCo compiled adequate sets of available resource options for each type of resource identified during this proceeding.

i. <u>Types of Resource Sets</u>

During this proceeding, NEPCo identified five types of resource sets for consideration in its supply planning process: (1) C&LM programs; (2) AE purchases;[38] (3) unit life extension and fuel conversion; (4) new NEPCo-owned generation, and (5) purchases of power from other utilities (Exh. HO-C-3, vol. 2, Appendix C, pp. 6-18).

NEPCo's five types of resource sets represent a broad spectrum of resource options available to the electric utility industry. Accordingly, the Siting Council finds that NEPCo has identified a reasonable range of resource sets.

ii. <u>Compilation of Resource Sets</u>

NEPCo stated that C&LM program concepts were obtained from internal and external sources (Exh. HO-C-3, vol. 1, Section IV, A). Internal sources for information on C&LM programs included NEPCo departmental and interdepartmental groups, and NEPCo's research and development programs (<u>id.</u>).[39] External sources for information on C&LM programs included other electric utilities, industry organizations such as EPRI, and New England groups such as the Conservation Law Foundation and the Massachusetts Audubon Society (Tr. II, pp. 8-9).

NEPCo stated that C&LM programs were designed "to address load growth in all classes" (<u>id.</u>, p. 15). NEPCo provided a

---

<u>38</u>/ NEPCo described AE as including cogenerators, small power producers, small hydro developers, qualifying facilities, and alternate sources of energy such as solid waste, wood, wind, solar, and petroleum coke (Exh. HO-1, vol. 2, p. 13; Exh. HO-C-3, vol. 2, Appendix C, pp. 37-44).

<u>39</u>/ NEPCo stated that it has an active C&LM research and development program investigating innovative rates, innovative technologies, load shape impacts, and customer behavior (Exh. HO-C-3, vol. 1, Section IV, A).

description of 28 C&LM programs which were considered in development of the 1986 balanced plan (Exh. HO-C-3, vol. 1, Section V).[40] NEPCo did not indicate that there was any change in the method by which C&LM programs were identified for consideration in development of the 1987 balanced plan.

In order to ensure a least-cost resource plan, a company's process for identifying resource sets must be based on a wide range of sources. In particular, the process of identifying a C&LM resource set benefits from the input of both industry and public interest sources. In addition, a C&LM resource set considered for supply planning purposes should include programs which target all customer classes.

In this case, NEPCo's C&LM resource set was based upon information gathered from both internal and external industry sources, as well as certain public interest groups. In addition, NEPCo's C&LM resource set included programs targeted for residential, commercial, and industrial customers. Accordingly, the Siting Council finds, for purposes of this review, that NEPCo compiled an adequate set of available C&LM

40/ C&LM programs described by NEPCo were: time-of-use rates, interruptible rates, transmission loss reduction, distribution loss reduction, thermal loss reduction, hydro loss reduction, motor rebate program, large commercial-industrial performance contracting program, refrigerator rebate, residential free lamp program, commercial and industrial lighting program, residential home rebate, storage cooling, small commercial and industrial performance contracting program, water heater rebate program, water heater control program, water heater rental program, water heater wrap program, residential air conditioning rebate program, street light program, stand-by generation, cogeneration, residential lighting catalog, air conditioning maintenance program, residential conservation program, low income conservation program, residential radio-based program, and commercial radio-based program (Exh. HO-C-3, vol. 1, Section V). In addition, NEPCo stated that C&LM pilot programs have been implemented, including the MECo Enterprise Plan, Narragansett Electric Company's Customer Load Control Load Management Program, and Granite State Electric Company's Batch Solar Water Heating Experiment (id., vol. 2, Appendix C, p. 27).

programs.

In regard to AE purchases, NEPCo stated that 250 MW of AE capacity is currently on line (Exh. HO-1, vol. 1, p. 7). Further, NEPCo reported another 420 MW of AE capacity, scheduled for commercial operation by 1991, is under contract (id.). NEPCo indicated the mix of the foregoing AE purchases consists of hydropower, solid waste, coal, landfill gas, natural gas, and a small amount of wood and wind (Exh. HO-S-14; Exh. HO-C-3, vol. 2, Appendix C, p. 43). At least part of the 670 MW identified above has been contracted for by MECo through a negotiating process under the terms of an agreement reached with the Massachusetts Department of Public Utilities ("MDPU") (Exh. HO-1, vol. 1, p. 18). NEPCo, through MECo, has received an exemption from the MDPU's request for proposal ("RFP") process in favor of its own negotiation process. This exemption was granted in the MDPU's decision in Massachusetts Electric Company, D.P.U. 86-265 (1987).[41] Pursuant to that decision, MECo must annually report to the MDPU the results of its negotiation process. In view of the MDPU's oversight of this process, the Siting Council accepts, for the purposes of this proceeding, that portion of NEPCo's compilation of an AE purchases resource set which is based on this process.

In addition, NEPCo indicated that a solicitation was recently issued for 200 MW of capacity from cogenerators, small power producers ("SPPs"), independent power producers ("IPPs"), and utility generation projects, but the date of commercial operation for this capacity was not specified by NEPCo (id.). Finally, NEPCo stated that a total of 975 MW of AE is expected

---

41/ The Siting Council takes administrative notice both of this decision and of the MDPU's decision in D.P.U. 84-276-B (1986), a rulemaking pertaining to the sales of electricity by small power producers and cogenerators to utilities and sales of electricity by utilities to small power producers and cogenerators. The decision in D.P.U. 84-276-B set forth the terms of this exemption.

to be operating commercially by the year 2007 (Exh. HO-1, vol. 1, p. 22). In a previous decision, the Siting Council has found that solicitation constituted a reasonable method for a company to research available capacity purchases for both utility and QF capacity. 1989 BECo Decision, EFSC 88-12, pp. 52, 54, 56.

Accordingly, for purposes of this review, the Siting Council finds that NEPCo has compiled an adequate set of AE purchases through the combination of its solicitation and negotiation processes. Due to the significance the Siting Council places on these processes and their results, the Siting Council ORDERS NEPCo in its next forecast filing to provide a detailed analysis of the negotiation and solicitation processes for AE purchases so that the Siting Council can review them as a part of NEPCo's least-cost supply plan.

In regard to unit life extension and fuel conversion, NEPCo stated that examining the potential of existing facilities is a critical element of supply planning (Exh. HO-C-3, vol. 2, Appendix C, p. 12). NEPCo asserted that existing facilities will supply the bulk of its load over the forecast period, and that existing generating facilities were cost-efficient energy producers (id., p. 45).

NEPCo stated that its life extension program is an outgrowth of the age of its fossil-fired capacity and its anticipated loss of 350 MW of power in the years 2000 and 2001 (id., p. 13). NEPCo indicated that by the year 2000, 1707 MW of its fossil-fired capacity will be over 30 years old, and 569 MW will be over 40 years old (id., pp. 12-13).[42]

NEPCo asserted that a study of each existing thermal

42/ NEPCo reported that the Yankee Atomic Energy Company, the operator of the Yankee Rowe plant from which NEPCo receives power, is in the process of requesting an extension of the plant's Nuclear Regulatory Commission operating license (Exh. HO-S-4). The extension, if approved, would allow operation of the Yankee Rowe plant until June, 2001, 40 years from the date of initial commercial operation of the plant (id.).

plant would be performed, evaluating major components in terms of possible life extension (id., p. 47). The study would employ state-of-the-art techniques to determine the remaining life and suitability for continued service of each thermal plant's boiler, turbine, generator, major steam and feedwater piping, and auxiliary systems (id.). In addition, NEPCo stated that such studies already had been completed for hydropower units, but that life extension investments would be made for these units only when justified by the balanced planning process (id., p. 48).

NEPCo stated that thermal and hydropower units selected for life extension also would be considered in programs designed to enhance unit availability (id., p. 13). NEPCo asserted that the benefits of unit availability consisted of three primary elements: (1) reducing the average cost per KWH -- for example, a one percent improvement in unit availability at Brayton Point unit 3 would save customers $1.8 million dollars per year; (2) improving reliability of service by ensuring that adequate supplies are available at all times; and (3) reducing the need for additional reserve capacity (id., p. 48).

Finally, with respect to fuel conversions of existing facilities, NEPCo stated that fuel conversion consisted entirely of conversions to gas from another fuel (id., p. 14).[43] NEPCo identified three units fueled with residual oil -- South Street, Brayton Point unit 4, and Salem Harbor unit 4 -- that

---

43/ NEPCo reported that fuel conversions from oil to coal totaling 1,428 MW were completed in 1984 at Brayton Point units 1, 2, and 3 and at Salem Harbor units 1, 2, and 3, resulting in significant cost savings (Exh. HO-C-3, vol. 2, Appendix C, pp. 14, 45, 52).

are candidates for conversion to natural gas (id.).[44]

In order to ensure a comprehensive life extension resource set, systematic assessment of all potential candidates should be undertaken to determine the specifics associated with life extension of each candidate. In this case, NEPCo included as an integral part of its identification process the evaluation of each plant's major systems and components. By so doing, NEPCo is able to establish the true potential for life extension for each member of a set of power generating facilities. NEPCo's additional review of candidates for fuel conversions and enhanced unit availability ensures that life extension programs will incorporate technological advances and overall NEPCo goals such as fuel diversity and improved system reliability.

In that NEPCo's unit life extension and fuel conversion resource set is based on a systematic review of facility potential and incorporates stated NEPCo goals, the Siting Council finds that, for the purposes of this review, NEPCo has compiled an adequate resource set for enhanced use of existing facilities.

In regard to new NEPCo-owned generation, NEPCo stated that such generation warranted consideration but was not the sole solution to supply planning (id., p. 18). NEPCo stated that under the current forecast, new NEPCo-owned generation would not be needed until the year 2001 (id., p. 20). See note 44, supra. Nonetheless, NEPCo stated that the need for new base load generation in New England is under continuous evaluation (id., p. 59). NEPCo indicated that if base load generation were

---

44/ NEPCo indicated that its only other remaining large, residual-oil-fueled facility is the Manchester Street station in Providence, Rhode Island (Exh HO-1, vol. 2, pp. 20-21). Currently, Manchester Street station generates up to 150 MW (id., vol. 1, p. 10). In its 1988 forecast, NEPCo stated that it would install 300 MW of new generation at this station by 1995-96 (id.). This would be accomplished, according to NEPCo, by retiring three oil-fired boilers and adding gas-fired combined-cycle units at that station (id.).

determined to be needed, technology options would be: (1) combined-cycle (with or without coal gasification); and (2) fluidized bed coal (Exh. HO-S-19). For peak load generation, NEPCo mentioned only one unit type -- gas turbines (Exh. HO-S-19). See note 33, supra.

The Siting Council has found that a comprehensive resource set for company-owned generation should include, at a minimum: (1) options that are capable of operating at high, intermediate, and low capacity factors; (2) options which use traditional and alternative fuels; (3) options which could be built in relatively large or small increments; and (4) options which include advanced generation technologies which potentially could contribute to a least-cost supply. 1989 BECo Decision, EFSC 88-12, p. 53.

In this case, NEPCo did not specify size increments considered for base load generation, nor did NEPCo indicate consideration of available fuels, other technologies, or capacity factors other than those represented by base load and peak load units. In addition, NEPCo omitted consideration of advanced generation peak load technologies, such as compressed-air storage or fuel cells, which potentially could contribute to a least-cost supply plan. Consequently, the record shows that NEPCo failed to consider significant aspects of NEPCo-owned generation in the development of its resource set.

While the Siting Council has found that it may be appropriate to reduce the emphasis utilities have placed on company-owned generation and emphasize other aspects of a supply plan, particularly C&LM, responsible least-cost planning requires that NEPCo take reasonable measures to identify a wide range of options for every resource set. Based on the record in this proceeding, the Siting Council finds that NEPCo failed to compile an adequate set of NEPCo-owned generation options. In its next forecast filing, NEPCo should demonstrate that it has considered a wider range of fuels, sizes, capacity factors and technologies for NEPCo-owned generation.

In regard to purchases of power from other utilities, NEPCo indicated that purchases of power from utilities could be a source of capacity after the year 2001 (Exh. HO-C-3, vol. 2, Appendix C, p. 58). NEPCo stated that even after the Hydro Quebec contract terminates in the year 2000, excess hydropower in Quebec may allow NEPCo to continue purchasing power (id.). NEPCo indicated that it could receive as much as 360 MW from the interconnection (id.).[45] Further, NEPCo stated that future transmission additions, including additional Hydro Quebec ties and interconnections to excess Midwestern coal-fired capacity, might be feasible (id., pp. 58-59). Utility purchases from the New Brunswick Electric Power Commission also were identified by NEPCo as a future option (id.). In addition, NEPCo asserted that its solicitation for 200 MW of capacity would serve as an appropriate means for identifying purchases of power from other utilities (Exh. HO-1, vol. 1, pp. 18-19). In that NEPCo has included a wide range of potential sources of power from other utilities, including sources from diverse geographical locations and those possible through potential future transmission system enhancements, and, in addition, has included power purchases in its solicitation process for AE purchases described above, for purposes of this review, the Siting Council finds that NEPCo compiled an adequate resource set of purchases from other utilities.

iii. Conclusions on Available Resource Options

The Siting Council has found that NEPCo has identified a reasonable range of resource sets. In addition, the Siting Council has found that NEPCo compiled adequate sets of C&LM

45/ In this proceeding, NEPCo reported completing the purchase of 49 MW of Hydro Quebec Phase II capacity from the United Illuminating Company (Exh. HO-1, vol. 2, p. 18).

programs, AE purchases, unit life extension and fuel conversions, and purchases of power from other utilities. The Siting Council also has found that NEPCo failed to compile an adequate set of new NEPCo-owned generation.

While the failure to compile an adequate set of NEPCo-owned generation is significant, NEPCo has indicated significant strengths in other aspects of compiling resource options, particularly C&LM, and, on balance, the Siting Council finds that NEPCo has demonstrated that it compiled a comprehensive array of available resource options. However, pursuant to the discussion on NEPCo-owned generation above, the Siting Council ORDERS NEPCo in its next forecast filing to analyze for inclusion in its array of new NEPCo-owned generation a wider range of fuels, sizes, capacity factors, and technologies.

b. Development and Application of Screening Criteria

To determine whether NEPCo 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 NEPCo's resource sets. For one of its resource sets, unit life extension and fuel conversion, NEPCo did not eliminate any of the identified options. In addition, the Siting Council has found that NEPCo failed to compile an adequate set of new NEPCo-owned generation (see Section III.E.1.iii, supra). Thus, the Siting Council reviews the criteria for the remaining resource sets: C&LM programs, AE purchases, and purchases of power from other utilities.

In general, NEPCo states that it intends to develop C&LM programs that are: (1) acceptable to its customers; (2) fair to all customers; and (3) manageable by NEPCo (Exh. HO-C-3, vol. 2, Appendix C, p. 28). NEPCo stated that C&LM program concepts were obtained from both internal and external sources (id., Section IV, A). See Section III.E.1.a.ii, <u>supra</u>. Following program conceptualization, C&LM programs were screened for data sufficiency (<u>id.</u>, Figure IV.3). Data elements -- such as annual on- and off-peak energy reductions, peak demand reductions, capital costs, and operations and maintenance costs -- were scrutinized (Tr. II, p. 9). If data were insufficient, then a research or pilot program might be undertaken (<u>id.</u>; Exh. HO-C-3, vol. 1, Section IV, Figure IV.3). Once sufficient data were furnished, a C&LM program's costs and benefits were derived by the Least Cost Model, a C/B ratio was calculated, and the C&LM program was made available for inclusion in NEPCo's balanced plan (Tr. II, p. 9; Exh. HO-C-3, vol. 1, Section IV, B).[46] A decision to include a specific C&LM program in NEPCo's balanced plan triggered detailed planning of that program (<u>id.</u>).

As part of detailed planning, C&LM program assumptions were further refined based on market research, program evaluation requirements, and implementation requirements (Exh. HO-C-3, vol. 1, Section IV, B). Following detailed planning, a C&LM program's costs and benefits were recalculated with the Least Cost Model, and C/B ratios again were used to validate cost-effectiveness (<u>id.</u>). NEPCo stated that in its 1986 balanced plan, 28 C&LM programs were considered; 16 of them were screened out by the foregoing process, primarily because they were not cost-effective or because there were implementation obstacles (<u>id.</u>, Section V, A).

NEPCo's screening process for C&LM programs addresses the needs of its customers as well as itself. Additionally, by performing studies as necessary to ensure that comprehensive

---

<u>46</u>/ If the C/B ratio for any C&LM program was unfavorable prior to detailed planning, NEPCo performed additional analysis to determine the reasons for the unfavorable ratio (Exh. HO-C-3, vol. 1, Section IV, B). NEPCo focused its analysis largely on the assumptions underlying the C&LM program in order to determine their effects on program design and cost (<u>id.</u>).

data exists for all of the programs under consideration, NEPCo's screening process ensures that potentially viable programs are not eliminated from continued consideration due simply to a lack of data. By proceeding to evaluate the cost-effectiveness of the programs, the incorporation of C&LM programs into a least-cost supply plan is enhanced. The manner in which NEPCo has developed and applied these criteria is logical and generally well-founded and results in programs which address NEPCo goals and meet customer needs.

Accordingly, based on the foregoing, the Siting Council finds that NEPCo developed and applied appropriate criteria for screening its set of available C&LM programs.

NEPCo conducted its AE purchases through negotiations with AE developers and solicitations (Tr. III, pp. 32, 37). NEPCo applied a threshold criterion that AE capacity be priced no higher than NEPCo's avoided cost (id., p. 37). In addition, NEPCo considered non-price factors such as reliability of operation, dispatchability, short- and long-term financial viability, the possibility of using the generating facility to meet state emission criteria, transmission and line loss advantages (id., pp. 38-41). NEPCo did not indicate whether relative weights were applied to price and non-price factors. However, NEPCo's witness, Mr. Levett, stated that AE contracts contained price provisions that were adjustable based on project reliability, and in the event of closely competitive projects, transmission and line loss advantages to NEPCo would be carefully considered (id., pp. 39, 41; Exh. HO-C-3, vol. 2, Appendix C, pp. 37-44). NEPCo reported that, as of 1988, NEPCo was receiving power from 136 AE projects, and that NEPCo had agreements to purchase power from ten other projects which were not yet operating (Exh. HO-1, vol. 2, p. 17).

In that NEPCo has developed appropriate threshold criteria for its AE purchases and included non-price factors related to project viability, NEPCo's screening criteria for AE projects are likely to result in projects which will become a part of NEPCo's least-cost supply plan. NEPCo's interest in obtaining AE purchases is evidenced by the number of projects currently on line. Thus, for purposes of this review, the Siting Council finds that NEPCo developed and applied appropriate criteria for screening its set of AE purchases.

NEPCo indicated that purchases of power from other utilities were considered for: (1) the short-term period, consisting of the first five years of the forecast period, and (2) the long-term period, which consisted of years five and beyond of the forecast period (Exh. HO-1, vol. 1, p. 20). In either case, NEPCo asserted that purchases of power from other utilities would be subject to balanced plan requirements including low cost and reduced risks (id.).

NEPCo stated that one of its short-term objectives was to improve its economic position "by looking into the market and try[ing] to optimize our position within that market" (Tr. III, p. 16). For example, NEPCo stated that capacity was purchased from the Long Island Lighting Company and Niagara Mohawk Company specifically for this purpose (Exh. HO-1, vol. 1, p. 20; Tr. III, p. 17). In addition, based on a contingency study covering the 1987-1992 period, NEPCo purchased 225 MW from NU, for the 1987-1992 period (Exh. HO-S-5; Tr. II, p. 20). NEPCo described its purchase of NU capacity as an "insurance policy," since it was intended to address higher than anticipated load growth and provide flexibility in scheduling implementation of other resource options over the 1987-1992 period (Tr. II, p. 126). Nonetheless, while NEPCo stated that short-term utility purchases would be subject to balanced planning requirements, no indication was made by NEPCo that specific price and non-price criteria were applied to screen other individual short-term purchases of power from other utilities prior to completing the foregoing contracts.

For the long-term period, NEPCo asserted that purchases of power from other utilities also would be evaluated according to price, using consistent economic criteria (Exh. HO-C-3, vol. 2, Appendix C, p. 19). However, in its recent purchase of 49 MW of additional Hydro-Quebec Phase II capacity from the United

Illuminating Company, NEPCo did not indicate that other utility purchase sources available during the same time period were considered prior to reaching an agreement with United Illuminating. See note 45, supra. In addition, while NEPCo indicated that non-price factors including flexibility, feasibility, risk and regulatory constraints, environmental impacts, and fuel and size diversity were considered in the composition of the balanced plan, NEPCo provided no evidence to demonstrate that these non-price factors were applied as criteria to screen individual long-term utility purchases prior to completing contracts.

In order for purchases from other utilities to be appropriate elements of a company's short- or long-term least cost supply plan, price and non-price criteria must be established and consistently applied to a wide range of options. Despite the fact that NEPCo's resource set for utility purchases includes a wide range of potential sources for both short- and long-term utility purchases, the record in this proceeding fails to demonstrate that NEPCo has established and consistently applied appropriate criteria to such options. Accordingly, based on the foregoing reasons, the Siting Council finds that NEPCo failed to develop and apply appropriate criteria for screening purchases of power from other utilities.

The Siting Council has found that NEPCo developed and applied appropriate criteria for screening C&LM programs and AE purchases. The Siting Council also has found that NEPCo failed to develop and apply appropriate criteria for screening purchases of power from other utilities. While the failure to develop and apply appropriate criteria for screening purchases of power from other utilities is significant, NEPCo has indicated significant strengths in other aspects of developing and applying screening criteria. Accordingly, on balance, the Siting Council finds that NEPCo 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 NEPCo (1) has demonstrated that it compiled a comprehensive array of available resource options, and (2) has developed and applied appropriate criteria for screening its array of available resource options.

Accordingly, the Siting Council finds that NEPCo has identified a reasonable range of resource options.

2. Evaluation of Resource Options

The Siting Council reviews NEPCo's resource evaluation process to determine whether NEPCo (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 the resource options identified in Section III.C.1, supra. This review addresses NEPCo's evaluation process described in Section III.C, supra, as it was applied to development of the balanced plan.

a. Objectives of the Resource Evaluation Process

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 capacities for existing and proposed facilities ... include an adequate consideration of conservation and load management." G.L. c. 164, sec. 69J. In addition, the Siting Council reviews a company's supply plan to determine whether it is the result of an adequate consideration of potential risks. See 1989 BECo Decision, EFSC 88-12, pp. 66-74. Thus, in reviewing NEPCo's resource evaluation process, the Siting Council addresses NEPCo's objectives of diversity, cost, and risk management.

Although the Siting Council addresses each of these objectives individually here, we acknowledge that in developing its balanced plan, NEPCo considers these objectives collectively.

i. Diversity

As set forth in Section III.C, supra, once NEPCo completes its identification and screening processes, NEPCo begins its resource evaluation process. Generally, NEPCo's resource evaluation process consists of balancing costs and risks to arrive at a balanced plan.

NEPCo approached balanced planning largely through consideration of diversity of resource options. NEPCo asserted that no single set of resource options should be selected to the exclusion of others, and that one way of reducing risk is to ensure that a plan is diversified (Exh. HO-C-3, vol. 2, Appendix C, pp. 5, 24). NEPCo stated that NEESPLAN II would employ a diverse portfolio of resources containing C&LM programs, AE purchases, unit life extension and fuel conversion, new-NEPCo owned generation, and purchases of power from other utilities (id., pp. 4-18). In order to ensure that diversity would be achieved, NEESPLAN II established quantitative goals and implementation timetables for C&LM programs, AE purchases, and unit life extension and fuel conversion (id., pp. 37-60).

NEPCo has developed an impressive array of C&LM programs which appear to be supported by commensurate levels of research and organizational commitment. See Section III.C.1.a.ii, supra. Yet, NEPCo has set quantitative goals for C&LM implementation without indicating how those goals were established. Since such decisions -- i.e., setting implementation goals for a particular resource set -- may exclude consideration of competing alternative resource sets, it is essential that the goals be well founded in theory and well supported with documentation, description, and analysis.

In addition, NEPCo indicated that major decisions within its resource evaluation process depended somewhat on the judgment of the planning staff and various managers (Tr. II, pp. 44-45, 66). For example, NEPCo stated that the balanced plan is based on the judgment of various analysts adding and deleting combinations of projects, until an "optimum mix" is found (id., p. 44). Yet, it remains unclear to what extent this judgment is constrained by previously established goals set forth in NEESPLAN II.

Further, major resource implementation decisions could be largely predetermined by quantitative goals, perhaps to the exclusion of other cost-effective options which are not set forth in the NEESPLAN II goals. For example, while NEPCo set a target for enhanced unit availability of two to four percent above the national average, NEPCo provided no objective analysis to support the selection of this level of enhancement. Although some increased availability may be warranted, the level of enhancement selected should be justified by economic analysis. In sum, the target level of two to four percent above the national average does not appear to be an outcome of an objective planning process, and may lead to incorrect resource implementation decisions.

Similarly, in the case of C&LM programs, where NEPCo stated that the C&LM quantitative goal was "not a ceiling," and in the case of AE purchases, where NEPCo asserted that goals have been upgraded several times since 1979 (Tr. II, p. 57), NEPCo did not provide the economic bases used to determine the quantitative goals. While the quantitative C&LM goals may have led to the integration of an appreciable amount of cost-effective C&LM programs in the balanced plan, the lack of an objective analysis to support goals raises the question of whether additional cost-effective C&LM options may have been overlooked.

While many of the problems in NEPCo's methodology for developing a diverse balanced plan have been highlighted, these problems hinge on one issue: NEPCo's failure to adequately document and describe the analysis supporting its goals. As a result, it is unclear from this record whether NEPCo achieved its diversity objective and thus, evaluated all resource options fully and considered all resource options on an equal footing. In its next forecast filing, NEPCo should fully document and describe its methodology for developing a diverse balanced plan. Because of the lack of adequate documentation, the Siting Council here makes no finding as to whether NEPCo's methodology for achieving its diversity objective is appropriate.

ii. Cost

NEPCo stated that it performed its cost analysis based on a consistent set of economic criteria. NEPCo ranked resource options in terms of a C/B ratio, and derived resource option cost and benefit data from its Least Cost Model. Thus, based on the record, NEPCo has developed a reasonable methodology to achieve its cost objective.

However, the record indicates that NEPCo overlooked some key economic factors in its resource evaluation process. First, while NEPCo recognized that C&LM programs contributed to efficient use of transmission and distribution facilities, NEPCo attributed no benefits to C&LM programs for these efficiency contributions (Exh. HO-C-3, vol. 2, Appendix C, pp. 6-7). See note 35, supra. Further, NEPCo neglected to recognize benefits from line loss reductions which would result from C&LM program implementation (Tr. II, p. 105). It is worthwhile to note that NEPCo has currently identified nine "developing supply problems" within its service territory, all of which are likely to require major investments in transmission, reinforcement, or distribution (Exh. HO-1, vol. 2, pp. 68-85). In each case, load growth was cited as the cause of the supply problem (id.). Yet, NEPCo does not credit any transmission or distribution capacity deferral to C&LM programs that could lead to mitigation of load growth effects. By ignoring the benefits of deferred investment in transmission and distribution which could be realized through C&LM programs, NEPCo's resource evaluation process undervalues the benefits of C&LM programs.

NEPCo also excluded transmission costs as a factor in evaluating new NEPCo-owned generation (Tr. II, pp. 104-105). For purposes of resource evaluation, NEPCo assumed that any new NEPCo-owned generation would be built at the same hypothetical site, thereby masking transmission costs and siting advantages that one generation option might have over another option. While such an assumption might be reasonable for a smaller-sized utility, where siting of company-owned generation would be limited to a smaller geographic area, a utility with a service territory and a transmission network the size of NEPCo's offers numerous siting and transmission alternatives, the costs of which could be significant when considered in a comparative analysis of new NEPCo-owned generation options.

In past cases, the Siting Council has criticized supply planning methodologies that fail to attribute benefits such as transmission deferral and line loss reductions to C&LM programs. See 1988 EUA Decision, EFSC 87-33, p. 54. In addition, the Siting Council has criticized supply planning methodologies that fail to incorporate costs of transmission and siting, as well as distribution, into costs of company-owned generation. Id. In this case, the failure of NEPCo's resource evaluation process to incorporate all economic benefits of C&LM programs, as well as its failure to adequately consider all transmission and siting costs attributable to NEPCo-owned generation, may inhibit NEPCo's ability to fully evaluate all resource options and to consider all resource options on an equal footing. Although the Siting Council has raised significant questions regarding these failures, on balance, the Siting Council finds that NEPCo's methodology for achieving its cost objective is appropriate.

iii. Risk Management

NEPCo's objective in risk management is to identify potential risks to supply plans and formulate supply plans that will minimize the impacts of the potential risks (Exh. HO-1, vol. 1, pp. 12-13). NEPCo indicated that potential risks to supply plans included: (1) technological risk, for example the failure of generating units or C&LM programs to perform as expected; (2) financial risk, such as bankruptcy of an SPP; and (3) economic risk, the risk that changed circumstances would render a project uneconomical (Exh. HO-C-3, vol. 2, Appendix C, pp. 23-24).

NEPCo has added a new step in its planning process, described in its 1988 forecast, specifically designed to disclose and respond to potential risks to its supply plans (Exh. HO-1, vol. 1, p. 13). In addition to the base case scenario, NEPCo designed scenarios based on variations to key planning variables (id.). Using scenarios for high economic growth, oil interruption, high C&LM penetration, industrial bypass, and capacity constraints, NEPCo developed the potential for risk to its supply plans (id.).

The Siting Council notes that NEPCo initially considered 15 scenarios, but selected six for further analysis, including the base case. The Siting Council further notes that electric utilities in the Commonwealth of a similar size and scale to NEPCo have developed a more detailed risk analysis process, involving as many as 81 scenarios. 1989 BECo Decision, EFSC 88-12, pp. 66-74. In the 1989 BECo Decision, the Siting Council recognized the strengths of the scenario process which was premised on high, base, and low forecasts of key planning variables, resulting in 81 scenarios which also included multiple combinations of risks (Id.). Here, NEPCo has provided a total of only six scenarios for further analysis, one of which is the base case. Of the six scenarios, NEPCo selected three extreme scenarios -- an oil interruption, high C&LM penetration, and industrial bypass. Analysis of such a limited number of scenarios with half of them emphasizing extreme conditions, could limit the ability of NEPCo's scenario analysis to adequately reflect the extent and magnitude of potential risks likely to impact supply plans. In addition, formulating scenarios based on combinations of risks, as opposed to single risk scenarios, would strengthen NEPCo's ability to address potential risks facing its supply plans.

In this case, the inability of NEPCo's risk management methodology to incorporate a wider range of the potential risks facing supply plans may reduce NEPCo's ability to fully evaluate all resource options and to consider all resource options on an equal footing. The Siting Council ORDERS NEPCo in its next forecast filing to (a) develop a risk management methodology which incorporates a wider range of potential risks facing supply plans, or (b) justify continued use of NEPCo's current risk management methodology.

In addition, the record shows that NEPCo has failed to adequately document and describe the methodology for achieving its risk management objective. As a result, it is unclear from this record whether NEPCo achieved its risk management objective. In its next forecast filing, NEPCo should fully document and describe its methodology for developing a risk-adjusted balanced plan. Because of the lack of adequate documentation, here the Siting Council makes no finding as to whether NEPCo's methodology for achieving its risk management objective is appropriate.

b. Conclusions on the Resource Evaluation Process

The Siting Council has found that NEPCo's methodology for achieving its cost objective is appropriate. The Siting Council has made no findings as to whether NEPCo's methodologies for achieving its diversity and risk management objectives are appropriate.

As part of our review of a company's resource evaluation process, we consider whether a company has attributed environmental impacts or benefits to resource options. See 1989 BECo Decision, EFSC 88-12, p. 66. In this proceeding, NEPCo has not demonstrated that it attributes environmental impacts or benefits to resource options. For instance, NEPCo did not show that environmental benefits associated with C&LM options were considered adequately. Our enabling statute directs us to balance economic considerations with environmental impacts in ensuring that the Commonwealth has a necessary supply of energy. G.L. c. 164, sec. 69H. 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 power. See Section III.A, supra. Therefore, the Siting Council ORDERS NEPCo in its next forecast filing to implement a methodology which includes an adequate consideration of the environmental impacts of resource options.

The Siting Council could not make findings as to whether NEPCo's methodologies for achieving its diversity and risk management objectives are appropriate largely because NEPCo failed to adequately document and describe these methodologies. In the past, the Siting Council has held that a company's filing must be self-contained and supported by sufficient documentation. Bay State Gas Company, 11 DOMSC 283, 307 (1987); Eastern Utilities Associates, 11 DOMSC 61, 65 (1984). See also 980 CMR 7.03(5)(c). A forecast filing not supported by sufficient documentation could lead to a rejection of that forecast. The Siting Council ORDERS NEPCo in its next forecast filing to fully document and describe its methodologies for achieving its diversity and risk management objectives.

Despite the limitations in NEPCo's documentation of its resource evaluation process and the failure of NEPCo to include an adequate consideration of the environmental impacts of resource options, the Siting Council notes that NEPCo has set goals that are ambitious and which demonstrate a commitment to balancing its supply plan, particularly in terms of C&LM program implementation. In addition, NEPCo has augmented its analytical capability in terms of risk analysis by adding scenario analysis to its supply planning process, and we note that NEPCo intends to strengthen its expansion planning capability by adding a production cost submodel to its Least Cost Model. Thus, in making our decision today, we recognize NEPCo's efforts to enhance its resource evaluation process.

For the purposes of this review, the Siting Council makes no finding on whether NEPCo established that it (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 resource options.

3. Conclusions on Least-Cost Supply

The Siting Council has found that NEPCo has established that it has identified a reasonable range of resource options. The Siting Council has made no finding on whether NEPCo established that it (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 resource options.

The Siting Council made no finding on whether NEPCo established that it developed and applied a resource evaluation process which fully evaluates all identified resource options largely because NEPCo has failed to adequately document and describe its resource evaluation process. We expect NEPCo in its next forecast filing to rectify these documentation deficiencies in a manner that will enable the Siting Council to fully review NEPCo's resource evaluation process. Nonetheless, the Siting Council notes that from the evidence offered in this proceeding, NEPCo has developed a sound framework for achieving an appropriate resource evaluation process.

Accordingly, the Siting Council finds that, on balance, NEPCo has established that its supply plan ensures a least-cost energy supply.

F. Conclusions on the Supply Plan

The Siting Council has found that NEPco has established that its supply plan (1) ensures adequate resources to meet projected requirements, and (2) ensures a least-cost energy supply.

Accordingly, the Siting Council hereby APPROVES the 1986 and 1987 supply plans of NEPCo.

IV. DECISION AND ORDER

The Siting Council hereby APPROVES the 1986 and 1987 demand forecasts of the Massachusetts Electric Company, and hereby APPROVES the 1986 and 1987 supply plans of the New England Power Company.

The Siting Council ORDERS Massachusetts Electric Company in its next forecast filing:

(1) to explain in detail the methodology used to support a constant price assumption for electricity in real terms, including (a) a listing of major additions to capacity or major investments of capital planned over the forecast period with estimates of related cost impacts to MECo customers, (b) a full description of analyses performed on each of the basic components of the assumption, and a full description of the methodology used to integrate the results of these analyses, and (c) a full explanation of the methodology used by MECo to determine real prices, including sources of inflation forecasts used by MECo;

(2) to fully explain the relationship between the quadrant system and the methodologies used to forecast individual appliance-type saturations;

(3) to (a) file a complete description of its residential average use per appliance forecast methodology, including the sources and dates of all data and elasticities, and (b) explain why a forecast based on such data is appropriate;

(4) to (a) fully reevaluate its use of constant floor space-per-employee ratios including justification of the use of these ratios with respect to other reasonable methods of commercial floor space growth estimation, (b) undertake further analysis to determine whether or not the EPRI decay function reasonably reflects the rate of decay of floor space within the MECo service territory, (c) explain how it matched historic employment data to building-types, (d) identify the source of historic employment data, (e) specify the base year used in floor space estimations, and (f) explain any assumptions relating to floor space-per-employee ratios for estimates of existing floor space;

(5) to explain fully (a) the basis for and source of data used to determine the age distribution of existing end-use equipment within the MECo service territory, (b) the basis for and source of data used to determine the frequency of replacement for end-use equipment within the MECo service territory, and (c) how fuel competition was accounted for in the cooking end-use fuel share estimate, and what methodology was used to determine the fuel share of the refrigeration end-use;

(6) to (a) use territory-specific elasticity estimates in the commercial forecast, including estimates calculated endogenously within the commercial energy forecast, or to justify use of other estimates, and (b) explain how marginal EUIs were determined to be representative of consumption characteristics for new additions to floor space and end-use replacements within the MECo service territory;

(7) to (a) model computerization and automation as a separate end-use with territory-specific data, or (b) justify continued use of increases to the miscellaneous end-use EUI as a methodology to reflect increasing computerization and automation loads in MECo's commercial sector;

(8) to (a) explain in detail the use of dummy variables, (b) explain in detail the relationship assumed between energy consumption and industrial production growth rates, for SIC groups forecasted on this basis, (c) explain in detail the relationship between the Transportation SIC and real national defense spending, and the premise for that relationship, (d) explain how the specific adjustment was implemented to incorporate price effects in the forecasts of SIC groups without electric price variables and associated coefficients, (e) identify the key factors which determine energy intensiveness of MECo's industrial customers, and establish a logical relationship between these key factors and any future changes in industrial energy intensiveness, and (f) justify in detail any projected reductions in energy intensiveness in the industrial sector that are independent of MECo's industrial model structure, and to explain in detail why that reduction is representative of MECo's industrial customers;

(9) to file forecasts of streetlighting use, sales for resale, internal use, and losses in a form that is fully reviewable;

(10) to explain whether, and if so how, it projected naturally-occuring or market-based changes in customer group consumption patterns, as well as to provide complete descriptions of load-profile development;

(11) to document carefully the use of the sets of monthly peak-load factors; and

(12) to describe and document peak-load forecasting in detail, including a full description of peak-load and econometric models, theoretical assumptions, and logical relationships represented in the peak-load methodology.

The Siting Council FURTHER ORDERS New England Power Company in its next forecast filing:

(13) to provide a detailed analysis of the negotiation and solicitation processes for AE purchases so that the Siting Council can review them as a part of NEPCo's least-cost supply plan;

(14) to analyze for inclusion in its array of new NEPCo-owned generation a wider range of fuels, sizes, capacity factors, and technologies;

(15) to (a) develop a risk management methodology which incorporates a wider range of potential risks facing supply plans, or (b) justify continued use of NEPCo's current risk management methodology;

(16) to implement a methodology which includes an adequate consideration of the environmental impacts of resource options; and

(17) to fully document and describe its methodologies for achieving its diversity and risk management objectives.

The Siting Council FURTHER ORDERS Massachusetts Electric Company and New England Power Company to file their next forecast on May 1, 1990.

Frank P. Pozniak

Frank P. Pozniak
Hearing Officer

Dated this 30th day of March, 1989

UNAMIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of March 30, 1989, by the members and designees present and voting: Sharon M. Pollard (Secretary of Energy Resources); Barbara Anthony (for Paula W. Gold, Secretary of Consumer Affairs and Business Regulation); Jeanette Willett (for Grady Hedgespeth, Secretary of Economic Affairs); Joseph W. Joyce (Public Labor Member); and Madeline Varitimos (Public Environmental Member).

Sharon M. Pollard

Sharon M. Pollard, Chairperson

Dated this 30th day of March, 1989

TABLE 1

Massachusetts Electric Company
Demand Forecast by Customer Class

	Annual Energy Requirements (GWH) 1987	1996	Average Annual Compound Growth Rate 1987-1996
Residential	5,269	5,814	1.1%
Commercial	4,601	6,239	3.4%
Industrial	3,868	4,602	1.9%
Streetlighting	121	121	0.0%
Sales for Resale	5	5	0.0%
Losses/Internal	715	851	1.9%
Total	14,579	17,632	2.1%

	Peak Capacity Requirements (MW) 1987	1996	Average Annual Compound Growth Rate 1987-1996
MECo Winter	3672	3985	.91%
MECo Summer	3731	4196	1.31%

Notes:

a. Energy and peak data include effects of company-sponsored DSM programs.

b. Energy and peak data based on base case.

c. Peak-load data based on New England Power Company as a whole.

Source: Exh. HO-C-2, vol. 3, pp. 48, 118

TABLE 2

New England Power Company
Consolidated Base Case Demand Forecast and Supply Plan

Summer and Winter Peaks (MW)

Year	Capability Responsibility	Existing Capability	Base Case Surplus (Deficit)	Percent
S 1988	4708	4851	143.0	3.0%
W 1988-89	4993	4998	5.0	.1%
S 1989	4906	4991	85.0	1.7%
W 1989-90	5044	5023	(21.0)	-.4%
S 1990	4914	5128	214.0	4.4%
W 1990-91	5105	5437	332.0	6.5%
S 1991	4950	5568	618.0	12.5%
W 1991-92	5099	5610	511.0	10.0%
S 1992	4927	5600	673.0	13.7%
W 1992-93	5089	5582	493.0	9.7%
S 1993	4930	5452	522.0	10.6%
W 1993-94	5114	5486	372.0	7.3%
S 1994	4958	5467	509.0	10.3%
W 1994-95	5156	5501	345.0	6.7%
S 1995	4986	5482	496.0	10.0%
W 1995-96	5185	5531	346.0	6.7%
S 1996	5084	5507	423.0	8.3%
W 1996-97	5287	5541	254.0	4.8%

Source: Exh. HO-C-2, Table E-17; Exh. HO-RR-12

TABLE 3
New England Power Company
Short-Run Contingency Analysis(MW)

Cancellation or Delay of Seabrook 1[a]

Year	Base Load[b] Cap. Res.	Base Rsc.	Loss of Seabrook 1	Contingency Surpl/(Def)
S 1988	4708	4851	0	143.0
W 1988-89	4854	4998	(115)	29.0
S 1989	4767	4991	(115)	109.0
W 1989-1990	4922	5023	(115)	(-14.0)
S 1990	4792	5128	(115)	221.0
W 1990-91	5000	5437	(115)	322.0
S 1991	4845	5568	(115)	608.0
W 1991-92	5154	5610	(115)	341.0

Delay of Hydro Quebec Phase II[c]

Year	Base Load Cap. Res.	Base Rsc.	Delay of H-Q	Contingency Surpl/(Def)
S 1988	4708	4851	0	143.0
W 1988-89	4854	4998	0	144.0
S 1989	4767	4991	0	224.0
W 1989-1990	4922	5023	0	101.0
S 1990	4792	5128	0	336.0
W 1990-91	5000	5437	(162)	275.0
S 1991	4845	5568	(162)	561.0
W 1991-92	5154	5610	(162)	294.0

Loss of Seabrook 1 and Delay of Hydro Quebec Phase II

Year	Base Load Cap. Res.	Base Rsc.	Delay of H-Q&Seabrk	Contingency Surpl/(Def)
S 1988	4708	4851	0	143.0
W 1988-89	4854	4998	(115)	29.0
S 1989	4767	4991	(115)	109.0
W 1989-1990	4922	5023	(115)	(-14.0)
S 1990	4792	5128	(115)	221.0
W 1990-91	5000	5437	(277)	160.0
S 1991	4845	5568	(277)	446.0
W 1991-92	5154	5610	(115)	341.0

Notes:
a. NEPCo assumed it would begin receiving its Seabrook 1 entitlement of 115 MW in Winter of 1988-89.
b. See Table 1 for short-run base case surplus/deficit.
c. NEPCo assumed it would begin receiving its Hydro Quebec Phase II entitlement of 162 MW in Winter of 1990-91.

Sources: Exh. HO-C-2, vol. 2, Table E-17; Exhs. HO-S-8, HO-RR-13

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

Such petition for appeal shall be filed with the Siting Council within twenty days after the date of services of the decision, order or ruling of the Siting Council or within such further time as the Siting Council may allow upon request filed prior to the expiration of twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said Court. (See. 5, Chapter 25, G.L. Ter. Ed., as most recently amended by Chapter 485 of the Acts of 1971).

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Massachusetts Electric Company and New England Power Company, Subsidiaries of New England Electric System, for Approval of its Occasional Supplement to Construct a Single Circuit 3.2-Mile, Overhead 69 Kilovolt Electric Transmission Line	EFSC 88-24(A)

FINAL DECISION

Frank P. Pozniak
Hearing Officer
June 29, 1989

On the Decision:

William S. Febiger

APPEARANCES:

Philip H.R. Cahill, Esq.
Kathryn J. Reid, Esq.
New England Power Service Company
25 Research Drive
Westborough, Massachusetts 01582
FOR: Massachusetts Electric Company
New England Power Company
Petitioner

Stephen H. Oleskey, Esq.
Rushna T. Heneghan, Esq.
Hale and Dorr
60 State Street
Boston, Massachusetts 02109
FOR: Pepperell Power Associates Limited Partnership
Intervenor

TABLE OF CONTENTS

The Energy Facilities Siting Council hereby REJECTS the petition of the Massachusetts Electric Company and New England Power Company to construct a single circuit 3.2-mile, overhead 69 kilovolt electric transmission line in the Towns of Pepperell and Dunstable, included as part of the proposed project, along either the primary route or alternate route described herein.[1]

I. INTRODUCTION

A. Summary of the Proposed Project and Facilities

Massachusetts Electric Company ("MECo") and New England Power Company ("NEPCo") (collectively "Companies") are subsidiaries of the New England Electric System. MECo's service territory includes most of central Massachusetts, and many other communities in diverse locations around the state. New England Electric System, EFSC 86-24, p. 1 (1989) ("1989 NEES Decision"). Total energy output requirements for MECo during 1987 were 115,111,000 megawatthours ("MWH"). Id. MECo is a winter peaking utility with a winter peak load of 2,864 megawatts ("MW"). Id., p. 2. NEPCo supplies almost all of the electricity distributed by MECo. Id. NEPCo's total energy output requirements during 1987 were 21,223,000 MWH while peak demand reached 3,960 MW in the winter of 1987. Id.

After reviewing the Companies' most recent forecast filing, the Energy Facilities Siting Council ("Siting Council")

1/ The rejection of the petition does not preclude the rebuilding of the existing 69 kilovolt transmission line in the Towns of Pepperell and Dunstable in accordance with the single-line plan described herein. See Section II.B.2.d, infra. See also Sections II.B and C, and Section III, infra.

approved MECo's demand forecast and NEPCo's supply plan. Id., p. 74.[2]

The Companies have proposed to construct a single-circuit, 3.2-mile overhead 69 kilovolt ("kV") transmission line in the Towns of Pepperell and Dunstable, which would interconnect a 40 MW gas- and oil-fired cogeneration plant,[3] currently under construction in Pepperell, with the existing 115 kV grid of the Companies (Exh. C-1, pp. 1-2; Exh. PPA-1, p. 2).[4] The total capacity of the cogeneration plant would be wheeled over the Companies' existing 115 kV grid to the Commonwealth Electric Company ("CELCo"), a Massachusetts public utility (id., p. 1).[5]

Pepperell Power Associates Limited Partnership ("PPA"), a Massachusetts limited partnership, is the owner of the 40 MW cogeneration plant (or "PPA plant") (id.). Construction of the cogeneration plant began in July, 1988, and it is expected to be in service by February, 1990 (Tr. III, pp. 52-53; Exhs. PPA-1, p. 3, JRH-14, JRH-15). In addition to generating 40 MW of electricity, the PPA plant will provide an average of 40,000 pounds per hour ("pph") of process steam to the James River

---

2/ In the 1989 NEES Decision, the Siting Council reviewed the 1986 and 1987 demand forecasts of MECo and the 1986 and 1987 supply plans of NEPCo. In addition, the 1988 demand forecast and supply plan was made part of the record in that proceeding to assist the Siting Council in its review of the other two forecast filings.

3/ The cogeneration plant will primarily operate with natural gas as the fuel source, although it is designed to operate with fuel oil if sufficient gas is unavailable (Exh. PPA-1, p. 2).

4/ The interconnection with the 115 kV grid occurs at a substation in Ayer (Exh. C-1, pp. 5, 7-8). See Section II.3.b, infra.

5/ On April 13, 1987, PPA and CELCo executed a 25-year purchased power contract for the entire output from the cogeneration plant (Exh. JRH-16).

Paper Company at Pepperell ("James River"), and can produce up to 90,000 pph of process steam (Exh. PPA-1, pp. 1,3; Tr. III, pp. 59-60). The cogeneration plant has been designated as a qualifying facility ("QF") by the Federal Energy Regulatory Commission ("FERC") (Exh. JRH-7). Finally, James River is located adjacent to the cogeneration plant (Exh. PPA-1, p. 2).

The Company identified two routes for the proposed 69 kV line: a primary route and an alternate route (Exh. C-1, pp. 7-8). Both routes are approximately 3.2 miles in length (id., p. 2; Revised Description).[6] The primary route originates at the PPA plant, located on the westerly side of the Nashua River, adjacent to James River (id., Revised Description). From the cogeneration plant, the route runs easterly spanning a rebuilt covered bridge known as the Memorial Bridge at the Groton Street crossing of the Nashua River, to a point 30 feet south of the centerline of the Companies' existing 69 kV transmission line,[7] a total distance of approximately 500 feet from the cogeneration plant (id.; Exh HO-2; Tr. 2, p. 104). The point 30 feet from the existing 69 kV line is located within an existing

6/ On January 26, 1989, the Companies filed revised descriptions of the primary and alternate routes. The revised descriptions are included as part of Exhibit C-1, the Companies' Occasional Supplement.

7/ This 69 kV line runs along the existing right-of-way between the Dunstable substation in Dunstable and the Groton Street substation in Pepperell, and is an extension of a 69 kV line that runs between a substation in Ayer and the Dunstable substation (Exh. C-1, Exhibit S-1). The Companies have designated this existing transmission line between the substation in Ayer and the Groton Street substation as the O-42 line (id.). However, the Companies indicated that they plan to redesignate the segment of the existing 0-42 line between the Dunstable substation and the Groton Street substation as the S-45 line if the proposed 69 kV line is built (Exh. C-2, pp. 4-5). The Companies indicated that they then plan to designate the proposed 69 kV line as the O-42 line (id.).

right-of-way of the Companies' (Exh. C-1, Revised Description; Tr. 2, pp. 29-30).[8] From that point, the primary route runs within the existing right-of-way for its entire distance, first in an east-northeasterly direction for a distance of approximately 1.2 miles crossing Groton Street, the Nashua River, the Boston & Maine Railroad, the Nissitissit River, the Nashua River, and the Pepperell-Dunstable town line, and then in an east-southeasterly direction for a distance of approximately 1.1 miles to a point in Dunstable after crossing the Boston & Maine Railroad, the Dunstable-Pepperell town line, River Street in Pepperell, the Pepperell-Dunstable town line, and the Unkety Brook (Exh. C-1, Revised Description). From the point in Dunstable, the primary route runs in an easterly direction for a distance of approximately .7 miles, and then turns in a southerly direction for a distance of approximately 900 feet to a substation in Dunstable ("Dunstable substation") (id.). The width of the existing right-of-way is approximately 100 feet (Exh. JFV-4).

The alternate route extends almost entirely along state and town roads in Pepperell and Dunstable (Exh. C-1, Revised Description). The alternate route begins at the cogeneration plant, and runs easterly across the Nashua River to Groton Street, a distance of approximately 500 feet (id.). It then proceeds southerly along Groton Street for a distance of approximately 175 feet to its intersection with Lowell Road (Route 113), then easterly along Lowell Road for a distance of approximately 2.3 miles to the Pepperell-Dunstable town line (id.). In Dunstable, Lowell Road becomes Pleasant Street, and the alternate route continues in a generally northeasterly and

---

8/ For the 500 feet of distance between the cogeneration plant and the existing right-of-way, the Companies' indicated that they plan to obtain an easement for a new right-of-way from James River, the owner of the property (Exh. HO-E-5). As of the close of the proceeding, the Companies had not acquired this property.

easterly direction along Pleasant Street for a distance of approximately .8 miles to the Dunstable substation.

This is the first case in which a utility has submitted a proposal to construct a transmission line that would connect a non-jurisdictional cogeneration plant to the existing transmission grid.

B. Procedural History

On October 27, 1988, the Companies filed an Occasional Supplement with the Siting Council requesting approval to construct the proposed 69 kV line. On March 8, 1989, the Siting Council conducted a public hearing in Pepperell. In accordance with the directions of the Hearing Officer, the Companies provided confirmation of publication, posting, and mailing of the Notice of Public Hearing and Adjudication.

On March 15, 1989, PPA filed a petition to intervene in the proceeding. On March 23, 1989, the Hearing Officer issued a Procedural Order granting such petition.

The Siting Council conducted evidentiary hearings on April 25 and 28, 1989. The Companies presented six witnesses: Gordon E. Marquis, senior environmentalist; Robert H. Snow, manager of transmission and supply planning; David L. Therrien, supervisor of licenses and permits; Rufin VanBossuyt, Jr., system forester; John F. Vance, manager of transmission engineering; and Jonathan M. Charry, president and director of Research Laboratories, Environmental Research Information, Inc., consulting environmentalists. PPA presented two witnesses: J. Ronald Hosie, project manager; and Gene Thomas, vice-president and general manager of James River.

The Hearing Officer offered 87 exhibits into the record, largely composed of the Companies' responses to information and record requests. The Companies presented 11 exhibits into the record. PPA offered 22 exhibits into the record.

Pursuant to a schedule established by the Hearing Officer, PPA filed its brief on May 26, 1989. The Companies filed its brief on May 31, 1989, and a revised brief on June 5, 1989.

C. Jurisdiction

The Companies' Occasional Supplement is filed in accordance with G.L. c. 164, sec. 69H, which requires the Siting Council to ensure a necessary energy supply for the Commonwealth with minimum impact on the environment at the lowest possible cost, and G.L. c. 164, sec. 69I, which requires electric companies to obtain Siting Council approval for construction of proposed or alternative facilities at proposed or alternative sites before a construction permit may be issued by any other state agency.

The Companies' proposal to construct the single-circuit, 3.2-mile overhead 69 kV electric transmission line falls squarely within the second definition of "facility" set forth in G.L. c. 164, sec. 69G. That section gives the Siting Council jurisdiction over any new electric transmission line having a design rating of sixty-nine kilovolts or more which is one mile or more in length except reconductoring or rebuilding of existing transmission lines at the same voltage.

The construction of the 40 MW cogeneration plant does not fall within the first definition of "facility" set forth in G.L. c. 164, sec. 69G. This definition provides that a facility is "any bulk generating unit, including associated buildings and structures, designed for, or capable of operating at a gross capacity of one hundred megawatts or more." Further, the 40 MW cogeneration plant does not fall within the third definition of facility set forth in G.L. c. 164, sec. 69G. The third definition provides that a facility is "any ancillary structure including fuel storage facilities which are an integrated part of the operation of any electric generating unit or transmission line which is a facility." In Commonwealth Electric Company, 17 DOMSC 249, 259-265 (1988) ("1988 CELCo Decision"), the Siting Council established a two part standard for determining whether a structure is a facility for the purposes of the third definition. A structure is a facility under G.L. c. 164, sec. 69G, if: (1) the structure is subordinate or supplementary to a jurisdictional facility; and (2) the structure provides no benefit outside of its relationship to the jurisdictional facility. Id. Here, the 40 MW cogeneration plant is not subordinate or supplementary to the jurisdictional facility.[9]

In accordance with G.L. c. 164, sec. 69H, before approving an application to construct facilities, the Siting Council requires applicants to justify facility applications in three phases. First, the Siting Council requires the applicant to show that the facilities are needed (see Section II.A, infra). Next, the Siting Council requires the applicant to present plans that satisfy the previously identified need and that are superior to alternative plans in terms of reliability, cost, and environmental impacts (see Section III.B, infra). Finally, the Siting Council requires the applicant to show that the proposed site for the facility is superior to alternate sites in terms of cost, environmental impacts, and reliability of supply.

9/ While the 40 MW cogeneration plant is not a jurisdictional facility, certain information regarding the cogeneration plant is necessary for determining whether additional energy resources are needed in Massachusetts. See Section II.A, infra.

II. ANALYSIS OF THE PROPOSED PROJECT

A. Need Analysis

1. Standard of Review

In accordance with G.L. c. 164, sec. 69H, the Siting Council is charged with the responsibility for implementing energy policies to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

In carrying out this statutory mandate with respect to proposals to construct energy facilities in the Commonwealth, the Siting Council evaluates whether there is a need for additional energy resources to meet reliability or economic efficiency objectives.[10] The Siting Council therefore must find that additional energy resources are needed as a prerequisite to approving proposed energy facilities.

In evaluating the need for new energy facilities to meet reliability objectives, the Siting Council has evaluated the reliability of supply systems in the event of changes in demand or supply or in the event of certain contingencies. With respect to changes in demand or supply, the Siting Council has found that new capacity is needed where projected future capacity available to the system is found to be inadequate to satisfy projected load and reserve requirements. Altresco-Pittsfield, Inc., 17 DOMSC 351, 359-369 (1986) ("Altresco"); Northeast Energy Associates, 16 DOMSC 335, 344-360 (1987) ("NEA"); Cambridge Electric Light Company,

---

10/ In this discussion, "additional energy resources" is used generically to mean both energy and capacity additions, including, but not limited to, electric generating facilities, electric transmission lines, energy or capacity associated with power sales agreements, and energy or capacity associated with conservation and load management.

15 DOMSC 187, 211-212 (1986) ("1986 CELCo Decision"); Massachusetts Electric Company, 13 DOMSC 119, 137-138 (1985) ("1985 MECo Decision"); New England Electric System, 2 DOMSC 1, 9 (1977). With regard to contingencies, the Siting Council has found that new capacity is needed in order to ensure that service to firm customers can be maintained in the event that a reasonably likely contingency occurs. Middleborough Gas and Electric Department, 17 DOMSC 197, 216-219 (1988) ("Middleborough"); Boston Edison Company, 13 DOMSC 63, 70-73 (1985) ("1985 BECo Decision"); Taunton Municipal Lighting Plant, 8 DOMSC 148, 154-155 (1982) ("Taunton"); Commonwealth Electric Company, 6 DOMSC 33, 42-44 (1981); Eastern Utilities Associates, 1 DOMSC 312, 316-318 (1977).

The Siting Council also has determined in some instances that utilities need to add energy resources primarily for economic efficiency purposes. The Siting Council has found that a utility's proposed energy facility was needed principally for providing economic energy supplies relative to a system without the proposed facility. 1985 MECo Decision, 13 DOMSC at 178-179, 183, 187, 246-247; Boston Gas Company, 11 DOMSC 159, 166-168 (1984).

While G.L. c. 164, sec. 69H, requires the Siting Council to ensure an adequate supply of energy for Massachusetts, the Siting Council has interpreted this mandate broadly to encompass not only evaluations of specific need within Massachusetts for new energy resources (1988 CELCo Decision, 17 DOMSC at 266-279; Middleborough, 17 DOMSC at 216-219; 1985 BECo Decision, 13 DOMSC at 70-73), but also the consideration of whether proposals to construct energy facilities within the Commonwealth are needed to meet New England's energy needs. Altresco, 17 DOMSC at 359-365; NEA, 16 DOMSC at 344-354; Massachusetts Electric Company, 15 DOMSC 241, 273, 281 (1986); 1985 MECo Decision, 13 DOMSC at 129-131, 133, 138, 141. In so doing, the Siting Council has fulfilled the requirements of G.L. c. 164, sec. 69J, which recognizes that Massachusetts' generation and transmission system is interconnected with the region's and that reliability and economic benefits flow to Massachusetts from Massachusetts' utilities' participation in the New England Power Pool ("NEPOOL").

Here, the Siting Council is presented with a proposal by a utility to construct a jurisdictional transmission line that would connect a non-jurisdictional cogeneration plant constructed by a non-utility developer to the regional transmission system. In cases such as this, whether the proponent is a utility or a non-utility developer, the proponent first must establish that the power from the non-jurisdictional cogeneration plant is needed on either reliability or economic efficiency grounds. If it can be established that the cogeneration plant is needed, the proponent then must show that the existing transmission system is inadequate to support this new power source and that additional energy resources are necessary to accommodate the new power source. Turners Falls Limited Partnership, EFSC 88-101, pp. 10-21 (1988) ("Turners Falls").

In setting this standard, the Siting Council emphasizes that our review of need is not limited to the need for a physical connection between a non-jurisdictional cogeneration plant and the electric transmission grid or end-users. To address the need issue here so narrowly would be inconsistent with our need analysis for other facilities, as well as with our statutory mandate. It also is important to emphasize that the scope of our review here is not premised on general jurisdiction over the cogeneration facility. In fact, we readily acknowledge that the cogeneration plant is non-jurisdictional and can be constructed and operated without our approval. Instead, our review initially is focused exclusively upon the need for the power generated by the non-jurisdictional facility because the need for this power must be established before the Siting Council can determine whether additional jurisdictional energy resources are needed.

2. Need for the Non-Jurisdictional Cogeneration Plant

a. Standard of Review

In order to evaluate the need for the additional power resources from the non-jurisdictional cogeneration plant, the Siting Council first must identify whether: (1) all power purchasers are known and the power will be distributed in Massachusetts; or (2) some power purchasers are as yet unknown or some power will be distributed outside of Massachusetts.

In the first case, in order to establish need, the Siting Council requires a demonstration that the utility purchaser needs the additional power resources either to address reliability concerns or for economic efficiency reasons.

In the second case, in order to establish need, a two-part demonstration is required. The proponent must demonstrate that there is a regional need based on reliability or economic efficiency grounds. The proponent also must demonstrate that the additional power resources result in Massachusetts benefits -- that is they must result in a significant level of reliability, economic efficiency, environmental, or other benefits to the Commonwealth. Turners Falls, EFSC 88-101 at 10; Altresco, 17 DOMSC at 360-361.

b. Need for Additional Power Resources

The Companies have demonstrated that CELCo has contracted with PPA to purchase the total capacity of the cogeneration plant (Exhs. PPA-1, p. 4, JRH-16).[11] Under the terms of the contract, the cogeneration plant will provide a

---

11/ The Companies stated that the PPA plant is currently under construction, and is expected to be in-service by February 1990 (Exhs. PPA-1, p. 3, JRH-14, JRH-15).

portion of CELCo's NEPOOL capability responsibility, and also will be available for NEPOOL dispatch (Exh. JRH-18). The Massachusetts Department of Public Utilites ("MDPU") approved the contract on July 9, 1987 (Exh. PPA-1, p. 3; Exh. JHR-11).

The Siting Council has found in past decisions that: (1) a signed and approved power sales agreement between a QF and a utility constitutes prima facie evidence of the utility's need for additional energy resources for economic efficiency purposes; and (2) a signed and approved power sales agreement which includes a capacity payment constitutes prima facie evidence of the need for additional energy resources for reliability purposes. Turners Falls, EFSC 88-101 at 13; NEA, 16 DOMSC at 358. In previous decisions, the Siting Council also has found that, consistent with current resource use and development policies of the Commonwealth, ratepayers in Massachusetts benefit economically from the addition of cost effective QF resources to their utilities' supply mix. Altresco, 17 DOMSC at 366; NEA, 16 DOMSC at 358.

Here, the Companies have provided the signed agreement between PPA and CELCo for the purchase of the total plant output beginning in 1990, and this agreement has been approved by the MDPU (Exh. PPA-1, pp. 3-4; Exhs. JHR-11, JHR-16). In addition, the contract includes provisions for capacity payments to PPA (Exh. JHR-16). Thus, the Siting Council finds that the Companies have established that the power from the non-jurisdictional cogeneration plant is needed on reliability or economic efficiency grounds.

Accordingly, the Siting Council finds that the Companies have established the need for additional power resources from the non-jurisdictional cogeneration plant.

3. Need for Additional Transmission Capacity

a. Standard of Review

As noted previously, this is the first case before the

Siting Council in which a utility has proposed the construction of a transmission facility which would link a non-utility-owned cogeneration plant to the regional transmission system. While this is the first case in which the Siting Council has reviewed such a proposal from a utility, the standard of review for need as applied in previous transmission facility cases remains essentially unchanged. The mere fact that the utility proposing the transmission facility acts as a transporter rather than a purchaser of the output from the cogeneration plant has no effect on the physical limitations of the existing system. Consequently, the Siting Council's review of the need for the proposed transmission facility proceeds in the same manner as if a utility were proposing a facility to serve its own load growth or supply addition. In the final analysis, the need for energy resources in the form of additional transmission capacity hinges upon the adequacy of the existing system to accommodate both its current system needs, including anticipated system growth, as well as the new source of supply.

In previous cases, the Siting Council has found that additional transmission facilities are needed to meet reliability objectives in the event of changes in demand or supply, or in the case of certain contingencies. See Section II.A.1, supra. Therefore, the Siting Council reviews the utility's existing transmission system and its adequacy in relation to: (1) the Companies' reliability objectives and load projections; and (2) the new supply source.

b. Description of the Existing System

The PPA plant is located near the end of a radial 69 kV transmission line that is part of a larger 69 kV system serving the Companies' Ayer power supply area (Exh. C-1, Exhibit S-1). The nearest source of supply for the 69 kV system in the area of the proposed project is a 115 kV/69 kV substation in Ayer ("Ayer substation") (id.). The existing Ayer power supply area is shown in Figure 1.

From the Ayer substation, one 69 kV transmission line ("existing R-43 line") extends 9.4 miles on an existing right-of-way through the Town of Groton to the Dunstable substation, supplying one of two transformers at a distribution-level substation in the Town of Groton for the Groton municipal system ("Groton municipal substation"), and a single transformer at the Dunstable substation, which also is a distribution-level substation (id.). A second 69 kV transmission line ("existing O-42 line") extends parallel to the existing R-43 line from the Ayer substation to the Dunstable substation, serving a second transformer at the Groton municipal substation and providing a backup supply to the Dunstable substation (id.). The existing O-42 line then continues for an additional 3.2 miles from the Dunstable substation into Pepperell, where it supplies both a single transformer at a distribution-level substation in Pepperell ("Groton Street substation") and a transformer directly serving James River also in Pepperell ("James River substation") (id.).

Finally, the Companies indicated that the poles along the segment of the existing O-42 line between the Dunstable substation and the Groton Street substation are wood structures (Southern Yellow Pine) and with exceptions, range in height from 30 to 55 feet (Exh. HO-E-2). The Companies indicated that the exceptions exist in Pepperell where 80 and 85 foot poles are used to span the Memorial Bridge (id.).

c. Adequacy of the Existing System

i. Ability to Accommodate Current System Needs and Anticipated Load Growth

In regard to reliability objectives, the Companies provided service reliability and area supply planning criteria applicable to the classes of transmission and distribution found in the proposed project area (Exh. HO-N-2). The Companies' criteria indicated that the supply system should be designed so that: (1) there are no contiguous load areas in excess of 30 MW that are not provided with firm supply (i.e. redundant transmission capacity); and (2) there are no load areas in excess of 20 MW that experience a three-hour outage more often than once in three years, or a 24-hour outage more often than once in ten years (id.). The Company also provided economic criteria indicating that investments in system improvements should be made based on an expectation that cumulative present worth revenue requirements will be reduced, provided that the break-even point occurs within five years of the initial investment (id.).

In regard to current system needs and anticipated growth in relation to transmission requirements, the Companies provided forecasted annual summer and winter peak load for proposed project area substations in the years 1989-2002 (Exhs. HO-N-1). The Companies forecasted that summer peak load at the substations served by the existing O-42 and R-43 lines (Ayer substation, Groton muncipal substation, Dunstable substation, Groton Street substation, and James River substation) will increase from 17.8 MW in 1989 to 24.1 MW by the year 2002, and that winter peak load will increase from 24.8 MW in 1989 to 29.9 MW by the year 2002 (id.).

The Companies also provided forecasted load flow information for 69 kV transmission and low-voltage systems in the proposed project area for the summer of 1990, and identified capacity limits in the transmission and distribution system (Exhs. HO-N-3, HO-N-13; Tr. 3, pp. 17-22). The Companies provided that the existing O-42 line and the existing R-43 line each have an existing summer capacity of 18 megavaramperes ("MVA"), and an existing winter capacity of 28 MVA (Exh. C-1, Exhibit S-3). Additionally, the Companies forecasted the combined peak load of the Groton Street substation and the James River substation by the year 2002 to be 10.9 MW in the summer and 13.1 MW in the winter (Exh. HO-N-1), well below the firm-load thresholds established in the Companies' service reliability criteria.

Finally, the Companies provided information on unplanned outages on the existing R-43 and O-42 lines, and at the Dunstable and Groton street substations which supply the distribution system in the area of the proposed project (Exh. HO-N-16). The Companies noted that, in the last ten years, the Groton Street substation in Pepperell had experienced only one service interruption (id.). In sum, the Companies stated that, based on their reliability and planning criteria and prior to being contacted by PPA about transmission support for the cogeneration plant, there was no need to make system improvements in the service area of the existing O-42 and R-43 lines (Exh. HO-N-4).

In determining the adequacy of the existing system to meet the current system needs and anticipated growth, the Siting Council considers both the Companies' load flow studies and reliability criteria.

In support of their criteria, the Companies asserted that "if reliability standards were lower, customers would object enough to require raising the standards, while if reliability standards were higher, system investment and operating costs would be higher" (Exh. HO-RR-19). However, the Companies provided no analysis of customer complaints or of system costs to support their contention. Further, in response to inquiries by the Siting Council, the Companies failed to justify their criteria based on comparison with industry practices (id.).

Establishing thresholds for firm supply based on size of contiguous load appears reasonable, as does the approach of establishing a lower threshold where outage experience indicates customers would benefit more from investment in improved reliability. However, based on the record, the Siting Council cannot conclude that the Companies' criteria are appropriate without more complete and detailed documentation and analysis of the factors that justify the specific load levels reflected in the criteria. Consequently, the Siting Council makes no findings in this review as to the appropriateness of the Companies' service reliability and area supply planning criteria.[12]

In regard to the forecasted load flow and line capacity information provided by the Companies, the Siting Council finds that the Groton Street substation and the James River substation in Pepperell currently are supplied with adequate transmission to meet forecasted needs on a non-firm basis. In addition, the Siting Council finds that the forecasted load flow and line capacity information presented by the Companies establishes that the Dunstable substation currently is supplied with adequate transmission to meet forecasted needs on a firm basis.

Accordingly, the Siting Council finds that the Companies have established that the existing system is adequate to support the current system needs and anticipated load growth.

ii. Ability to Accommodate New Supply Source

The Companies stated that the electric power output of the cogeneration plant will exceed the present electric capacity of the existing O-42 line between the Dunstable substation and the Groton Street substation in Pepperell (Exh. C-1, p. 2). The Companies further indicated that the PPA load will exceed the combined summer capacity of the existing O-42 and R-43 lines between the Ayer substation and the Dunstable substation (id.).

12/ The Companies' service reliability and area supply planning criteria have been of considerable interest in the Siting Council's overall review, not only with respect to determining need, but also with respect to the comparison of alternative project approaches based on reliability, cost, and environmental impacts. Additional concerns with respect to the Companies' service reliability and area supply plannning criteria are noted in the Siting Council's review of the comparison of the proposed project and alternative approaches (see Section II.B, *infra*).

In support of its position, the Companies provided load flow information indicating that operation of the cogeneration plant at full capacity would require transmission of up to 40 MW of additional load on the existing transmission system between the Dunstable substation and the Groton Street substation, and up to a 34.3 MW load on the two 69 kV transmission lines between the Dunstable substation and the Ayer substation (Exhs. HO-N-6, HO-N-7). Given the existing summer capacity limit of 18 MVA on the segment of the existing O-42 line between the Dunstable substation and the Groton Street substation, the Companies have demonstrated that the existing transmission system is inadequate to carry the 40 MW load from the PPA plant (Exh. C-1, Exhibit S-3).

Based on the foregoing, the Siting Council finds that the Companies have established that the existing transmission system is inadequate to meet the needs of the new supply source. Accordingly, the Siting Council finds that the Companies have established that there is a need for additional energy resources to accommodate the new supply source.

4. Conclusions on Need

The Siting Council has found that the Companies have established: (1) the need for additional energy resources from the non-jurisdictional cogeneration plant; (2) that the existing system is adequate to support the current system needs and anticipated load growth; (3) that the existing system is inadequate to meet the needs of the new supply source; and (4) that there is a need for additional energy resources to accommodate the new supply source.

Accordingly, the Siting Council finds that additional energy resources are needed.

B. Comparison of the Proposed Project and Alternative Approaches

1. Standard of Review

G.L. c. 164, sec. 69H, requires the Siting Council to evaluate proposed projects in terms of their consistency with providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at lowest possible cost. In addition, G.L. c. 164, sec. 69I, requires a project proponent to present "alternatives to planned action" which may include (a) other methods of generating, manufacturing, or storing, (b) other sources of electrical power or gas, and (c) no additional electrical power or gas.[13]

In implementing its statutory mandate, the Siting Council has required a petitioner to show that, on balance, its proposed project is superior to alternative approaches in terms of cost, environmental impact, and ability to meet the previously identified need. Turners Falls, EFSC 88-101 at 28; Braintree Electric Light Department, EFSC 87-32, p. 24 (1988) ("Braintree"); 1988 CELCo Decision, 17 DOMSC at 279-288; Middleborough, 17 DOMSC at 219-225; 1986 CELCo Decision, 15 DOMSC at 212-218; 1985 MECo Decision, 13 DOMSC at 141-183; 1985 BECo Decision, 13 DOMSC at 67-68, 73-74. In review of proposed facilities, the Siting Council has required a petitioner to show that the proposed site for the facility is superior to the alternative site(s), on the basis of balancing cost, environmental impacts, and reliability of supply. Braintree, EFSC 87-32 at 28; 1988 CELCo Decision, 17 DOMSC at 298-303; Middleborough, 17 DOMSC at 227-228; NEA, 16 DOMSC at 381-409; 1986 CELCo Decision, 15 DOMSC at 195-196, 229-237; Hingham

---

13/ G.L. c. 164, sec. 69I, also requires a petitioner to provide a description of "other site locations."

Municipal Lighting Plant, 14 DOMSC 7, 22-32 (1986). Similarly, a proposed project and alternative approaches may offer varying levels of reliability to a company's supply system. While in the past the Siting Council has not required a petitioner to consider reliability of supply as part of its showing that its proposed project is superior to alternative approaches, the Siting Council will require a petitioner to make this showing in future reviews.

2. Project Approaches to the Identified Need

The Siting Council considers four project approaches to meet the identified need: the Companies' proposed project; the Companies' alternative project approach of reconductoring the existing O-42 line between the Ayer substation and the Groton Street substation -- herein referred to as the reconductoring plan; and two other alternative project approaches raised by the Siting Council staff -- herein referred to as the firm-supply plan and the single-line plan. The four project approaches are described below.

a. Proposed Project Approach

The Companies' proposed project approach consists of: (1) constructing the proposed 3.2-mile 69 kV line between the

Dunstable substation and the PPA plant in Pepperell;[14] and (2) upgrading with larger conductors 9.4 miles of the existing 0-42 line between the Ayer substation and the Dunstable substation to carry the PPA load at the existing voltage of 69 kV (Exh. C-1, pp. 2-3, 7-8; Exh. C-2, p. 4).[15] See Figure 2. The segment of the existing 0-42 line that is not proposed for upgrading, a segment that extends from the Dunstable substation to the Groton Street substation in Pepperell (and also serves the James River substation in Pepperell), would be retained as a 3.2-mile tap line extension from the upgraded existing 0-42 line at the Dunstable substation (Exh. C-2, p. 5). The upgraded existing 0-42 line and the proposed 69 kV line would interconnect the 40 MW PPA plant to the 115 kV transmission grid at the Ayer substation (Exh. C-1, pp. 5, 7-8). With operation of the PPA plant at full capacity, all existing loads tapped on the existing 0-42 line would continue to be served by that line, but the direction of net power flow on the upgraded existing 0-42 line would run from the PPA plant back to Ayer substation -- a reversal of the current condition (Exhs. HO-N-6, HO-N-7).

The Companies specified that the poles along the proposed 69 kV line would be wood structures (Southern Yellow Pine or Douglas Fir) and would range in height from 35 to 55 feet, with the exception that poles 80 and 85 feet in height

---

14/ The Companies identified two possible routes for the proposed 69 kV line. The primary route extends predominantly along an existing right of way; the alternate route extends predominantly along state and town roads (see Section I.A, supra).

15/ The Companies indicated that they would use 477 MCM aluminum steel-reinforced ("477 ACSR") conductors to construct new circuits, or to upgrade the existing smaller circuits with larger conductors, as part of the proposed project approach or any of the alternative project approaches (Exh. C-2, p. 5; Exhs. HO-N-9, HO-N-10). The Companies stated that the 477 ACSR circuits would have a normal summer capacity of 96 MVA (Tr. 3, pp. 131-132).

would be used to span the Memorial Bridge (Exhs. HO-E-2, HO-RR-5). The Companies also specified that, wherever possible, the pole heights would be equivalent to the height of the poles along the segment of the existing O-42 line between the Dunstable substation and the Groton Street substation (Exh. HO-E-2).

The Siting Council finds that, based on the record in this proceeding, the proposed project approach would meet the identified need to interconnect the PPA plant.

b. Reconductoring Plan

The Companies indicated that they considered one alternative 69 kV project approach to meet the identified need: upgrading with larger conductors the existing O-42 line along its present alignment for the full 12.6-mile distance between the Ayer substation and the Groton Street substation in Pepperell (Exh. C-1, pp. 6-7; Exh HO-A-1).[16]

16/ The Companies indicated that they considered two other project approaches as part of an initial screening analysis, including: (1) upgrading with larger conductors the segment of the existing O-42 line between the Dunstable substation and the Groton Street substation, while relying on parallel operation of the existing R-43 and O-42 lines between the Ayer substation and the Dunstable substation; and (2) constructing a 3.2-mile 69 kV line between the Dunstable substation and the PPA plant, and upgrading with larger conductors both the existing R-43 and O-42 lines to provide firm capacity for carrying the PPA load between the Ayer substation and the Dunstable substation at the existing voltage (Exh. HO-A-1). The Companies indicated that, based on consultation with PPA, they eliminated the first option based on its higher cost and less certain reliability compared to the proposed project, and eliminated the second option based on its substantially higher cost (Tr. 3, pp. 43-47; Exh. HO-N-5).

The Companies did not pursue alternative project approaches involving voltages other than 69 kV. The Companies stated that the capacity of the 13.8 kV distribution system in the area is far too low, and that a 115 kV interconnection is unrealistic based on the 10-mile distance to the nearest 115 kV tap point and the lack of additional right-of-way in the area of the proposed project (Exh. HO-A-1).

The Siting Council finds that, based on the record in this proceeding, the reconductoring plan would meet the identified need to interconnect the PPA plant.

The Siting Council notes that reconductoring the entire 12.6 miles of the existing 0-42 line between the Ayer substation and the Groton Street substation under the reconductoring plan, as it has been presented here, is expressly excluded from the second definition of "facility" contained in G.L. c. 164, sec. 69G (see Section I.C, _infra_), and therefore is not considered to be a facility requiring Siting Council approval.

c. _Firm-Supply Plan_

In response to a request of the Siting Council staff, the Companies addressed an additional alternative 69 kV project approach to meet the identified need. This approach, referred to as the firm-supply plan, consists of: (1) constructing a 3.2-mile 69 kV line between the Dunstable substation and the PPA plant in Pepperell, serving the James River substation and the Groton Street substation via a direct tap of the 69 kV line near its terminus at the PPA plant (rather than near its origin at the Dunstable substation) with associated switching to allow firm transmission capabilities for supplying these local substation loads; and (2) upgrading with larger conductors the existing O-42 line between the Ayer substation and the Dunstable substation to carry the PPA load (Exhs. HO-RR-16, HO-RR-24). Under this project approach, the segment of the existing O-42 line between the Dunstable substation and the Groton Street substation in Pepperell would not be upgraded with larger conductors, but retained at its existing size as a backup line to serve the Groton Street substation and the James River substation under the contingency of a loss of the 69 kV line and the simultaneous shutdown of the PPA plant.

The Companies indicated that the firm-supply plan would meet the identified need to interconnect the PPA plant (Tr. 3, pp. 136-137). Accordingly, the Siting Council finds that the firm-supply plan would meet the identified need to interconnect the PPA plant.

d. Single-Line Plan

In response to a request of the Siting Council staff, the Companies addressed a second additional alternative 69 kV project approach to meet the identified need. This approach, referred to as the single-line plan, consists of: (1) rebuilding on a parallel alignment within the same right of way, with larger conductors and with poles of comparable size and materials, the segment of the existing O-42 line between the Dunstable substation and the Groton Street substation; and (2) upgrading with larger conductors the segment of the existing O-42 line between the Ayer substation and the Dunstable substation to carry the PPA load (Exh. HO-RR-24A). Under this project approach, the segment of the existing O-42 line between the Dunstable substation and the Groton Street substation would be retired, and the rebuilt line would be constructed according to the same specifications and alignment as the proposed 69 kV line that would be constructed under the proposed project approach.

The Companies indicated that the single-line plan would meet the identified need to interconnect the PPA plant (Tr. 3, pp. 136-137). Accordingly, the Siting Council finds that the firm supply plan would meet the identified need to interconnect the PPA plant.

The Siting Council notes that rebuilding the segment of the existing O-42 line between the Dunstable substation and the Groton Street substation on the existing right-of-way under the single-line plan, as it has been presented here, is expressly excluded from the second definition of "facility" contained in G.L. c. 164, sec. 69G (see Section I.C, infra), and therefore is not considered to be a facility requiring Siting Council approval.

e. Conclusions on Project Approaches to the Identified Need

The Siting Council has found that the proposed project approach, the reconductoring plan, the firm-supply plan, and the single-line plan all would meet the identified need to interconnect the PPA plant. The Siting Council compares these project approaches with respect to reliability, cost, and environmental impacts.

3. Reliability

Each of the identified project approaches uses 69 kV reinforcements to interconnect the PPA plant with the 115 kV transmission grid at Ayer substation (Exh. C-1, p. 15). The Companies provided system diagrams and load flow information that show expected conditions assuming operation of the PPA plant at full capacity and interconnection of the PPA plant output via the proposed or rebuilt 69 kV line and the upgraded existing O-42 line (Exh. C-1, Exhibit S-5; Exhs. HO-N-7, HO-N-9, HO-N-10). This data indicate that the existing substation loads on the existing O-42 line can continue to be adequately supplied by tapping the existing O-42 line after the reinforcements are completed (id.).

With respect to system operation after the PPA plant is interconnected, the Companies provided no evidence that the proposed project approach, the single-line plan, or the reconductoring plan would either improve or adversely affect reliability of supply to existing substations in the project area. With respect to system operation during the construction period, however, the Companies stated that the existing O-42 line between the Dunstable substation and the Groton Street substation is the only source of supply to the Groton Street substation and the James River substation, and thus could not be deenergized for purposes of implementing the reconductoring plan (Exh. C-1, p. 7). The Companies provided load flow information that supports their position that under the reconductoring plan, it would be necessary to reconductor the existing line while energized in order to ensure reliability of supply under various expected load conditions (Exh. HO-N-13; Tr. 3, pp. 17-21). The Companies asserted that reconductoring an energized line requires special working procedures and increases the risk of unplanned service outages during construction (Exh. C-1, p. 7; Exh. C-2, p. 12).

In regard to the firm-supply plan, the Companies assumed that the backup transmission line and related equipment would be designed to operate as reliably as the existing 0-42 line in supplying the Groton Street substation and the James River substation (Exh. HO-RR-22C). Based on the redundant supply capability, the Companies stated that the firm-supply plan would provide a "small but unneeded" improvement in supply reliability for the Groton Street substation (Exh. HO-N-5).

The combined peak load at the Groton Street substation and the James River substation is forecast to reach 13.1 MW by 2002 (Exh. HO-N-1). However, the Companies indicated that the Groton Street substation had experienced only one service interruption in the last ten years, 22 minutes in length (Exh. HO-N-16; Tr. 3, pp. 35-36). The Company further asserted that affected load would have to be 30 MW or greater to meet the Companies' threshold for establishing need to provide firm supply (Exh. HO-N-2; Tr. 3, pp. 33-36).

The opportunity to provide a new firm supply to a contiguous load -- even a load below the Companies' size threshold for establishing need -- is a potentially important factor in the review of proposed and alternative project approaches.[17] Here, given the forecasted 2002 load of 13.1 MW, the provision of a firm supply to the Groton Street

---

17/ There is not sufficient evidence in the record to determine whether the Companies' reliability threshold is appropriate. See Section II.A.3.c.i, <u>infra</u>.

substation and the James River substation is an important reliability benefit of the firm-supply plan.

Nonetheless, the Siting Council notes that this is the first time that a company's proposed project approach has been compared with alternative project approaches with respect to reliability of supply. While we have some serious concerns regarding reliability benefits of the firm-supply plan that may have been overlooked, holding the Companies to a new reliability standard without affording the Companies the opportunity to amend its filing to comply with this standard would be inappropriate. In future facility proposal reviews, the Siting Council will require a petitioner to consider reliability of supply as part of its showing that its proposed project is superior to alternative approaches.

Accordingly, for the purposes of this review, the Siting Council finds, with respect to reliability of supply, that the proposed project approach and single-line plan are comparable, and that both are superior to the reconductoring plan. In addition, the Siting Council makes no finding in regard to the reliability of the firm-supply plan.

4. Cost

The Companies estimated that the total cost of the proposed project in 1989 dollars would be $1,489,100, comprising $601,000 for the proposed 3.2-mile 69 kV line,[18] $793,100 for the 9.4-mile upgrade of the existing O-42 line between the Ayer substation and the Dunstable substation, and $95,000 for permit and licensing costs (Exh. HO-RR-2). The Companies estimated that the total cost of the reconductoring plan would be $1,730,100, including $842,000 for the 3.2-mile

---

18/ The $601,000 cost is based on use of the primary route; the Companies indicated that the construction cost for the alternate route would be $775,000 (Exh. HO-RR-4A).

upgrade of the existing O-42 line between the Dunstable substation and the Groton Street substation, $793,100 for the 9.4-mile upgrade of the existing O-42 line between the Ayer substation and the Dunstable substation, and $95,000 for permit and licensing costs (Exh. HO-RR-4B).

The Companies indicated that the firm-supply plan would involve an additional cost of $160,000 above that of the proposed project approach, in order to provide two additional air brake switches and other related equipment at the Groton Street substation, as well as to allow for relocation of certain equipment at this substation (Exhs. HO-RR-16, HO-RR-22). The cost includes $73,600 for two air brake switches, $48,800 for the other equipment and equipment relocation, and $37,600 in engineering and administrative costs (Exh. HO-RR-22).

The Companies indicated that, beyond the equipment included in the proposed project approach, the single-line plan would require only one additional air brake switch to be located at the Groton Street substation -- an incremental cost of approximately $36,800 (id.). This project approach also would require the removal of the segment of the existing O-42 line between the Dunstable substation and the Groton Street substation; however, the Companies provided no separate estimate of the cost to remove the existing line.

The Companies also compared the proposed project approach, the firm-supply plan, and the single-line plan, based on cumulative present worth analysis of revenue requirements, both with and without consideration of line loss savings (Exhs.

HO-RR-16, HO-RR-24A).[19] The Companies' analysis shows that the single-line plan, although involving slightly higher initial installation costs than the proposed project approach, would be approximately equal to the proposed project approach based on present worth revenue requirements including line losses over a 10 to 15 year period beginning in 1989 (Exh. HO-RR-24A). Over longer periods, up to 30 years, the single-line plan would remain approximately equal to the proposed project approach or provide slight net present worth savings (id.).[20]

By contrast, the Companies' analysis shows that the firm-supply plan would result in cumulative present worth revenue requirements approximately $175,000 greater than those for the proposed project over a 15-year period beginning in 1989, even after consideration of line losses (id.). Moreover, the firm-supply plan would provide little or no dimunition of the $175,000 difference over longer periods, up to 30 years (id.).

The Siting Council notes that the Companies provided the results of their cumulative present worth revenue requirements

---

19/ The analysis reflects all cost differences between the project approaches, including the cost to install necessary switching capabilities, the cost to retire or maintain the segment of existing O-42 line between the Dunstable substation and the Groton Street substation, and the line loss differences between the project approaches (Exh. HO-RR-24A). Based on the Companies' analysis, both the firm-supply plan and the single-line plan, each of which would tap the 69 kV line at the Groton Street substation in Pepperell rather than at the Dunstable substation, would result in approximately $50,000 in cumulative present worth line loss savings by 2003 compared to the proposed project approach (Exh. HO-RR-16).

20/ The single-line plan could provide larger net present worth savings, well in excess of the initial construction cost difference, in the event that reconductoring is required to maintain the existing O-42 line serving the Groton Street substation and the James River substation from the Dunstable substation as part of the proposed project approach (Exh. HO-RR-24A).

analysis in the form of a summary graph, without breaking out the derivation of the annual and amortized costs by either functional or accounting categories (Exh. HO-RR-24A). The Companies further indicated uncertainty as to whether or when reconductoring of the existing O-42 line between the Dunstable substation and the Groton Street substation, under the proposed project approach and the firm-supply plan, would be required to maintain reliable equipment over the 30-year period of analysis (id.). Notwithstanding these uncertainties, the Companies' analysis provides a reasonable basis to conclude that, over a 30-year period, the proposed project approach and the single-line plan are not likely to differ significantly with respect to cost.

Accordingly, the Siting Council finds, with respect to cost, that the single-line plan and the proposed project approach are comparable, and that both are superior to the firm-supply plan and the reconductoring plan.

5. Environmental Impacts

The Companies stated that the proposed project approach, if constructed along the primary route, would include 3.2 miles of new transmission facilities, of which all but 500 feet would be located on an existing right-of-way parallel to existing transmission facilities of comparable size and design (Exh. C-1, pp. 7-8; Exhs. HO-E-2, HO-E-3). The primary route would extend outside of the existing right-of-way for a distance of 500 feet to interconnect with the PPA plant, crossing the Nashua River and traversing land owned by James River (Exh. C-1, 7-8; Exhs. HO-E-4, HO-E-5).

In addition, all three alternative approaches traverse the same primary route. The Companies indicated that the reconductoring plan would differ from the proposed project approach by avoiding a second 69 kV line on the existing right-of-way (Exh. C-1, p. 14). However, the Companies also stated that, in the short term, the reconductoring plan would result in a longer period of construction-related disruption based on the need to reconductor an energized line (id.).

The Companies provided no information on the environmental impacts of the firm-supply plan. The Siting Council notes however, that under the firm-supply plan, two 69 kV lines would extend along the existing right-of-way, and thus, this plan would have similar environmental impacts to those of the proposed project approach. Finally, under the single-line plan, one 69 kV line would extend along the existing right-of-way.

The Companies stated that the existing 100-foot wide right-of-way along the primary route is substantially clear of vegetation, and that construction of the transmission facilities on the proposed alignment would entail only the clearing of 10-12 trees and additional minor side trimming (Exh. C-1, pp. 10-11; Tr. 2, p. 30). The Companies indicated that the primary route includes a number of waterway and wetland crossings, and that construction along the route would alter up to 9,375 square feet of wetlands with filling for access roads and one transmission structure pad (Exh. C-1, p. 10; Exh. HO-E-6; Tr. 2, pp. 122-123, 130-131).

With respect to land use, the Companies indicated that the 3.2 miles of transmission construction along the primary route right-of-way would abut predominantly wooded, undeveloped land (Exhs. C-1, p. 10-11, JFV-1; Exh. HO-E-13). The Companies acknowledged the existence of nearby residences at Route 113 (Pleasant Street) in Dunstable, East Street in Pepperell, and Groton Street in Pepperell, but indicated that at one of these locations -- East Street -- the existing abutting subdivision is screened from the right-of-way and would remain so even with construction of the proposed project there (Exh. C-1, pp. 10-11; Exh. HO-E-21). Additional special use concerns along the primary route include: (1) the state classification of the Nashua River, crossed three times by the route, as an urban-recreational river; and (2) the identification by the Massachusetts Historical Commission of areas of potential historical concern on or immediately adjacent to the route, including the Ready Meadow Brook archaeological site on the east bank of the Nashua River in Pepperell, a rebuilt covered bridge known as Memorial Bridge at Groton Street in Pepperell, and an industrial area known as the Mill Village at the terminus of the primary route in Pepperell (Exh. HO-2; Tr. 2, pp. 82-84, 101-106).[21]

In the past, the Siting Council has raised concerns about the impact of transmission facility proposals on rivers and wetlands, as well as on historical and archaeological sites. Turners Falls, EFSC 88-101 at 38-43; Boston Gas Company, 17 DOMSC 155, 182-187 (1988); 1988 CELCo Decision, 17 DOMSC at 316-323. In addition, the Siting Council has given considerable weight to the relative visual impacts of different facility plans. Middleborough, 17 DOMSC at 223, 234-236; 1988 CELCo Decision, 17 DOMSC at 287, 323-328. It is clear that visual impacts would be increased by the presence of a second transmission line on the existing right-of-way, particularly in the area where the two 69 kV lines would cross the historically recognized Memorial Bridge, as well as in the areas where the lines would make multiple crossings of the Nashua River -- a designated urban-recreational river. While the Companies

21/ The Companies stated that the proposed 69 kV line, if constructed along the alternate route, would follow existing roads passing through primarily residential areas (Exh. C-1, p. 13). The Companies stated that construction of the proposed 69 kV line along this route would require extensive tree trimming and installation of transmission structures approximately 10 feet higher than the existing utility poles there (id.). The Companies estimated that there are 174 residences within 100 feet of the public way along the alternate route, compared with 12 residences within 100 feet of the existing right-of-way along the primary route (Exh. HO-E-12). The Companies concluded that the proposed 69 kV line would be highly visible if constructed along the alternate route (Exh. C-1, p. 13).

maintained that the right-of-way is already open and that the presence of a second line would change the nature of the area little (Exh C-1, p. 11), the Companies provided photographs that demonstrate the visibility of the existing O-42 line at a residence near Groton Street in Pepperell[22] (Exh. HO-E-21A), and further acknowledged the proximity of residences to the right-of-way near the crossing of Route 113 in Dunstable (Exhs. HO-E-14, HO-E-19).

The Companies stated that under the single-line plan, the retirement and removal of the existing 69 kV line along the primary route would reduce the necessary width of maintained right of way from 100 feet to 60 feet (30 feet on either side of the rebuilt 69 kV line, which would replace the existing

---

22/ At this residence, the existing O-42 line spans a horse corral, and a 85-foot high pole is required on the property to enable the existing O-42 line to span the nearby covered bridge (Memorial Bridge) at the Groton Street crossing of the Nashua River (Exhs. HO-E-21, HO-RR-5; Exh. JFV-4). A second 69 kV line also would require a pole of similar height on the property of this residence (id.).

0-42 line on a parallel alignment under this project approach) (Exh. HO-RR-24B).[23] Further, the Companies indicated that the single-line plan would result in a minor reduction in expected electric and magnetic field levels along the existing right-of-way edges, compared to the corresponding field levels estimated for the proposed project approach (id.; Exh. HO-E-15).

Under all the project approaches, the Companies expect to use herbicides to maintain the primary route right-of-way, as has been done in the past (Exhs. HO-E-8, HO-E-10). Thus, based on the Companies' statement that the necessary width of the maintained right-of-way would be less under the single-line plan than under the proposed project approach, the single-line plan would result in use of less herbicides on the project right-of-way. Herbicide use could be similarly minimized under the reconductoring plan. As part of their Five Year Right-of-Way Management Plan submitted to the Massachusetts

---

23/ The Companies indicated that they had discussed a proposal by Champlain Pipeline Company ("Champlain") to build a natural gas pipeline parallel to a portion of the primary route, extending from the Dunstable substation to the former railroad right-of-way now owned by the Massachusetts Department of Environmental Management, which crosses the primary route just west of East Street in Pepperell (Exh. HO-E-19). As proposed, Champlain would use a 75-foot overall corridor for pipeline construction purposes, of which 50 feet would be new permanent right-of-way adjacent to the power line right-of-way and 25 feet would be a temporary construction easement overlapping the existing power line right-of-way (Exh. HO-E-19; Tr. 2, pp. 40-43). The Companies stated that, with implementation of the single-line plan, a 50-foot wide corridor extending inward from the northern edge of the power line right-of-way would be open to the construction of the pipeline (Exh. HO-RR-24B). Under the reconductoring plan, the southern edge of the power line right-of-way similarly would be open for construction of the pipeline. Although the Companies noted that the pipeline could affect the siting of any future electric circuits on the existing right-of-way (id.), the single-line plan and the reconductoring plan likely would reduce the requirements of Champlain for additional right-of-way acquisition and clearing of vegetation along the affected section of the primary route.

Department of Agriculture pursuant to 333 CMR 11.00, the Companies stated that it is a goal of their vegetation management program to minimize use of herbicides (Exh. HO-E-10A).

Based on the foregoing, the single-line plan and the reconductoring plan have clear environmental advantages relative to the proposed project approach and firm supply plan with respect to visual impacts in the areas of the Memorial Bridge and the Nashua River, an urban-recreational river, visual impacts in the various residential areas near the existing right-of-way, vegetation maintenance, and use of a more narrow cleared right-of-way.[24]

Accordingly, the Siting Council finds, with respect to environmental impacts, that the single-line plan and reconductoring plan are superior to the proposed project approach and the firm-supply plan.

6. Conclusions: Weighing Reliability, Cost, and Environmental Impacts

The Siting Council has found that: (1) with respect to reliability of supply, the proposed project approach and the single-line plan are superior to the reconductoring plan; (2) with respect to cost, the proposed project approach and the single-line plan are comparable, and that both are superior to the firm-supply plan and the reconductoring plan; and (3) with respect to environmental impacts, the single-line plan and reconductoring plan are superior to the proposed project approach and the firm-supply plan.

The single-line plan, which consists of one 69 kV line

24/ The Siting Council notes that to a lesser extent, electric and magnetic field level effects will be reduced with the single-line plan relative to the Companies' proposed project approach.

on the existing right-of-way, has environmental advantages with respect to visual impacts, vegetation maintenance, and use of a narrower cleared right of way, without any cost or reliability disadvantages, relative to the proposed project approach, which consists of two 69 kV lines on the existing right-of-way. The single-line plan also has a cost advantage relative to the reconductoring plan. On balance, the Siting Council finds that the single-line plan is superior to the proposed project approach and the reconductoring plan.

The firm-supply plan offers more reliable service to a forecasted 13.1 MW peak load, compared to the single-line plan. However, in this proceeding, the Companies have provided its service reliability and area supply planning criteria which indicate that the Companies would not secure energy resources capable of ensuring the level of reliability embodied in the firm-supply plan. In addition, the Companies' service reliability and area supply planning criteria does not consider environmental impacts (Exh. HO-N-2), and the Companies have provided no other basis by which it considers environmental impacts and relates such impacts to increased reliability. Further, the firm-supply plan, which consists of two 69 kV lines on the existing right-of-way, has cost and environmental disadvantages relative to the single-line plan. On balance, the Siting Council finds that the single-line plan is superior to the firm-supply plan.

Accordingly, the Siting Council finds that: (1) the Companies have not demonstrated that their proposed project is consistent with the Siting Council's mandate of ensuring a necessary energy supply with a minimum impact on the environment at the lowest possible cost; and (2) the single-line plan is consistent with the Siting Council's mandate of ensuring a necessary energy supply with a minimum impact on the environment at the lowest possible cost.

C. Conclusions on the Analysis of the Proposed Project

The Siting Council has found that additional energy resources are needed. The Siting Council also has found that the single-line plan is superior to the proposed project approach, the reconductoring plan, and the firm-supply plan. Further, the Siting Council has found that: (1) the Companies have not demonstrated that their proposed project is consistent with the Siting Council's mandate of ensuring a necessary energy supply with a minimum impact on the environment at the lowest possible cost; and (2) the single-line plan is consistent with the Siting Council's mandate of ensuring a necessary energy supply with a minimum impact on the environment at the lowest possible cost.[25]

While taking the extraordinary measure today of rejecting the Companies' project approach in favor of the

---

25/ In this case, it is not necesary for the Siting Council to include an analysis of the proposed and alternate sites for the jurisdictional facility in light of our finding that the single-line plan is the superior project approach and is consistent with the Siting Council's mandate of ensuring a necessary energy supply with a minimum impact on the environment at the lowest possible cost, and given that the rebuilding of the segment of the existing 0-42 line between the Dunstable substation and the Groton Street substation under the single-line plan is non-jurisdictional and therefore does not require the Siting Council's approval. See Section II.B.2.e, *supra*.

single-line plan,[26] the Siting Council clearly is not adopting a position inconsistent with recent cases which have underscored the important role played by cost-effective cogeneration projects in ensuring an economic and reliable power supply for the Commonwealth. See Turners Falls, EFSC 88-101 at 13-21; Altresco, 17 DOMSC at 366-369; NEA, 16 DOMSC at 354-360. Rather, the Siting Council's decision in this case emphasizes that the introduction of cost-effective and reliable power supply additions to the state's resource mix can be only achieved through responsible planning efforts on the part of utilities in the design and development of transmission facilities necessary to accommodate such new resources.

The Siting Council's decision in this matter is not intended to create a roadblock to the successful integration of cost-effective non-utility-generated energy resources in the state's energy mix. Indeed, in this case, the Siting Council has found that the addition of 40 MW from the PPA cogeneration plant is needed as an economic and reliable resource addition for Massachusetts ratepayers. Further, the Siting Council has found that by rebuilding the existing transmission line in Dunstable and Pepperell, an approach that does not require Siting Council approval, the Companies can provide transmission access to PPA in a reliable, least-cost and environmentally acceptable manner. Therefore, our decision in this matter need

---

26/ We previously have noted that the rebuilding of the segment of the existing O-42 line between the Dunstable substation and the Groton Street substation under the single-line plan is non-jurisdictional and therefore does not require the Siting Council's approval. See Section II.B.2.e. In our view, in order to fall within the definition of rebuilding set forth in G.L. c. 164, 69G, the rebuilt line must be constructed within the existing right of way in a manner consistent with the general physical characteristics of the existing O-42 line between the Dunstable and Groton Street substations. The existing O-42 line between these substations also must be removed within a reasonable length of time after the rebuilt line is energized.

not inhibit or delay the purchase by CELCo of these cost-effective resources from PPA.

Similarly, the Siting Council's decision in this matter recognizes that the emerging independent power marketplace and the associated questions regarding transmission access present complex and difficult issues for utilities. However, through responsible planning efforts that include thoughtful and comprehensive examination of potential cost and reliability benefits to its own ratepayers, utilities can ensure the interests of its ratepayers while affording non-utility developers access to the transmission system.

III. DECISION AND ORDER

The Siting Council finds that the construction of the single-circuit 3.2-mile, overhead 69 kilovolt electric transmission line, included as part of the proposed project, along either the primary or alternate routes described herein, is not consistent with the Siting Council's mandate to ensure a necessary energy supply with a minimum impact on the environment at the lowest possible cost. The Siting Council also finds that construction of the rebuilt transmission line along the primary route, included as part of the single-line plan described herein, is consistent with the Siting Council's mandate to ensure a necessary energy supply with a minimum impact on the environment at the lowest possible cost.

Accordingly, the Energy Facilities Siting Council hereby REJECTS the petition of the Massachusetts Electric Company and New England Power Company to construct a single-circuit 3.2-mile, overhead 69 kilovolt electric transmission line in the Towns of Pepperell and Dunstable, included as part of the proposed project, along either the primary route or alternate route described herein. Despite the rejection of the petition, Massachusetts Electric Company and New England Power Company may rebuild the transmission line in accordance with the single-line plan because rebuilding of the transmission line, as it has been presented here, is non-jurisdictional.

Frank P Pozniak

Frank P. Pozniak
Hearing Officer

Dated this 29th day of June, 1989

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of June 29, 1989 by the members and designees present and voting. Voting for approval of the Tentative Decision as amended: Sharon M. Pollard (Secretary of Energy Resources); Barbara Anthony (for Paula W. Gold, Secretary of Consumer Affairs and Business Regulation); Michael Ruane (Public Electricity Member); Madeline Varitimos (Public Environmental Member); and Joellen D'Esti (for Grady Hedgespeth, Secretary of Economic Affairs).

Sharon M. Pollard
Sharon M. Pollard
Chairperson

Dated this 29th day of June, 1989

EXISTING SYSTEM

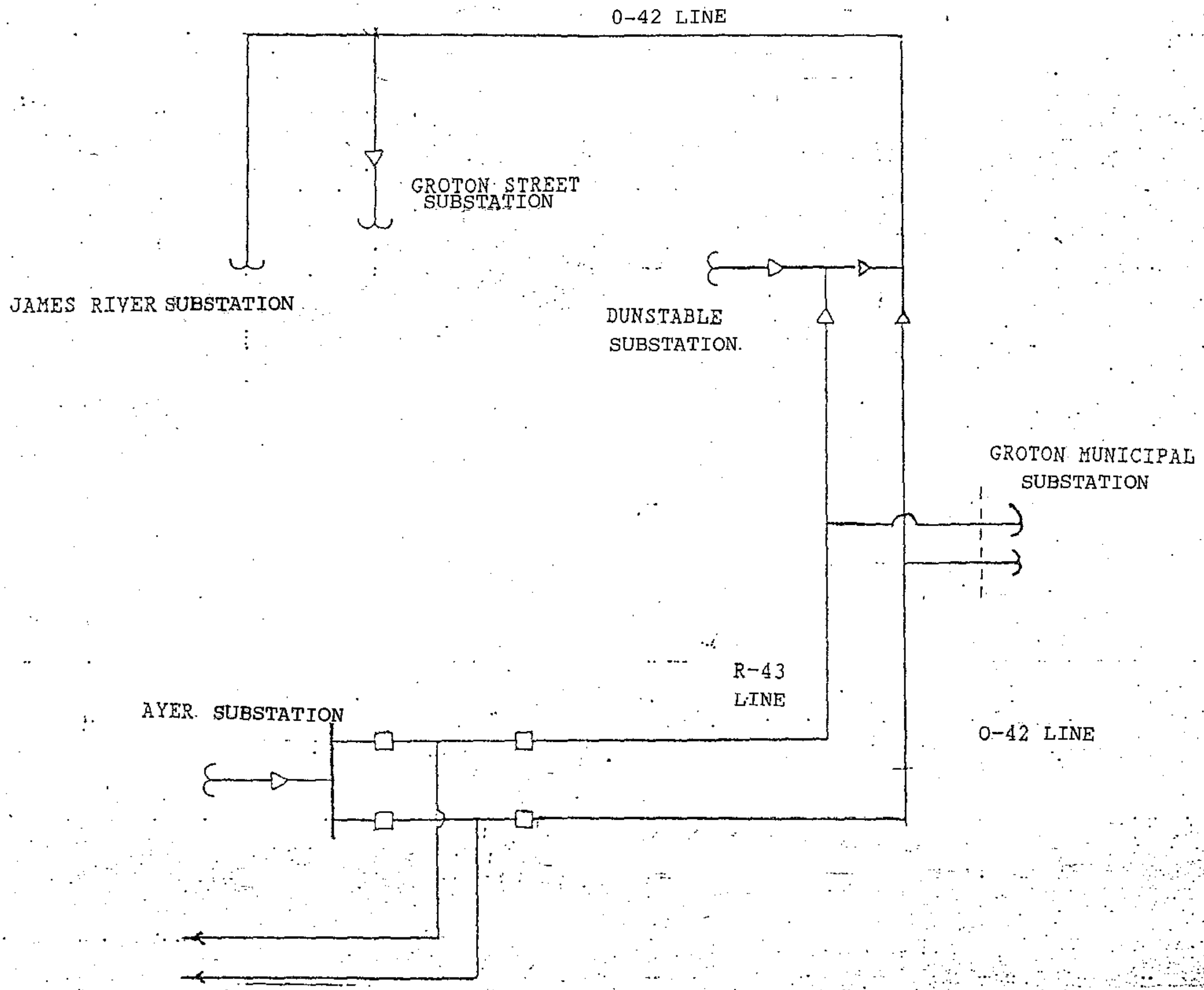


FIGURE 1

PROPOSED PROJECT

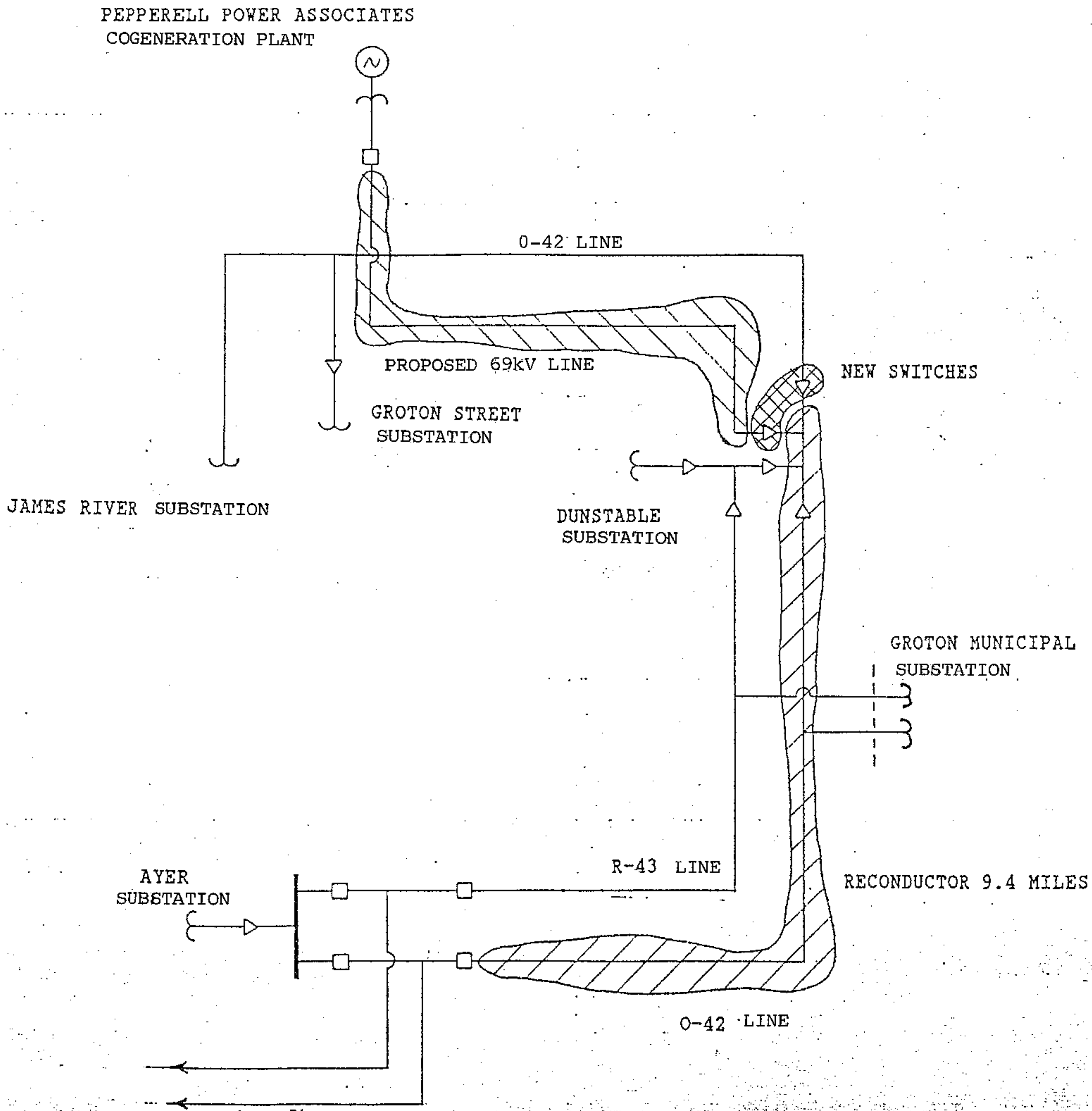


FIGURE 2

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

Such petition for appeal shall be filed with the Siting Council within twenty days after the date of services of the decision, order or ruling of the Siting Council or within such further time as the Siting Council may allow upon request filed prior to the expiration of twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said Court. (See. 5, Chapter 25, G.L. Ter. Ed., as most recently amended by Chapter 485 of the Acts of 1971).