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The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

October 30, 1980

D.P.U. 19733

Joint petition of Montaup Electric Company and the Connecticut Light and Power Company under General Laws, Chapter 164, section 97 and 101, as amended, for approval by the Department of Public Utilities of the purchase by Montaup Electric Company and the sale by the Connecticut Light and Power Company of certain property and the determination that the terms thereof are consistent with the public interest; and

D.P.U. 19743

Joint petition of Fitchburg Gas and Electric Light Company and Connecticut Light and Power Company under General Laws, Chapter 164, section 97 and 101, as amended, for approval by the Department of Public Utilities of the purchase by Fitchburg Gas and Electric Light Company and the sale by the Connecticut Light and Power Company of certain property and the determination that the terms thereof are consistent with the public interest; and

D.P.U. 20055

Joint petition of Montaup Electric Company and New Bedford Gas and Edison Light Company and the Public Service Company of New Hampshire under General Laws, Chapter 164, section 97 and 101, as amended, for approval by the Department of Public Utilities of a readjustment of certain interests in property located in New Hampshire by the acquisition of interests in such property by Montaup Electric Company and New Bedford Gas and Edison Light Company and the corresponding reduction of interest therein of Public Service Company of New Hampshire, and determination that the terms thereof are consistent with the public interest; and

D.P.U. 20109

Joint petition of Montaup Electric Company and the United Illuminating Company under General Laws, Chapter 164, section 97 and 101, as amended, for approval by the Department of Public Utilities of the purchase by Montaup Electric Company and the sale by the United Illuminating Company of certain property and the determination that the terms thereof are consistent with the public interest; and

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D.P.U. 72

Joint petition of Fitchburg Gas and Electric Light Company and the Public Service Company of New Hampshire under General Laws, Chapter 164, section 97 and 101, as amended, for approval by the Department of Public Utilities of a readjustment of certain interests in property located in New Hampshire by the acquisition of interests in such property by Fitchburg Gas and Electric Light Company, and the corresponding reduction of interest therein of Public Service Company of New Hampshire, and determination that the terms thereof are consistent with the public interest.

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TABLE OF CONTENTS

Table of Contents

Table of Contents

I. STATEMENT OF THE CASE

On September 22, 1978, Montaup Electric Company ("Montaup"), New Bedford Gas and Edison Light Company ("New Bedford") and the Connecticut Light and Power Company ("CL&P") filed a petition, pursuant to G.L. c. 164, sec. 97 and 101, as amended, for approval by the Department of Public Utilities ("Department") of the purchase by Montaup and New Bedford and the sale by CL&P of certain ownership interests in Seabrook Units I and II, and for a determination that the proposed transfers are consistent with the public interest. This petition was docketed as D.P.U. 19738. On September 25, 1978, Fitchburg Gas and Electric Light Company ("Fitchburg"), as purchaser, and CL&P, as seller, filed a substantially identical petition which was docketed as D.P.U. 19743. 1/

1/ Purchasing petitioners' present ownership interests in the project are: Montaup 1.9064 percent or 43.88 MW, New Bedford 1.3539 percent or 31 MW and Fitchburg 0.1716 percent or 3.9 MW. These interests are not at issue in this proceeding.

On October 13, 1978, the Commission, pursuant to its investigative authority under the present sec. 97 and 101, ordered each petitioner to file direct testimony and exhibits addressing at a minimum:

1. The future capacity needs of the purchasing companies;

2. The complete cost of the proposed acquisition of the additional ownership shares in the Seabrook facilities;

3. The reasons for selecting this method of meeting future capacity needs in preference to alternative programs considered by the purchasing companies; and

4. A complete description of the characteristics of service from the Seabrook facilities.

On November 16, 1978, the Department issued an order of notice scheduling a pre-hearing conference for December 11, 1978. At this pre-hearing conference, the Attorney General of the Commonwealth of Massachusetts ("Attorney General") filed a petition for intervention which was subsequently granted.

After a discovery stage, the first hearing was conducted on February 13, 1979. At that hearing, a motion by Fitchburg to consolidate the two proceedings was granted. Fourteen days of hearings were held, concluding on April 11, 1979. Briefs and reply briefs were filed by all parties, with petitioners' reply briefs being received on June 1, 1979.

On May 18, 1979, Public Service Company of New Hampshire ("PSCO"), as seller, and Montaup and New Bedford, as purchasers, petitioned the Department for approval of the proposed realignment of additional ownership interests in the Seabrook units. This petition was docketed as D.P.U. 20055. On June 7, 1979, we ordered PSCO to file direct testimony and exhibits on the viability of the Seabrook project.

On June 26, 1979, Montaup, as purchaser, and United Illuminating Company ("UI"), as seller, petitioned the Department for approval of further proposed readjustments of the ownership interests in the Seabrook project; this petition was docketed as D.P.U. 20109.

On June 28, 1979, we issued an interim order that the petitions docketed as D.P.U. 19738 and D.P.U. 19743 be consolidated for further hearing, investigation and consideration with the petition docketed as D.P.U. 20055 ("June 28th Order"). The June 28th Order also defined the standard of review for the case, further delineated the issues in the case, assigned the burden of proof to the petitioners, 2/ and required petitioners to provide the Department with certain additional information. A copy of the June 28th Order is attached hereto as Appendix A. 3/

Subsequent to the June 28th Order, we granted intervention status to Safe Energy Alliance ("SEA"), an association representing

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2/ Throughout this order we collectively refer to the utility parties as petitioners and companies. While we are not always referring to all six utility parties, the context of use should remove any ambiguity.

3/ The June 28th Order inadvertently transposed the parties associated with the docket numbers.

various customers of New Bedford. August 2, 1979, was the first hearing day subsequent to the June 28th Order. On September 6, 1979, we consolidated D.P.U. 20055 and D.P.U. 20109. On January 3, 1980, Fitchburg and PSCO petitioned the Department for approval of the further realignment of certain ownership interests in the Seabrook project which was docketed as D.P.U. 72. On January 4, 1980, counsel for New Bedford announced that company's intention to let its agreement to purchase from CL&P expire (D.P.U. 19738). On January 21, 1980, acting on the joint motion of Fitchburg and PSCO, we consolidated D.P.U. 72 with D.P.U. 20055 and D.P.U. 20109.

After fifty days of hearing, excepting certain minor outstanding matters, the record was closed on April 15, 1980. Briefs and reply briefs were filed by all parties with the reply briefs received on June 3, 1980.

The proposed realignment of ownership interests in the Seabrook project presently before the Department in the consolidated proceedings is as follows:

Purchaser	Seller	% Interest	MW	DPU #
Fitchburg	PSCO	0.2609	6.00	72
	CL&P	0.4349	10.00	19743
Montaup	CL&P	1.03542	23.81	19738
	UI	1.06469	24.49	20109
	PSCO	1.00000	23.00	20055
New Bedford	PSCO	2.1739	50.00	20055

II. THE CONTEXT OF REVIEW

In the June 28th Order, we placed the burden on petitioners to establish by credible evidence that the proposed transactions were consistent with the public interest in a reliable source of electric power at just and reasonable rates. We further indicated that this burden could be satisfied by an affirmative demonstration with regard to four overriding issues. These issues are whether:

1. There is a need for the amount of capacity sought to be acquired;
2. Purchase of the ownership shares represents the most economical available alternative;
3. The purchasing utility has the ability to finance the proposed acquisition without imposing an undue burden upon its ability to provide service currently and in the future; and

4. PSCO has the ability to complete the Seabrook project. 4/

When we initially determined these issues to be the principal areas of inquiry in this proceeding, we were fully aware that answers to these issues could not be derived through the application of some well-established formula or by reference to easily verified historical facts. Each issue is multi-faceted, dependent upon numerous variables, and shrouded in large part by future events. Moreover, the scope of our inquiry is necessarily dictated by the nature of the proposed transfers. Given that the projected contributions of the in-service costs to the

4/ As is fully explicated in the June 28th Order this proceeding does not involve a decision on the health or safety of nuclear power. While our jurisdiction clearly encompasses issues dealing with the need for power, we question whether the Department has any authority at all to regulate in the area of radiological health and safety. See Northern States Power Company v. State of Minnesota, 447 F. 2d 1143 (CA 8 1971), aff'd 405 U.S. 1035 (1972).

capital structures of these three relatively small Massachusetts utilities are extraordinary in magnitude, it is clear that the proposed additional acquisitions are not mere realignments of utility properties in any traditional sense, but, rather, are more akin to a joint venture, the ultimate success of which may not be known for 30 years. The extent of the complexity inherent in presenting and deciding these issues does much to explain the complete review which we have insisted upon in this case.

Of the complexities which underlie each issue, their inherent future orientation has had a significant bearing upon both the type of evidence presented and the nature of our review. As will be seen throughout this Order, it is in the unfolding of future events where many of the factual ingredients necessary to achieve certitude regarding the issues raised are to be found. Much of the evidence presented by the petitioners has, therefore consisted of ·jections about these future occurrences, and our evaluation of that evidence takes the form of an assessment as to the reasonableness of the methodologies and assumptions utilized in the process. Such an exercise cannot be equated with the review of historical events, but rather, demands that we exercise our judgment in determining at virtually every step whether the projections are founded upon an analysis that can be relied upon with a reasonable degree of confidence.

While the future-contingent nature of the issues presented in itself creates difficult analytical problems, these problems are further compounded by recent economic changes in the electric utility industry.

Petitioners' generating mixes are largely dependent upon oil for fuel. The stability of the region's oil supply in terms of both availability and price has become very uncertain. The cartelization of foreign oil production and the legitimate profit maximizing behavior of domestic oil suppliers create a situation which does not necessarily coincide with petitioners' production needs and thereby injects major uncertainty with respect to the uninterrupted future availability of oil as a reliable fuel for electric generation. Moreover, we find it difficult to overstate the problems associated with petitioners' principal dependence upon a commodity which in less than eight years has increased in price in excess of 700 percent.

Due to petitioners' leveraged capital structures, their financing capabilities are directly dependent on the stability of the capital market. Recent experience with the capital market has demonstrated little stability, as evidenced by prime lending rate fluctuations ranging from 9 percent to 20 percent during the course of this proceeding. Recent utility offerings, when viewed from a historical perspective, have been extraordinarily expensive. This dependency is particularly critical when large construction projects such as the present venture, which represents significant additions to the purchasing companies' capital bases, are being undertaken. Further, the question of undue financial burden must not be reviewed solely within the context of capital construction costs, but also with regard to the effect on the ratepayer in terms of reliable service in light of a company's present overall generation mix and reliance on a particular form of generation.

The capitalization of funds used during construction ("AFUDC") and the attendant direct reduction of internally-generated cash flows further compound the problem of access to external capital sources when the construction period for the project encompasses several business cycles and lasts ten years or longer. As a consequence, ill-defined current or reasonably foreseeable future interest rates add tremendous uncertainty to the task of forecasting the financial impact of utility investment decisions.

Present uncertainty regarding access to the capital market, however, must be viewed in the context of the utility planning process: capital additions to utility base load plant have construction lead times and useful lives which are of a long-term nature, and which, in combination, may exceed forty years.

The provision of an adequate and reliable supply of electricity is an absolute public necessity which must not be dominated by short-term economic uncertainties. The rapid increases in fuel oil costs, and the change from relatively easy access to external capital at moderate cost to difficult access at unprecedentedly high cost have, however, further complicated both the petitioners' ability to plan, and our ability to review those plans with exact precision. Whereas the industry has historically been characterized by a relatively high proportion of fixed to variable costs, a factor which both increases management control over the production process and lends stability and predictability to end-user prices, this situation has been reversed to such an extent that it is not unusual for the fuel clause adjustment alone to exceed the fixed cost portion of the consuming public's monthly utility bill. As a result, electricity prices, rather than declining in real terms and being relatively stable as in the past, have been accelerating at unprecedented rates.

These price increases have in turn undermined our knowledge of the structure of demand and our ability to predict its future course. While it is clear that there is some level below which, regardless of price, consumption of electricity will not fall, and while it is also clear that the recent increases in the price of electricity have encouraged a slackening of growth in demand significantly below historical levels, the fact remains there is little experience with which to reasonably predict the elasticity of demand for electricity in response to price changes, let alone to predict the cross elasticities associated with various asserted alternatives.

Governmental response to changes in utility industry economics has likewise been evolving. The Power Plant and Industrial Fuel Use Act, the National Energy Conservation Policy Act, the Public Utility Regulatory Policies Act of 1978 ("PURPA"), and our own D.P.U. 18810 proceedings evidence broad based attempts to increase sources of supply, decrease demand, and both stabilize prices and ensure their equitable distribution among classes of ratepayers. That these actions are forcing structural change in the industry is indisputable. On the supply side, for example, the now mandatory interconnection of independent power producers and cogenerators has injected a competitive element and external source of generation capacity which was virtually non-existent prior to the enactment of PURPA. The relative newness of these governmental actions, and the fact that their effective implementation is only partially complete, however, make the task of projecting their intermediate to long-term impact on supply and consumption patterns problematical.

CL&P and PSCO have suggested that, regardless of the complexity of the questions presented in this case, the Department should not impose the same standards of technical sophistication and rigor upon these three small Massachusetts utilities that it would expect from larger utilities in the same situation. They maintain that to do so, in light of the companies' limited planning resources, would place an unconscionable burden upon their customers. As a novel variant of the deep-pocket theory of competitive advantage we find this argument interesting. In this case, however, it cannot be used to support a lesser degree of scrutiny.

It may be true that these small companies have smaller service territories and serve fewer customers than do larger utilities in the Commonwealth; this fact does not, however, make the problem of demand forecasting less complex. Rather, it merely reduces the absolute size of the numbers involved in the forecasting task. The same may be said for the production simulation of those least cost alternatives which should be included in a company's generation mix.

In fact, since the magnitude of the investment is much larger relative to these companies' respective sizes than for a significantly larger utility, and since the potential for financial ruin resulting from a mistaken allocation of more limited resources is greater in this instance, CL&P and PSCO's suggestion leads us to the conclusion that imposing a greater number of front-end simulations of alternative system generation mixes prior to the irrevocable commitment of resources is necessary, rather than fewer such analyses. And if, in fact, the suggestion that these companies are incapable of performing the required analysis is true, the only possible inference we could draw is that these small companies should be relieved of this heavy burden and that it should be assumed by the Department. To do otherwise would truly place the customers of these companies in an unconscionable position.

In fact, we do not find such an

inability to plan flowing from a lack of resources. As will be seen in the area of demand forecasting, Montaup's overall approach, despite some technical problems, is adequate in terms of sophistication and reviewability. In the area of financial analysis, Fitchburg's approach is complete in terms of identifying and discussing each of the major financial variables. Likewise in the area of fixed and variable cost simulation of alternative system generation mixes, each of the companies has demonstrated the ability to produce technically competent analyses.

The burden of adequate analysis is not proportionate to size, nor is it related to the number of man hours spent on the task. We agree with PSCO's assertion that the concept of proving the need for power is an evolving issue, and we find that this assertion applies equally well to the issue of forecasting both financial ability and alternative strategies. Most fundamentally, the process of proving these issues is iterative in nature. The inferential chains are extremely long and ultimately dependent upon judgment at each link. Even with complete agreement about methodology, slight variations in the application of judgment easily lead to different conclusions. Our principal concern is with the sufficient articulation of the bases of these judgments in order that we may review their reasonableness in the context of the ultimate conclusions for which they are offered in proof.

We are cognizant that rational forecasting and planning is very much an art; and that insofar as it may be called a science, the rigorous employment of alternative analytical and inferential tools is to a great extent dependent upon a company's experience with these tools. Yet detailed public scrutiny of company forecasts and the methodologies employed is a relatively recent phenomenon. 5/

5/ See Chapter 1232 of the Acts of 1973; see also D.P.U. Docket 19494.

For many years there was little need for such detailed review, a fact witnessed by Fitchburg's record of serving its customers for the fifty-two years prior to 1972 without a rate increase.

The process resulting from the accretion of utility experience in these areas and the attendant public scrutiny and criticism of utility efforts leads us to the conclusion that the concept of adequate proof in these areas is evolving. For example, purchasing petitioners are currently in the fourth iteration of their demand forecasts with each subsequent forecast clearly showing marked improvement over its predecessor. That is not to say an optimum has by any means been reached; in fact, there are a substantial number of areas where our review is reduced to evaluating naked assertions of judgment supported solely by a claim of experience. This problem is particularly acute when the methodology employed is not reviewable and we are left with assessing the reasonableness of quantitative assertions <u>in</u>

se.

Although our specific criticisms and findings with regard to whether petitioners have met their burden are found in the following sections, we are not willing to impose on petitioners the burden of meeting standards we may consider ideal, nor are we willing to judge their efforts by those evolving standards which are more appropriate for the future. 6/

6/ We do, however, place petitioners on notice that we expect continued improvements in the future. In particular, we expect more factual support for judgments presented as based on experience and greater reviewability of whatever methodological approaches are chosen. In the areas of fixed and variable cost simulation of generation alternatives and financial impact analysis, we expect more comprehensive sets of simulations. Specifically, there should be more sensitivity analyses employing the systematic variation of the values assigned to critical assumptions, and there should be a greater range of "worst case" simulations wherein larger numbers of the critical variables are simultaneously set to their extreme values. The advent of low cost, high speed digital computers makes the "in-house" development of the software to support this type of analysis clearly within the financial capabilities of the purchasing companies; furthermore, the magnitude of the resource commitments at stake makes the increased use of this type of front-end analysis not only a legitimate above-the-line expense, but imperative.

III. THE NEED FOR POWER

A. Introduction

In the following sections we will examine purchasing petitioners' projected need for power. This examination will consist primarily of a detailed review of petitioners' ten-year demand forecasts, the capacity requirements implied by those forecasts and the generation capacity projected to be available in order to reliably supply that demand. That load forecasting is an inextricable combination of art, science and informed judgment, there is no dispute. We now turn to the manner in which these elements have been applied.

B. Montaup Demand Forecast

Montaup is the wholesale power subsidiary in the Eastern Utilities Associates ("EUA") system. There are two retail subsidiaries in the system, Eastern Edison Company ("Eastern Edison") and Blackstone Valley Electric Company ("Blackstone"), both of which are wholly owned by EUA. Eastern Edison is the present name of the Brockton Edison Company, whose name was changed when the Fall River Electric Light Company was merged into it on July 31, 1979. Montaup is wholly owned by Eastern Edison. Although Montaup is the petitioner in this proceeding, its justification for need is system-wide. Consequently, we will consider Montaup's demand forecast and capacity requirements within the context of its affiliation with EUA and EUA's participation in NEPOOL.

EUA called three witnesses in support of its demand forcast: Mr. John R. Gmeiner, Vice President of EUA Service Corporation; Mr. Wilfred W. Freve, Jr., Supervisor of System Planning for EUA Service Corporation; and Mr. John F. Marien, Senior Engineering Assistant for EUA Service Corporation. EUA forecasts its primary energy requirements in its Third Supplement to the 1976 Long-Range Forecast of Electric Power Needs and Requirements, 1979-1988 (Exh. M-10) by separately estimating the demands of its three retail service territories, Blackstone, Brockton, and Fall River, summing these requirements and adding to this result the estimated miscellaneous and wholesale contract demands of non-affiliated customers (Exh. M-10, Section VI). For each service territory EUA has separately estimated the energy requirements of the residential, commercial and industrial classes, and then summed these requirements across service territories.

EUA's forecasting methodology varies according to customer class (Exh. M-10, Section II). Similarly, the requisite forecasting assumptions vary according to methodology employed, service territory analyzed, end-use under consideration and available data. In assessing the sufficiency of EUA's forecast, we will look to the reasonableness of these assumptions and the results thereby derived.

Our ultimate concern is with the growth rates projected by EUA and the reasonableness of these rates in light of the evidence presented in this proceeding. We do not, however, limit ourselves to accepting solely the testimony of either EUA or the Attorney General. 7/ Where appropriate, we will apply our independent judgment to the evidence submitted and arrive at figures we deem most reasonable.

1. Residential Forecast

The residential portion of EUA's forecast calculates, for each service territory, the estimated number of residential customers and the average use per customer in kilowatthours ("KWH"). EUA then multiplies these values to arrive at an overall residential energy forecast (Exh. M-10, pp. II-3 to II-22).

The residential customer estimate is calculated by dividing local planning agency population estimates by an econometrically-derived people/customer ratio which represents family size (Exh. M-10, pp. II-3 to II-7). EUA utilizes an engineering approach to estimate

7/ The other intervenor in this proceeding, SEA, presented no testimony on EUA's demand forecast.

average yearly energy use per customer. Energy consumption is broken down into major end-use categories. Penetration, saturation, conversion and conservation rates are then applied to these categories and average use per customer figures are derived (Exh. M-10, pp. II-11 to II-19).

Attorney General witness Paul Chernick, a utility rate analyst, criticizes five major aspects of the residential forecast. We will examine the residential forecast in detail and deal with these criticisms *seriatim*.

a. Residential Household Size Projections

EUA employs the ratio of service territory population to customer number as a proxy for family size (Exh. M-10, p. II-5). This ratio is then divided into independently estimated population forecasts to arrive at the projected customer number. Mr. Chernick does not take issue with EUA's decision to econometrically estimate family size. He does, however, criticize EUA's complete lack of method for estimating family size for Brockton 8/ (Exh. AG-232, p. 5) as well as the data base choice for Blackstone (1950-1980), for Brockton (1945-1980) and for Fall River (1950-1979) on the ground that they are unrepresentative of today's trends (Exh. AG-232, p. 4). Mr. Chernick substitutes alternative time periods (1966-1980 for Blackstone, 1969-1980 for Brockton and 1960-1979 for Fall River) 9/ and reperforms EUA's regression analysis to derive family size values which, when applied to the independently derived population forecasts, result in a total estimate of growth in the number of customers for 1988 which is 2 percent lower than that derived by EUA. Mr. Chernick points out that his customer number growth estimate for the forecast period is 21.7 percent lower than EUA's (Exh. AG-232, p. 5).

8/ EUA rejected its Brockton regressions as inadequate and projected the Brockton family size ratio subjectively (Exh. M-29, IR-2).

9/ Exh. AG-232, p. 6.

EUA rebuts this criticism by pointing to Mr. Chernick's essentially constant family size values (see Exh. AG-232, p. 6) for the period 1979-1988 (Exh. M-76, pp. 2-3). EUA's principal planning witness, Mr. Gmeiner, argues that EUA's projected decline in family size from 3.2687 in 1978 to 3.1844 in 1988, a decrease of only .0843, or less than one-tenth of a person, is reasonable (Exh. M-76, p. 2). He compares EUA's decline of .0843 for 1978-1988 to Electric World's projected decrease of .3457 for the same period and suggests that EUA's decrease in household size is arguably too small (Exh. M-63; Exh. M-76, p. 2).

We consider that Mr. Chernick's estimated family size decrease over the next decade is too small. While we do not find simple time trend equations entirely satisfactory for the prediction of family size, we find the modest decreases in family size which EUA projects over the next decade to be reasonable, and therefore we accept EUA's residential customer number projections.

b. Saturation, Conversion, Replacement, and Penetration Rates of Appliances

EUA generates future appliance saturations by applying penetration rates to new customers and conversion rates to existing customers in each year (Exh. M-14, pp. 2-6). Mr. Chernick claims EUA's saturation and penetration rates are unsubstantiated and too high (Exh. AG-232, pp. 7-8). Mr. Chernick notes that the penetration rates employed by EUA for water heating increase over the forecast period are 463 percent for Blackstone, 317 percent for Brockton and 454 percent for Fall River, while the increases in space heating penetration rates for the service territories are 529 percent, 560 percent and 500 percent, respectively (Exh. AG-232, p. 7). EUA offers as support for these increasing penetration rates its judgment that electric heating will become more competitive with home oil heating due to oil price increases and uncertainty concerning oil supply availability.

Mr. Chernick quantifies the

effect of EUA's penetration and saturation rate increases over the forecast period, calculating that 5.2 percent of residential use in 1988 is due to increases in these parameters over the period 1980-1988 (Exh. AG-232, p. 8). Mr. Chernick asserts that this increase in use is entirely unjustified (Exh. AG-232, p. 8).

We have carefully examined Mr. Chernick's argument and the figures he presents. Mr. Chernick has calculated 1988 appliance energy consumption based on 1980 penetration and saturation rates (see Exh. AG-232, p. 8). We do not think that some increase in penetration and saturation rates over the forecast period is unjustified. The assumption that penetration and saturation rates will not increase at all beyond 1980 strikes us as too conservative, and without adequate justification. We deem EUA's justification for the penetration and saturation increases in electric space and hot water heating (Exh. M-29, IR-11; Exh. M-14, pp. 17-18) to be reasonable. We do not find Mr. Chernick's refutation of EUA's position persuasive. Nor are we convinced that Mr. Chernick's analysis of marginal fuel costs (Exh. AG-232, pp. 10-11) is either accurate or appropriate. And although we agree with Mr. Chernick that EUA's argument concerning relative fuel prices (Exh. AG-232, p. 10) does not account for increased saturations of electric appliances, we nevertheless think EUA has provided satisfactory corroboration elsewhere (Exh. M-10, p. II-7; Exh. M-29, IR-2) for the assumptions employed concerning electric appliance saturation rates.

The conversion and replacement rates employed by EUA are, in our opinion, modest and justified. The absolute numbers which result from this portion of EUA's forecast are not exorbitant, nor do we find that EUA exercised inappropriate judgment with respect to the determination of penetration, saturation, conversion and replacement rates. We acknowledge the absence of data analysis to determine these rates and we would have liked to have seen a more rigorous determination of such rates;

however, we recognize the difficulty of obtaining reliable data and acknowledge the necessity of applying judgment when such data is unavailable.

c. <u>Average Use Per Appliance</u>

Mr. Chernick claims EUA makes the following four errors in projecting average use per appliance by assuming that: (1) existing federal Department of Energy appliance efficiency standards will not be met; (2) new, tougher appliance efficiency standards will not be imposed before 1988; (3) historic declines in hot water and space heating usage will not continue; and (4) decreasing family size will not affect average use (Exh. AG-232, pp. 11-12).

We find Mr. Chernick's testimony regarding efficiency standards unconvincing. The standards to which Mr. Chernick refers and which EUA modifies are preliminary technologically feasible energy efficiency levels, and are presented in a DOE January, 1980, advance notice of proposed rulemaking (Exh. M-64, p. 56). The standards are subject to modification. When adopted in their final form, they will apply only to appliances manufactured after June, 1981, and will be phased in over a five-year period. It is our judgment that EUA acted reasonably in the manner in which it incorporated these appliance efficiency improvements into its forecast.

Mr. Chernick next criticizes EUA's forecasted average heating use figures for inclusion of an unwarranted 1978-1979 increase and subsequent constancy (Exh. AG-232, pp. 17-20). He has analyzed normalized space and water heating consumption for the period 1976-1978 (Exh. AG-232, pp. 17-20) and finds that each territory has exhibited negative growth in energy consumption during this period (Exh. AG-232, p. 17). Mr. Chernick extrapolates this 1976-1978 decline in space heating and water heating use over the forecast period, projecting 1988 consumption which is 220 GWH less than that projected by EUA (Exh. AG-232, p. 19).

We find Mr. Chernick's analysis and conclusions deficient for several reasons.

We do not believe that EUA's average space heating consumption figures for the forecast period reflect an unwarranted increase from 1978 to 1979. EUA employs 1978 average unadjusted KWH consumption figures for each service territory throughout the forecast period (Exh. M-29, IR-8, 11). We acknowledge the decrease in average use which has occurred since 1975 and attribute this decrease to increased energy awareness and conservation by consumers. We reject the claim, however, that the 1976-1978 trend is likely to continue as Mr. Chernick has predicted. We do not find this prediction plausible. We find similarly with respect to water heating.

Mr. Chernick's final criticism with respect to average use per appliance is that EUA has erroneously assumed that reduced family size does not affect average use. We note that the reduction in family size predicted by EUA is on the order of a tenth of a person (Exh. M-76, p. 2), while that suggested by Mr. Chernick is considerably less (Exh. AG-232, p. 6).

The Tennessee Valley Authority study results presented by Mr. Chernick, that a household reduction of one child for an average EUA sized family results in 16.1 percent less electricity consumed (Exh. AG-232, p. 22), deals with family size changes ten times as large as those predicted for EUA's service territory. We find no evidence in the record which suggests a proportionality effect (which would reduce the total electricity consumption effect to 1.6 percent for each one-tenth of a person reduction in household size), nor do we believe such a proportionality effect is likely. While we agree that the consequences of reduced family size as suggested by Mr. Chernick (Exh. AG-232, p. 21), with the exception, perhaps, of home occupancy, are likely results, given the family size reduction and time period under consideration, we feel that the home, refrigerator and freezer size effects are unlikely to be experienced. We find the magnitude of the remaining consequences to be extremely uncertain. In general, we find the household size reductions under consideration to be of a sufficiently small magnitude as to have a negligible effect on EUA's projected average electricity consumption per household.

d. Base Use

To calculate base use, EUA applied saturation rates to the average use of six major household appliances for specified historical years and subtracted the resulting average effective use from the total average use of a non-electric space heating customer (Exh. M-14, p. 8). To derive annual electric space heating average use, EUA subtracted the sum of average effective appliance use and average base use from average total use for a space heating customer (Exh. M-14, p. 8).

Mr. Chernick criticizes the use of constant saturation rates for major appliances during the historical years 1975, 1976 and 1978, and the use of increasing saturation rates for these appliances during the forecast period (Exh. AG-232, p. 22). He also faults EUA for failing to acknowledge substantial space and water heating usage decreases over the same period in its base use calculations (Exh. AG-232, p. 22). Mr. Chernick produces new base use figures (Exh. AG-232, pp. 23-24), consistent with saturation assumptions in EUA's forecast, which show negative growth in base use for each service territory.

In rebuttal testimony (Exh. M-76, pp. 3-15), Mr. Gmeiner points out several errors in Mr. Chernick's analysis. The most crucial error, in our opinion, is Mr. Chernick's inclusion of the space and water heating reduction due to normalization in the base use category. We agree with Mr. Gmeiner that base use should be independent of space and water heating electricity usage (Exh. M-76, pp. 7-8). We think that the large decreases in base use produced by Mr. Chernick are due largely to this analytical error.

We now turn to the issue of major appliance saturation rates as used in the base use calculation. The Company asserts these rates were constant during 1975-1978 (Exh. M-76,

p. 12). Mr. Chernick prefers to utilize the saturation rate increase predicted by EUA for 1979-1980, as evidenced for Brockton in Exhibit M-10, pp. 11-16. We note an absence of data in the record regarding major appliance saturation rates for the years 1975-1978, 10/ and therefore will deal with this issue by examining the actual base use growth rates predicted by EUA.

EUA's analysis of base use growth is presented in Exhibit M-14, pp. 6-10. Compound growth rates for each of the three service territories are on the order of 12 percent for 1960-1970, 6.5 percent for 1960-1978/1979 and slightly less than 1 percent for 1970-1978. 11/ EUA utilized roughly

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10/ Exh. M-29, IR-2 provides incomplete data on saturation rates.

11/ The actual 1970 to 1978 rates for Blackstone and Fall River are .83 percent and .70 percent, respectively (Exh. M-14, p. 10). The rate for Brockton based on a 1970 average use of 1,824 KWH (Exh. M-14, p. 10) and a recalculated 1979 average base use of 1,941 KWH (Exh. M-76, p. 10) is .69 percent.

one-half the 1960-1978 growth rate for the forecast period, relying on judgment for the selection of this figure (Tr. 20, pp. 57-59; Exh. M-14, p. 10).

We note both petitioner's and intervenor's acknowledgement that historical base use figures have both an existing and "new" component. We see the majority of increases in the former component coming from two basic sources: more intensive use of appliances already owned by consumers and the purchase of additional appliances which are not new to the market. The latter component is equivalent to EUA's new developments category.

We consider 1970-1978/1979 to be the most relevant period for assessing growth in the base use category. In this instance, the more recent past, 1970-1978/1979, is a more reliable guide for the future than data (1960-1978) which includes demand patterns that are no longer relevant for forecasting purposes. We therefore adjust EUA's base use growth, exclusive of new developments, to increase at the historical rates observed for this period.

e. New Developments

EUA forecasts the electricity consumption of a new developments category to account for demand attributable to presently unforeseen appliances (Exh. M-14, p. 11). Mr. Chernick argues that historical base use data includes a consumption effect attributable to new developments, and that the inclusion of a separate new developments category for the forecast period double-counts electricity consumption attributable to new developments (Exh. AG-232, p. 27).

We acknowledge the overlap between base use and new developments, and agree with Mr. Chernick that EUA's method of accounting for such growth is analytically incorrect. When employing an engineering analysis which accounts for electricity consumption by end-use category, one must factor out of the aggregate category 12/ (in this

12/ This category is forecast based upon historical consumption patterns.

instance, base use) specific end-uses (e.g., new developments) which are forecast separately. A component of the historical consumption in the aggregate category is due to the now separately forecasted specific end-use. The result is double-counting unless this overlap is acknowledged and somehow factored out of base use.

EUA reasons that it has indeed conceptually adjusted its forecast for this overlap (Exh. M-14, p. 10). Selecting the 1960-1978 compound growth rate as the relevant period, EUA determines base use, including all components, to have grown at around 6.5 percent. EUA concludes that base use, less new developments, has grown at around 3.5 percent. New developments, EUA reasons, will comprise 8 percent of 1988 average residential consumption (Exh. M-10, p. II-10), and smooths this new developments consumption judgmentally back to 1981. The sum of new developments and base use produces a growth rate of approximately 5 percent (Exh. M-14, p. 10), which compares favorably with the identified 6.5 percent benchmark.

We find EUA's conceptual reasoning intuitively attractive, especially in light of what we see as considerable difficulties in identifying the historical occurrence of new developments and factoring this consumption out of base use. However, as we disagree with EUA over the relevant base use historical period, we do not accept EUA's figures.

We find the 1970-1978/1979 compound growth rates to be appropriate estimates for base use growth due to the previously identified former component of base use, but too conservative to include growth in base use due to new developments. We conclude that an additional .3 percent growth in base use will account for growth attributable to new developments. We therefore eliminate EUA's separate new developments category, and adjust base use to grow at compound rates, inclusive of new developments, of 1.13 percent for

Blackstone, .99 percent for Brockton, and 1 percent for Fall River.

We summarize the result of our adjustments in Table 1.

TABLE I

EUA RESIDENTIAL ADJUSTMENTS (MWH)

Exh. M-10

	1979	1988	
PII-13 Blackstone			
customer number	66,579	70,579	
total residential	304,898	425,962	
(less new dev. & base use)	(113,332)	(195,433)	
avg. base & new dev. @1.13%	1,702	1,883	
plus effective base use	113,348	132,900	
Total Adj'd Residential	304,914	363,429	
PII-16 Brockton			
customer number	88,612	102,588	
total residential	633,962	876,756	
(less new dev. & base use)	(161,390)	(303,865)	
avg. base & new dev. @.99%	1,[illegible]21	1,990	
plus effective base use	161,362	204,132	
Total Adj'd Residential	633,934	777,023	
PII-19 Fall River			
customer number	44,795	46,429	
total residential	196,823	272,251	
(less new dev. & base use)	(75,248)	(127,772)	
avg. base & new dev. @1%	1,680	1,837	
plus effective base use	75,256	85,308	
Total Adj'd Residential	196,831	229,787	
EUA Total Adj'd Residential	1,135,679	1,370,239	Compound Growth 2.11%

2. Industrial Forecast

EUA forecasts industrial growth by separating the industrial sector into two categories. One consists of known, large industrial customers and the other of EUA's remaining small industrial customers (Exh. M-10, p. II-26; Exh. M-29, IR-22). Historical data is then adjusted to account for patterns EUA considers aberrant, namely, the departure of certain customers from EUA's service territory (Exh. M-29, IR-22; Tr. 22, pp. 68-69). Adjusted historical data is analyzed, and, in most instances, EUA applies the 1970-1979 compound growth rate as a simple growth rate in the latter years of the forecast, and smooths the simple growth rate in the immediately preceding years back to the simple growth rate experienced in the last historical year, 1979 (Exh. M-29, IR-22). 13/ The exceptions to this procedure are for Blackstone, which also has a level adjustment for specified forecast years to

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13/ 1979 actually contains only three months of historical data.

account for known, anticipated load changes (Exh. M-29, IR-22, pp. 1-3; Tr. 22, pp. 60-65), Brockton's small industrial class, for which the 1979 simple growth rate of .42 percent is increased to .5 percent by 1983 and applied constantly thereafter (Exh. M-29, IR-22, pp. 4-5), and Fall River's small industrial class, for which the 1970-1979 compound growth rate is applied evenly throughout the forecast period (Exh. M-29, IR-22, pp. 6-7).

Mr. Chernick makes three general criticisms of EUA's industrial forecast. First, he takes issue with the propriety of adjusting historical data as EUA has done (Exh. AG-232, pp. 32-33). The net effect of such an adjustment is to attenuate the actual out-migration of industrial customers experienced by EUA. This adjustment masks the true desirability of EUA's service territory to industrial customers. Mr. Chernick notes that including all historical data would decrease service territory historical growth rates, actually making the growth rate negative for large Fall River customers (Exh. AG-232, p. 33).

Second, Mr. Chernick faults EUA's method of subjectively interpolating forecast growth rates from the 1979 simple growth rate to the 1970-1979 compound growth rate in 1988 (Exh. AG-232, p. 33). Mr. Chernick points to EUA's volatile historical industrial sales (Exh. M-29, IR-22) and states there is no justification for assuming that short-term growth will approximate 1979 growth. He suggests EUA might more reasonably use the 1970-1979 compound growth rate to approximate the forecast period growth rate (Exh. AG-232, p. 33; Tr. 41, p. 11).

Third, Mr. Chernick faults EUA's methodology of separating the industrial class into two categories which consume significantly different amounts of electricity (Tr. 41, pp. 18-19; Tr. 42, pp. 23-26). Such a method places undue emphasis on small, rapidly growing categories and results in a higher composite growth rate than would calculating a growth rate for the industr[illegible] class as a whole.

First, we note that industrial

growth rates in EUA's service territory have indeed been volatile (Exh. M-29, IR-22, pp. 2, 4, 67), even to the point of being random. This fact leads us to disagree with Mr. Chernick that unadjusted sales data is more informative, especially of structural or macro-economic conditions, than is adjusted data. The seemingly random fluctuations in EUA's industrial data tell us nothing about economic conditions for industry in the EUA service territories. We find EUA's adjustments warranted, especially in light of the asserted unusual circumstances behind the departure of the two large industrial customers in Fall River (Exh. M-29, p. 6; Tr. 22, pp. 68-70) and the sudden and very likely non-representative sales decrease in Brockton due to the loss of two large industrial customers in 1974 (Tr. 22, pp. 65-67).

Given the small number of large industrial customers in these two territories (four in Fall River, nine in Brockton), 14/

14/ Exh. M-29, IR-22.

inclusion of the data in question may result in non-representative growth patterns. Mr. Chernick's analysis of Fall River (Exh. AG-232, p. 35) is a case in point. Including all data for the large industrial group results in a -6.34 percent compound growth rate over the 1970-1979 historical period. Applying this value to the forecast period results in 1988 consumption of 18,492 MWH (compared to 1979 consumption of 43,064 MWH). 15/ This value indicates the loss of perhaps two of the remaining four customers. There is no evidence to suggest such an outcome is likely. Mr. Chernick's adherence to historical data, without interpretation of his results, simply for the sake of consistency (Tr. 41, p. 20) is inappropriate. We therefore allow EUA's adjustment of historical data.

We also disagree with Mr. Chernick's third criticism. We find that the volatility of EUA's industrial data necessitates disaggregation to obtain meaningful results. We

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15/ Exh. M-29, IR-22, p. 6.

note that Mr. Chernick is correct with respect to his mathematical observation concerning disaggregated growth rates (Tr. 42, pp. 23-26); however, he provides no rationale for the employment of his recommended "aggregate" methodology other than to achieve a lower forecast. We find this approach unacceptable. It is quite likely, in view of the randomness of EUA's industrial data, that forecasting the industrial class as a whole will underestimate EUA's true industrial growth. We find EUA's method of disaggregating the industrial forecast acceptable.

We find Mr. Chernick's second criticism to be well founded. We can see no rational justification for employing the 1970-1979 compound growth rate as a simple growth rate in the latter years of the forecast, and smoothing the preceding yearly simple growth rates back to the growth rate for the final historical year. We note that the net effect of such a methodology is to produce compound growth rates for the forecast period which are larger than the 1970-1979 compound growth rates. EUA has provided no evidence which suggests such a result will indeed obtain, nor has it provided adequate justification for the use of this methodology.

While we have previously noted the great volatility of EUA's historical industrial data, we see no better evidence in the record to use for projecting industrial growth during the forecast period. We are reluctant, however, to include projected 1979 data (Exh. M-29, IR-22, p. 2, fn. 1) as part of the historical period. We prefer to accept 1970-1978 as the relevant historical period for analysis, and with the exception of Brockton's small industrial class, apply the 1970-1978 adjusted compound growth rates to the forecast period (1978-1988) for each industrial class in each service territory.

Brockton's small industrial class has experienced a very nearly steady declining growth rate from 1970 to 1978 (Exh. M-29, IR-22, p. 4), resulting in a compound growth rate of -3.63

percent. FUA attributes this decline to a failing shoe industry (Exh. M-29, IR-22, p. 5); however, we note a fairly consistent historical (1970-1978) pattern of declining or near constant consumption for thirteen of the nineteen industrial classifications with positive consumption in Table E-4 of Exhibit M-10 (Exh. M-10, p. IV-3). We are unwilling, however, to project negative growth for this class without additional evidence. We therefore limit Brockton's small industrial class to a zero growth rate over the forecast period.

We summarize the result of our adjustments in Table 2.

Table 2

EUA Industrial Growth (MWH)

	Blackstone	Brockton	Fall River	Total
1978 MWH[1/]				
large class[2/]	189,792	49,063	41,876	
small class	342,956	88,240	107,133	
Total	532,748	137,303	149,009	819,060
Compound Growth Rate				
large class	1.10%	4.04%	1.77%	
small class	1.80%	0%	5.82%	
Total (1978-1988)	2.06%[3/]	1.62%	4.82%	2.54%
1988 MWH				
large class	211,733	72,930	49,931	
small class	410,076	88,240	188,635	
level adjustment	31,300			
Total	653,109	161,170	238,566	1,052,845

1/ Large and small class data taken from Exh. M-29, IR-22.

2/ Brockton and Fall River are adjusted (Exh. M-29, IR-22, pp. 4, 6).

3/ Includes level adjustment of 31,300 MWH.

3. EUA Commercial Forecast

EUA forecasts commercial consumption for each service territory using regression analysis (Exh. M-10, p. II-21; Exh. M-14, p. 18). This procedure entails separately estimating the number of commercial customers as a function of population and family size, and average use per commercial customer as a function of population and the ratio of residential to commercial customers (Exh. M-10, p. II-21; Exh. M-29, IR-13). The number of commercial customers is then multiplied by average use per commercial customer for each year of the forecast to derive total average commercial consumption (Exh. M-14, p. 18; Exh. M-10, p. II-21). To total average commercial consumption EUA then applies a conservation adjustment, reducing 1988 commercial consumption by 10 percent (Exh. M-10, pp. II-22, 23).

Mr. Chernick criticizes EUA's commercial forecast as based on unsound methodology (Exh. AG-232, p. 30). Specifically, Mr. Chernick posits that the number of commercial customers is not a useful predictor of commercial use; that EUA's data and projections reflect subjective adjustments (Exh. M-29, IR-16, 13); and that the regression equations tested and selected are frequently inappropriate (Exh. AG-232, p. 30).

Mr. Chernick posits that commercial electricity use can vary widely according to business type and size. For this reason, commercial customer number is not a "natural unit" (Exh. AG-32, p. 30) and, presumably, does not convey information reflective of commercial use.

Mr. Chernick also asserts that EUA's choice of variable and functional specification has no logical or theoretical foundation (Exh. AG-232, p. 31). Furthermore, for the commercial customer number model, Mr. Chernick notes that for Blackstone, household size has a positive coefficient; that for Brockton, this variable has a negative coefficient; and that for Fall River, regression analysis produced no acceptable results (Exh.

AG-232, p. 32; Exh. M-29, IR-13).

We have examined EUA's commercial forecast carefully (Exh. M-14, pp. 18-19; Exh. M-10, pp. II-2 to II-25; Exh. M-29, IR-12, 13, 14, 15, 16, 17, 18, 19, 21) and find that it suffers from a number of methodological flaws which concern us. First we will address Mr. Chernick's concerns; then we will address our own.

We agree with Mr. Chernick that the number of commercial customers is not a "natural unit" for conveying information regarding commercial consumption. We are not persuaded, however, that this variable cannot be used effectively to predict commercial consumption, regardless of the methodology employed. Our concern, therefore, is with how this variable is used, not whether it should be used at all. We do not think the record supports the conclusion that there is so much variability among the various commercial establishments' yearly consumption that one cannot meaningfully multiply average commercial consumption by number of commercial customers to derive average total commercial consumption.

We also agree that EUA has employed numerous subjective adjustments to data and regression results (Exh. M-29, IR-13, pp. 2, 5, 8, 11, 15, IR-16), but do not find these inappropriate in every instance. Specifically, those adjustments made to residential customer counts (Exh. M-29, IR-16) we find acceptable. Those adjustments made to regression results 16/ we find most unusual and of questionable theoretical (especially statistical or econometric) justification. In fact, these adjustments bear on the appropriateness of using EUA's econometric analysis as a general model for the commercial class.

This brings us to Mr. Chernick's third criticism, which we will expand upon in order to more fully address our own concerns.

16/ We refer specifically to utilization of the upper and lower limits of the 99 percent confidence interval in place of predicted values (Exh. M-29, IR-13, pp. 2, 8, fn.1).

EUA employs multi-variate regression analysis to estimate the number of commercial customers as a linear function of population and family size (Exh. M-10, p. II-21). The latter explanatory variable, family size, is the same variable employed in the residential model (Exh. M-10, p. II-22), where it is defined as the ratio of people (or population) to number of residential customers (Exh. M-29, IR-13; Exh. M-10, p. II-5). Data from each service territory are regressed using this model (Exh. M-29, IR-13).

We have examined the regression results for each service territory (Exh. M-29, IR-13) and find that they indicate the presence of numerous statistical problems. First, we note that no acceptable results were obtained for Fall River (Exh. AG-232, p. 32; Exh. M-29, IR-13, p. 13). Second, we note that the Durbin-Watson statistic for Blackstone 17/

17/ $d=.51004 < d_{L,.05}=1.05$ for $N=18$, $k'=2$, where k'=Number of explanatory variables.

(Exh. M-29, IR-13, p. 3) indicates the presence of positive autocorrelation, as does the Durbin-Watson statistic for Brockton. 18/ Also, the Blackstone simple correlation coefficient for the independent variables 19/ is sufficiently high to indicate to us the existence of problematical multicollinearity, and the Brockton simple correlation coefficient 20/ indicates rather serious multicollinearity. We do not find th presence of multicollinearity surprising, since both explanatory variables, population and family size, or the ratio of population to number of residential customers, have the variable population in them, and therefore are quite likely to be correlated. We interpret the existence of autocorrelation and multicollinearity as seriously problematical in that these phenomena bias the estimated

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18/ $d = .85336 < d_{L,.05} = 1.02$ for $N=17$, $k'=2$.

19/ $r=.6116$ (Exh. M-26, IR-13, p. 3).

20/ $r=.8421$ (Exh. M-26, IR-13, p. 9).

regression coefficients, and we disagree with Mr. Marien that the existence of these phenomena is not of sufficient cause for concern to employ standard statistical procedures to correct for their presence.

We are further disturbed by opposite signs for the family size variable in the Blackstone equation (positive, see Exh. M-29, IR-13, p. 1) and in the Brockton equation (negative, see Exh. M-29, IR-13, p. 7). This result leads us to question the plausibility of EUA's proposed model.

EUA also forecasts average per customer commercial use using multi-variate regression analysis. Commercial average use is forecast as a linear function of population and the ratio of residential to commercial customers. While the Blackstone equation exhibits satisfactory test statistics (Exh. M-29, IR-13, pp. 5-6), we do not find similarly for the Brockton and Fall River equations.

Specifically, the Brockton equation exhibits autocorrelation. 21/ In addition, the coefficients for the residential/commercial customer ratios for both the Brockton 22/ and Fall River 23/ equations are not statistically significant.

Finally, we note sign changes for the coefficient to the residential/commercial customer ratio among the equations for the three service territories (Exh. M-29, IR-13, pp. 4, 10, 14). 24/

The problems we have identified with the relatively sophisticated approach in

21/ $d=.51978 < d_{L,.05}=1.02$, $N=17$, $k'=2$ (Exh. M-29, IR-13, p. 12).

22/ The t statistic for the coefficient in the Brockton equation indicates that the coefficient is not statistically different from zero at the 33 percent significance level (t equals -1.002; Exh. M-29, IR-13, p. 11).

23/ The t statistic for the coefficient in the Fall River equation indicates that the coefficient is not statistically different from zero at the 42 percent significance level (t equals .837; Exh. M-29, IR-13, p. 15).

24/ It is positive for Blackstone, negative for Brockton and positive for Fall River. As with the customer number model, this change in sign leads us to believe that the hypothesized model is not supported by the data.

EUA's commercial forecast are in themselves an indication of the complexity and intractability likely to be encountered in projecting this component of demand. We laud, however, EUA's attempt to employ such analysis, and encourage EUA to develop and refine its econometric forecasting capabilities further. Moreover, we find this sort of analysis, when properly performed, informative and helpful for managing uncertainty.

As a result of our observations concerning technical deficiencies, we are hesitant to accept EUA's commercial analysis as a general model for commercial consumption. However, review of the historical data relative to total commercial growth in the Brockton, Fall River and Blackstone service territories indicates that historical commercial consumption patterns yield compound growth rates generally in excess of those projected by EUA. 25/ In fact, of the twenty-eight total commercial growth rates which can be derived for the total system and the three service territories by using 1970 to 1976 actual data for the base period and 1978 actual data for the end period, only the 1976 to 1978 total commercial growth for Brockton is less than the rate utilized by

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25/ Utility companies have traditionally relied on extrapolations of data describing the historical use of electricity to predict future power needs. Niagara Mohawk Power Corp. (Nine Mile Point), ALAB-264, 1 NRC 347 at 363 (1975). Although the compound growth extrapolations we examine are perhaps the simplest form of trend analysis, the state of the record precludes us from attempting more sophisticated approaches in a number of instances. Our concern is not that this type of analysis is inadequate because it is simple, but rather, that we prefer growth projections to be based upon explicitly stated theoretical considerations of the underlying causal relationships which determine growth. Accordingly, we do not expect petitioners to revert to the wholesale adoption of this type of trend analysis; indeed, we expect them to further refine their present efforts.

EUA in its projections; 26/ and, in any event, the total system commercial growth rate for this period is still greater than the growth rate utilized by EUA. 27/ Consequently, despite our reservations about the utility of EUA's commercial model, we do not find the compound growth rates employed by the Company to be unreasonable.

26/ We would note that such a historical trend analysis was utilized by the Attorney General for this very example in an effort to refute EUA's commercial growth projection. The Attorney General focused on the growth rate in average consumption per commercial customer and found that average consumption increased by only .7 percent for the period 1976-1978 (Exh. AG-232, p. 31). Reliance solely upon average consumption growth data is, however, misplaced since the information tells us nothing about growth in total commercial consumption, i.e., the commercial consumption variable in which we are ultimately interested.

27/ See Exh. M-10, pp. II-25, III-2, IV-3, V-3.

4. Wholesale Contracts

EUA has forecast sales for resale to non-affiliated customers based on existing contracts and on estimates of contracts which will be negotiated in the future. EUA asserts that, "In all cases, projections were made based on conversations with these customers on their respective forecasts" (Exh. M-10, p. II-28). Mr. Chernick asserts that the Town of Middleboro "does not need, does not want, and does not intend to take" a 6 MW demand contract which EUA has forecast (Exh. AG-232, p. 37). We find no evidence in the record to support this assertion and consequently reject this claim.

5. Street Lighting and Miscellaneous Forecast

EUA's street lighting and miscellaneous forecast was not contested in these proceedings. After careful review, we accept the forecast as projected by EUA in Exhibit M-10.

6. Peak Demand

EUA converts sales into peak demand 28/ as follows. First, EUA weather-corrects by affiliated company the most recent historical year's winter peak demand (Exh. M-29, IR-24, 25). Next, for the same year, weather-adjusted load factors are derived from the weather-corrected peak demands and the actual yearly energy consumption. Then, these load factors are applied to the previously derived 1988 energy forecast to derive company peak demands which entail no additional load management effects. This calculation assumes peak demand and energy will grow at the same rate. Next, to the 1988 unadjusted (for load management only) peaks, EUA applies a load management calculation (Exh. M-29, IR-26). This produces an aggregate load management result which in 1988 translates into an overall 12.8 MW reduction in the previously determined EUA peak (Exh. M-29, IR-26). Finally, the 1988 weather

28/ Peak demand or load is the highest demand experienced by the utility during the year.

and load management adjusted peaks are translated into 1988 load factors and smoothed judgmentally back to the last historical year's load factors, and, using forecasted energy values, intervening peak demands, adjusted for weather and load management, are derived.

Mr. Chernick argues that EUA has inappropriately weather-adjusted peak demands (Exh. AG-232, p. 26). EUA uses 15 degrees Fahrenheit as a winter peak temperature (Exh. M-10, p. II-30). Mr. Chernick argues that this value is too low and that EUA should use the service territories' 1970-1978 average temperatures experienced at winter peak. These values are 22 degrees Fahrenheit, 23 degrees Fahrenheit and 22 degrees Fahrenheit for Blackstone, Brockton and Fall River, respectively (Exh. AG-232, p. 36; Exh. M-29, IR-24, 25, 31). Using these values would decrease the weather-adjusted 1978 peak by about 13.5 MW, 29/ and because the 1978 weather-adjusted load factors are the basis for the peak demand forecast, Mr. Chernick claims

29/ See Exh. M-29, IR-24, 25.

that this 2.2 percent 30/ reduction in the 1978 peak reduces EUA's projected 1988 peak by 2.2 percent also, thereby reducing EUA's projected 1988 peak by about 19 MW.

EUA defends the use of 15 degrees Fahrenheit as a winter peak base temperature on the ground that it approximates December's average temperature at peak for the last several years (Exh. M-76, p. 21). Specifically, EUA States that the "post-embargo (post-1974) peak temperature averages are in the 12-13 degrees Fahrenheit range (and that) it was these latter averages which EUA used as the guide for its peak temperature base of 15 degrees Fahrenheit" (Exh. M-76, p. 21).

We can see no causal relat. nship whatsoever between weather and the 1973-1974 oil embargo and, in fact, consider yearly variations in weather to be randomly distributed. In light

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30/ Mr. Chernick derives 2.2 percent (Exh. AG-232, p. 36). We derive 13.5 over 678.8, equals 2 percent.

of this likely randomness, a larger sample of weather values is more appropriate than the small sample obtained using only post-1974 weather values. We note that Mr. Chernick's sample contains eight observations (1970-1977), whereas EUA's has only three (1975-1977). We would in fact prefer to use a much larger data base, but select the largest available in this record.

Aside from statistical arguments for using a larger data base to generate a winter peak base temperature, we also see common sense reasons for doing so. It is more reasonable to assume that the predicted winter peak base temperature employed over the next decade will approximate a long-term historical average rather than a short-term average or particular historical value. We therefore reject EUA's short-term average winter peak temperature base of 15 degrees Fahrenheit in favor of Mr. Chernick's longer-term values, and accordingly decrease the 1978 weather-adjusted peak by 13.5 MW.

Mr. Chernick also faults EUA's curtailment of the estimated effectiveness of load management efforts from 25 percent to only 10 percent each for the residential and commercial classes (Exh. AG-232, p. 36). EUA explains that this reduction in effectiveness is due to the decreased saturation of electric space heating from the Second to the Third Supplement (Exh. M-29, IR-26). We find EUA's explanation satisfactory.

Mr. Chernick also faults EUA's exclusion of a load management effect for the industrial class. We agree with Mr. Chernick that the effect for this class may be more pronounced than for either the residential or commercial class, but believe EUA's overall load management adjustment to this forecast to be reasonable. We would, however, urge EUA to incorporate into future forecasts a likely load management consequence for the industrial class.

We translate our findings regarding EUA's demand forecast into a new 1988 peak first by reducing EUA's 1978 weather-corrected peak of 678.8 MW (Exh. M-29, IR-24, 25, p. 2) by 13.5 MW to 665.3 MW. This yields a 1978 load factor of .6335. 31/ We apply this adjusted, weather-corrected load factor to EUA's adjusted 1988 energy requirements of 4,704,862 MWH to derive a 1988 weather-adjusted peak demand of 847.8 MW. 32/ We then adjust this 1988 peak demand figure to reflect load management by subtracting from it EUA's estimated 1988 peak demand reduction of 12.8 MW (Exh. M-29, IR-26). Our calculations produce a 1988 weather-corrected and load management adjusted peak of 835 MW with an associated 1988 load factor of .6432. 33/ Our adjustments reduce EUA's compound growth rate in internal peak demand from 3.16 percent 34/ to 2.33 percent. 35/

We summarize these adjustments in Table 3.

31/ $\frac{3692155}{665.3 \times 8760}$ (1978 KWH)

32/ $\frac{4704862}{.6335 \times 8760}$

33/ $\frac{4704862}{835 \times 8760}$

34/ 663 MW in 1978 to 905 MW in 1988 (*see* Exh. M-11; Exh. M-10, p. VI-7).

35/ 663 MW in 1978 to 835 MW in 1988.

TABLE 3

SUMMARY OF EUA SYSTEM ENERGY AND PEAK ADJUSTMENT

M-10		1978 unadjusted	1988 unadjusted	1988 adjusted	Compound Growth
	Blackstone (MWH)				
	Residential				
II-20	Unadjusted	301,879	425,962		
	Adjusted			363,429	
	Commercial				
II-25	Unadjusted	278,944	397,987	397,987	
II-26	Industrial				
	Unadjusted	532,747	723,969		
	Adjusted			653,109	
II-27	Streetlighting & Misc.	26,293	32,284	32,284	
II-29	Internal use	4,646	4,934	4,934	
II-29	Losses (5.55% of total sales plus internal use)	69,979	87,975	80,572	
	Total	1,214,488	1,673,111		3.26%
	Adjusted			1,532,315	2.34%
	Brockton (MWH)				
	Residential				
II-20	Unadjusted	627,687	876,756		
	Adjusted			770,023	
	Commercial				
II-25	Unadjusted	526,980	730,073	730,073	
II-26	Industrial				
	Unadjusted	137,303	183,330		
	Adjusted			161,170	
II-27	Streetlighting & Misc.	17,118	24,772	24,772	
II-29	Internal Use	1,793	2,141	2,141	
II-29	Losses (7.37% of total sales plus internal use)	96,763	133,918	124,419	
	Total	1,407,644	1,950,990		3.32%
	Adjusted			1,812,598	2.56%

M-10		1978 unadjusted	1988 unadjusted	1988 adjusted	Compound Growth
	Fall River (MWH)				
II-20	Residential Unadjusted	194,874	272,251		
	Adjusted			229,787	
II-25	Commercial Unadjusted	215,495	260,732	260,732	
II-26	Industrial Unadjusted	149,009	217,366		
	Adjusted			238,566	
II-27	Streetlighting & Misc.	7,053	9,425	9,425	
II-29	Internal use	1,704	1,923	1,923	
II-29	Losses (6.05% of total sales plus internal use)	33,584	46,083	44,796	
	Total	601,719	807,780		2.99%
	Adjusted			785,229	2.7%
	Montaup (MWH)				
VI-2	Sales to Subsidiaries	3,223,851	4,431,881		
	Adjusted			4,130,142	
VI-2	Contract sales	401,598	488,808	488,808	
II-29	Losses & internal use (1.86% of sum of retail and wholesale sales)	66,706	91,524	85,912	
	Total	3,692,155	5,012,213		3.1 %
	Adjusted			4,704,862	2.45%
	Peak MW	663	905		3.16%
	Adjusted			835	2.33%

7. Reserve Margins and the Need for Power

We have reviewed EUA's demand forecast in great detail and made numerous adjustments to it. Our principal concern here is whether EUA will have adequate power to reliably meet the future demand of its customers. Basic to this concern is the duty of EUA to meet this future demand when it becomes actualized. In practice, EUA satisfies this duty by obtaining generating capacity sufficient to meet criteria set by NEPOOL. The focus of these criteria is to ensure that petitioner has a minimum reserve margin 36/ greater than its forecast annual peak load sufficient to ensure system reliability during routine maintenance, unanticipated forced outages and unexpected increases in peak demand.

EUA has adopted a 22 percent reserve margin in projecting its system

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36/ Reserve margin is the difference between total system generating capacity and adjusted peak demand. When expressed as a percentage, this difference is divided by adjusted peak demand.

generation needs for the power years 1986/1987 to 1990/1991 (Exh. M-11). In the hearings and briefs subsequent to our June 28th Order, the Attorney General did not address the issue of reserve margins and, with the exception of updating Exhibit M-2 to Exhibit M-11, neither did EUA. 37/ Prior to our June 28th Order, however, the Attorney General conducted extensive cross-examination on this issue and argued that EUA's forecast of anticipated reserve margins was deficient. 38/

The Attorney General argues that the forecast is deficient because it is dependent upon arbitrarily inflated NEPOOL reserve margin forecasts and because EUA's forecast produces greater reserve margins than NEPOOL's forecast. We do not agree with the Attorney General that NEPOOL's 1 percent bandwidth simply serves to inflate capability responsibility by 1.2 percent and thereby

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37/ We note that Exh. M-11 has generally lower estimated reserve margins than Exh. M-2.
38/ D.P.U. 19738/19743 AG initial brief, pp. 41-46; reply brief, pp. 26-32.

provides a market for large participants' excess capacity. For the purposes of this proceeding, we find that use of the 1 percent bandwidth mechanism to limit the effect of NEPOOL participants' incorrect forecasting of demand on the reserve requirements of participants who correctly forecast demand is reasonable and not arbitrary. 39/

Nor do we agree that the forecasted 1984/1985 NEPOOL reserve margin is spuriously inflated by 1.8 percentage points. 40/ Table 2 of Exhibit AG-83 predicts a decrease in reserves due to load shape in 1977-1978; this prediction corresponds with the deeper demand valleys experienced in 1978. While the experienced 1978 valleys may be deeper than those predicted, the forecast correctly predicted the direction of change due to load shape and the attendant lessening of forecasted required reserves implied by that change in

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39/ D.P.U. 19738/19743 Tr. pp. 525-529; Exh. AG-35, pp. 1-2.
40/ D.P.U. 19738/19743 AG initial brief, pp. 43-44. *See* Exh. AG-83, cover letter, Table 2.

direction. We find that the experienced confirmation of this forecasted change tends to validate the 1984/1985 predicted load curve reserve margin effects rather than, as the Attorney General suggests, indicating that those forecasted effects are spurious.

In any event, it is clear that Mr. Gmeiner did not depend solely upon Exhibit AG-83 (the January 1978 NEPOOL Capability Responsibilities Report) for projecting EUA's 1986 to 1991 reserve requirements. We note the report does not extend beyond 1985. Mr. Gmeiner's testimony indicates he used the pool estimates in the exhibit as guides (D.P.U. 19738/19743 Tr. pp. 1377-9), and that he rejected the EUA specific estimates (ibid., Tr. p. 1376) as inappropriate since EUA had historically never experienced required reserves that low (ibid., Tr. p. 1380). Mr. Gmeiner's testimony further indicates his reserve requirement projections were based on a combination of discussions with NEPLAN staff (ibid., Tr. pp. 246-248), different schedules for nuclear generating units, his professional judgment as an expert in the field and EUA's actual reserve margin requirements of 22 percent, 20.2 percent and 22.2 percent for the last three power periods prior to his forecast. 41/

We find this combination of factors a reasonable basis for EUA's reserve margin projections. That the EUA system has experienced required reserves in excess of 22 percent would in itself be a reason for caution in predicting these requirements to be substantially less than 22 percent. In addition, EUA's relativ flat load curve (ibid., Tr. p 537) further tends to drive up EUA's required reserves. Based on the record before us concerning reserve margins, we find EUA's utilization of a 22 percent reserve margin is a reasonable upper limit for this critical index of system reliability.

By our calculations, with no additional power, Montaup will have a 1988

41/ See generally D.P.U. 19738/19743 Tr. pp. 240-252, 531-542, 1365-1400.

reserve margin of 15.2 percent; 42/ this is clearly too low to ensure system reliability. Addition of 23 MW, the power represented by the proposed PSCO acquisition, will increase the reserve margin to 18 percent. In light of our previous discussion, this reserve margin is clearly justified. Inclusion of the power represented by the proposed UI and CL&P purchases (24.9 MW and 23.81 MW) will increase Montaup's 1988 reserve margin to 21 percent and 23.8 percent, respectively. This range brackets the 22 percent reserve margin we previously found a reasonable upper limit for system planning purposes.

The Attorney General has also argued that the Company's projected reserve margins are inflated by unrealistic nuclear construction schedules. We note that EUA's projected 1988 generating capability assumes 71 MW from Pilgrim II and Millstone III (Exh. M-13).

42/ $\frac{962}{835} = 1.152$

If this power is unavailable, 43/ EUA's 1988 reserve margin will range between 6.7 and 15.2 percent assuming no additional Seabrook to the full 71.3 MW Montaup proposes to acquire. The upper limit of this range is still significantly lower than the 17 percent NEPOOL Objective Capability based upon the inclusion of up to two immature 1,100 to 1,200 MW nuclear units (Exh. AG-140, p. B-3).

With the determination of both future demand and the likely availability of supply to meet that demand, the calculation of an electric system's reserve margin is straightforward. Due to the complexity of evaluating supply and demand estimates, however, we find little comfort in being able to reduce these complex underlying inferential chains to a single number. Seeing ten years into the future with accuracy cannot be expected. Forecasts of

43/ Indeed, apart from unavailability due to scheduling delays, Mr. Chernick believes there is a substantial probability that Pilgrim II will not be completed and that there is less than a 50 percent probability it will be on line by 1991 (Tr. 39, p. 130).

demand, supply and reserve margins, however, cannot be avoided. As we stated above, our principal concern is assurance that EUA will have adequate power to reliably meet the future demand of its customers. We have estimated EUA's growth in peak to be about 2.33 percent. Based upon this projected growth and upon Montaup's projected 1988 system capacity and capability responsibility, we find these projections reasonably support a need for a maximum additional interest of 56 MW in the Seabrook project.

C. Fitchburg Demand Forecast

Fitchburg forecasts its primary energy requirements in its Long-Range Forecast, Supplement 1c (Exh. FGE-7) by separately estimating the energy demands of its residential, commercial and municipal, and industrial classes. These demands are summed for each year to produce a yearly forecast through 1988.

Fitchburg's peak load forecast is then derived from the energy forecast using customer class load curve information (Exh. FGE-7, p. 5). Customer class load curve characteristics are taken from a 1973 transmission study performed for Fitchburg by United Engineers and Constructors ("United Engineers") (Exh. FGE-7, p. 5).

Fitchburg's energy demands for each customer class are derived in a substantially identical manner. In each instance, Fitchburg examines known or anticipated load additions and sums these additions by class. For the forecast period beyond the short term, Fitchburg relies principally on its forcasters' judgment to determine anticipated load additions. Fitchburg also relies on such judgment for numerous assumptions concerning short-term growth. As with EUA, in assessing the reasonableness of Fitchburg's forecast, we will look to the reasonableness of the assumptions employed.

1. Residential Forecast

Fitchburg separates its residential class into two categories -- those with and those without electric space heating. Additions to these categories are forecast separately.

Fitchburg estimates it will have ten new electric space heating customers per year over the forecast period, with corresponding consumption of 150,000 KWH per year (Exh. FGE-7, p. 5-a).

Non-space heating customer additions are estimated at 200 per year. Fitchburg finds this figure consistent with recent construction trends, plans of various developers and independent agency population projections. Average consumption is estimated at 4,000 KWH per customer per year in 1980, falling 5 percent per customer per year until 1984, remaining at 3,200 KWH per customer per year thereafter (Exh. FGE-5, p. 8; Exh. FGE-8, Sch. 1). Fitchburg incorporates this reduction in average consumption to reflect appliance efficiency improvements.

Growth in consumption by existing customers is estimated at 1 million KWH in 1980; this growth is reduced 5 percent per year until 1984 to reflect appliance efficiency improvements (Exh. FGE-8, Sch. 1). In addition to these estimated load additions, Fitchburg forecasts load requirements imposed by various known additions.

Attorney General witness Mr. Chernick criticizes three aspects of Fitchburg's residential forecast. Mr. Chernick finds fault with the projection of growth in sales to existing customers for 1979 (Exh. AG-232, p. 38), the projection of average electric heating energy use, and the allowance for appliance efficiency standards.

Mr. Chernick asserts that Fitchburg's growth in base use for 1979 (use by existing residential customers) is incorrectly calculated. Fitchburg details the methodology used for the growth calculation which is applied to the entire forecast period in Exhibit FGE-8, Schedule 2. Exhibit AG-201, IR-41 44/ estimates KWH sales to existing customers for 1979. The methodology employed in Exhibit AG-201, IR-4 which is used to calculate "actual growth in KWH sales to existing customers for 1979" differs substantially from the methodology in Exhibit FGE-8, Schedule 2, used to calculate forecasted growth in residential base use for the forecast period. The methodologies in both exhibits project growth of approximately 1 million KWH per year.

The first alleged error identified by Mr. Chernick's analysis of

44/ This exhibit was supplied in response to an Attorney General information request to explain the development of the last line of Exhibit FGE-8, Schedule 2.

Fitchburg's residential base use calculation is with respect to the 1979 KWH estimate derived in Exhibit AG-201, IR-41. This calculation projects eleven new customers between December 1978 and May 1979. The consumption 45/ of these eleven customers for the first five months of 1979 is subtracted from the January to May 1979 KWH increase over the same period in 1978. 46/ Fitchburg then multiplies this value by 12/5 to arrive at a yearly consumption of 1,047,192 KWH.

Mr. Chernick claims that the appropriate customer number to apply to the five month period KWH data employed by Fitchburg is the number of new customers added between the two periods, not those added in the 1979 period alone (Exh. AG-232, p. 39). Using an average value of 204.5 new customers, Mr. Chernick derives annual growth of 273,192 KWH for existing customers.

45/ $(11)(4000)(\frac{5}{12})$=18,333 KWH

46/

Jan.-May 1979	37,512,842 KWH
Jan.-May 1978	37,058,197
	454,663
	-18,333
	436,330 KWH

On redirect examination, however (Tr. 34, pp. 42-44), Fitchburg's witness, Mr. Bruce R. Garlick, Manager of Energy Planning, supplied actual 1979 residential consumption data and revised the 1979 line of Exhibit FGE-8, Schedule 2, to reflect actual rather than estimated data (Tr. 34, p. 43). Using actual data and the calculation methodology employed in Exhibit FGE-8, Schedule 2, growth in consumption due to existing customers totals 912,000 KWH for 1979. We prefer to use actual rather than estimated data when possible, and accept these figures for 1979. This produces a 1975-1978 average yearly growth in consumption by existing customers of 999,000 KWH by Mr. Garlick's estimate (Tr. 34, p. 44).

We find the method of calculating growth in base use by existing customers during the forecast period as presented in Exhibit FGE-8, Schedule 2, to be reasonable. It enables one to use a longer time span to smooth out the irregularities exhibited by Fitchburg's volatile customer growth data (a methodological characteristic Mr. Chernick noted as desirable 47/ (Tr. 42, pp. 30-31)).

In accepting the period 1975-1978 as relevant for our calculation, we do not accept Mr. Chernick's argument that post-1976 data is most relevant for the base use growth calculation (Exh. AG-232, p. 43). We acknowledge that the calculation's sensitivity to starting year is not marginal (Exh. AG-232, p. 43), but conclude that 1975 is the appropriate year in which to start. We include 1975 data specifically to smooth out data fluctuations.

Mr. Chernick also finds Fitchburg's projection of constant use per electric heating customer unreasonable (Exh. AG-232, p. 43). Mr. Chernick notes that average use per heating customer has remained steady over the last few years, while the weather has become

47/ We disagree with Mr. Chernick, however, that data separated by long time spans, rather than back to back data, is more desirable or necessarily smooths out data irregularities in a more desirable manner than does calculating an average using a long, continuous time span.

increasingly colder. The witness interprets the relatively constant heating use over this period, especially in the face of the last three years' consistently colder than average weather, as evidence that customers are reducing their heating use. The witness measures the extent of conservation by focusing on the ratio of heating use per heating degree day (HDD) (Exh. AG-232, p. 44).

In quantifying his observation, Mr. Chernick regresses post-1974 heating use per heating degree day on time to derive a time trend equation with which he predicts 1988 heating use of 6,141 KWH and 1988 total use of 10,756 KWH per customer. Mr. Chernick's 1988 total use figure is 26 percent less than Fitchburg's 1988 value for consumption per electric heating customer.

Although we have reason to believe that there undoubtedly has been some conservation in heating use since 1975, we cannot accept that the trend in conservation is as pronounced as Mr. Chernick suggests or that the method he uses to quantify conservation is appropriate.

We find the data, and the conclusions drawn by Mr. Chernick from this data, problematical. First, we are not at all sure how consumers' electric heating use responds to temperature, as measured by heating degree days (HDD). Second, we are not confident that the decline in "Heating Use Per HDD" indicates that substantial conservation has taken place. The ostensible reason for the decline in this ratio is inordinately large HDD values for 1976-1978 (see Exh. AG-232, p. 44), and not a sudden drop in heating use. 48/ We do not know whether the reduction in this ratio due to constant

48/ The average HDD for 1976-1978 is 7,301, whereas for the previous six years the average value is 6,212. Comparable average heating use averages are 9,911 KWH and 10,114 KWH; this is only about a 2 percent difference in average heating consumption between the two periods. The difference in the average KWH/HDD ratios for these two periods is 21 percent. These data imply to us that, whatever the actual underlying causal relations are, they are much more complex than the simple model the Attorney General uses to be relied upon for a ten-year projection (see Exh. AG-232, p. 44).

heating use in the face of colder weather is the result of physical conservation, higher electricity bills, sensitivity of heating use to HDD, sensitivity to weather patterns, a reduction in non-heating use consumption, or a combination of these factors. What we do know is that total consumption has remained relatively constant.

Mr. Chernick assumes that the sudden decline in this ratio of average heating use to HDD is due to conservation, and that the 1975-1978 trend will continue through 1988. We are neither willing to assume that a simple time trend regression analysis using data as problematical as this can adequately model future consumption trends, nor are we willing to assume that one can confidently attribute the precipitous decline in "Heating Use Per HDD" to conservation alone. We are thus unwilling to accept Mr. Chernick's results in place of Fitchburg's, and, after review of the record, we find Fitchburg's determination regarding constant consumption per heating customer over the forecast period reasonable.

Fitchburg incorporates the effects of improved appliance efficiency into its forecast by reducing both the residential base use increase and the load increase due to estimated new non-space heating customers by 5 percent per year, starting in 1981 and continuing through 1984. These 5 percent per year reductions are an exercise of judgment that approximate the consequenc of an average appliance efficiency impr vement of 20 percent (Tr. 28, pp. 119-120). On its face, we find this reduction due to appliance efficiency improvements reasonable.

Mr. Chernick, however, asserts that Fitchburg neglects to include in its calculation the reduction in consumption attributable to the replacement of worn-out appliances with more efficient appliances (Exh. AG-232, p. 45). Mr. Chernick estimates a 4.8 GWH reduction in refrigerator usage alone due to 42 percent more efficient replacements in the refrigerator stock starting in 1981. As noted in our discussion concerning EUA's treatment of efficiency improvements, supra, the record does not adequately support the rapid achievement of efficiency improvements to the large extent that Mr. Chernick suggests. Accordingly, we decrease Mr. Chernick's refrigerator example to reflect a frost-free refrigerator efficiency improvement of 21 percent and a standard refrigerator improvement of 15 percent, both starting in 1981. These efficiency improvements are consistent with those used by EUA (Exh. M-10, p. II-8). By our calculation 49/ one might expect, as an upper limit, an efficiency improvement less than half that suggested by Mr. Chernick. Nevertheless, this value (2.03 GWH) is nearly as

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49/ 1981 customer number - 19,383

19383(.5)(1.05)=10,176 standard refrigerators
19383(.5)(1.05)=10,176 frost-free refrigerators
10176(900)=9,158,400 KWH (standard)
10176(1400)=14,246,400 KWH (frost-free)
23,406,800 TOTAL

$9158400 \left(\frac{7}{15}\right)(.15) = 641,088$

$14,246,400 \left(\frac{7}{15}\right) = 1,396,147$

2,037,235 KWH reduction

large as the entire KWH reduction due to estimated appliance efficiency improvements, exclusive of appliance replacement (.99 GWH 50/ for new customers and 1.21 GWH 51/ for existing customers), which we above found reasonable.

Mr. Chernick also points out that consumption by existing and new electric space heating customers should be adjusted to reflect increased appliance efficiency (Exh. AG-232, p. 45).

We find the example of refrigerators with respect to energy reduction due to appliance replacement to be particularly relevant. We accept the premise that refrigerator saturation is 100 percent or greater. Also, basing our estimate on the proportion of FUA refrigerator KWH to total residential KWH (Exh. M-10, pp. II-13, II-16, II-14) and the refrigerator usage statistics we employ above for Fitchburg, refrigerators in the

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50/ (.8)(9)-6.21=.99 (see Exh. FGE-8, Sch. 1)

51/ (1)(9)-7.79=1.21 (see Exh. FGE-8, Sch. 1)

Fitchburg territory may consume approximately 20.25 percent of total residential consumption. Even without specific data on penetration, saturation and replacement rates, we are confident that refrigerator efficiency improvements for all new and existing residential consumers in Fitchburg's service territory will comprise a significant portion of the energy reduction attributable to efficiency improvements. These considerations lead us to find that Fitchburg has underestimated the effect of appliance efficiency improvements. We will, therefore, further reduce Fitchburg's 1988 residential consumption by .75 GWH. This additional reduction, while modest, will adequately account for efficiency improvements.

2. Industrial Forecast

Fitchburg forecasts its industrial energy demand by summing the respective contributions from an existing base, known new loads, the expected yearly contribution from three industrial parks (Tr. 29, pp. 4-5), the expected demand from miscellaneous small new customers and the increase in demand from existing customers (Exh. FGE-10, p. 1 of 2). Fitchburg estimates that with current subdivision plans, there are 41 potential lots in the three industrial parks (Tr. 29, p. 5), five of which already have buildings on them. Mr. Garlick determined that demand from these parks will increase at the rate of four lots per year, each customer drawing 500 KW per year with a 50 percent yearly capacity factor (Exh. AG-201, IR-56; Tr. 28, pp. 109-110, 112-113). This amounts to a cumulative contribution from the industrial park customers of 8.76 GWH yearly. The "Other Small New" customer category is estimated to increase consumption at the rate of 2 GWH per year (Exh. FGE-5, p. 10). The yearly increase in "Existing Customer" consumption is increased 3 GWH in 1979 to reflect known expansions for present customers, reduced to .4 GWH in 1980, and gradually reduced further to .2 GWH to reflect conservation by existing customers (Exh. FGE-5, p. 10).

Exhibit FGE-10, p. 2 of 2.

presents historical data on total industrial growth. The 1975-1978 growth was 15.5 GWH, 1.6 GWH and 6.9 GWH, resulting in an average growth of 8 GWH over the three-year period. Fitchburg's total industrial growth for the period after 1981 is approximately 11 GWH per year (Exh. FGE-10, p. 1 of 2), a value considerably greater than the average historical growth in Exhibit FGE-10, p. 2 of 2. We have difficulty interpreting this historical information for purposes of growth extrapolation into the future, especially in light of Mr. Garlick's statement that he does not expect industrial growth by existing customers to be as great in the future as it has been in the past (Tr. 23, p. 114). Furthermore, we find no analysis in the record which separates this historical growth into growth due to new customers, and growth due to existing customers. We certainly see no basis in the record for exceeding the average historical growth, and we have no specific business or general economic information concerning Fitchburg's territory on which we can reasonably rely in order to utilize the historical average growth as an approximation of yearly growth over the forecast period. Consequently, we will look to the reasonableness of the various components of Fitchburg's industrial growth, and their relation to total growth, in order to assess this portion of the forecast.

Mr. Chernick levels the general criticism against Fitchburg's industrial forecast that the subjective derivation of those components which are the major contributors to growth (industrial parks and other small new customers) is incommensurate with the importance of these contributions to the industrial forecast (Exh. AG-232, pp. 46-47). Specifically, Mr. Chernick charges that Fitchburg relied on neither historical data nor other sources to determine the rate at which new customers would enter the industrial parks (Exh. AG-232, p. 46). Nor did Fitchburg provide sufficient evidence from which to conclude that four 500 KW customers are likely to move into the parks each year, or that the parks can accommodate 30 such customers (Exh. AG-232, p. 46). Additionally, Mr. Chernick claims that Fitchburg forecasts industrial park consumption for 1988 (79.2 GWH) which is inconsistent with the physical capacity of the parks (30 customers, by Mr. Chernick's estimate) and the yearly per customer consumption assumed by Fitchburg (2.19 GWH per customer per year). Finally, Mr. Chernick estimates maximum 1988 industrial park consumption consistent with Fitchburg's forecast assumptions to be 65.7 GWH, compared to Fitchburg's 1988 estimate of 79.2 GWH (Exh. AG-232, p. 47).

We disagree with Mr. Chernick's conclusion that Fitchburg's 1988 industrial park forecast is inconsistent with the forecast assumptions, viz., that it exceeds the physical limitations of the parks, based on a per customer yearly consumption of 2.19 GWH. While Mr. Garlick initially testified that there were only 30 industrial lots (Exh. AG-201, IR-56; Tr. 28, p. 111), he subsequently modified his testimony to include one additional industrial park for a total of 41 lots as currently subdivided (Tr. 29, pp. 4-5). As we find no evidence in the record which controverts Mr. Garlick's revised testimony, we accept these figures. Furthermore, we note that the lots identified by Mr. Garlick are subject to possible further subdivision (Tr. 29, p. 6), and that the estimated 2.19 GWH consumption per year per customer is likely to vary with lot size. Fitchburg's assumptions regarding consumption and the potential number of total industrial lots are sufficiently flexible to preclude a conclusion that Fitchburg's GWH predictions are inconsistent with a likely maximum GWH amount. 52/

We do agree with Mr. Chernick, however, that Mr. Garlick has failed to document adequately the basis for his judgment that four 500 KW industrial park customers will be added

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52/ In fact, given the uncertainty surrounding the maximum potential aggregate demand of these parks, no determination of maximum demand is even possible.

each year throughout the forecast period. As far as we can determine, Fitchburg has performed no analysis, nor conducted any research, on either the feasibility or the likelihood of adding four such industrial park customers per year. The mere availability of real estate does not, in our opinion, constitute convincing evidence that such industrial growth will occur. Nor do we believe that interviewing just four industrial customers (Tr. 28, pp. 113-114), or the results of these interviews (Exh. AG-201, IR-1), is a sufficient basis for supporting Fitchburg's assumptions concerning industrial park growth.

Furthermore, Fitchburg's historical industrial growth does not inform us as to the likely rate of industrial park occupancy or size of occupant. Indeed, we see no reasonable way to rely on this aggregate historical information in assessing industrial park growth.

We do not find sufficient evidence in the record to support as reasonable

Mr. Garlick's assumption that industrial parks within Fitchburg's electric service territory will add four 500 KW customers per year to Fitchburg's load. We consider a growth rate of two 500 KW industrial park customers per year throughout the forecast period a more reasonable estimate in light of the scant information in the record on these industrial parks, and accordingly, so adjust Fitchburg's industrial forecast.

Fitchburg's growth for its "Known New Load" category is projected to increase only through 1981 and is held constant thereafter. We find it reasonable to accept the short-term growth Fitchburg has projected for this industrial category. Likewise, we accept Fitchburg's forecast of a constant base throughout the forecast period.

Mr. Chernick criticizes Fitchburg's lack of substantiation for its "Other Small New" industrial growth of 2 GWH per year. We agree that Fitchburg has failed to document adequately its growth assumptions for this industrial category. Lack of both detailed and general economic information, data on long-term consumption trends, and an industrial sector analysis commensurate with such data and information, complicates our finding as to the reasonableness of projecting growth for these customers at 2 GWH per year. We prefer to resolve this issue by examining the final industrial category, growth in existing customers' consumption, and total yearly industrial growth.

Fitchburg forecasts significant (3 GWH) growth for existing customers in 1979 due to known expansions in production schedules, and reduces this growth substantially (to .4 GWH, .3 GWH and then .2 GWH) toward the latter years of the forecast (Exh. FGE-5, p. 10; Exh. FGE-10, p. 1 of 2). This reduction in growth is intended to reflect conservation by existing customers (Exh. FGE-5, p. 10). We note that Mr. Garlick employed no calculations to support his judgment in arriving at the .2 GWH growth employed after

1980 (Tr. 28, p. 114), a fact which disturbs us. Although Mr. Garlick asserts that the growth in existing customers allows for normal growth in all industries, including new customers that come on line after 1980, and that it also reflects the potential for conservation (Tr. 34, p. 41), there is a lack of analysis, or even data, in the record to support this claim.

After a careful review of the evidence, we find that the growth projected for the "Other Small New" category is, more likely than not, too large, but that the "Existing Customer" category growth is too small to include customer expansion growth from all of the other categories. We have already reduced the "Industrial Park" growth by half. Total yearly growth after 1980, with our adjustment to the industrial park growth, is approximately 6.6 GWH per year. This total figure is reasonable and, therefore, we make no further adjustments to Fitchburg's industrial forecast.

3. Commercial and Municipal

This portion of Fitchburg's

forecast was uncontroverted by the Attorney General. After carefully reviewing this section of Fitchburg's foreca[illegible] find it to be reasonable. We there[illegible]ccept Fitchburg's projections of comme[illegible]d municipal growth.

We sum[illegible]e our adjustments to Fitchburg's energy demand forecast in Table 4.

TABLE 4
ADJUSTMENTS TO FORECAST

Fitchburg Energy GWH

Energy	80	81	82	83	84	85	86	87	88
Residential - w/o electric heat									
Base	87.69	87.69	87.69	87.69	87.69	87.69	87.69	87.69	87.69
St. Joseph Apts.	.19	.75	.75	.75	.75	.75	.75	.75	.75
200 cust. per year	.80	1.56	2.28	2.96	3.61	4.26	4.91	5.56	6.21
Exist. cust. growth	1.00	1.95	2.85	3.70	4.51	5.33	6.15	6.97	7.79
Efficiency Adjustment 1/	(.08)	(.17)	(.25)	(.34)	(.42)	(.50)	(.59)	(.67)	(.75)
	89.60	91.78	93.32	94.76	96.14	97.53	98.9	100.3	101.69
Residential w/heat	12.4	12.6	12.7	12.9	13.0	13.2	13.3	13.5	13.6
Commercial & municipal*	53.9	55.9	57.2	58.4	59.5	60.5	61.4	62.2	62.9
Industrial									
Base	249.2	249.2	249.2	249.2	249.2	249.2	249.2	249.2	249.2
Known New Loads	16.1	18.9	18.9	18.9	18.9	18.9	18.9	18.9	18.9
Industrial Parks	8.8	17.6	26.4	35.2	44.0	52.8	61.6	70.4	79.2
Industrial Park Adjustment	(4.4)	(8.8)	(13.2)	(17.6)	(22.0)	(26.4)	(30.8)	(35.2)	(39.6)
Other Small New	4.0	6.0	8.0	10.0	12.0	14.0	16.0	18.0	20.9
Existing cust.	5.2	5.6	5.9	6.1	6.3	6.5	6.7	7.0	7.2
	278.9	288.5	295.2	301.8	308.4	315.0	321.6	328.3	334.9
Street lighting & losses 2/	40.2	41.1	42.0	43.1	44.2	45.4	46.5	47.6	48.7
Revised total	475.00	489.88	500.42	519.96	521.24	531.63	541.7	551.9	561.79
Original total 3/	479.5	498.9	513.9	528.9	543.7	558.5	573.1	387.8	602.1
% reduction	1%	1.8%	2.6%	3.4%	4.1%	4.8%	5.4%	6.1%	6.7%

1/ .75 spread over 9 years

2/ FGE-7, Table E-8, p.2

3/ Ibid.

* unadjusted

4. Fitchburg's Peak Demand

Fitchburg's peak demand forecast is derived from its energy forecast. Load factors consistent with customer consumption patterns at system peak are applied to each class' yearly energy forecast to derive a peak load forecast for the Company (Exh. FGE-5, p. 11; Exh. FGE-7, pp. 5-6; Exh. FGE-11, Sch. 1-5). Residential customer load curve information was taken from a 1973 transmission study performed for Fitchburg by United Engineers (Exh. FGE-7, p. 5-b). Our interpretation of Mr. Garlick's testimony indicates that the coincidence factors for new residential loads were estimated to be 50 percent of the residential peak load in the summer and 100 percent in the winter (Tr. 29, p. 10).

Additional load attributable to commercial growth is also derived from the United Engineers' study (Exh. FGE-7, p. 5-b), as well as from customer specific analysis (Tr. 29, pp. 11, 18). Similarly, the additional contribution to peak attributable to the industrial class is calculated using customer specific analysis and load information derived from the United Engineers' study (Exh. FGE-7, p. 5-c; Exh. AG-200, IR-14; Tr. 29, pp. 13-21).

These peak load additions are then summed across customer class to derive a seasonal, cumulative forecasted contribution to peak (Exh. FGE-11, Sch. 4). The contribution to peak values are then added, by season, to the 1978 summer peak and the 1979 winter peak to derive forecasted internal peaks (Exh. FGE-11, Sch. 5). Next, estimated transmission losses are added to the yearly internal peaks to derive Fitchburg's forecasted peak demands (Exh. FGE-11, Sch. 5). Finally, NEPOOL reserve requirements are added to the forecasted peak loads to derive Fitchburg's yearly capability responsibility (Exh. FGE-5, p. 11, Exh. AG-201, IR-39; Exh. FGE-22, Revised).

On cross-examination the Attorney General challenged Mr. Garlick on the appropriateness of using class coincident load factors developed in a 1973 transmission study to forecast peak load through 1988 (Tr. 29, pp. 20-21). Mr. Garlick replied that although load shapes may have changed since 1973, in his opinion, the load factors utilized in the forecast were still valid for load forecasting purposes (Tr. 29, p. 21). The issue raised by the Attorney General is whether future load management efforts are satisfactorily included in Fitchburg's load forecast. We note that although Fitchburg has not analytically estimated the consequences of load management, the system-wide forecast nevertheless exhibits an improved load factor over the forecast period (Exh. FGE-7, Table 11, p. 2; Tr. 29, p. 29). While we would prefer an analytical derivation of how Fitchburg's load factor will improve due to conservation and load management, and the application of this analysis to Fitchburg's forecast, we acknowledge that a lack of appropriate data makes such analysis difficult, if not completely impracticable.

We accept the manner in which Fitchburg relied on historical load factors to forecast peak load. We do so not because Fitchburg has adequately forecast the effects of load management, but because the forecast period exhibits a steadily improving load factor which may adequately capture the load management effects we anticipate. 53/

As we have adjusted Fitchburg's energy forecast, we must now adjust its peak load forecast by a commensurate amount. In total, we make three adjustments to Fitchburg's forecast, two to the residential forecast and one to the industrial forecast. The sum total of our adjustments, however, only reduces the 1988/1989 winter peak from 95.6 MW to 92.9 MW and the 1988 summer peak from 99.3 MW to 97.2 MW. We discuss the reasons for this rather marginal reduction below.

The first correction we make to the residential peak load forecast is the St.

53/ In any future proceedings in which this issue may prove relevant, we will expect the collection of load management data and the analytical integration of this data into the Company's load forecast in order to capture the effects of load management.

Joseph Apartments double-counting error (Exh. FGE-11, Sch. 1; Exh. AG-200, IR-14a, Sheet 1 of 3), conceded by Mr. Garlick on examination by the hearing officer (Tr. 30, pp. 70-72).

Reducing the 1988 residential peak in order to reflect our .75 GWH reduction due to increased appliance efficiency is more problematical than the previous straightforward elimination of double-counting. The actual load factors Fitchburg used to develop the residential peak load are not in evidence. However, even if they were, we are not confident that they would be the appropriate load factors to use for this adjustment. Some of the appliances for which we expect efficiency improvements, such as refrigerators, have a high load factor. 54/ Others, such as ovens, air conditioners and miscellaneous appliances, are used only intermittently. Further analysis concerning actual efficiency improvements,

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54/ But even so, the power drawn will vary as the compressor kicks on and off.

saturation, conversion and penetration rates, and intensity and time of appliance use, is needed to determine the true load factor commensurate with the energy reduction attributable to appliance efficiency improvements. In the absence of such data, we have employed a 50 percent load factor. This is a reasonable 55/ estimate which, by our calculation, 56/ produces a 1988 reduction of 171 KW. Applying this to the 1988/1989 winter residential peak reduces the peak by .2 MW, after rounding. In all, we reduce the 1988/1989 residential contribution to peak by .4 MW.

Our adjustment to the industrial peak reflects a halving of the estimated growth in capacity requirements which Fitchburg has attributed to industrial park customers.

55/ A high load factor would produce a lower KW reduction than would a low load factor. A good portion of Fitchburg's additional KWH efficiency reductions may be due to large appliances such as refrigerators and freezers. The high load factors of these appliances will be offset by numerous miscellaneous low load factor appliances.

56/ $\frac{750{,}000 \text{ KWH}}{(.5)\ (8760)} = 171 \text{ KW}$

However, whereas Fitchburg's energy forecast reflects 50 percent of the maximum non-coincident energy requirements of four new 500 KW customers per year, the estimated capacity requirements of these new customers is based on only 25 percent of maximum non-coincident demand (Exh. AG-201, IR-14a, Sheet 3 of 3, line 31; Tr. 29, p. 15). Instead of projecting demand from these customers to increase by 2,000 KW per year (which would be consistent with assuming 100 percent capacity factor and 100 percent industrial park coincidence with system peak), Fitchburg projected industrial park demand to increase at only 500 KW per year (which is consistent with assuming 50 percent capacity factor and 50 percent industrial park coincidence with system peak) (Exh. AG-201, IR-14a, Sheet 3 of 3). When asked on cross-examination about the development of forecasted industrial park demand, Mr. Garlick responded that the figure employed "was a figure that I had assigned to those industries going into the industrial park" (Tr. 29, p. 15) and that the figure employed was a total figure

(Tr. 29, p. 15). We interpret Mr. Garlick's statement on cross-examination, 57/ the correspondence of the column totals of the exhibit referred to by Mr. Garlick with Exhibit FGE-11, Schedules 3-5 and Exhibit FGE-7, Table E-11, p. 2 (Fitchburg's Third Supplement forecast), and Fitchburg's failure to address these "understated" figures either on redirect or by submission of revised testimony or exhibits, to indicate that the 500 KW was a figure deliberately assigned to those industries going into the industrial park. We conclude from this that Fitchburg believes industrial park demand at system peak will only be 25 percent of maximum non-coincident industrial park demand, and accordingly adjust industrial park peak growth to reflect the addition of only 250 KW per year, or 125 KW per half year, a figure which represents 25 percent of our estimated maximum non-coincident demand attributable to the industrial parks.

57/ "The estimated four industrial customers was 500 KW per customer. The figure here in column 5, line 31 of Exh. AG-201, IR-14a, Sheet 3 of 3 for the 500 in reality should have been 2,000. So this is understated" (Tr. 29, p. 15).

We summarize our adjustments to Fitchburg's peak forecast in Table 5, noting that our energy reduction for the industrial class is proportionally greater than our demand reduction for this class. We attribute this in small part to routine rounding errors in converting kilowatthours into kilowatts and in large part to the fact that whereas the industrial park energy projection uses only a 50 percent capacity factor, the industrial park demand forecast further assumes a 50 percent coincidence (with system peak) factor.

TABLE 5

FITCHBURG PEAK ADJUSTMENTS (KW)

FGE 11

	Actual Summer 78	Actual Winter 78/79	Projected Winter 87/88	Projected Summer 88	Projected Winter 88/89	Compound Growth Rate
Sch. I Residential						
original total			4,014	2,122	4,291	
-St. Joseph dbl. count			200	150	200	
-efficiency at .5 LF			171	171	171	
New Total			3,643	1,801	3,920	
Sch. 2 Commercial & Munic.			6,400	6,400	6,900	
Sch. 3 Industrial						
original Ind. Park			4,300	4,500	4,800	
new Ind. Park			2,125	2,250	2,375	
New Total			13,700	14,700	15,000	
x .7 winter & .9 summer			9,600	13,200	10,500	
Sch. 4 Total Contribution to Peak (MW)			20.5	21.4	22.3	
Sch. 5 Internal Peak (MW)						
summer				93.6		
winter			89.1		90.9	
transmission losses			2.0	3.5	2.0	
New Summer Peak Total	75.33			97.1		2.57%
New Winter Peak Total		70.0	91.1		92.9	2.87%
Old Summer Peak Total	75.33			99.3		2.80%
Old Winter Peak Total		70.0	93.1		95.6	3.17%

5. The Effect of 1979 Actual Data

The Attorney General argues in his initial brief, p. 53, and in his reply brief, pp. 6-9, that 1979/1980 actual data (Exh. FGE-23, S.E.C. Form S-7, Table E-8) demonstrates Fitchburg's forecast is significantly overstated and unreliable and that, therefore, it cannot justify the Company's proposed Seabrook purchases. We do not agree. With any forecast, one would expect projected values to vary with actual data. The focus is not on one particular year, but rather the reasonableness of the forecast as a whole. The Attorney General's argument, without more analysis, is not persuasive. For example, Fitchburg projected an annual 3.17 percent growth in winter peak over the forecast period. Our adjustments reduce this rate to 2.87 percent; actual growth in peak for winter 1979/1980 was 2.7 percent (AG reply brief, p. 7). The magnitude of deviation is simply not sufficient to undermine the validity of the forecast as a planning document. This is not to imply we do not consider the adjusted growth rates to be somewhat optimistic, but rather that we find them reasonable upper limits for estimating Fitchburg's likely growth.

6. Reserve Margins and the Need for Power

Without fully reiterating our general discussion concerning reserve margins and the need for power which we developed in the context of Montaup's need for power section, we note that those concerns apply equally to Fitchburg. Most fundamentally, we find it imperative that Fitchburg have sufficient power to reliably supply the continuing demands of its customers.

We have found that for planning purposes it is reasonable to expect Fitchburg will experience an annual growth in its summer peak of 2.57 percent. 58/ This growth rate implies a 1988 summer peak of 97.1 MW. Without

58/ We note that this growth rate is very close to the 2.5 percent rate the Attorney General suggested may be more reasonable for Fitchburg in his initial brief for the proceedings prior to our June 28th Order (D.P.U. 19738/19743, AG initial brief, p. 89).

the power represented by the proposed Seabrook acquisitions, Fitchburg will have a reserve margin of 2.9 percent; this margin is clearly inadequate to ensure system reliability. With an additional 16 MW of capacity, Fitchburg would have a reserve margin of 19.4 percent. 59/ We find this margin reasonable.

The choice of a particular year with which to make these calculations is more a matter of convenience generated by the underlying necessity of making the calculations, rather than a matter of auguring some future moment with certainty. We are particularly concerned with Fitchburg's situation in the power years 1991/1992 when the 40 MW Boston Edison Company contract will expire. In the hearings prior to our June 28th Order, Fitchburg had included this power in its system mix only through the power years 1985/1986, since that is when the contract expires. In the present

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59/ These calculations have assumed full power availability from both Seabrook units, Millstone III and Pilgrim II (*see* Exh. FGE-22, Revision 1).

proceedings, the Company has indicated that the contract can probably be extended another five years, and consequently, has included this power in its revised exhibits. We have no reason to believe, however, that the contract can be extended beyond 1991/1992 and find it imprudent to believe so for planning purposes.

As a result of this loss of contract capacity, Fitchburg's reserve margin in 1991-1992 will be 5.1 percent if we assume no growth in peak for those three years and include the proposed 16 MW of Seabrook in the Company's generation mix. If we were to further assume an additional 10 MW from the conversion of Unit 7 to combined cycle operation, Fitchburg would have a reserve margin of 15.4 percent. Based upon our findings, we conclude that Fitchburg has thus demonstrated an intermediate to long-term need for additional capacity equaling at least 16 MW.

D. New Bedford Demand Forecast

New Bedford, a retail gas and electric company, is a subsidiary of New England Gas and Electric Association ("NEGEA"). NEGEA also owns another electric retail subsidiary, Cambridge Electric Light Company ("Cambridge"), and a wholesale subsidiary, Canal Electric Company ("Canal"). NEGEA forecasts the electric demands of these three affiliate companies in its Third Supplement to its Long-Range Electric Forecast (Exh. NB-3). Because New Bedford's demand forecast and capacity requirements are determined on a basis which considers the combined needs of the NEGEA affiliates (Exh. NB-8, p. 2), we shall consider New Bedford's requirements within the context of its affiliation with NEGEA and NEGEA's participation in NEPOOL.

NEGEA's Third Supplement separately forecasts the electric requirements of New Bedford, Cambridge and Canal (Exh. NB-3). To the resulting combined peak demand of its subsidiaries, NEGEA adds contract sales to the

City of Belmont (Tr. 28, p. 10). Our evaluation of NEGEA's forecast will, as in the case of Montaup and Fitchburg, consider the appropriateness of the forecasting methodology employed and the reasonableness of the assumptions made. 60/

1. New Bedford Residential Forecast

NEGEA relies heavily on an interview methodology to forecast energy and load requirements over the forecast period for New Bedford (Exh. NB-8, pp. 12-22). New customer projections were based on interview findings and historical dwelling unit permit data (Exh. NB-8, p. 14). The resulting new customer estimates were then converted into population projections and compared for accuracy

60/ Due to the manner in which the NEGEA forecast is derived, class by class schedules of our adjustments are extremely difficult to produce separately. Consequently, all of our adjustments to the forecast have been incorporated in Tables 6 through 11 which immediately follow the text of our analysis.

against population projections developed by the Massachusetts Office of State Planning and various regional planning agencies (Exh. NB-8, p. 14).

New customers were then divided into two groups: those with electric heating and those without (Exh. NB-8, p. 15). New and existing general residential customers were forecast to increase average yearly consumption at the same rate the existing general residential customers have exhibited since 1974. NEGEA adjusted this increase downward by 5 percent per year in the latter three years of the forecast to reflect conservation (Exh. NB-8, p. 15). Existing electric heating customers were forecast to increase their non-weather sensitive use at the same rate as the general residential customers' use (Exh. NB-8, p. 15). Based on information collected from interviews, the weather sensitive portion of the existing electric heating customers' use was held constant at its 1978 level throughout the forecast period (Exh. NB-8, p. 15). The non-weather sensitive portion of new electric heating customers' use was assumed to be similar to that of existing customers and therefore forecast similarly (Exh. NB-8, p. 15). The weather sensitive portion of their use was assumed to be greater than the average weather sensitive use of existing customers. This assumption was based on an interview derived judgment that during the forecast period, new electric heating customers will occupy larger, more expensive homes than those occupied by existing customers (Exh. NB-8, p. 16). NEGEA also relied on billing analysis data to support this assumption (Exh. AG-197, IR-23; Exh. AG-199, IR-1).

Off-peak water heating penetration for the forecast period is based on post-embargo data. Average use per customer is held constant throughout the forecast period (Exh. NB-8, p. 16).

All other residential customers, composed primarily of seasonal customers, increase their use at the same rate as the average KWH use per customer for the general residential customer class (Exh. NB-8, p. 16). NEGEA then summed these components of residential consumption to arrive at residential requirements by division and for New Bedford as a whole.

a. Customer Number

NEGEA's forecast is challenged by SEA witness John K. Stutz and Attorney General witness Susan Geller. We examine Dr. Stutz's criticisms first.

Dr. Stutz first notes that NEGEA has explained its forecast methods in insufficient detail for one to reproduce NEGEA's calculations (Exh. SEA-35, p. 9). Dr. Stutz claims that a forecast that cannot be evaluated with respect to its embodied premises and procedures is inadequate (Exh. SEA-35, pp. 6, 9).

Specifically, Dr. Stutz criticizes the presumption of a constant population per customer ratio over time, as is evidenced by NEGEA's check on customer number reasonableness. NEGEA uses 1970-1975 new customer only data concerning the number of persons per customer to convert the customer number forecast into a population forecast (Exh. SEA-35, p. 9). Dr. Stutz asserts that the number of persons per household has not been stable since 1970 and is expected to change in the future (Exh. SEA-35, p. 9).

Using the regional agency population forecasts which were employed by NEGEA as a check on the reasonableness of its customer forecast, Dr. Stutz developed yearly population growth rates. To these growth rates Dr. Stutz applied data on yearly changes in per-person electricity consumption. Data on per-person consumption was derived from a demand forecast for the Long Island Lighting Company ("LILCO") of New York, co-authored by Dr. Stutz. Dr. Stutz derives a compound growth rate for residential usages of 1 percent per year.

There is insufficient evidence in the record to support the use of LILCO per-person consumption data in place of such data for New Bedford. We find that the dissimilarities between LILCO and New Bedford elicited on cross-examination (Tr. 37, pp. 36-50) are sufficient to preclude our reliance on the similarities asserted by Dr. Stutz (Tr. 42, pp. 93-104). Given the importance of this purported similarity in per-person consumption between LILCO and New Bedford in the derivation of New Bedford's growth rate in residential consumption, we would expect a more detailed analysis of the two service territories than that provided by Dr. Stutz.

We now turn to Ms. Geller's analysis of NEGEA's forecast. Ms. Geller levels the general methodological criticism against NEGEA's forecast that it is the product of largely unsubstantiated judgment (Exh. AG-237, p. 4). She asserts that the open-ended interviewing methodology employed by NEGEA is deficient (Exh. AG-237, p. 6). Interviews were conducted unsystematically and without standardization (Exh. AG-237, p. 6; Tr. 27, p. 140); results were often undocumented (Exh. AG-237, pp. 6-7); no documentation of standard questions asked was kept (Exh. AG-237, p. 7; Exh. AG-197, IR-7); and interview responses, as distinct from the interviewer's interpertation of those responses, was also undocumented (Exh. AG-237, p. 7; Exh. AG-197, IR-8; Exh. AG-198). Our careful review of the evidence confirms Ms. Geller's criticisms. These methodological failings are serious for a forecast based solely on interviews.

In brief, it becomes almost impossible to verify the objectivity of the interview results proffered. In the behavioral sciences, decisions pertaining to the appropriateness of sample size, sample selection, questionnaire design, standardization of questions, and other aspects of statistical testing are of paramount importance in minimizing the possibility of interviewer bias in the interpretation of the outcome and in ensuring the possibility of independent duplication of the survey and its results.

The existence of these methodological flaws does not, however, lead inexorably to the conclusion that the end product of NEGEA's forecast is without merit. The experience and judgment of NEGEA's forecasters, as expert witnesses, are entitled to weight in their own right. Moreover, we can evaluate NEGEA's forecast by examining the forecast's constituent parts, searching for independent corroboration of key results, and, in the absence of such corroboration, ultimately applying our own expertise in evaluating the reasonableness of pivotal exercises of judgment.

Ms. Geller criticizes NEGEA's forecast of new customers on two basic counts. She asserts that insofar as the customer number projections are based on interview results, the values actually derived are based on unsubstantiated judgments made by the interviewer (Exh. AG-237, p. 9). Second, despite the fact that new dwelling unit permit data are used to project new customers, there has been no simple historical relationship between the number of new dwelling permits issued and the number of new customers (Exh. AG-237,

p. 11) and, Ms. Geller implies, the use of new dwelling permits as a proxy for new customers is therefore inappropriate. Ms. Geller also claims that NEGEA's method ignores demolitions and vacancies (Exh. AG-237, p. 10) and that data inconsistencies in the yearly change in customer number cast doubt on NEGEA's entire data base (Exh. AG-237, p. 12).

We share Ms. Geller's concern that the customer number projections derived from the interview process and detailed in the interview summaries (Exh. AG-198) cannot be easily reviewed. We find no record of the questions asked to elicit these responses, do not know on what premise each respondent based his answer, do not know if the responses can be aggregated and interpreted in a consistent manner, and do not know how or to what extent the interviewer subjectively consolidated the interview responses. Furthermore, our review of the interview notes (Exh. AG-198) confirms Ms. Geller's contention that interview responses concerning the projected number of dwelling units covered only the near-term future (Exh. AG-237, p. 10).

NEGEA claims, however, that forecasted new customers are also based on historical new dwelling unit permit data (Exh. AG-197, IR-8; Exh. NB-8, p. 14; Tr. 28, p. 39). NEGEA equates new permit data (see Exh. NB-8, Sch. F3, pp. 7, 19, 32) with new dwelling starts (Tr. 38, p. 40). Mr. Robert Fox, Director of Systems Planning for NEGEA, testified during cross-examination that NEGEA tested the reasonableness of this assumption by comparing new dwelling unit permits issued to NEGEA's change in customer count (Tr. 28, p. 42). On redirect examination Mr. Fox supplied such an analysis (Exh. NB-10), showing that during the period 1971-1978, 95.2 percent of the dwelling permits issued resulted in new residential customers (Tr. 33, pp. 22-23).

We find the result of NEGEA's check of permit data against new customers to be sufficient to allow the use of permit data as a proxy for new customers. 61/

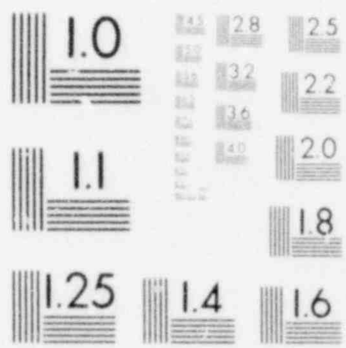
61/ With a caveat, however, which we discuss later.

We do not find Ms. Geller's criticism concerning demolitions and vacancies convincing. We would expect vacancies in the existing housing stock to fluctuate randomly and to have minimal effect over the forecast period. We find no evidence to indicate the existence of demolitions, either historical or planned, and accept the premise that demolitions do not affect the forecast.

NEGEA provides no testimony as to how the actual new customer figures employed in the forecast are derived, other than referencing interviews and permit data, but it does check the reasonableness of the figures employed by converting them to population estimates and comparing these population figures to state and regional planning agency population estimates (Exh. NB-8, p. 14). Mr. Fox asserts that NEGEA's population estimates show results similar to those estimated independently by these state and regional planning agencies (Exh. NB-29; Exh. NB-8, p. 14).

Ms. Geller faults NEGEA's

IMAGE EVALUATION
TEST TARGET (MT-3)



6″

MICROCOPY RESOLUTION TEST CHART

IMAGE EVALUATION
TEST TARGET (MT-3)

6"

MICROCOPY RESOLUTION TEST CHART

corroborative check on a number of grounds. First, she argues that the independent population projections used by NEGEA are old (Exh. AG-237, p. 13) and that the comparison made by NEGEA is with evidence on which the Second Supplement is based, not the Third (Exh. AG-237, p. 13).

She argues that the comparison check does not even support the Second Supplement customer number forecast (Exh. AG-237, p. 13). Focusing on the population increase over the forecast period rather than the population totals, Ms. Geller estimates that NEGEA overestimated New Bedford's increase in population by 20 percent (Exh. AG-237, p. 14).

Ms. Geller further contends that NEGEA employed incorrect 1985 population figures for the Town of Dartmouth ("Dartmouth") and the City of New Bedford (Exh. AG-237, p. 15). Ms. Geller revises NEGEA's forecast of new customers for 1976-1985 to be consistent with the Third Supplement; she revises NEGEA's 1985 population forecast to be consistent with the Third

Supplement customer number forecast; and she revises the Dartmouth and the City of New Bedford population forecasts to be consistent with the Southeastern Regional Planning and Economic Development District ("SRPEDD") forecasts as evidenced in Exhibit SEA-31 (Exh. AG-237, p. 15). Ms. Geller estimates that the Third Supplement overestimates the population increase in New Bedford's service territory by 20.3 percent in 1985.

On rebuttal, Mr. Fox responded that the consistency test performed for the Second Supplement was reduced to writing (see Exh. AG-197, IR-12 and Exh. AG-238), while the consistency test for the Third Supplement was not because it was, in NEGEA's judgment, "plainly evident...that the population projections determined from the Third Supplement would display a greater degree of consistency with independently derived population estimates because the Third Supplement forecasts contained lower projections of new customers than the Second Supplement" (Exh. NB-29, pp. 2-3).

Mr. Fox also suggested on rebuttal that comparing population totals is at least as useful as examining changes in population (Exh. NB-29, p. 5). Mr. Fox points to the ±15 percent variation in 1990 population projections for Cape Cod made by various planning agencies (Exh. NB-29, p. 6; Exh. AG-197, IR-11) as evidence that population totals are not necessarily "bound to be similar" (Exh. NB-29, p. 5; Exh. AG-237, p. 13).

Finally, Mr. Fox presented an explanation for the population figures of 26,600 for Dartmouth (versus 25,600 in Exh. SEA-31) and 98,650 for the City of New Bedford (versus 91,650 in Exh. SEA-31) employed in Schedules 7-1, 7-2 and 7-3 of Exhibit AG-238.

The SRPEDD population figures in Exhibit SEA-31 were published in 1975 (see Exh. NB-19). These figures were used in a Draft Water Quality Report published by SRPEDD in 1977 (see Exh. NB-27). The Final Water Quality Report was published in 1978 and contained new, higher population figures for Dartmouth and the City of New Bedford (see Exh. NB-23). Mr. Fox claims that NEGEA personnel obtained these revised population estimates for the municipalities and incorporated them into Schedules 7-1, 7-2 and 7-3 of Exhibit AG-238, NEGEA's "population consistency check."

After careful review of the evidence, we find Mr. Fox's explanation of the population discrepancy for the City of New Bedford and Dartmouth satisfactory. However, we agree with Ms. Geller that the implied population increases resulting from NEGEA's new customer forecast are more informative about the consistency of NEGEA's results with SRPEDD population forecasts than are comparisons of population totals. We have examined the record with respect to this issue and find that the figures in Schedule C of Mr. Fox's rebuttal testimony, Exhibit NB-29, are the most appropriate figures to use for evaluating population increases. We note that Mr. Fox has revised the population estimates for Duxbury and

Marshfield in this Schedule, and find this revision acceptable (Tr. 49, p. 16). While the population increases for each of New Bedford's three divisions vary rather significantly from the independently calculated population increases, the aggregate variance is on the order of 4 to 6 percent (Exh. NB-29, Sch. C). We find this margin of error acceptable, especially in light of the admittedly subjective judgment exercised by SRPEDD in distributing Massachusetts Office of State Planning population totals among southern SRPEDD communities (Exh. NB-19, p. 11). We would encourage NEGEA, however, to employ a more rigorous method of calculating new customers than that employed in the Third Supplement.

b. Electric Heat Penetration

NEGEA forecasts electric heat penetration separately for each service division based on interviews and historical data (Exh. AG-197, IR-8). For each division NEGEA projects that penetration rates will increase a percentage point per year over most of the forecast period (Exh. NB-8, Sch. F3, pp. 1, 13, 25).

The Attorney General argues that while service division penetration rates forecast for 1979 are similar to penetration rates of the most recent past, the projected increases cannot be derived from the historical data (Exh. AG-237, p. 17). The Attorney General further argues that the interview summaries imply penetration rates nearly 50 percent less than those forecast by NEGEA (Exh. AG-237, p. 17).

The discrepancy between NEGEA's forecasted penetration rates and those implied by the interview summaries renders NEGEA's interview results inadequate to rely on as the sole source of NEGEA's forecast. An examination of both the interview results and the historical penetration rates causes us to find the actual penetration rates forecast by NEGEA reasonable. In addition, they are consistent with those forecast independently by EUA and we find the reasons stated in Exhibit AG-197, IR-20 sufficient to support this aspect of the forecast.

c. Average Residential Non-Weather Sensitive Use

Average non-weather sensitive use, or average yearly use by general residential customers, was calculated by Mr. Byrne by drawing a line through 1974-1978 historical data and extrapolating the linear increase out to 1988 (D.P.U. 19738, Tr. VIII, p. 1121). Mr. Byrne drew this line "by eye" through rolling twelve-month average consumption data (D.P.U. 19738, Tr. VIII, p. 1121). Plots of these lines are in Exhibit NB-8, Sch. F3, pp. 8, 20, 33. Ms. Geller contends these lines are too steep to be consistent with available data points (Exh. AG-237, p. 19).

We have examined the evidence and find that the lines drawn by Mr. Byrne are indeed too steep. 62/ We have adjusted 1979-1988 average KWH use to correspond to the equations

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62/ We checked the accuracy of Mr. Byrne's eye-drawn lines by regressing, for each New Bedford division, the average annual KWH use of non-heating customers as found in Exhibit AG-197, IR-9, Exhibit 9-B, p. 2 against time for 1974-1978. We think that in this instance, the use of linear regression is the most appropriate method to extrapolate a linear trend into the future. Our resulting equations produced a 1988 estimate of 5,865 KWH for the Cape and Vineyard division, a figure approximately 1 percent less than New Bedford's forecasted, conservation-adjusted value of 5,912 (see Exh. NB-8, Sch. F3, p. 1). We derived 6,072 KWH for the Plymouth division, a 1988 value approximately 3 percent less than Plymouth's conservation-adjusted forecasted value of 6,240 KWH (see Exh. AG-197, IR-23, 24 for an explanation of NEGEA's conservation adjustments). Our regression results for New Bedford indicate that the 1988 KWH value of 5,142 (versus our 4,641) is nearly 10 percent too large. Our equations were as follows:

Cape and Vineyard: $KWH=67.9(Yr)-121.6$; $r^2 = .95$

Plymouth: $KWH=94.1(Yr)-2209$; $r^2 = .98$

New Bedford: $KWH=56.1(Yr)-295.4$; $r^2 = .77$

Where Yr=74,75,76,77,78

Applying the F test, we reject at a 1 percent level of significance the hypothesis that the coefficients equal zero for the Plymouth and Cape and Vineyard divisions, and at a 5 percent level of significance for the New Bedford division.

presented in the previous footnote. 63/

These 1988 average KWH values per general residential customer do not include any conservation adjustment. 64/

d. <u>Average Residential Weather Sensitive Use</u>

Weather sensitive use by existing electric heating customers is forecast to remain constant at 1978 levels (Exh. NB-8, p. 15). Such use for new electric heating customers was assumed to be greater than for existing electric heating customers and was held constant throughout the forecast period (Exh. NB-8, pp. 15-16). NEGEA based this assumption on interview information which informed its forcasters that only the new, larger and more expensive homes would install electric heat

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63/ The line drawn by Mr. Byrne for the New Bedford division excluded data for 1975 which we feel should be included (see Exh. NB-8, Sch. F3, p. 33). We see no reason to exclude these data.

64/ We will address conservation separately, *infra*.

during the forecast period, and on an analysis of monthly billing data for new electric heating customers (Exh. AG-197, IR-8(e); Exh. AG-197, IR-23 (d),(e)).

Ms. Geller challenges NEGEA's assumption that new electric heating customers will have a higher annual weather sensitive use than existing electric heating customers, claiming that this assumption is unsubstantiated and unreasonable (Exh. AG-237, p. 21). She claims that the interview responses contain only isolated references to the prices of new electrically heated homes and only one reference to the attitude of expensive home buyers toward electric heat (Exh. AG-237, pp. 21-22). Consequently, she claims there is no support for this assumption in the interview results.

Ms. Geller finds numerous faults with the billing analysis performed by NEGEA. She claims that the Trout Farm analysis is unrepresentative of Plymouth division electric heating customers (Exh. AG-237, p. 23). NEGEA's use of the Cape and Plymouth samples, she asserts, overestimates heating use. Rather than applying the results of the Plymouth sample (21,637 KWH per customer per year) to the Plymouth division, and likewise for the Cape division (17,621 KWH per customer per year), NEGEA averaged the billing analysis results and held the result as representative for each division (Exh. AG-237, p. 24). The resulting forecasted electric heating usage for the Cape division, which has three times as many electric heating customers as the Plymouth division, is thus asserted to be targeted to a spuriously high average consumption value and thereby an overestimate of Cape heating use. Ms. Geller also claims that since NEGEA projects off-peak hot water use separately, NEGEA's failure to subtract off-peak hot water use from the billing analysis data results in double-counting (Exh. AG-237, p. 25). Finally, she claims that NEGEA failed to weather-adjust the 1978 billing data; and consequently, new heating customers' forecasted use is targeted too high.

We have reviewed the evidence

concerning weather sensitive use for new and existing electric heating customers carefully and find NEGEA's assumption concerning ferential weather sensitive use inappropriate. After examining the interview results (Exh. AG-198), we can find no reliable, documented evidence or sufficiently substantiated judgments to support the conclusion that electrically heated homes built during the forecast period will be larger and more expensive than those built in the past, or that owners of larger, more expensive homes will be insensitive to electricity prices.

We agree that the Trout Farm billing analysis is unrepresentative of New Bedford's Plymouth division and deem it inappropriate to draw inferences concerning future average consumption from this single sample. We also agree that the weather sensitive portions of the Cape and Plymouth billing analysis figures should be weather-adjusted if they are used as a basis for estimating the weather sensitive use of new electric heating customers. We note that weather sensitive use by existing electric heating customers is weather-adjusted (see Exh. NB-8, Sch. F3, pp. 2, 14, 26, line 19), and believe it appropriate to base use for new electric heating customers on commensurately adjusted figures.

Finally, examination of each New Bedford division energy forecast in Schedule F3 of Mr. Fox's testimony confirms Ms. Geller's allegation that NEGEA has improperly used the billing analysis data for the Cape and Plymouth divisions by neglecting to consider the water heating use component of the derived average yearly consumption values. The billing analysis in Exhibit AG-199, Schedule IR-1, produced an average yearly use for Plymouth division new electric heating customers of 21,367 KWH and 17,621 KWH for Cape division new electric heating customers. NEGEA averaged these figures to derive a consumption estimate for the Cape and Plymouth divisions of 20,000 KWH per year per new electric heating customer (Exh. AG-199, IR-1-1; Exh. AG-237, p. 24). NEGEA estimated average annual use for new electric heating customers to be 18,000 KWH per year for the New Bedford division (Exh. AG-199, IR-1-1). If we assume, exclusive of a weather adjustment allowance, that these values are representative of average yearly electricity consumption for new electric heating customers in 1978, then we would expect near-term forecasted average consumption per new electric heating customer to approximate these figures for the three divisions. However, we find that 1979 consumption for these customers is 24,050 KWH 65/ for the Cape division, 24,300 66/ KWH for the Plymouth division and 22,750 KWH 67/ for the New Bedford division.

65/

5,175	line 15, Exh. NB-8, Sch. F3, p.1
14,825	line 17, Exh. NB-8, Sch. F3, p.2
4,050	line 30, Exh. NB-8, Sch. F3, p.3
24,050	

66/

5,150	line 15, Exh. NB-8, Sch. F3, p.13
14,850	line 17, Exh. NB-8, Sch. F3, p.14
4,300	line 30, Exh. NB-8, Sch. F3, p.15
24,300	

67/

4,120	line 15, Exh. NB-8, Sch. F3, p.25
13,880	line 17, Exh. NB-8, Sch. F3, p.26
4,750	line 30, Exh. NB-8, Sch. F3, p.27
22,750	

Although NEGEA claims to forecast average annual use for new electric heating Cape and Plymouth division customers at 20,000 KWH and New Bedford customers at 18,000 KWH, we find forecasted average annual per customer consumption values for these divisions which are higher by an amount equal to the average annual water heating consumption for each division, respectively. This leads us to believe that NEGEA has double-counted water heating consumption for new electric heating customers.

For each division, forecasted average annual consumption for electric heating customers is substantially greater in 1979 than in 1978:

	1978*	1979**	Difference
Cape division	14,834	24,050	9,216
N.B. division	13,574	22,750	9,176
Ply. division	18,547	24,300	5,753

* Exh. AG-197, IR-9, Exh. 9-B, p.1

** derived supra.

Even if we were to accept NEGEA's assumption that new electric heating customers will have greater consumption than existing customers, there is insufficient evidence in the record to support the average use figures employed in NEGEA's forecast. We therefore adjust average weather sensitive energy use of new electric heating customers to be the same as that of existing electric heating customers. Specifically, we adjust line 17 of each division's forecast in Exhibit NB-8, Schedule F3 to read 9,676 68/ for the Cape division, 12,617 69/ for the Plymouth division, and 9,193 70/ for the New Bedford division.

68/ (5929 HDD)(1.632 KWH/HDD/Cust.). See line 19, Exh. NB-8, Sch. F3, p. 2.
69/ (5764 HDD)(2.189 KWH/HDD/Cust.). See line 19, Exh. NB-8, Sch. F3, p. 14.
70/ (5395 HDD)(1.704 KWH/HDD/Cust.). See line 19, Exh. NB-8, Sch. F3, p. 26.

e. Seasonal Customers

NEGEA includes use attributable to seasonal customers in the "All Other Residential Classes" category (Exh. AG-197, IR-15, 16,17). NEGEA assumes this class will increase consumption at the base load rate of growth (Exh. NB-8, Sch. F3, line 34, p. 3).

Ms. Geller faults NEGEA for failing to consider separately the differential consumption of seasonal and year-round new customers (Exh. AG-237, pp. 25-26). By Ms. Geller's estimate, seasonal customers occupied 30 percent of the Cape division dwelling units and 20 percent of the Plymouth division dwelling units in 1978 (Exh. AG-237, p. 25; Tr. 46, pp. 32-34).

Although Mr. Fox testified that he did not know the proper portion of seasonal customers in the Cape and Plymouth divisions (Tr. 28, p. 59), he assumed that seasonal customers purchased homes in proportion to their representation in historical data (Tr. 28, p. 60). We agree with Ms. Geller, and Mr. Fox, that a portion of new homes purchased in the Cape and

Plymouth divisions are purchased by seasonal customers. We find that the record lacks complete historical data on seasonal customer representation in these two divisions; Exhibit AG-197, IR-15, Exhibit 15, however, contains data on the peak number of seasonal customers (correctly defined by Ms. Geller as the maximum number of seasonal customers recorded in a single month (Tr. 46, p. 34)). The peak number of seasonal customers is the best indication of seasonal customers in the record. Consequently, we accept Ms. Geller's estimates and adjust NEGEA's figures by reducing the projected number of non-seasonal residential customers by 30 percent in each year of the forecast for the Cape and Vineyard division and by 20 percent for the Plymouth division. We do so because the distinction between seasonal and non-seasonal residential customers is important in making accurate forecasts of future consumption for these two service territories. In order to complete this adjustment we also adjust the category "All Other Residential Classes" by equating the growth rate for this category to the growth rate for the general residential class and by assuming that consumption for all seasonal customers is reflected in this growth rate. 71/

71/ NEGEA clearly needs to collect more accurate and more detailed data on the use characteristics of its seasonal customers. This type of data can and should be collected by NEGEA in its ordinary course of business; and, accordingly, we will expect this refinement in future forecasts.

2. New Bedford Commercial Forecast

NEGEA's near-term commercial sales projections are based on interview results and its long-term projections are based on its judgment that the commercial and residential growth rates will converge, exhibiting a pattern it feels is the "natural" long-run relationship between these two classes (Exh. AG-197, IR-41). We accept NEGEA's judgment that short-term commercial growth will be slow, and find its interpretation of interview results reasonable (Exh. AG-197, IR-42, IR-43; Exh. NB-8, p. 17). However, the growth rates for the New Bedford division for the 1978-1988 period and the other two divisions for the 1981-1988 period are founded on assumptions of a purportedly known proportional relationship between commercial and residential consumption which has not been properly documented.

Dr. Stutz criticizes NEGEA's assumption of proportional growth as inferior to an independently derived commercial forecast (Exh.

SEA-35, p. 12), but accepts this assumption in his adjustment to NEGEA's forecast. As with the residential sector, Dr. Stutz bases his adjustment on the LILCO demand forecast, lowering commercial growth to 1.3 percent per year through 1985 and 1.6 percent per year thereafter (Exh. SEA-35, p. 12).

Ms. Geller criticizes NEGEA's underlying assumption that there exists a "natural" long-term linear relationship between residential and commercial consumption as having no basis in fact (Exh. AG-237, pp. 29-30). Ms. Geller asserts that NEGEA's assumption that commercial growth will return to its long-run linear relationship with residential growth entails the following hypotheses: (1) the linear relationship has existed in the past, (2) there are theoretical reasons to explain the relationship and (3) recent commercial growth can be explained as a temporary departure from the "natural" relationship (Exh. AG-237, p. 30). Ms. Geller finds that none of these hypotheses is adequately supported (Exh. AG-237, p. 30).

We concur with Dr. Stutz and Ms. Geller that the evidence presented by NEGEA tells us nothing about any underlying causal relationship or about the existence of any "natural" relationship. We conclude there is insufficient analysis of commercial growth by NEGEA to rely on its conclusions with an acceptable level of confidence. Nor, as previously explained regarding the residential sector, can we accept Dr. Stutz's adjustment to the commercial class based on LILCO data. We agree with Ms. Geller that NEGEA's ratio analysis (see Exh. NB-8, Sch. F3, p. 44) is inadequate, and rely on her analysis of Plymouth and New Bedford ratios for this conclusion (Exh. AG-237, pp. 31-32). Her graphic analysis (Exh. AG-237, pp. 33-34) as well as that presented by NEGEA (Exh. NB-26) leads us to acknowledge a downward change in the rate of growth of consumption since approximately 1973 for both the residential and commercial classes for all three New Bedford Company divisions (see Exh. AG-237, pp. 33-34;

Exh. AG-241).

We have calculated the commercial compound growth rates for the period 1973-1978 (1.47 percent for Plymouth, 3.8 percent for the Cape and Vineyard and -.25 percent for New Bedford) and used these rates to replace those in the forecast that are founded on the commercial/residential relationship propounded by the Company and disputed by both Dr. Stutz and Ms. Geller. As noted earlier, our use of these compound growth rates is not to be considered as a precedent; however, we believe that they are the only justifiable rates that can be drawn from the evidence presented. In order to ensure more satisfactory results, we urge the Company to take more care in detailing its assertions of causal relationships in the future.

3. New Bedford Municipal Forecast

NEGEA holds municipal consumption constant for the near term and increases the rate of consumption in the latter years of the forecast based on residential consumption rates

(Exh. NB-8, p. 17; Exh. NB-8, Sch. F3, pp. 5, 17, 30). The only new customers added were those found through interviews (Exh. NB-8, p. 17).

No intervenor contested NEGEA's forecast of municipal consumption. We find NEGEA's method of forecasting municipal consumption reasonable and, for each division, adjust municipal consumption to reflect previously adjusted residential consumption.

4. New Bedford Industrial Forecast

NEGEA's industrial forecast is based on interviews with industrial customers (Exh. NB-8, p. 17) and NEPOOL's long-range forecast for industrial sales in Massachusetts and New England (Exh. AG-197, IR-54).

The industrial energy consumption forecast for the Cape and Plymouth divisions was based solely on judgments drawn from interviews (Exh. AG-197, IR-53). Judgments made concerning New Bedford industrial growth were based on NEPOOL's Report of the NEPOOL Load Forecasting Task Force on the NEPOOL Model-Based Forecast of

New England Electric Energy and Peak Load 1979-1989 (Exh. AG-197, IR-54) as well as interview results. Dr. Stutz made no adjustment to NEGEA's industrial forecast. Ms. Geller claims that the industrial interview notes contain inadequate information on which to base the individual industrial customer forecast (Exh. AG-237, p. 38). She also claims that NEGEA made no attempt to ensure that the assumptions underlying the NEPOOL forecast for Massachusetts and New England, on which the New Bedford division forecast was based, also hold for the New Bedford division.

The record with respect to the industrial forecast contains insufficient support for the Department to judge the appropriateness of certain aspects of the forecast with the degree of confidence we would prefer. We urge NEGEA to analyze industrial consumption with greater thoroughness in future demand forecasts, but find the growth rates utilized reasonable and, therefore, accept the forecast for the purpose of this proceeding.

5. Cambridge Forecast

NEGEA forecasts Cambridge residential consumption to grow at .5 percent yearly. This is due entirely to increased consumption by existing customers. No increase in consumption is attributed to new customers (Exh. NB-8, p. 18).

The existing commercial, municipal and industrial customers are forecast to maintain their current use (Exh. NB-8, p. 18). The only growth forecast for these classes is that due to anticipated new customers. This growth is based on information gathered from interviews (Exh. NB-8, p. 18).

The Cambridge forecast was not contested in these proceedings. We find NEGEA's Cambridge forecast reasonable and accept the figures presented by NEGEA.

6. Conservation

NEGEA accounts for conservation in its New Bedford forecast by adjusting the average per customer consumption growth rate of general residential customers downward 5 percent yearly in the latter years of the forecast (Exh. NB-8, p. 15). NEGEA's forecaster based this adjustment on his judgment, and conceded that no systematic, mathematical methodology had been developed to incorporate the effects of conservation into the forecast (Exh. AG-197, IR-23). Conservation attributable to increased appliance efficiency was taken into account by using a time lag formula which forecast new general residential customer average use at a level equivalent to the average use of the previous year's general residential customers (Exh. AG-197, IR-24).

Ms. Geller described NEGEA's conservation adjustments as minuscule, stating they comprise only a 13 GWH reduction by 1990 (Exh. AG-237, p. 41). She suggests this 13 GWH reduction is so small as to be the result of round-off error.

In his initial brief, the Attorney General points out that the time lag formula was also developed to capture the effects of "immature" customers, i.e., new customers on-line for less than an entire year. This further diminishes the net effect attributable to conservation.

In the preparation of a demand forecast, we consider it reasonable to assume that all customers, both new and existing, will engage in conservation throughout the forecast period. Detailed inspection of the record indicates, however, that NEGEA has failed to adequately reflect conservation. The Attorney General is essentially correct when he categorizes New Bedford's conservation adjustment as minuscule; and we concur with his assertions that virtually no adjustment was made for conservation and that what little there was could easily be attributable to round-off error. While informed persons may differ on the amount of conservation which may be expected to occur over a given forecast period, it is unreasonable to assume in effect that there will be no conservation.

Although we do not accept New Bedford's conservation adjustment, tne record contains evidence which nevertheless enables us to assess to some degree the potential impact of conservation efforts on New Bedford's future demand. SEA's witness, Dr. Stutz, testified at great length on a wide range of conservation measures that could be vigorously promoted in order to lessen consumption. He determined a level of residential conservation using methodologies similar to those he employed in studies carried out in other states. In utilizing these methodologies, he estimated the amount of electricity attributable to the different end-uses by multiplying the saturation rate for the respective end-uses by the annual unit KWH use per year and by the current number of New Bedford's residential customers. The saturation rates and the annual unit KWH use per year figures are largely drawn from the Energy Systems Research Group's 1979 New England Study referenced in his direct testimony. To estimate the percentage savings attributable to efficiency gains for each end-use, he multiplied the unit energy savings which he claimed are explained in his prefiled testimony by the fraction of replacements and new units introduced during the target period. He implicitly assumes that the fraction of replacements and new additions (Exh. SEA-35, Sch. JS-7, Sheet 1 of 2) utilized will be valid by the year 1985.

Unfortunately, Dr. Stutz did not indicate the derivation of the unit energy savings nor of the replacement fractions used. With no detailed knowledge of the composition of the appliance and housing stock energy consumption characteristics in the New Bedford area, or at least knowledge of the assumptions Dr. Stutz made with respect to their composition, it becomes extremely difficult to estimate potential energy savings. This problem is further compounded by a lack of data to support his supposition that the replacement stock will be as efficient as he claims. In addition, the three divisions that constitute the New Bedford service area are diverse enough to warrant estimating conservation levels for each division separately. Finally, as we have previously expressed, we have serious reservations about the wholesale application to the New Bedford area of estimates calculated for other service territories.

Dr. Stutz estimates that 100.5 GWH of electricity can be conserved in the residential sector during 1985. Success of such a vigorous residential energy conservation program involves well-aimed publicity drives to make consumers aware of more efficient appliances and requires that they in fact purchase these appliances. Dr. Stutz also suggests the free distribution of inexpensive energy saving devices such as showerhead flow restrictors, the offering by the company of cash rebates against the cost of the more expensive major appliances and/or helping to arrange financing for customers purchasing these appliances. He further cites the significance of a rigorous implementation of the Residential Conservation Service Program by New Bedford suggesting that in order to maximize the effectiveness of the program petitioner should offer free energy audits and small interest-free loans.

Dr. Stutz describes an overly ambitious residential conservation target. We see this as an extremely optimistic upper limit unlikely to be attained by 1985, although possibly by 1988.

With respect to the commercial sector, Dr. Stutz assumes that its savings will at least equal those in the residential sector. There is no basis for this assertion and the witness admitted the absence of adequate local or national data on commercial end-use, which data are crucial for calculating commercial savings. Consequently, we cannot accept his proposal for commercial sector savings.

In spite of our belief that the 9.8 percent or 100.5 GWH savings in the residential sector by 1988 are very optimistic, we shall incorporate these estimated savings into the forecast, bearing in mind our inability to account for commercial and industrial savings due to the paucity of data for these sectors and the lack of any estimate regarding them by New Bedford.

7. Peak Load Forecast

NEGEA develops its peak load forecast by applying historical load factors to the energy requirements of the New Bedford divisions and the Cambridge division (Exh. NB-8, pp. 18-20). The Cape and Plymouth divisions, which are primarily residential, have load factors historically 2 to 3 percent below that of the more industrially intense New Bedford division (Exh. NB-8, p. 19). NEGEA does not expect these division characteristics to change over the forecast period, and thus anticipates that their respective load factors will continue in the same relationship (Exh. NB-8, p. 20).

Because NEGEA anticipates faster growth in the low load factor Cape and Plymouth divisions than in the high load factor New Bedford division, absent any offsetting influences, NEGEA would expect New Bedford's overall load factor to fall. NEGEA, however, forecasts New Bedford's load factor to remain constant at 65 percent in anticipation of positive load factor consequences from the implementation of load management techniques and from expected rate reform initiatives, such as time of use rates (Exh. NB-8, p. 20).

Cambridge is a summer peaking company with a heavy air conditioning load (Exh. NB-8, p. 20). The annual load factor has decreased markedly since 1974, from 59.5 percent to 55.7 percent in 1978 (Exh. NB-8, p. 21). Owing to load management and time-of-use rate benefits, NEGEA slows this historical load factor erosion, forecasting a 1980 load factor of 56 percent which decreases only 1.2 percent over the ten-year forecast period (Exh. NB-8, p. 21).

NEGEA forecasts peak load capacity requirements based on normal peak loads (Tr. 28, p. 9). NEPOOL requirements are forecast using summer peaks (Tr. 28, p. 10). The coincident peak load of the distributing companies is based on the sum of the peak loads of the individual companies multiplied by a diversity factor (Exh. NB-8, p. 21). The diversity factor applied is 99 percent of the Cambridge peak added to 100 percent of the New Bedford peak (Exh. NB-8, p. 22; Exh. NB-8, Sch. F3, p. 43). Our review of Schedule F3 p. 43, however, is at variance with NEGEA's assertion concerning the appropriate system diversity factors. We simply cannot find any clear support for the percentages utilized and, in this instance, we find the average historical diversity factors of 96.5 percent for Cambridge and 99 percent for New Bedford more appropriate.

NEGEA forecasts New Bedford's normal summer peak to grow at 3.3 percent during the forecast period (Tr. 28, p. 65). The Cambridge peak is forecast to grow at 2.3 percent, including sales to Belmont (Tr. 28, p. 10). The combined companies' peak is forecast to grow at 3.3 percent, using normal summer peak loads for the period 1978 to 1988 (Tr. 28, p. 10).

Ms. Geller does not address

NEGEA's method of calculating peak growth. Dr. Stutz translates his energy adjustments into peak growth using a constant, extreme weather load factor of 57.1 percent (Exh. SEA-35, p. 14). He terms this calculation conservative, disagreeing with Mr. Fox that the effects of rate reform initiatives will be offset by shifts in the relative size of New Bedford's customer classes (Exh. NB-8, p. 14).

Although we agree with Dr. Stutz that rate reform intiatives may reduce peaks more than they reduce total energy consumption, we are concerned about the deteriorating load factors exhibited by Cambridge, and the potential for deterioration in New Bedford. Given the present state of knowledge in this area, we find that for the purposes of this proceeding, NEGEA has adequately taken into consideration both expected improvements in load factors due to anticipated rate reform initiatives and load management, as well as the observed and potential deterioration of load factors for its distributing companies.

Consequently, we find Mr. Fox's application of judgment with respect to these diametric influences reasonable. We also find the use of summer normal peaks in estimating peak growth reasonable.

Using NEGEA's method of calculating peak sales, the total effect of our adjustments to NEGEA's forecast reduces normal summer peak load growth from 3.3 percent (Tr. 28, p. 10) to 2.24 percent, including sales to Belmont.

8. The Need for Power

No question has been raised concerning the appropriateness of New Bedford's utilization of a 22 percent reserve margin for planning system reliability. Based on the record in this proceeding, we find this reserve margin reasonable.

Based on our adjustments to NEGEA's forecast, we find that without the additional capacity represented by the proposed Seabrook acquisition NEGEA will have a system reserve mar... of 13.0 percent. 72/ We find this margin too low. Inclusion of the capacity represented by the proposed Seabrook acquisition would increase the NEGEA system 1988 reserve margin to 19.6 percent. 73/ This margin is within the range supported by the evidence in this case. Consequently, we find that NEGEA has demonstrated a need for the 50 MW of Seabrook capacity.

72/ $\frac{861}{762} = 1.13$

73/ $\frac{911}{762}$

TABLE 6

Cape and Vineyard Division - Revised Energy Forecast

		1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
Residential Annual												
1)	*Total customers (actual)	56,476										
2a)	Forecast of new dwellings 2 x .7		2,030	2,100	2,170	2,170	2,170	2,170	2,170	2,170	2,170	2,170
3)	Penetration rate (%)		10	11	12	13	14	15	16	17	18	19
4a)	(3 x 2a) New electric heat customers		203	231	260	282	304	326	347	[illegible]	391	412
5a)	(2a - 4a) New general dwellings		1,827	1,869	1,910	1,888	1,866	1,844	1,823	[illegible]	1,779	1,758
6a)	Total customers (forecast)		58,303	60,172	62,082	63,970	65,836	67,680	69,503	[illegible]	73,083	74,841
7a)	Avg. KWH/cust.	5,175	5,243	5,310	5,378	5,446	5,514	5,582	5,650	5,718	5,786	5,854
8a)	Energy-existing customers (previous year's customers x 7a) (MWH)		296,104	309,589	323,605	338,099	352,731	367,497	382,392	397,418	412,565	427,834
9a)	Additional energy-new customers (5a x previous 7a)		9,455	9,799	10,142	10,154	10,162	10,168	10,176	10,176	10,172	10,172
10a)	Total residential annual (8a + 9a) (act.)	292,488	305,559	319,388	333,747	348,253	362,893	377,665	392,568	407,594	422,737	438,006
	Growth rate (%)		4.47	4.53	4.5	4.35	4.2	4.07	3.95	3.83	3.72	3.61
	Compound rate	4.12%										

* These line numbers correspond to those used by the company. Where the designation "a" appears, we have substituted our own adjustments to the company's projections.

POOR ORIGINAL

Cape and Vineyard Division - Revised Energy Forecast (cont.)

		1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
Residential With Electric Heat												
12)	Actual customers	8,440										
13a)	New electric heat customers (4a)		203	231	260	282	304	326	347	369	391	412
14a)	Total customers (forecast)		8,643	8,874	9,134	9,416	9,720	10,046	10,393	10,762	11,153	11,565
15a)	Non weather sensitive average annual use KWH (7a)	(act.15,175	5,243	5,310	5,378	5,446	5,514	5,582	5,650	5,718	5,786	5,854
17a)	Weather sensitive portion of average use of new electric heat customers (KWH)		9,676	9,676	9,676	9,676	9,676	9,676	9,676	9,676	9,676	9,676
16a)	Avg. annual use of new electric heat customers (1986 + previous 15 + 17a)		14,851	14,919	14,986	15,054	15,122	15,190	15,258	15,326	15,394	15,462
18a)	Non weather sensitive energy-existing customer base (previous year's customers x 15a) MWH		44,251	45,894	47,724	49,744	51,920	54,257	56,760	59,427	62,269	65,290
19a)	Weather sensitive energy existing customer base (1979 = company's figure; 1980 = previous 19a + previous 21a) (MWH)		81,667	83,631	85,866	88,382	89,899	91,555	93,353	95,290	97,375	99,611
20a)	Additional non weather sensitive energy - new customers (13a x previous 15) (MWH)		1,053	1,211	1,381	1,517	1,656	1,798	1,937	2,085	2,236	2,384
21a)	Additional weather sensitive energy - new customers (13a x 17a) MWH		1,964	2,235	2,516	2,729	2,942	3,154	3,358	3,570	3,783	3,987
22a)	Total sales forecast - electric heat customers (18a + 19a + 20a + 21a)	126,035	128,933	132,971	137,487	142,372	146,417	150,[illegible]	155,408	160,372	165,663	171,272
23a)	Growth rate (%)		2.3	3.13	3.4	3.55	2.84	2.92	3.08	3.19	3.3	3.34
	Compound growth	3.11%										

Cape and Vineyard Division - Revised Energy Forecast (cont.)

		1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
	Off Peak Hot Water											
26)	Total customers (act.)	11,620										
27)	Forecast penetration rate (%)		17	17	17	17	17	17	17	17	17	17
28a)	Number of new customers (27 x 2a)		345	357	369	369	369	369	369	369	369	369
29a)	Tot.' customers (forecast)		11,965	12,322	12,691	13,060	13,429	13,798	14,167	14,536	14,905	15,274
30)	Avg. use of new customer (KWH)		4,050	4,050	4,050	4,050	4,050	4,050	4,050	4,050	4,050	4,050
31a)	Total off peak sales from new customers (2. x 30) (MWH)		1,397	1,446	1,494	1,494	1,494	1,494	1,494	1,494	1,494	1,494
32a)	Total off peak sales (31a + previous 32.) (MWH)(act)	42,527	43,924	45,370	46,864	48,358	49,852	51,346	52,840	54,334	55,829	57,322
33a)	Growth rate (%)		3.28	3.29	3.29	3.19	3.09	3.0	2.82	2.83	2.75	2.68
	Compound growth rate	3.03%										
	All Other Residential Classes											
	Growth rate (general residential growth rate)		4.47	4.53	4.5	4.35	4.2	4.07	3.95	3.83	3.72	3.61
35a)	Total (MWH)	49,262	51,469	53,801	56,222	58,667	61,132	63,620	66,133	68,666	71,220	73,791
	Compound rate	4.2%										

POOR ORIGINAL

Cape and Vineyard Division - Revised Energy Forecast (cont.)

Residential Summary (MWH)	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
Residential annual	292,488	305,559	319,388	333,747	348,253	362,893	377,665	392,568	407,594	422,737	438,006
Residential with elect. heat	126,035	128,933	132,971	137,487	142,372	146,417	[illegible],764	155,408	160,372	165,663	171,272
Off peak hot water	42,527	43,924	45,370	46,864	48,358	49,852	51,346	52,840	54,334	55,828	57,322
All other classes	49,267	51,469	53,801	56,222	58,667	61,132	63,620	66,133	68,666	71,220	73,791
Total sales (MWH)	510,317	529,885	551,530	574,320	597,650	620,294	643,395	666,949	690,966	715,448	740,391
Simple growth rate %		3.83	4.08	4.13	4.06	3.79	3.72	3.66	3.60	3.54	3.49
Compound rate	3.79%										

TABLE 7

Flymouth Division-Revised Energy Forecast

		1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
	Residential Annual											
1	Total customers (actual)	33366										
2a)	(2X.8) forecast of new dwellings		920	920	960	960	960	960	960	960	960	960
3	Penetration rate (%)		9	7	10	11	12	13	14	15	16	17
4a)	New electric heat customers (3X2a)		83	64	96	106	115	125	134	144	154	163
5a)	New dwellings (2a-4a) forecast		837	856	864	854	845	835	826	816	806	797
6a)	Total customers (forecast)	33366	34203	35059	35923	36777	37622	38457	39283	40099	40905	41702
7a)	Avg. kwh/customer	5150	5225	5319	5413	5507	5601	5695	5790	5884	5978	6072
8a)	Energy-existing customers (previous year's customers X 7a) MWH		174337	181926	189774	197828	205988	214257	222666	231141	239712	248375
9a)	Additional energy new customers (5a X previous 7a)		4310	4473	4596	4653	4677	4704	4725	4725	4743	4764
10a)	Total residential annual (8a + 9a)	171328	178647	186399	194370	202481	210665	218961	227391	235866	244455	253137
	Growth Rate (%)		4.27	4.34	4.28	4.17	4.04	3.94	3.85	3.73	3.64	3.53

Compound Rate 3.98%

POOR ORIGINAL

Cape and Vineyard Division - Revised Energy Forecast (cont.)

Residential Summary (MWH)	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
Residential annual	292,488	[illegible]	319,388	333,747	348,253	362,893	377,665	392,568	407,594	422,737	438,006
Residential with elect. heat	126,035	128,933	132,971	137,487	142,372	146,417	[illegible]	155,408	[illegible]	165,663	171,272
Off peak hot water	42,527	43,924	45,370	46,864	48,358	49,852	[illegible]	52,840	[illegible]	55,828	57,322
All other classes	49,267	51,469	53,801	56,222	58,667	61,132	63,620	66,133	68,666	71,220	73,791
Total sales (MWH)	510,317	529,885	551,530	574,320	597,650	620,294	643,395	666,949	690,966	715,448	740,391
Simple growth rate %		3.83	4.08	4.13	4.06	3.79	3.72	3.66	3.60	3.54	3.49
Compound rate	3.79%										

POOR ORIGINAL

D.P.U. 19738, 19743, 20055, 20109 &72

TABLE 7

Plymouth Division-Revised Energy Forecast

		1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
	Residential Annual											
1	Total customers (actual)	33366										
2a)	(2X.8) forecast of new dwellings		920	920	960	960	960	960	960	960	960	960
3	Penetration rate (%)		9	7	10	11	12	13	14	15	16	17
4a)	New electric heat customers (3X2a)		83	64	96	106	115	125	134	144	154	163
5a)	New dwellings (2a-4a) forecast		837	856	864	854	845	835	826	816	806	797
6a)	Total customers (forecast)	33366	34203	35059	35923	36777	37622	38457	39283	40099	40905	41702
7a)	Avg. kwh/customer	5150	5225	5319	5413	5507	5601	5695	5790	5884	5978	6072
8a)	Energy-existing customers (previous year's customers X 7a) MWH		174337	181926	189774	197828	205988	214257	222666	231141	239712	248375
9a)	Additional energy new customers (5a X previous 7a)		4310	4473	4596	4653	4677	4704	4725	4725	4743	4764
10a)	Total residential annual (8a + 9a)	171328	178647	186399	194370	202481	210665	218961	227391	235866	244455	253139
	Growth Rate (%)		4.27	4.34	4.28	4.17	4.04	3.94	3.85	3.73	3.64	3.53

Compound Rate 3.98%

PLYMOUTH DIVISION-REVISED ENERGY FORECAST (Continued)

		1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
	Residential With Electric Heat											
12	Total customers (actual)	3634										
13a)	New electric heat customers (4a)		83	64	96	106	115	125	134	144	154	163
14a)	Total customers (12a + 13a) forecast		3717	3781	3877	3983	4098	4223	4357	4501	4655	4818
15a)	Non weather sensitive average annual use (kwh)	5156	5225	5319	5413	5507	5601	5695	5790	5884	5978	6072
16a)	Avg. use of new electric heat customers (1980 + = previous 15a + 17a)		17767	17842	17936	18030	18124	18218	18312	18407	18501	18595
17a)	Weather sensitive portion of avg. annual use of new electric heat customers (kwh)		12617	12617	12617	12617	12617	12617	12617	12617	12617	12617
18a)	Non weather sensitive energy-existing customer base (previous year's customers X 15a) (MWH)		18988	19771	20467	21351	22309	23338	24451	25637	26907	28265
19a)	Weather sensitive energy-existing customer base 1979 = company's figure (1980 + = previous 19a + 21a)MWH		45852	46899	47705	48917	50254	50887	51587	52350	53184	54090
20a)	Additional non weather sensitive energy-new cust. (13a X previous 15a)		427	334	511	574	633	700	763	834	906	974

D.P.U. 19738, 19743, 20055, 20109 &72

PLYMOUTH DIVISION-REVISED ENERGY FORECAST (Continued)

		1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
	Residential With Electric Heat											
21a)	Additional weather sensitive energy-new customers (13a X 17a) MWH		1047	807	1211	1337	1451	1577	1691	1817	1943	2057
22a)	Total sales forecast - electric heat customers (18a + 19a + 20a + 21a)	67438	66314	67811	69894	72179	74647	76502	78492	80638	82940	85386
	Growth Rate %		-1.67	2.26	3.07	3.27	3.42	2.49	2.6	2.73	2.85	2.95
	Compound Growth 2.39%											
	Off-Peak Hot Water											
26	Total customers	6471										
27	Penetration rate %		34	34	34	34	34	34	34	34	34	34
28a)	New customers (2a X 27)		313	313	326	326	326	326	326	326	326	326
29a)	Total customers (forecast)		6784	7094	7423	7749	8075	8401	8727	9053	9379	9705
30	Avg. use of new customers		4300	4300	4300	4300	4300	4300	4300	4300	4300	4300
31a)	Total off-peak sales from new customers (28a X 30a) MWH		1346	1346	1402	1402	1402	1402	1402	1402	1402	1402
32a)	Total off-peak sales (31a + previous 32a)	26044	27390	28736	30138	31540	32942	34344	35746	37148	38550	39952
	Growth Rate %		5.17	4.91	4.88	4.65	4.45	4.26	4.08	3.92	3.77	3.64
	Compound Rate 4.37%											

PLYMOUTH DIVISION-REVISED ENERGY FORECAST (Continued)

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
All Other Residential Classes											
Growth Rate = residential annual growth rate (%)		4.27	4.34	4.28	4.17	4.04	3.94	3.85	3.73	3.64	3.55
Total all other (MWH)	6859	7152	7462	7782	8106	8434	8766	9103	9443	9787	10134
Compound Rate 3.98%											
Residential Summary (MWH)											
Residential annual	171328	178647	186399	194370	202481	210665	218961	227391	235866	244455	253139
Residential with electrical heat	67438	66314	67811	69894	72179	74647	76502	78492	80638	82940	85386
Off-peak hot water	26044	27390	28736	30138	31540	32942	34344	35746	37148	38550	39952
All other classes	6859	7152	7462	7782	8106	8434	8766	9103	9443	9787	10134
Total (MWH)	271669	279503	290408	302184	314306	326688	338573	350732	363095	375732	388611
Growth Rate (%)		2.[illegible]	3.90	4.05	4.01	3.94	3.64	3.59	3.52	3.48	3.43

Compound Growth Rate 3.64%

TABLE 8

New Bedford Division - Revised Energy Forecast

		1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
	Residential Annual											
5	New general dwellings		510	507	487	436	432	427	470	465	460	455
6	Total customers (forecast)		54710	55217	55704	56140	56572	56999	57469	57934	58394	58849
7a	Average kWh/Cust.	act. 4120	4137	4193	4249	4305	4361	4417	4473	4529	4585	4641
8a	Energy-existing customers (previous yr's cust X 79a) MWH		224225	229399	234617	239806	244827	249879	254957	260277	265627	271007
9a	Additonal energy-new customers (5 X previous 7a) MWH		2101	2097	2042	1853	1860	1862	2076	2080	2083	2086
10a	Total residential annual (8a + 9a) MWH	act. 222273	226326	231496	236659	241659	246687	251741	257033	262357	267710	273093
	Growth rate %		1.8	2.3	2.2	2.1	2.08	2.04	2.1	2.02	2.04	2.0
	Compound growth rate % (2.08%)											
	Residential With Electric Heat											
14	Total customers forecast	act. 1417	1427	1440	1453	1467	1485	1508	1538	1573	1613	1658
13	New electric heat customers		10	13	13	14	18	23	30	35	40	45
15a	Nonweather sensitive avg. annual use	4120	4137	4193	4249	4305	4361	4417	4473	4529	4585	4641
16a	Avg. annual use of new electric heating customers (1980=previous 15a + 17a)		13313	13330	13386	13442	13498	13554	13610	13666	13722	13778
17a	Weather sensitive portion of avg. annual use of new electric heat customers (kwh)		9193	9193	9193	9193	9193	9193	9193	9193	9193	9193
18a	Nonweather sensitive energy-existing customer base (previous year's customers X 15a) (MWH)		5862	5983	6119	6255	6398	6559	6745	6966	7212	7486

D.P.U. 19738, 19743, 20055, 20109 &72

New Bedford Division - Revised Energy Forecast (Continued)

		1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
	Residential With Electric Heat											
19a	Weather sensitive energy-existing customer base (1979=company's figure) (1980 + = previous 19 X previous 21) (MWH)		13027	13119	13239	13359	13488	13653	13864	14140	14462	14830
20a	Additional nonweather sensitive energy new customers (13 X previous 15a) (MWH)		41	54	55	59	77	100	133	157	181	206
21a	Additional weather sensitive energy-new customers (13 X 17a) (MWH)		92	120	120	129	165	211	276	322	368	414
22a	Total sales forecast - electric heat customers (18a + 19a + 20a + 21a) (MWH)	19234	19022	19276	19533	19802	20128	20523	21018	21585	22223	22936
	Growth rate %		-1.1	1.3	1.3	1.4	1.6	2.0	2.4	2.7	3.0	3.2
	Compound growth rate (1.78%)											
	Residential Summary MWH											
	Residential annual		226326	231496	236659	241659	246687	251741	257033	262357	267710	273093
	Residential with electric heat		19022	19276	19533	19802	20128	20523	21018	21585	22223	22936
	Off peak hot water		3472	3619	3762	3890	4018	4146	4289	4432	4575	4718
	All other residential classes (baseload growth rate)		326	331	335	340	344	348	353	358	362	366
	Total	245157	249146	254722	260289	265691	271177	276758	282693	288732	294870	301113
	Compound growth rate (2.08%)											

TABLE 9

Commercial Sectors Revised Energy Forecast

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
Plymouth Division											
(1979 - 1981 Company forecast. 1982 + = 1.0147 X previous year's forecast.)	105423	106578	[illegible]	109824	111438	113077	114739	116425	118137	119874	121636
New Bedford Division											
(1979 - 1981 -- Company forecast. 1982 + = .9975 X previous year's forecast.)	176410	175969	175529	175090	174653	174216	173780	173346	172913	172480	172049
Cape & Vineyard Division											
(1979 - 1981 -- Company forecast. 1982 + = 1.038 X previous year's forecast.)	284734	286734	288734	290734	301782	313250	325153	337509	350334	363647	377466
Total (MWH)	566567	569281	572932	575648	587873	600543	613672	627280	641384	656001	671151

Compound Rate 1.71%

POOR ORIGINAL

Total Demand Revised Forecast (continued)

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
New Bedford											
Residential	245157	249146	254722	260289	265691	271177	276758	282693	288732	294870	301111
Industrial	310627	316840	323176	329640	336233	356957	378096	393220	408949	425307	442319
Street Lighting	9021	9021	9021	9021	9021	9021	9021	9021	9021	9021	9021
Municipal	72411	73161	73161	73161	73380	73821	74485	75260	76042	76633	77632
Commercial	176410	175969	175529	175090	174653	174216	173780	173346	172913	172480	172049
Total (MWH)	813626	824137	835609	847201	858978	885192	912140	933540	955657	978511	1002134
Compound Growth Rate	1978-1988										
	2.12%										

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
Cambridge											
Residential	103016	103531	104049	104569	105092	105617	106145	106676	107209	107745	108284
Commercial	302251	307952	310388	315665	321031	330341	339921	349778	369933	370360	381110
Industrial	351063	356490	361041	366041	376041	386041	396041	406041	416041	426041	436041
Street Lighting	9192	9200	9200	9200	9200	9200	9200	9200	9200	9200	9200
Municipal	56166	58286	60286	67000	75000	80000	85000	90000	95000	100000	105000
Total (MWH)	821688	835459	844964	862475	886364	911199	936307	961695	987372	1013346	1039635
Compound Growth Rate	1978-1988										
	2.38%										

POOR ORIGINAL

Table 10

Total Demand Revised Forecast

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
Cape and Vineyard											
Residential	510317	529885	551530	547320	597650	620254	643195	666949	690966	715448	740391
Commercial	284734	286734	288734	290734	301782	313250	325153	331509	350334	363647	377466
Industrial	12051	13051	15179	16179	16679	17179	17679	18179	18679	19179	19679
Otis AFB	22734	22000	22000	22000	22000	20000	20000	22000	22000	22000	22000
Street Lighting	9191	9283	9376	9470	9564	9660	9756	9854	9953	10052	10151
Municipal	59184	64709	66264	67024	67795	68676	69672	70989	72337	73698	75091
Total (MWH)	898261	925662	953083	979727	1015034	1050154	1086248	1123533	1161739	1200882	1240978
Compound Growth Rate	1978-1988 3.28 %										
Plymouth											
Residential	271669	279503	290408	302184	314306	326688	338573	350732	363095	375732	388611
Commercial	105423	106578	108669	109824	111438	113077	114739	116425	118137	119874	121636
Industrial	234445	23505	23565	23625	23685	23745	23805	23865	23925	23985	24045
Street Lighting	4546	4550	4550	4550	4550	4550	4550	4550	4550	4550	4550
Municipal	45394	45594	45956	47156	50356	51272	52206	53155	54123	55146	56150
Total (MWH)	450477	459730	473148	487339	504335	519332	533873	548727	563830	579287	594992
Compound growth rate	1978-1988 2.82 %										

TABLE 11
ADJUSTED NEGEA SYSTEM PEAK SUMMARY

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
N.B. Total Sales	2162366	2209529	2261840	2314267	2378347	2454769	2532139	2605880	2681225	2756680	2838104
Losses and internal use (Assumption 9% of total output)											
Total output	2376226	2428054	2485539	2543151	2613568	2697548	2782790	2863516	2946402	3031516	3118796
Compound rate 2.39%											
Load Factor	.63	.65	.65	.65	.65	.65	.65	.65	.65	.65	.65
Output incorporating Conservation adjustment (previous output X 1.0239)	2376226	2433018	2491167	2550706	2611668	2674087	2737997	2803435	2870438	2939041	3008356
Adjusted peak load		427.3	437.5	448	458.7	469.6	480.9	492.3	504.1	516.2	528.3
Cambridge Total Sales	821688	835459	844964	862475	886364	911199	936307	961695	987372	1013346	1039635
Losses and internal use	37119	37129	37527	38246	39221	40233	41256	42291	43337	44395	45466
Total output	858807	872588	882491	900721	925585	951432	977563	1003986	1030709	1057741	1085101
Load factor	.557	.556	.56	.559	.556	.554	.552	.554	.552	.551	.548
Peak load	176	179	180	184	190	196	202	207	213	219	226
Belmont	20	22	22	22	22	22	22	22	22	22	22
Total projected peak load	196	201	202	206	212	218	224	229	235	241	248
Coincident peak											
Cambridge .965 diversity factor X projected peak load		194	195	199	205	210	216	221	227	233	239
New Bedford .99 diversity factor X projected peak load adjusted for conservation		423		443.5	454.1	46.	476	487.4	499	511	523
Total peak coincident demand	611	617	628	642.5	659.1	675	682	708.4	726	744	762

Growth Rate =
2.24%

IV. ALTERNATIVES

A. Introduction

Petitioners assert that, given their demonstrated need for future power, Seabrook is the least costly available alternative. They point to the inclusion of conservation adjustments in their demand forecasts and a variety of particular efforts to encourage consumer conservation. Petitioners also argue that load management, by flattening their load curves, will increase rather than decrease the need for base load capacity. With regard to particular generation technologies, petitioners limit their direct cases to the economic comparison of oil, coal, gas and nuclear fueled units. 74/ This limitation of alternatives is essentially based on petitioners' assertions that there are simply no other realistic alternatives. We will assess petitioners' and intervenors' claims concerning alternatives in the following sections.

74/ Fitchburg's planned inclusion of 2 MW of base load hydro, a notable exception, is discussed in section C below.

B. Conservation and Load Management

Mr. Chernick categorizes conservation and load management techniques as supply options in the "Alternatives" section of his testimony (Exh. AG-232, pp. 87-105), stating that they are superior to the construction of new generators for providing equivalent amounts of energy and capacity (Exh. AG-232, pp. 87-88). Mr. Chernick asserts that additional insulation of residential structures is cost effective, as is water heater tank insulation (Exh. AG-232, p. 90). Mr. Chernick also identifies the Nola Power Factor Controller 75/ as an electricity saving device with wide and effective potential application (Exh. AG-232, p. 90). Mr. Chernick further discusses rate reform, conversion of master-metered apartments and businesses to

75/ This is a device which can reduce the energy consumption of electric motors in certain applications.

individual meters, voltage control and the utilization of controlled storage hot water and space heating as promising conservation techniques (Exh. AG-232, p. 92).

Dr. Stutz, as does Mr. Chernick, categorizes conservation and load management techniques as supply options superior to the construction of new generating capacity (Exh. SEA-35, pp. 15-23). He further discusses particular residential and commercial conservation strategies as well as recent federal legislation and finds energy consumption by these two classes could be cut by at least 9.8 percent for New Bedford by 1985.

We agree with Mr. Chernick and Dr. Stutz that conservation and load management techniques have an important role to play in capacity planning. We recognized this some time ago in D.P.U. 18810 and have taken steps to implement this order via administrative proceedings with respect to each investor owned Massachusetts electric utility.

Our recognition of the

contribution of conservation and load management is evidenced in this proceeding by our attention to these issues in each company's demand forecast. We have taken into account adjustments in each petitioner's demand forecast to reflect what we consider reasonable reductions in demand and shifts in load attributable to conservation and load management.

Although the intervenors view conservation and load management techniques as capable of providing similar amounts of capacity as can the construction of new generating capacity, we presently see successful conservation efforts by consumers as a reduction in demand, and successful load management efforts by utilities as an alteration in consumer demand patterns, viz., an improvement in load factor. Although we realize that an investment which reduces demand may be functionally equivalent (with regard to energy and capacity necessary to meet demand) to an investment which increases supply, we feel that there is a distinction in emphasis between demand and supply.

The difference on the record before us is one of planning. Investments in new supply require concrete planning capable of producing a clearly identifiable amount of firm capacity. The same sort of planning is necessary to treat a likely reduction in demand as the equivalent of firm supply. Although the proceedings emanating from D.P.U. 18810 have begun, these proceedings are still inchoate; at present, utility conservation and load management plans are insufficiently formulated, and consumer responses to these conservation and load management efforts are not sufficiently certain to treat the potential resulting reductions in demand as the equivalent of firm supply.

We fully expect such conservation and load management plans to result from the administrative hearings required by D.P.U. 18810 for every investor-owned Massachusetts utility.

We are firmly committed to realizing all potential benefits from conservation and load management. 76/ Once such plans are fully articulated 77/ and we have more information with which to gauge consumer responses, we will consider plans for conservation and load management the equivalent of plans for additional capacity. 78/

76/ We also realize, however, that there is considerable disagreement over the most equitable and efficacious means of achieving these goals.

77/ Recent passage of the Residential Conservation Service Act, Chapter 465, Acts of 1980, will further ensure such plans are indeed developed.

78/ We realize that traditional regulatory review, which allows a return for utility investment in capital equipment but no such return for expense items, provides utilities with a disincentive to make investments in conservation and load management which do not contribute to rate base. We would expect such a situation to inhibit the expeditious development of efficacious conservation and load management plans. To correct this regulatory equivalent of a market failure, we are utilizing our D.P.U. 18810 proceedings, Chapter 465 of the Acts of 1980 as well as various provisions of PURPA.

With particular reference to voltage control, the Attorney General suggests that it is a significant source of potential energy savings in terms of both cost and peak reduction. Petitioners contend that the implementation of voltage control would be too expensive, that present information about the benefits of voltage control is inconclusive, and that their systems are not appropriate candidates for voltage control. We agree that it represents a potential for energy savings; the evidence before us is, however, simply insufficient to conclude that voltage control is an appropriate strategy for petitioners to pursue. Nevertheless, we urge petitioners to fully inform themselves about its applicability to their systems.

C. Alternative Power Sources

1. Introduction -- It is essential that the public be provided an adequate supply of power in the future. As we found in earlier sectons, petitioners have clearly demonstrated a future need for significant quantities of power. The issue before us now is what sources of power can reasonably be expected to be available to meet this need. Our concern is not what steps petitioners might have taken in the past to develop alternatives, but what they should do now and in the future.

In evaluating the competing claims of intervenors and petitioners about part r alternatives and classes of alternatives, we are repeatedly required to decide the sufficiency of the evidence concerning these alternatives. Much of the evidence presented is by nature forward looking and therefore predictive. In assessing whether an asserted alternative is preferable to Seabrook, we must first question whether that alternative is even likely to be available. Given our prospective viewpoint, a party advocating a particular alternative should show that the alternative is sufficiently particularized and definite to permit its use for supply planning purposes. We believe that this minimum threshold requirement is reasonable; to accept less would be to enter the realm of speculation and wishful thinking. 79/

79/ With regard to that class of alternatives which is dependent upon direct utility investment, we note that utility investment decisions are largely a matter of managerial discretion. The positive exercise of this discretion can in itself significantly affect the likely success of an alternative. We are well aware of the danger of circular reasoning: wherein the lack of management support for a promising alternative may in the future prevent its development; then, this lack of development is asserted as a reason for rejecting the alternative. We believe, however, that petitioners will need every alternative economical kilowatt they can find and believe that this need will in itself accelerate petitioners' development of alternatives.

2. Independent Power Production and Cogeneration

Intervenor arguments concerning non-utility power production as an alternative to Seabrook focus principally on the petitioners' general pessimism about both the usefulness and the potential for independent production, their failure actively to encourage or pursue it, the low rates offered to existing independent producers and the disincentives such low rates create for potential independent producers. We find these criticisms are, to a large extent, valid. With few exceptions, however, the actual implementation of non-utility sources of supply is a relatively recent phenomenon. This newness creates several problems which are unresolved on the record before us.

For example, we have no present basis on which to accept the suggestion of Dr. Stutz that 25 to 32 MW of cogeneration potential in NEGEA's service territories will in fact be developed. We also do not have a sufficient evidentiary basis upon which to assess the reliability, availability or cost characteristics of this potential were we to assume its timely development. That is not to say a non-specific argument of this type is without merit. Given a demonstrable pattern of cogeneration development, with an attendant specification of its characteristics and a showing of further development potential, we would have been willing to infer that for present planning purposes, specific amounts of power with particular characteristics would have been forthcoming. We do not, however, have this type of evidence before us.

We view investment in independent power production as a competitive response to utility rates over which petitioners exercise no control with respect to the decision to invest. If all investment of this type were solely for the internal needs of the producer, utility involvement with the producer would be limited to the provision of back-up service.

There are, however, a large number of possible situations where the economics of the investment decision depend upon production for sale. As purchasers of this power, petitioners are in a monopsonistic position which places sellers at an extreme disadvantage in bargaining over price. As a result, independent development has been largely restricted to industries where power production could easily be incorporated as a joint product in an ongoing production process and where the power produced has been principally for internal consumption.

Recent passage of PURPA, however, has articulated a national policy to encourage the non-utility development of economical power sources. Various provisions of this legislation have been specifically designed to restructure what has heretofore been exclusively a monopolistic market by introducing a competitive element. Mandatory interconnection of independent producers and the delegation of small power producer buyback ratemaking authority to the Department are the principal means of implementing this policy in

Massachusetts.

We are committed to the design of fair back-up rates, interconnection charges and buyback rates which will encourage the independent production of power. Given the diversity of potential independent producers and the attendant diversity of their production characteristics in terms of supply availability and reliability, we do not see the problem of designing these rates as a simple process. We are, however, currently devising regulatory procedures which will reduce the uncertainty surrounding the potential independent producer's investment decision. On the other hand, the process of designing these buyback rates raises a substantial number of identification and control problems which will require time to resolve.

We recognize the potential for alternative power sources in Fitchburg's service area represented by the Civic Center, General Electric, Great American Chemical and Siminds Saw and Steel plans. We also recognize the potential in New Bedford's service areas for the proposed Rochester trash burning facility and that there are presently several of New Bedford's industrial customers who are studying the potential for cogeneration. Despite the intervenors' comments about petitioners' lack of enthusiasm for these possible power sources, we see the decision to invest in them as essentially independent of petitioners' attitudes or control; we also see the responsibility for invoking our jurisdiction to establish buyback rates resting initially with those who would sell power to petitioners in accordance with such rates. We simply do not know when or if these investments will be forthcoming; nor have any potential producers petitioned us to establish buyback rates. Consequently, while independent power production and cogeneration may well represent a significant future potential, we do not find sufficient articulation of this potential on the record before us to use it for present planning purposes, nor do we find petitioners' actions concerning independent producer unreasonable.

3. Solar and Wind Power

Solar space heating, solar hot water heating and wind power may well become significant future sources of energy. Implementation of these alternatives, however, is largely dependent upon consumer investment decisions which are beyond petitioners' control. The potential impact of these types of investment is inherently dependent upon the cumulative effect of a large number of independent investment decisions. We do not have sufficient experience or evidence upon which to judge the extent to which these types of investment may be forthcoming. The record before us leads us to view these technologies as emerging, but insufficiently developed to be utilized in predicting quantifiable effects on petitioners' systems at this time.

4. Canadian Hydroelectric Power

Discussion in the record indicates the possibility of the future purchase of substantial amounts of Canadian hydroelectric ("hydro") power. At this time, however, we are unable to conclude this source is other than a potential source. Petitioners have demonstrated a long-term need for firm uninterrupted power. The evidence before us indicates that past contracts for Canadian power have been on a short-term, interruptible basis. That this state of affairs may change in the future gives us no assurance it in fact will change. Consequently, we are unwilling to find that Canadian hydro potential is presently a realistic planning alternative to Seabrook. 80/

5. Hydroelectric Power

We believe the development of hydro power has significant potential, and consider it to be a highly important economic source of future supply in New England. General Laws c. 164, sec. 97, serves to remind us that

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80/ Petitioners should, however, more actively inform themselves on the progress of these projects and on offers for sale which may be forthcoming.

hydro technology was once the region's major source of supply. The technology is well understood and highly reliable. The scale of plant is available to fit virtually any feasible commercial, industrial, residential or utility applications; and the markets for plant and equipment are highly competitive. We recognize that most major sites in the region are presently utilized and that this utilization thereby imposes a severe limitation on the additional absolute magnitude of hydro power available for direct utility investment. This limitation does not, however, preclude the development of sites which have historically been considered small scale and which may provide "low head" hydro power.

From an economic standpoint, the variable costs of hydro production are virtually non-existent; the region's flow of water, as a self-renewing natural resource, is essentially free relative to fossil and nuclear sources of fuel. Fitchburg's HYPROD hydro simulation is the only evidence in the record which assesses the variable cost impact of a hydro plant on a petitioner's system generation mix. 81/

In performing its cost simulations, Fitchburg assumes a constant load shape and a fixed set of generation mix characteristics. The base case simulation of the variable energy costs associated with an additional investment in 10 MW of Seabrook and 5 MW of hydro demonstrates a present worth of total system variable energy costs (PWTSVEC) over a fifteen year planning horizon equal to $374 million. This cost is comparable to a $404 million PWTSVEC for the base case with an additional 10 MW of Seabrook and no hydro. This represents a potential system savings in variable costs with a present worth approximately equal in magnitude to the Company's projected capitalized book costs for its total proposed additional 16 MW investment in the Seabrook venture.

81/ Exh. AG-202; see base case with 10 MW Seabrook and 5 MW hydro.

While there are some problems both with the Company's assumptions and with giving a full interpretation to the significance of this cost differential, the magnitude of savings this simulation identifies is substantial. An estimated $2.6 million capital investment 82/ will potentially reduce PWTSVEC by 8.02 percent. While a full analysis would account for the operation and maintenance expenses associated with these savings, Fitchburg did not model these costs in any of its simulations. We note, however, that the magnitude of the identified savings is comparable to the Seabrook savings relative to other alternatives Fitchburg has simulated and submitted in response to our June 28th Order to justify the cost effectiveness of the proposed Seabrook acquisitions (Exh. AG-202, Computer Runs).

Although we expect Fitchburg to pursue and develop hydro, there are several

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82/ In 1982 dollars as estimated by Mr. Garlick, Tr. 3, p. 46.

problems which raise substantial barriers to concluding that hydro can replace Seabrook capacity rather than complement it. Hydro is not always a constant source of base load power. This result follows from seasonal variations in regional water supplies; depending on water flow characteristics, these supplies may be at their lowest during the winter and summer system peaks. Additionally, much of New England's large scale hydro potential is presently utilized. Unfortunately, the evidence in the record is not detailed enough to allow us to assess realistically either the magnitude of the region's unutilized potential or the characteristics of other than a few sites. Moreover, the potential for the statutory preclusion of all New Hampshire sites from regional participation in their development for regional benefit further compounds the problems associated with the timely development of the region's hydro potential, and directly reduces the known options for Massachusetts utilities. 83/

Despite our determination that hydro power does not provide a source for petitioners capable of supplanting Seabrook capacity, we consider complete examination of the hydro potential to be a necessary feature of each petitioner's future capacity planning. Given the substantial savings to consumers that a relatively small amount of hydro can generate, the addition of hydro to the petitioners' system mixes should be given a high priority in their search for future supplies. We will, therefore, expect these companies to inform themselves fully as to the region's hydro potential and to begin the immediate identification and development of feasible sites. Fitchburg has already begun the process by planning a 2 MW addition of hydro to its

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83/ See New Hampshire R.S.A. 374:35 and 36. We note that the NHPUC recently applied this statute to impound the interstate transmission of approximately 419.8 MW of hydro capacity.

system mix. We applaud this decision and encourage Fitchburg to continue its examination and move on toward the development of the 5 MW of hydro which it simulated in its HYPROD runs.

We cannot agree with various contentions raised by petitioners regarding substantial barriers to their involvement in hydro projects. Montaup and New Bedford claim that hydro power is not a realistic source of supply for them because there is little or no hydro potential in their service territories. Assuming arguendo that this may be true, we do not consider it to impose serious limitations. Restating the obvious, we would note the location of Seabrook. In fact, were the non-local argument persuasive, there would be scant justification for the existence of NEPOOL. Furthermore, implicit in the language of G.L. c. 164, sec. 97, is the recognition that hydro sources may well exist outside an individual utility's service territory.

Nor can we agree with Fitchburg that 12 U.S.C.A. sec. 800, which gives preference to states and municipalities in the issuance of preliminary permits or licenses for the purpose of developing water resources, is a valid reason for a private utility not to pursue the development of available hydro power vigorously. The preference prevails only if the private and public plans for development are equally well suited to conserve and utilize the water resources of the region. Preliminary estimates indicate a commercially viable regional hydro potential of 534 MW to 753 MW. 84/ To remove a major potential source for the private development of these sites clearly conflicts with the present overriding regional interest in their expeditious development.

Although states and municipalities may have a slight competitive edge over private utilities, the latter

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84/ Exh. AG-230, p. 2; Tr. 17, p. 100. We note that Fitchburg's proposed total percentage interest in Seabrook when applied to this number would yield approximately 5 MW of hydro.

presently have a competitive advantage over all other private developers. The design of interconnection charges and buyback rates is only in the planning stages. Private utilities know the price they will receive for power; potential non-utility private investors do not. Until these buyback rates are established, non-utility private investors face substantial uncertainty in evaluating the investment value of these sites. This uncertainty and the transaction costs associated with having to negotiate price on an _an hoc_ basis prior to the commitment of funds raise investment barriers with which petitioners do not have to contend. 85/

6. Coal Conversion

Conversion of existing generating capacity to coal in itself is not an alternative source of supply for anticipated future demand;

85/ Indeed, this problem is not confined to potential independent hydro producers. These barriers confront all potential private non-utility power producers who would rely on buyback rates to evaluate the economic attractiveness of a particular investment.

rather, it merely substitutes one fuel source for another. There are, however, several ways in which coal conversion could impact on the least cost solution to each petitioner's optimum generating mix. Plant dispatch is based on continuous system minimization of variable costs over time subject to the plant capacity factor, plant availability and system demand characteristics. The variable costs are typically fuel and O&M expenses with fossil fuel costs occupying by far the largest portion of total variable costs. To the extent coal is less expensive than equivalent units of fuel oil, it is possible the conversion of existing oil-fired units to coal in combination with either the reactivation and renovation of oil-fired units or the reactivation, renovation and conversion to coal of oil-fired units could result in a system generation mix whose total fixed and variable costs are less than the total costs associated with the inclusion of the Seabrook units in the system's generating mix for the demand forecast period.

We note that reactivation, with conversion possibilities, does not presently exist for New Bedford. With respect to both Fitchburg and Montaup, although these possibilities arguably exist, there is insufficient evidence in the record to indicate either a feasible intermediate term realization of the prerequisite conditions for coal conversion or that the relative economics of this alternative possibility would with any reasonable degree of likelihood in fact lead to smaller total system costs. The recent passage of the Coal Conversion Act, Chapter 464, Acts of 1980, and the accelerated capital recovery provisions contained in it, however, creates a situation in which the reactivation or renovation and conversion possibilities deserve serious consideration by petitioners. 86/

86/ We will expect an analysis of this possibility should petitioners appear before us in the future.

D. The Seabrook Alternative

1. Capital Cost

In the June 28th Order, we addressed our concern about the lack of an opportunity to question the lead participant with respect to the Seabrook project (June 28th Order, p. 8). After the joint application in D.P.U. 20055 was filed (May 18, 1979), we ordered PSCO to prefile direct testimony. Mr. David Merrill, Executive Vice President with responsibilities in the areas of engineering, production and power supply, and Mr. Robert J. Harrison, Financial Vice President, presented testimony and were cross-examined on the status, costs and financing of the Seabrook project. Mr. Merrill testified that the cost of the project was estimated to be $2.8 billion, including AFUDC and nuclear fuel.

This estimate was completed in January 1979 and may be broken down as follows:

	($millions)
Nuclear Production Plant	1,825.0
Plant Related AFUDC	785.0
Nuclear Fuel	175.0
Fuel AFUDC	67.0
Total	2,852.0

On March 28, 1980, the intervenors filed a motion for certain updated information and the return of PSCO's witnesses for further cross-examination. The motion requested in part that PSCO provide the most recent itemized construction budget for the Seabrook project, documentation that the recent reduction in work force would not cause a delay in the projected in-service dates, and that witnesses Merrill and Harrison return for further cross-examination.

On April 7, 1980, we announced our decision concerning the motion (Tr. 48, p. 6). In effect, our ruling required the Company to provide the information which it had readily available and which we felt was necessary for a complete and thorough record without prolonging the proceeding interminably. We had previously announced our desire to close the record by April 15, 1980. We believe our decision on the motion struck a balance between the interests of the public in creating as complete a record as possible, the interests of the petitioners and the obvious need for an expeditious resolution of the matter. The record presently includes the most recent cost estimate for the project; this estimate as of March 1980 is as follows:

	($millions)
Nuclear Production Plant	2,085.0
Plant Related AFUDC	1,075.0
Nuclear Fuel	175.0
Fuel AFUDC	81.0
Total	3,416.0

PSCO's construction cost schedules are derived initially by its architect-engineer, United Engineers. The estimates are based upon the summation of detailed engineering specification of the particular labor, materials and equipment costs required for each aspect of the project. These estimates are reviewed by both PSCO and the

Nuclear Services Division of Yankee Atomic Electric Company ("Yankee"). PSCO then calculates both an inflation rate of 8 percent and AFUDC 87/ associated with the timing of the construction expenditures. While the accuracy of this method of estimation is subject to future price changes and general inflation, its main virtue is that it is specific to the unique circumstances of the project and not dependent upon analogy to other projects. Further, as the project progresses toward completion, the estimates become less subject to error. We find this methodology and the estimates produced by it to be reasonable; indeed, it is the preferred methodology.

The Attorney General's witness, Mr. Chernick, also presented testimony on the cost of the Seabrook units. Mr. Chernick claims that PSCO's estimate of the capital cost for the Seabrook project is understated. To support

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87/ AFUDC is of course dependent upon the rate and manner of calculation utilized by each participant.

this claim, Mr. Chernick relied upon two econometric studies and on recent historical experience which he asserts demonstrate a tendency by architect/engineers to understate the capital costs of nuclear plants.

Mr. Chernick first utilizes the so-called NERA "study" (Exh. M-24) to support his claim. Mr. Chernick took a regression equation derived by the study, substituted his own inflation rates 88/ and resolved the equation. The result of the recalculation of the formula is a capital cost of $2,203/KW for Seabrook I and $2,347/KW for Seabrook II, and a total project cost of $5.3 billion. With a four year delay in Unit II, he projects a total project cost of $8.0 billion. He then concludes that the capital costs provided by PSCO are understated.

88/ The study assumed a 5.5 percent general inflation rate and a 6 percent real inflation rate for nuclear units. Mr. Chernick substituted a 10 percent inflation rate for both general inflation and real inflation for nuclear units.

Our review of the "study" and of Mr. Chernick's testimony based on it indicates a substantial number of problems from which we conclude that we simply cannot rely on this testimony. Our review of Exhibit M-24 indicates that the document is a copy of a speech presented at a seminar with a number of tables appended and that it is essentially an abstract of a study. During cross-examination Mr. Chernick stated that he could not verify certain assumptions 89/ which he had made concerning the "study". In addition, there is no basis in the record for his assumptions concerning the inflation rates he used; in fact, he was not willing to testify that these rates were appropriate. 90/ Were we to assume his inflation rates correct, the fact that his

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89/ Tr. 38, pp. 7-9.

90/ Tr. 36, p. 166.

testimony is based on an understanding of the "study's" assumptions which he was not able to verify 91/ renders his testimony unreliable. 92/

Mr. Chernick also relies on the "Rand" 93/ econometric study as support for his assertion that the Seabrook project capital costs are understated. In order to reach this conclusion, Mr. Chernick took a regression equation derived by the study, substituted Seabrook data, resolved the equation, applied an inflation rate to the result and derived a capital cost for Seabrook Unit I of $2,189/KW and $2,489/KW for Seabrook II; these results imply total project costs ranging from $5.4 billion to $6.4 billion.

91/ Exh. AG-232, p. 55; Tr. 38, p. 8.

92/ We expect at a minimum that Mr. Chernick would have read the actual NERA study from which this document was derived or that, in the absence of the actual study, he be able to corroborate his understanding of its assumptions with the authors.

93/ Exh. PSC-6, William E. Mooz, Cost Analysis of Light Water Reactor Power Plants, R-2304-DOE.

We reject Mr. Chernick's findings that rely on the Rand study for the following reasons. First, the regression equation in the Rand study which Mr. Chernick used identifies time (i.e., date of construction permit issuance) as the chief variable to explain changes in real price per KW (1976 dollars) of light water reactors ("LWR"). Economists are generally loath to posit such a simplistic model for forecasting purposes, because it must be implicitly assumed that a stable relationship between the real price of a good and the passage of time exists and that this relationship will continue in the future. In fact, real price increases in a LWR are caused not by the passage of time, but by changes in the quality of the product (e.g., safety and reliability), changes in production techniques, changes in the real prices of raw materials and intermediate products and similar phenomena.

Second, we feel that the use of the Rand study to estimate the final cost o Seabrook is inappropriate because the data are extremely stale. The thirty-nine plants which were analyzed in the Rand regression equation were granted construction permits between 1966 and 1971. In contrast, Seabrook's construction permit was issued in mid-1977. In a forecast that uses time as an explanatory variable, the uncertainty of an estimate increases dramatically as the estimates go beyond the dates in the data base. PSCO notes that the 95 percent confidence interval around Mr. Chernick's estimated cost of Seabrook is plus or minus $1,000 per KW (PSCO initial brief at 19).

Finally, we reject Mr. Chernick's analysis using the Rand study because we believe that the inflation rates which Mr. Chernick used to translate the costs of Seabrook, as stated in 1976 dollars, into final construction costs are without substantiation or merit.

Mr. Chernick also analyzes historic cost increases associated with four New England nuclear units (Connecticut Yankee, Millstone I and II, Pilgrim I) and concludes the experience with these units demonstrates the

Seabrook project may cost between $5.88 billion and $11.48 billion (Exh. AG-232, pp. 59-61). He does not, however, present any analysis or evidence that would indicate the same factors which contributed to the cost increases for any of these units are substantially the same. 94/ Were we to assume such an identity of factors causing the cost increases for these units, there is still no analysis or evidence which would indicate those factors are also responsible for the experienced cost increases in the Seabrook project. The analysis is simply insufficient and absent additional evidence and analysis, we can find no logical or theoretical reason to believe Mr. Chernick's projected increases in Seabrook construction costs are justified.

In general, the intervenors did not analyze or dispute the engineering based

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94/ For example, his analysis gives no consideration to the time periods in which the plants were built, the architect/engineers or types of reactor; nor has there been any disaggregation of the cost data into construction costs and AFUDC costs.

methodology PSCO used in deriving its construction cost estimates; nor did they inquire into the basis for PSCO's revisions of its cost estimates or PSCO's belief that its present estimates are reliable. Rather, as just noted, they utilized analyses based upon reinterpretations of industry-wide econometric studies and on cost histories of four New England nuclear units. We have found these analyses inadequate to support total project cost estimates of the magnitudes asserted.

This is not to say that we necessarily consider PSCO's March 1980 estimate to be the final cost figure. We have no doubt that the cost of the project will increase due to money market conditions, inflation and scheduling changes. We do, however, find PSCO's most current estimate reasonable for planning purposes.

Nevertheless, because of uncertainty concerning the project's completion dates, we will consider a range of total costs within which the final cost will most likely fall. At one end of the spectrum is the March 1980 estimate of $3.42 billion, or a per KW cost of $1,487. At the other end is an amount of $4.28 billion, or $1,860 per KW, 95/ which PSCO estimates will be the total project cost should the in-service date of Unit II be delayed four years. 96/

In concluding this section, we would note that the $880 million difference between the March 1980 estimate and the cost we will utilize as an upper limit was identified in a stock prospectus issued by PSCO (Exh. PSC-12, p. 7) which only became available at the close of the hearings. The evidence in the record does not, however, enable us either to precisely determine the composition of the $880 million figure or to determine how it was derived. We

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95/ We note that this upper limit is still less than the estimated per KW cost for the proposed Burlington wood burning project.

96/ As a result of recent decisions by the New Hampshire Public Utility Commission which may result in a delay in the in-service dates of the units, we consider some increase in PSCO's March estimate a likely occurrence. See NHPUC Reports No. DR 79-187, June 7, 1980, and September 18, 1980.

would note that in our experience, estimates of this kind found in SEC filings tend to exhibit "worst case" assessments. Based upon the project's present state of completion, 97/ much of the increase is probably attributable to AFUDC accruals which are cost elements that are not a cash requirement of the petitioners during the construction period. As a consequence, we have difficulty in determining the additional amount which should be considered as a cash requirement when analyzing the petitioners' financial forecasts.

2. Capacity Factors

The average capacity factor of a nuclear plant which can be expected once the unit comes on line is an operating condition that has a direct bearing upon the cost of the

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97/ As of the end of 1979 approximately 87 percent of the basic engineering design was complete; 95 percent of the equipment was on order (portions of this equipment, however, are subject to escalation clauses); 91 percent of the construction work was under contract; construction of Unit I and the facilities common to both units was 31.1 percent complete; Unit II was 6.5 percent complete; and the whole project was 22.6 percent complete (Exh. PSC-10 at 2; Tr. 32, pp. 109-10).

power generated by the facility. The parties have, consequently, dealt at some length with the question, each attempting to predict the output of the Seabrook units over time. Careful review of the historical data concerning results for nuclear units nationwide and of the various analyses of this data conducted by the parties reveals, however, that there are tremendous difficulties in making definitive statements as to probable output.

Based upon a number of circumstances, not the least of which are that total nuclear experience is very limited and that there are virtually no mature units the size of the Seabrook units, historical data simply does not reflect a range of operating experiences useful for predictive purposes. Furthermore, as stated by the Attorney General's witness, the historical data on capacity factors shows "large year-to-year random variations" (Tr. 38, p. 98; emphasis added) among plants and even from year to year for a given plant's operation. 98/ In light of this range of variation, we must concur with the Attorney General's assertion that "some set of plants and years can probably be found that will support any position" (AG initial brief, p. 33). Indeed, the capacity factor characteristics of a given nuclear plant are more likely sui generis to that plant than predictable with a precision that is based upon any statistical analysis which has insufficient data to begin with.

Nevertheless, the record before us tends to suggest a few generalizations. New England units collectively have a higher average capacity factor than the nation as a whole; and Yankee units, with an average capacity factor slightly greater than 69 percent, are

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98/ Indeed, a plant can experience a low capacity factor for reasons as diverse as the Three Mile Island incident or merely because a particular utility has excess hydro capacity which it must use.

significantly higher than both the national and New England averages. Pressurized water reactors ("PWR") tend to have higher average capacity factors than boiling water reactors ("BWR"); and Westinghouse PWR's tend to have higher average capacity factors than other PWR's. Average capacity factors also tend to be affected by age or maturity, size of unit and possibly vintage: with larger units tending to have lower capacity factors than smaller units; with mature units, in operation six years or longer, having higher average capacity factors than immature units; and with more recent PWR units possibly having higher capacity factors than other PWR units due to improved construction and design resulting from technical innovation or experience.

The Seabrook project's units are 1,150 MW Westinghouse PWR plants which can be fairly characterized as Yankee units. 99/ Thus

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99/ Yankee provides engineering services, construction management services and nuclear fuel services management for the project (Tr. 35, p. 99; see Exh. M-67, M-76, App. C; Exh. PSC-8, 9, 10, pp. 2-3).

there are four factors which would tend to increase the Seabrook units' expected average capacity factors and one which would tend to decrease them. None of the Yankee units, however, exceeds 825 MW. Based on a 28-year life, Montaup's worst case assumptions imply an average lifetime capacity factor of 58 percent, while New Bedford and Fitchburg utilize 69 percent. Petitioners support their projections by pointing to the role of Yankee, and by utilizing a combination of modified PSCO projecions, NEPOOL data, historical data, and judgment. Of all the petitioners, Montaup conducted the most thorough examination of this issue.

The Attorney General criticizes petitioners' choices of capacity factors and suggests that the results of three studies demonstrate the likelihood of average capacity factors for the Seabrook units to range between 55 and 65 percent. Our review of Mr. Chernick's testimony concerning the Easterling study leads us to conclude that there is simply insufficient detail in the record about the reliability of the study to utilize its results. 100/ We do find that the Komanoff study 101/ tends to suggest the existence of an inverse relationship betweeen plant size and capacity factor as well as direct relationships between age, vintage and manufacturer. The R2's associated with the regression equations derived by the study, 102/ however, are too low to utilize the equations for predictive purposes and we consequently decline to do so. 103/ The low R2 and detail

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100/ Statistical Analysis of Power Plant Capacity Factors, Easterling, Robert G., NUREG/CR-0382, February 1979. In addition, we would point out that we consider the use of the regression equation in this study to predict capacity factors for other than the second, third and fourth years of a plant's operation, without careful qualification, to be misleading.

101/ Exh. PSC-7, Nuclear Plant Performance Update 2, Komanoff, Charles, Council on Economic Priorities, June 21, 1978.

102/ Ibid., e.g., pp. 36, 45; R2 equals.25,.24.

103/ While rejecting the reliability of this study, it is interesting to note that the average capacity factor for a 1,150 MW DER Westinghouse PWR unit built after 1973 and with a useful life of 28 years generated by equation No. 4.2 of the study (Exh. PSC-7, p. 54) is 68 percent.

problems apply equally to the so-called NERA "study." 104/

Faced with the difficulty in this area and viewing the record before us, we do not consider the average capacity factors utilized by Montaup, New Bedford and Fitchburg to be unreasonable, and we accept their projections for the purposes of this proceeding. However, in order that we may more fully analyze the sensitivity of alternative system generation mix economics to downside revisions in capacity factors, we will in the future expect petitioners to "bracket" their base case simulations by varying their capacity factor assumptions in increments from 2 to 5 percent.

104/ Exh. M-24, Table A-3, p.1, R2 equals .28. See also Tr. 38, pp. 70-115.

3. Operation and Maintenance Costs

Petitioners' estimates of operation and maintenance costs ("O&M") are principally based upon a 1974 study by PSCO for the predecessor of the Nuclear Regulatory Commission and upon information provided by Yankee. Petitioners contend that in their judgment, these estimates are reasonable and that, in any event, O&M expenses are relatively unimportant. We, however, must consider the total costs of the project. That petitioners have submitted no source documents which would enable us to verify the manner in which they derived their O&M estimates causes us to question the reliability of these estimates. The fact that petitioners judge these estimates to be reasonable coupled with the participation of Yankee, whose experience we recognize, entitle these estimates to be given some weight. In light of this, despite reservations about the adequacy of the analysis offered, we will accept petitioners' O&M estimates as setting the extreme lower bound for likely O&M costs.

Mr. Cherni.' asserts that Seabrook O&M expenses will be substantially higher than the estimates utilized by petitioners. 105/ To derive his result, Mr. Chernick takes historical O&M costs associated with the seven New England nuclear plants, regresses the costs for each plant with time as the independent variable and then averages the costs predicted by each regression equation to derive a New England average O&M expense. Using this process, Mr. Chernick derives both a geometric and linear time trend.

Implicit in this analysis is the assumption that annual O&M expenses can be modeled as a function of time. Mr. Chernick, however, offers no justification for this assumption. While we are willing to accept a simple regression against time for variables that are relatively insensitive to error, we have no basis in the record on which to infer

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105/ For example, his 1998 estimate is 5.80 times larger than Montaup's 1998 O&M expense.

the sensitivity of O&M, as derived by Mr. Chernick, to error. Mr. Chernick does not offer us a causal analysis of which variables drive O&M: there is no explanation of why we should accept his model. Annual O&M expense is a phenomenon too complex to be predicted by a simple time trend analysis absent a showing that time *in se* is the major determinant of O&M expense. 106/

106/ For example, we might expect O&M to vary with plant age as do capacity factors in the Komanoff study, or that O&M might vary with plant size, or with industry design experience. These possible causal variables, however, are simply not addressed in other than a conclusory fashion.

Were we to accept the assumption that yearly O&M is a function of time, we are still confronted with a lack of explanatory statistics for the regressions Mr. Chernick derived: we do not have the t or F statistics. 107/ Before we can accept this type of analysis, we need at a minimum some showing that the analysis has been subjected to and has withstood the indicia of reliability associated with the utilization of regression analysis. We do not find this showing and consequently do not find the analysis credible.

While we have rejected Mr. Chernick's analysis of O&M and while we do not believe O&M will increase at rates approaching those derived by Mr. Chernick, inspection of his

107/ We realize the statistics presented in Table 20 (Exh. AG-232) are, for this particular analysis, the most informative test statistics that the regression program on the calculator utilized by Mr. Chernick is capable of generating. We find, however, that the additional statistics mentioned above are necessary to assess the statistical significance of the explanatory variable and to inform us of the margin of error exhibited by the predicted dependent values.

tabulation of historical O&M costs for other New England nuclear units (Exh. AG-232, App. A) suggests Seabrook's O&M costs may well be significantly higher than those costs utilized by petitioners. We will examine the sensitivity of Seabrook's economics to increases in O&M in section E.

4. Interim Replacement Costs

Petitioners have failed to address interim replacement costs in projecting total project costs. In tabulating these costs for other New England nuclear facilities (Exh. AG-232, App. A), Mr. Chernick, in our opinion, has rightly identified a cost component which is not insignificant. Quantitatively analogizing the experience for these other nuclear plants to Seabrook, however, is extremely problematical. In particular, we have no basis upon which to accept that the simple discounted New England average computed by Mr. Chernick has any relationship to Seabrook; these costs vary widely from year to year and from plant to plant. The extent of this expense could easily be plant specific as it could be generic to New England nuclear plants or to all nuclear plants. In fact, we would expect the former, particularly in light of increased industry experience in designing and building these plants. Moreover, interim replacements attributable to ordinary wear are not specific to nuclear plants only, and none of the offered alternatives has been evaluated in terms of this cost. We would also note that to the extent the interim replacement costs identified by Mr. Chernick have resulted from design problems, we find petitioners' contention that these problems have been corrected in the design of Seabrook reasonable. We also find petitioners' inclusion of an additional amount in the cost of Seabrook for future safety design modifications as the result of the Three Mile Island experience to be reasonably based. We will, however, address the sensitivit[illegible]f Seabrook's economics to the inclusion [illegible]terim replacements in the following section.

E. Worst Case Simulation of Alternatives.

Petitioners have simulated the economic impact of including a number of alternatives in their system generation mixes. Comparison of these simulations indicates that the inclusion of Seabrook power in their systems has a decided economic advantage over the other available alternatives. These simulations, however, are dependent upon the assumptions petitioners have utilized. We will now examine a composite of Montaup's simulations (Exh. M-72) and substitute our own "worst case" assumptions. Simultaneously setting the capital cost, capacity factor and O&M variables to values that we consider unfavorable in the extreme will give us a composite worst case indication of the relative cost effectiveness of the project. 108/

108/ We note that nuclear fuel expense values have generally not been disputed (AG initial brief, p. 18).

Following the analysis the Attorney General utilizes in his initial brief (pp. 89-95), we first identify net annual savings of $19,037,000 associated with Montaup's base case when utilizing an average capacity factor not greater than 58 percent for Seabrook. This capacity factor is in the lower half of the Attorney General's estimated capacity factor range discussed above. Next, we adjust Montaup's base case to reflect the upper limit of our previously determined capital cost range for Seabrook. Including O&M and interim replacement costs at the full value suggested by the Attorney General yields a net annual savings attributable to Seabrook of $3,064,790. 109/ Were we to substitute Montaup's $2,360/KW simulation into this example and thereby increase the capital cost by 25 percent above our estimated upper limit of $1,860/KW, Seabrook

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109/ $11,511,000/1,180 equals $9,755 additional system cost per additional dollar of Seabrook per KW capital cost. $9,755 x ($1,860 - $1,180) equals $6,243,200. $19,037,000 - $6,243,254 - $9,728,956 equals $3,064,790.

would still be the least costly alternative as long as the combined O&M and interim replacement costs were less than or equal to 76 percent of the Attorney General's combined figures for O&M and interim replacements. This number is at least 4.6 times larger than the O&M expense modeled by Montaup.

We must reiterate that we simply do not find Mr. Chernick's estimates of O&M to be credible. His linear regression is methodologically incomplete and unconvincing, and his geometric regression is simply beyond belief. On the other hand, we find petitioners' estimates of O&M equally unbelievable for other reasons; further, as we pointed out in the previous section, petitioners did not account for interim replacements.

In our judgment, these two factors, while important, are not pivotal. In our preferred composite worst case, the project is demonstrably 110/ economical when full weight is given to the Attorney General's O&M and interim replacement estimates. Our second composite worst case also demonstrates the cost effectiveness of Seabrook. Indeed, we find it highly unlikely the combined effects of O&M and interim replacement costs will even approach 76 percent of the Attorney General's estimates. We find it also unlikely that the capacity factors and capital costs associated with the project will approach the extreme values simulated. A worst case analysis does not represent the expected result; rather, it represents exposure to the combined occurrence of remote possibilities.

We note that the cost effectiveness of the project demonstrated by the above examples is understated. Petitioners are largely dependent upon fuel oil as their major

110/ I.e., within the limitations of the model and its assumptions; the utilization of which we in fact find an appropriate and reasonable manner in which to address the convergence of many interdependent, but heretofore separately addressed, issues.

source of energy; this fact makes the simulations very sensitive to the fuel costs utilized. We find the fuel oil cost escalation assumptions very conservative. Further, the simulations demonstrate total system savings attributable to the project for only fifteen years or approximately half of the project's useful life. And while a delay in the in-service dates of the units will increase the capital cost of the project, the cost effect of which we have taken into account above, we also find it likely that the relative fuel cost advantage of the project will, in itself, continue to offset the capital cost increases associated with a delay.

The above analysis is not perfect; nor is it ideal. It is, however, based upon the best analysis of Seabrook's relative economics appearing in the record. Montaup's simulations model a large number of cases, are technically complete, are susceptible to adjustment and fairly represent the economics of the project.

The peaking unit modeled by New Bedford and the combined cycle 111/ unit modeled by Fitchburg would not be expected to be more economic than base load power; and we find their simulations reasonably demonstrate this conclusion. With respect to coal as a base load alternative, the results of New Bedford's simulation tend to confirm Seabrook is cost effective. We find this result, however, to be of secondary import. For were we to reach the opposite result, given the planning and construction lead times and the admitted environmental constraints, we find it unreasonable to expect a coal unit to be available in time to meet petitioners' demonstrated intermediate-term power needs.

111/ While the capital cost of converting Unit 7 to combined cycle operation may be only $623/KW and the O&M associated with the plant is relatively small, the inclusion of energy costs outweighs their apparent attractiveness. Further, a reactivated and converted Unit 7 would have a useful life approximately half that of Seabrook. See also p. 120.

V. FINANCIAL CAPABILITY

A. Introduction

In reviewing the financial ability of the petitioners to assume their proposed commitments, we will focus upon the financial plans submitted by them which show their total projected year-to-year construction fund requirements from 1979 to 1988. Each of the companies has presented its construction fund requirements for any given year, including its requirements relating to Seabrook, in terms of the sum of all planned construction expenditures, by aggregating the costs of all facilities under construction during the particular period. These financial plans reveal the sources from which the needed capital will be derived, and generally include allowances for internally generated funding, short-term borrowings, and proceeds from the sale of long-term debt and preferred or common equity. In view of the length of the construction period, the petitioners have necessarily made certain assumptions regarding future operating and money market conditions. The reasonableness of these assumptions and the impact of the financing plans upon each utility are the principal areas of any inquiry.

Prior to our discussion of the financial testimony presented by each petitioner, we must, however, address a threshold issue raised by the intervenors concerning the validity of the financial forecasts in light of changes in the construction estimates for the project.

When the petitioners filed their financial testimony in August 1979, they based their analyses as to capital requirements relating to Seabrook upon a PSCO January 1979 cost estimate of $1.825 billion. Thereafter, on April 8, 1980, a week before the record was to close, and after full cross-examination of the companies' direct cases, PSCO produced an updated cost estimate, prepared in March 1980, which estimated the cash cost of the project at $2.08 billion. 112/ Petitioners did not seek

112/ These estimates of cash cost do not include AFUDC since it is not a cash outlay during the construction period.

to amend their financial analyses to reflect the higher PSCO estimate.

The intervenors contend that since there has been an increase in the projected capital cost per PSCO's own estimate, the petitioners' financial testimony is outdated and leaves the Department with no evidence upon which to found a decision. According to intervenors, the failure to revise testimony on this issue is fatal to the petitioners' cause.

There can be no question that a more complete presentation of the petitioners' financial case would have included an analysis of the impact of the revised construction estimate upon their funding of the additional cost. Nevertheless, based upon the record in this proceeding, we cannot agree that the petitioners have thereby failed in meeting their burden of proof on this matter or that there is a lack of credible evidence from which a reasoned decision can be made.

Initially we would note that the updating of cost estimates for a project with the lead-time of Seabrook can be expected to be made throughout the construction period as a result of changes which occur over time in scheduling, money market conditions, and basic labor and materials costs. In presenting their direct cases, the petitioners of necessity had to rely upon the most current information then available as to the capital cost of the project. When the revised estimate was received, it would not have been reasonable for the Department to require that all materials previously submitted be recalculated, nor was it reasonable to expect across-the-board revisions from the petitioners.

If for every change in circumstance affecting the project we were to expect a complete analysis of the impact of that change upon each of the issues relating to it, the Department would become entwined in a proceeding which could end only when the units were placed in service. Independent of the merits of the intervenors' position, such a procedure would effectuate that position. Consequently, while we recognize that our decision must be founded upon the most reliable information, that decision must also be made in a timely fashion so that the companies involved can proceed with the substantial supply and financial tasks confronting them with or without Seabrook power. In this type of case, the public interest requires a substantive determination, for adequate future capacity cannot be provided by waiting for demand to exceed supply: the construction of generating facilities requires significant lead times. Inherent in the planning process is a present commitment to a variety of uncertain future occurrences; most basically, however, the continued existence of the opportunity for commitment is not insensitive to time. We must, therefore, at some point step down from the treadmill which a case such as this can become and determine the merits of the parties' claims despite less than ideal information and analysis.

More important, however, is the fact that despite changes in the PSCO construction estimate our ability to review the petitioners' financial ability is not seriously impaired. The updated cost esti e is in the record and the magnitude of the increased burden which the higher capital commitment will impose upon the petitioners can be assessed in light of the financial testimony presented. The issue is susceptible to this type of analysis because the ability to finance cannot be considered to exist only up to a clearly identifiable level of capital expenditure. There is not a particular dollar amount of investment which can be precisely pinpointed as the unquestioned dividing line between financial ability and ruin. Rather, the very nature of the question lends itself to qualitative judgments which can be made over a wide range of potential expense levels. These judgments are possible given the extensive evidence before us.

An additional observation regarding the assessment of financial ability is also warranted in light of our primary interest in this proceeding: to insure that the ratepayers continue to receive adequate and reliable service at just and reasonable rates.

Given a demonstrable need for the capacity sought to be acquired and the absence of reasonable alternatives, the possible strain which the financing of additional capacity may have upon a company and its customers must in certain instances be balanced against the threat of future service reductions or interruptions. The Department is obligated to assure adequate and reliable future power. Thus, while some financial burden may have to be assumed by both the company and its ratepayers, the consequences of not accepting this burden may make the additional financial obligation a highly reasonable and necessary step.

We will now proceed with our discussion of the financial evidence presented by each of the petitioners.

B. Fitchburg's Financial Capability

Fitchburg requests authorization to purchase an additional 10 MW of capacity in the Seabrook units from CL&P and 6 MW from PSCO. Mr. Frank Childs, the Company's Vice President and Assistant Treasurer, presented testimony regarding the purchase price of the proposed acquisitions, the Company's present construction program, and the Company's ability to finance its construction program.

For the purposes of its direct testimony, Fitchburg assumed that purchase of the 10 MW interest from CL&P would take place on July 1, 1980. As of that date petitioner estimated that the "transfer" costs would be $5,102,900 including progress payments for construction, fuel and CL&P's booked AFUDC. Fitchburg intends to generate this payment through a combination of internally generated funds and short-term borrowings. 113/

113/ Fitchburg recently renegotiated its credit lines to $9,650,000.

The proposed transfer of the 6 MW interest from PSCO would take place over an "adjustment period" of approximately 15 to 18 months. Once all regulatory approvals have been given, all construction costs incurred with respect to PSCO's share of the Seabrook project will be paid by all other joint owners purchasing from PSCO until such time as PSCO's share is reduced from its current level of 50 percent to approximately 35 percent. Fitchburg's total share after the "adjustment period" will be 0.86655 percent. On a per KW basis, the PSCO interest transferred will be less costly than the CL&P purchase because of timing differences associated with AFUDC accruals.

Petitioner's construction program for the next five years consists of expenditures for its currently owned portion of the Seabrook project (.17 percent), Pilgrim II, Millstone III, Montague Units I and II, and Fitchburg

Local. 114/ From 1980 to 1985, estimated construction expenditures are $35,273,100, of which 50.3 percent or $17,749,300 115/ represents both its present and proposed interest in the Seabrook project.

We note in reviewing Fitchburg's construction forecast that it has diversified its interest into several projects in which it is a joint participant. Assuming that the construction schedule proceeds as planned, Fitchburg will not be excessively dependent upon any single unit or source of power.

Petitioner presented a source of funds statement for the years 1979-1988 (Exh. FGE-14R). This statement is based upon a number of assumptions including the following:

1) New long-term debt at 13.5 percent;

2) Preferred stock at 12 percent;

114/ Fitchburg Local represents expenditures by the Company to maintain its equipment at present levels (capital additions).

115/ Based on PSCO construction cost estimate of January 1979.

3) Common stock issues priced to achieve a 10 percent yield on the then existing dividend (less $1.00 per share for the cost of issue);

4) Short-term borrowings at 14 percent;

5) Sufficient rate relief;

6) O&M and taxes other than income taxes increased at 7 percent per year;

7) Dividend payments increasing at 7 percent per year.

Based upon these assumptions and upon an analysis of its source of funds statement, Fitchburg has concluded that it can finance its construction program between 1980 and 1985 in the following manner:

	($ Millions)
Common stock	4.78
Preferred stock	2.50
Long-term debt	19.00
Notes payable	(3.81)
Other funds	(5.82)
Subtotal	16.65
Internal funds	18.63
Total	35.28

The Attorney General does not contest either the reasonableness of the assumptions used by Fitchburg in its forecast or whether the plan, as presented, illustrates an ability to meet the level of capital investmen deemed necessary. Rather, he asserts that the financial data is based upon an erroneous assumption as to the cost of Seabrook and is further outdated because of the revised PSCO cost estimate.

As we have already noted, Fitchburg's financial forecast was of necessity prepared at a certain moment in time and was based upon the then most recent cost estimate of the project from the lead participant. (See Section A above.) However, by PSCO's own estimate, the cost of construction for the project has increased from $1,825 million to $2,085 million: an increase of $260 million. Assuming Fitchburg would be responsible for both its present and proposed ownership share of the increased cost, it would thus need to generate $2.2 million in additional capital, or $367,000 per year. 116/

Petitioner's source of funds statement was predicated upon very reasonable assumptions. We note that its short-term borrowings do not become excessive over the forecast period. AFUDC as a percentage of net income does not become high, with the exception of 1982. Fitchburg's internally generated funds as a percentage of its total construction expenditures follow "normal industry standards," again with the exception of a single year. It also appears that Fitchburg will meet both its indenture and coverage requirements. In essence, the Company's forecast appears to be fairly sound and based upon reasonable assumptions. 117/

Fitchburg must, however, raise an additional $2.2 million above that detailed in its source of funds statement. Petitioner has

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116/ $260 million x 0.86655.
This calculation is of course quite simplistic; but it serves as a guide to the increased costs due to the updated construction budget.
117/ See p. 17, Fitchburg reply brief.

secured lines of credit equal to $9.65 million. In the early years of the source of funds statement, Fitchburg's borrowings do not approach this limit. We find Fitchburg will thus be able to raise the additional $2.2 million initially through short-term borrowings. Fitchburg's coverage ratios are strong throughout the period; due to this fact, Fitchburg should be able to secure additional long-term financing of $2.2 million without difficulty. 118/

118/ The Attorney General in his initial brief, p. 121, points to a Fitchburg preliminary prospectus (S.E.C. Form S-7, May 28, 1980), which indicates that Fitchburg may need to incur $1.1 million in expenditures through 1984 in addition to the $2.2 million based upon the latest PSCO construction cost estimate. A fair reading of the prospectus reveals that the reference to the higher project cost is premised upon different in-service dates than the latest PSCO estimate, as well as upon different construction costs and AFUDC rates. If, in fact, this scenario should turn out to be the case, the additional $1.1 million in required expenditures does not, in light of Fitchburg's short-term line of credit and its draw upon that line through 1984, have a significant effect upon its ability to finance.

In conclusion, we find the evidence before us persuasive that Fitchburg will be able to finance its present and proposed Seabrook interests. 119/

119/ We do not wish to imply, however, that we view as minimal the magnitude of either the Company's construction forecast or its investment in the Seabrook project. Nor do we wish to imply that the circumstances surrounding each debt and equity financing will not be carefully scrutinized. We will, at the appropriate time, decide the merits of each such issuance.

C. Montaup's Financial Capability

Montaup requests Department approval to increase its ownership s. es in the Seabrook project from its presently owned 1.9 percent to approximately 5 percent, or an increase of 3.1 percent. Montaup has agreed to purchase approximately 1.03 percent or 23.81 MW from CL&P; 1.06 percent or approximately 24.49 MW from UI; and approximately 1 percent or 23 MW from PSCO.

The terms of the agreement between Montaup and the sellers are identical to those of other petitioners. In the case of UI and CL&P, Montaup would make one large upfront payment for the construction expenditures and associated AFUDC incurred by the present owners. Montaup estimated that as of January 1, 1980, the purchase price from CL&P would be approximately $9.8 million, inclusive of AFUDC; the 1 percent entitlement from UI was imated at $10.2 million, inclusive of AFUDC, as of the same date.

The present agreement with PSCO requires a transfer of ownership interest over a period of approximately 15 to 18 months. All construction costs incurred with respect to PSCO's share of the Seabrook project will be paid by all other joint owners purchasing from PSCO until such time as PSCO's share is reduced from its current level of 50 percent to approximately 35 percent. Montaup estimated expenditures for this 1 percent share to be approximately $22.6 million between 1979-1985. As is the case with Fitchburg, the PSCO interest will be less costly on a per KW basis than the CL&P or UI purchases because of timing differences associated with AFUDC accruals.

On August 3, 1979, Montaup presented prefiled testimony in response to our request for additional information contained in our June 28th order. Mr. Richard M. Burns, Treasurer of Eastern Edison, and Mr. Donald G. Pardus, Treasurer and Chief Financial Officer of EUA, testified on Montaup's financial situation. The Company presented a forecast of construction expenditures for the period 1978-1988. The Company also presented a source of funds statement for the same period. Montaup projects cash requirements for its construction program of $154.4 million between 1980-1985. Of this amount, $89.6 million, or 58 percent, represents cash expenditures for the Seabrook project at a 5 percent ownership interest.

As can be seen below, all of the cash requirements needed by Montaup for its construction program would be acquired from outside financing; none of its cash requirements was projected to come from internally generated funds. In fact, the Company projected a negative cash flow of $49 million from 1980-1985.

The source of funds statement presented in its prefiled testimony (Exh. M-16) showed that Montaup intended to meet its cash construction requirements of $154.4 million plus cover its projected internal operating deficit of $49 million between 1980-1985 in the following manner:

	($millions)
Long-term debt	48.6
Common stock	73.2
Short-term borrowings	81.6
Total cash requirements	203.4

The source of funds schedule was prepared utilizing the following assumptions:

1) Long-term debt at 9-10 percent;

2) Sufficient rate relief;

3) Short-term interest rates (prime) at 10-11.75 percent;

4) Common stock dividend payout ratio of $12 per share;

5) Operating and maintenance increase of 8 percent per year;

6) AFUDC rate of 11.5 percent, calculated in accordance with FERC Order 561.

Subsequent to submission of the prefiled testimony and the cross-examination of its financial witnesses, 120/ Montaup filed a petition with FERC (Docket EL80-8). The application (Exh. AG-223) filed on December 13, 1979, requested FERC to allow Montaup to include a portion of CWIP in rate base in order to "...meet a severe financial difficulty arising from the large cash requirements of its construction program." 121/

120/ Cross-examination of the Company's financial witnesses on its prefiled testimony was concluded on October 31, 1979.

121/ Montaup has also filed with FERC an application for a general rate increase (Docket ER80-520). This action has been consolidated with Docket EL80-8, and the Department has intervened in these proceedings.

On March 24, 1980, additional financial testimony (Exh. M-72) was filed by Mr. Pardus on behalf of Montaup. The testimony indicated that for the short term (1980-1984) Montaup would face severe financial difficulties; the Company believed, however, that the purchase of the additional Seabrook shares was still in the public interest due to:

1) assurance of capacity; and
2) assurance of capacity at known costs.

Although Mr. Pardus was cross-examined on the financial information contained in the FERC filing, the Company presented no updated financial exhibits.

The Company's filing before FERC included a number of schedules on the Company's projected financial condition over the next six years. Among these exhibits is a forecast of the Company's cash requirements over the period 1980-1985:

Construction	154.4
Internal operating deficit cash	38.2
Working capital & debt retirement	6.6
Total cash requirements	199.2

The Attorney General contends that the financial picture presented in the FERC filing is understated due to two factors: (1) that the construction costs associated with the Seabrook project contained in Montaup's exhibits are now out of date; and (2) that petitioner has incorporated untenable assumptions in its source of funds statement, which in turn understate the serious financial difficulties with which Montaup will be faced. The Attorney General requests us, therefore, to deny the petitions due to the Company's financial difficulties and the ultimate impact on the ratepayers.

We agree with the Attorney General that, in preparing the assumptions to derive the source of funds statement, petitioner could have made more realistic assumptions with respect to the costs of long-term and short-term debt. However, we do not concur with the Attorney General's belief that more realistic debt assumptions would produce a situation .hich would catapult the Company into financial disaster.

This conclusion is based upon our analysis of the source of funds statement. If the Company had assumed more current interest rates for debt, and all aspects of the forecast remained constant, net income would decrease and cash required from outside financing would increase. We find that this increase in the cost of debt will not substantially affect the Company's total cash requirements. 122/

The record does indicate, however, that Montaup cannot presently finance its construction requirements at a 5 percent ownership interest in Seabrook. The FERC filing indicates that Montaup will not be able to raise approximately $50 million of the necessary capital. Mr. Pardus testified that, due to the instability of the capital markets and on advice

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122/ For example, had the assumption for the cost of long-term debt been increased by 2 percent, the Company's cash requirements would increase by approximately $4 million over the period, in contrast to total cash requirements of $203 million over the period.

from the Company's investment bankers, Montaup had lowered its estimate of proceeds from common stock issues by $50 million.

That Montaup cannot finance its proposed construction program is clearly shown in the following statements by the Company:

> Montaup was advised by commercial and investment bankers that an improvement in cash flow will be required to finance the construction program through to completion of the second Seabrook unit (Exh. AG-223, p. 2).
>
> If Montaup is unable to obtain the required rate relief from this Commission (FERC), it will be forced to attempt to reduce its ownership interest in Seabrook to a level that can be financed without any CWIP in rate base (Ibid., p. 3).

In our June 28th Order we stated that each petitioner must demonstrate "that the purchasing company has the ability to finance the proposed acquisition." The Company has filed a petition with FERC for the inclusion of a portion of CWIP in rate base, citing extreme financial hardship. Its cash flow statements forecast a large negative cash flow situation between 1981 and 1985. AFUDC as a percentage of the Company's earnings is extremely high for a number of consecutive years.

On the record before us, then, we must conlude that Montaup has not met its burden of proof with respect to its financing capabilities at a 5 percent ownership interest in the Seabrook project.

Yet, in our analysis and findings with respect to petitioner's demand forecast, we concluded that Montaup had demonstrated a need for a maximum additional interest of 56 MW in the project. If Montaup had otherwise shown a financial ability, approval of an interest approaching the 56 MW would have been forthcoming. The fact that Montaup has not shown an ability to finance its full proposed interest of 71.3 MW does not, however, lessen Montaup's need to obtain additional capacity to meet its future demand. With no additional interest in the project, Montaup's 1988 reserve will be 15.2 percent; this reserve margin is too low. Our review of the record indicates, however, that a lesser interest in the project than that proposed may be able to accommodate both need for power and financial capability criteria. The additional 1 percent interest represented by the PSCO offering will increase Montaup's reserve margin to 18 percent. This increase will enable petitioner to meet its internal peak and still maintain a reserve margin that, while not as great as the record would support, is not unacceptable under present circumstances. As we explain below, Montaup can presently finance this 1 percent interest because of both the reduction in overall capital expenditures and the nature of the PSCO transfer agreement.

At a 2.9 percent ownership share 123/ in the project, the Company's cash requirements will be reduced by $52 million, at a minimum (Exh. AG-173). This coincides almost exactly with the $50 million in financing which

123/ Montaup's present 1.9 percent share plus 1 percent from PSCO.

Montaup's FERC filing indicates it will not be able to acquire. Montaup's cash requirements should therefore be at a more manageable level.

In addition, the approval of the transfer agreement with PSCO will eliminate the large upfront cash expenditures required by the other purchases. The overall cost of the 1 percent PSCO acquisition will be less costly to both the consumer and Montaup than a similar acquisition from either CL&P or UI, and it should help alleviate some of PSCO's present cash flow problems and thereby contribute to the viability of the project.

We note that Montaup is taking some positive steps to improve its current cash flow problems, most notably, its FERC petition and its decision to investigate the normalization of the debt component of AFUDC. Recent decisions by the NHPUC that contemplate the possibility of a delay in the completion dates of the units could also serve to alleviate some of Montaup's cash flow difficulties, as well as offset the impact of the increased cost of the project. Moreover, the capital markets appear to be returning to more stable conditions which will provide a better climate for Montaup to raise the necessary capital. Although the project cost has been updated from $2.8 billion to $3.4 billion, a substantial portion of the increase is due to the accumulation of AFUDC. The increased cost due to AFUDC will not affect the cash requirements of the Company. Of the $260 million attributable to increased cash requirements for the project, Montaup's share of these costs will be approximately $7.5 million over a six to nine year period. In eliminating the cash commitments relating to the CL&P and UI purchases and taking into account the circumstances which will have a positive effect upon Montaup's cash flow, the additional burden created by the project's increased capital cost should not be excessive or beyond the Company's financial ability.

Based on the record before us, we will therefore allow Montaup to increase its ownership share pursuant to the transfer agreement with PSCO. If the Company's financial position improves to the extent it feels it can demonstrate that it is capable of funding a greater interest in the project, we will investigate a petition of more limited scope to determine whether the acquisition of additional shares would be consistent with the public interest. However, on the record before us, we must deny Montaup's petition with respect to the CL&P and UI purchases.

D. New Bedford's Financial Capability

New Bedford requests approval to acquire an additional 2.1739 percent interest (50 MW) in the Seabrook units from PSCO. As is the case with Fitchburg and Montaup, the acquisition of this interest would take place over an "adjustment period" of approximately 15 to 18 months. All construction costs incurred with respect to PSCO's share of the Seabrook project would be paid by the other joint owners purchasing from PSCO until such time as PSCO's share is reduced from its current level of 50 percent to approximately 35 percent. New Bedford's total interest in the project after the "adjustment period" would be 3.52317 percent. 124/

NEGEA is the parent of two retail electric operating subsidiaries, New Bedford and Cambridge, and one generating subsidiary, Canal. All of the subsidiaries pay out 100 percent of

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124/ It presently owns a 1.34927 percent interest.

their earnings to the parent, which in turn pays out dividends to the public. The subsidiary companies' debt issues (with the exception of Canal) are either privately or publicly placed. Canal's debt issues are publicly placed.

Mr. Earl Cheney, Financial Vice President of New Bedford, Cambridge and Canal, presented testimony and was cross-examined on the financial position and estimated construction expenditures of both New Bedford and Canal.

Mr. Cheney testified that, once regulatory approvals are received, New Bedford intends to petition the Department to transfer all of the NEGEA system nuclear project interests from New Bedford to Canal. He further testified that the primary reason for this proposed transfer was the financing flexibility of Canal: because of its more favorable indenture terms and its small present capital commitments when compared to New Bedford. The witness maintained that although New Bedford could finance the additional interest in

Seabrook, to do so would seriously jeopardize its bond ratings.

For the purpose of its testimony in this proceeding, New Bedford assumed that the sale of all its interests in nuclear projects to Canal, including its present and proposed Seabrook shares, would be effected in the second half of 1980. These units include Seabrook, Pilgrim II and the Montague units. All of petitioner's financial exhibits were based upon the assumption of an immediate transfer of the Seabrook interests to Canal. Consequently, we will focus on Canal's ability to finance, and any findings we make with respect to the NEGEA system will be based upon the assumption that New Bedford's interest in the project will in fact be transferred to Canal. 125/

125/ SEA argues in its initial brief, p. 24, that Canal is not presently before the Department, and therefore since New Bedford's financial exhibits focus on Canal's ability to finance and not its own, that New Bedford has failed to establish a *prima facie* case. We find, however, the appropriate time for making this argument has long passed. The Canal link in the "New Bedford" financial case has not changed throughout these proceedings; extensive cross-examination was conducted with knowledge

(continued on next page)

of the transfer to Canal assumption. Had the issue been raised formally at an earlier date, the procedural deficiency could easily have been cured by joining Canal as a party; this course, however, would have had no effect on the merits of the "New Bedford," NEGEA system case, the testimony presented or the witnesses called. To grant the SEA request for dismissal at this late date would serve no purpose other than delay.

New Bedford estimates that its present investment in planned nuclear facilities is approximately $72.3 million (Exh. NB-7, Sch. C-2). Upon the transfer, Canal proposes to finance these purchases initially through short-term borrowings, and subsequently through a debt issuance of $35 million and a common stock offering of $30 million, with the remainder being generated through internal funds.

Assuming the above transfers are approved, Canal would then be responsible for all expenditures relating to NEGEA's jointly owned nuclear units. For the period 1981-1985 Canal has estimated that its construction expenditures will be $114 million; 126/ of this amount, $85.9 million or 75 percent relates to the Seabrook project (Exh. NB-7, Sch. C-2). Canal forecasts that it will finance these construction costs over the five-year period

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126/ Excluding the New England Power Company Charlestown units (NEPCO units).

through a combination of \$56.2 million in internally generated funds and \$73 million in security issues and other funds.

Canal's source of funds statement is based on the following assumptions:

1) Short-term borrowings at 11-12 percent for 1979 and 10 percent thereafter;

2) Long-term debt at 10 percent;

3) Dividend payments of 70 percent of Canal to NEGEA (in contrast to the present 100 percent);

4) Local tax increase at 6 percent per year;

5) Sufficient rate relief for NEGEA subsidiaries.

New Bedford originally requested Department approval for the purchase of 70 MW from CL&P (D.P.U. 19738), as well as 50 MW from PSCO. New Bedford, however, allowed its agreement with CL&P 127/ to lapse and subsequently withdrew this portion of its

127/ The contract between CL&P and New Bedford expired on December 31, 1979.

transpired since New Bedford's financial testimony was presented: (1) the NEP units have been cancelled; (2) the CL&P agreement has expired and was not renewed; (3) the construction budget for the Seabrook project has been updated by the lead participant; and (4) the potential for delay in the in-service dates of the Seabrook units in accordance with recent NHPUC decisions. 128/

Of these events, three will decrease the cash requirements needed by Canal to finance its construction program. The cancellation of the NEP units will lower Canal's construction expenditures between 1979 and 1985 by $15.6 million. The expiration of the CL&P agreement will lower the Company's cash requirements by approximately $65 million. These combined factors will decrease the Company's need for outside financing by $80.6

128/ NHPUC Report No. DR 79-187, June 7, 1980, p. 59; DR 79-187, September 18, 1980.

million over the forecast period. The recent NHPUC orders which may affect the in-service dates of the units will also lower the Company's cash requirements.

The fourth event, the increase in the project cost announced by the lead participant, will, of course, increase the cash requirements 129/ of Canal for its construction program.

Our review of the source of funds statement also reveals somewhat optimistic assumptions for the cost of debt. Assuming all other aspects of the forecast remain constant, more realistic debt assumptions would tend to decrease net income and in turn increase the cash required from outside financing. We find this increase in the cost of debt, however, will not substantially increase the Company's cash

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129/ It should be noted that although the project cost has been updated from $2.8 to $3.4 billion, a substantial portion of the increase is due to the accumulation of AFUDC. The increased cost due to AFUDC will not affect the cash requirements of Canal.

requirements. 130/ Therefore, we find that the combination of these two factors which increase the Company's cash flow requirements does not begin to offset the decrease in cash requirements of over $80.6 million cited above.

Canal has no present short-term borrowings. It therefore has a great deal of flexibility in raising the initial amounts of outside capital required. Its indenture allows construction work in progress to be bondable and therefore gives Canal easier access to the capital market than New Bedford. In addition, Canal's present capital commitments to other projects are at relatively low levels.

Further analysis of the source of funds statement presented by Canal indicates that a substantial amount of its construction expenditures will be raised through internally

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130/ For example, had the assumption for the cost of long-term debt financings been 12 percent, the company's cash requirements would increase by $400,000 ($200 million in long-term debt x an additional 2 percent) per year for three years in comparison to total cash requirements per the Company forecast of $114 million.

generated funds. AFUDC as a percentage of net income exceeds net income for a period of three years, as the intervenors have pointed out. However, the expiration of the CL&P contract will obviously enhance this ratio.

After careful review, we find Canal has the ability to finance New Bedford's presently proposed additional interest in the Seabrook project.

VI. VIABILITY OF THE SEABROOK PROJECT

In our June 28th Order, we were concerned by the lack of evidence regarding the ability of PSCO to complete the Seabrook project. The development of this issue in D.P.U. 20055 focused on the ability of PSCO to meet the financial burden resulting from a proposed 35 percent interest in the project. As we view the issue, the determination of such ability depends on PSCO's access to capital markets and on the scope of the NHPUC's commitment to maintain PSCO's financial integrity. Both of these factors are dependent upon the interaction of a large number of essentially non-quantifiable variables which depend on future contingencies, are unknowable at this time with precision, and are by no means independently ascertainable.

In its July 27, 1979, decision the NHPUC stated: "The Commission would like to reiterate once again its belief that Seabrook is necessary for both New Hampshire and New England." 131/ In December 1979 the NHPUC further stated: "...the Company has maintained and correctly, we believe, that Seabrook is a valuable project." 132/ More importantly, however, the NHPUC backed up these statements in its June 7, 1980, order by providing PSCO $18.3 million 133/ in permanent rate relief out of an approximate $19.3 million 134/ requested. While the extent of relief is in itself significant, the disposition of certain substantive issues by

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131/ NHPUC Report No. DR 79-187, July 27, 1979, p. 11.

132/ NHPUC Report No. DR 79-187, December 21, 1979, p. 9.

133/ NHPUC Report No. DR 79 187, June 7, 1980, p. 56.

134/ Ibid., p. 3.

the NHPUC, especially the attrition allowance, the increase in the depreciation rate, the full normalization of interest expenses and the increase in rate of return, are also persuasive indicators of the NHPUC's scope of commitment to PSCO's continued financial integrity. After a careful reading of the NHPUC's decisions subsequent to the statutory elimination of construction work in progress ("CWIP") from PSCO's rate base, we believe that the NHPUC clearly supports the Seabrook project, and that it is committed to the provision of relief adequate to maintain PSCO's financial integrity.

A succinct statement of the factors affecting PSCO's access to capital markets is found in the November 30, 1979, affidavit of William O. Harty, 135/ submitted before the NHPUC in support of PSCO's petition for emergency interim rate relief:

135/ Mr. Harty is a Vice President of Morgan Guaranty Trust and head of the bank's public utilities department. Morgan Guaranty Trust is one of PSCO's lenders.

> Public Service's ability to raise capital is extremely vulnerable to deteriorating capital market conditions, unfavorable utility industry and nuclear power developments, and changing perceptions about political and regulatory developments surrounding the reduction of its interest in Seabrook and about the Company's rates (Exh. AG-214, p. 1, para. I1).

Subsequent to the submission of Mr. Harty's affidavit, the prime lending rate reached an unprecedented 20 percent. This peak in the prime rate was followed by an equally unprecedented decline. 136/ Present capital market conditions show significant improvement over the conditions prevailing earlier this year, and this improvement enhances the prospects for PSCO to raise additional capital. Furthermore, in spite of the fact that the recent perturbations in the prime lending rate which have dominated the capital market have made the task of projecting the average cost of capital

136/ NHPUC Report No. DR 79-187, June 7, 1980, p. 41.

yet to be raised extremely difficult, PSCO has been able to liquidate each of its public offerings subsequent to the November 1978 New Hampshire gubernatorial election. 137/ We find that the confluence of these factors supports the judgment of PSCO's management that the Company will be able to finance a 35 percent interest in the project.

With respect to the unfavorable utility industry and nuclear power developments mentioned by Mr. Harty, these developments are not generic to PSCO; they affect every electric utility in the country. Nuclear health and safety issues are clearly a major source of uncertainty. They are not, however, subject to our jurisdiction or control, and to date, litigation over these issues has been consistently resolved in the project's

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137/ The total amount of permanent financing raised by PSCO for 1979 and through March of 1980 is approximately $219 million. Exh. PSC-11, p. 12. See Tr. 32, pp. 78-84.

favor. 138/ We are unwilling to presume other than that the public health and safety are being carefully and judiciously protected, and insofar as these issues affect the cost of Seabrook, we refer to our discussion of total project costs.

Regardless of the investing public's present valuation of the utility industry relative to other industries, a situation over which neither we nor the NHPUC have any direct control, the provision of an a equate and reliable supply of electricity is an absolute public necessity which, as a consequence of the intermediate to long-term nature of the utility planning process, must not be dominated by short-term economic uncertainties.

Because we believe that the NHPUC is committed to maintaining the financial integrity of PSCO, we do not agree with the

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138/ It should be noted that the focus of inquiry regarding the issue of financial ability before the NRC concerns these very questions of health and safety; in particular, whether a participant's financial ability may lead to compromises in a project's integrity.

Attorney General's suggestion that the NHPUC's support of PSCO will not have a favorable impact upon investors. Rather, we think that the NHPUC's June order has largely lifted the cloud of uncertainty which heretofore has enveloped the Seabrook project and inhibited PSCO's ability to raise necessary capital at favorable rates.

With regard to the regulatory developments surrounding PSCO's reduction of its interest in Seabrook, we cannot ignore the result that we reach today. Although we have no direct control over the investing public's response to our Order, we believe our action will further reduce the uncertainty associated with the viability of the Seabrook project. Given PSCO's past financial difficulties, none of the factors we have addressed is alone sufficient to assure the project's continued viability. Taken as a whole, however, the record supports a finding that PSCO will be able to attract sufficient capital to complete the project at its proposed ownership level.

VII. CONCLUSION

Consideration of the issues which we articulated in our June 28th Order constitutes the structural means by which we have attempted to move toward our ultimate objective in these consolidated proceedings: to ensure for the consumers of the petitioning Massachusetts utilities that their future energy needs will be provided by reliable service at just and reasonable rates. As this decision demonstrates, extensive evidence was presented by the parties on the specific issues set forth in the June 28th Order. Our task has been to critically assess the evidence presented and determine from the record whether the proposed acquisitions will accomplish our underlying objective.

With regard to the Seabrook project, we have found that it is a viable undertaking and that PSCO will be able to complete it at a reduced ownership interest of approximately 35 percent. Implicit in this determination is the finding that the project represents a particularized and well defined future source of generation capacity. Moreover, with regard to the ability to finance, we have found that Fitchburg and New Bedford can meet the financial commitments of the full ownership interests requested in their petitions and that Montaup can meet the additional financial burdens given an interest less than that proposed.

We have also found that each of the Massachusetts petitioners has shown a need for significant amounts of capacity to satisfy future consumer demand. The reader has perhaps gleaned from the demand sections of this decision that forecasting future energy needs for a utility is not a simple undertaking. As we noted in Section II, inferential chains in the forecasting process are interdependent, extremely long, and ultimately rely upon the application of informed judgments at each link. In reviewing the various need for power claims we have, thus, carefully considered all of the projections and where appropriate applied our own expertise in assessing the significance of data furnished by the parties. If in this process we have appeared conservative in our approach, this conservatism proceeds from our judgment that, from a planning perspective, it is generally prudent to view the upper limits of estimated growth and system capacity requirements as deserving somewhat greater weight than the lower limits. Within the context of our review of the investment decisions as proposed and approved herein, the consequences of some modest future excess capacity are far less severe than those flowing from insufficient capacity. As a Federal Power Commission witness explained in a case involving similar forecasting issues:

> The consequences of insufficient reserve are manifold. It can lead to small scale interruptions or widespread blackouts, affecting a few individuals or leading to situations affecting the health, safety, and economic well-being of large numbers of people. The life of individuals dependent upon iron lungs, artificial kidney machines, and other life sustaining equipment will be endangered. Manufacturing activities involving electric heating, constant temperature conditions, and electric drive and controls will be interrupted, with possible spoilage of work in process.

> Other manufacturing activities will be interrupted but may suffer no more than loss of time and the losses that accompany unscheduled stoppages. Nine Mile Point, supra at 364, fn. 57.

In order for each of the Massachusetts petitioners to satisfy their demonstrated future power needs, we have found that the acquisition of additional ownership interests in the Seabrook project is, for these companies, the most viable option which can be relied upon at this time in planning future system requirements.

In our decision, we fully discuss many other energy sources which have been proposed as possible alternatives to Seabrook. The petitioners have shown that some of these alternatives, for example, oil and gas fired units, do not offer less costly power. Independent of cost, we are also concerned about the future assured stability of petroleum supplies. In light of petitioners' already principal reliance upon fossil fuel dependent capacity, the inclusion of additional nuclear capacity in their system mixes further offers obvious diversity advantages.

For other asserted alternatives, such as solar and wind power, independent power production, and cogeneration, the record indicates that none of these presently represents a source which offers, when compared to Seabrook, the same degree of certainty for meeting the demonstrated capacity needs of petitioners. Recognition must be given to the simple fact that firm commitments must be made today for definite quantities of power in order to assure anticipated future demand. These companies cannot base their present planning responsibilities upon alternatives which only offer at this time the potential that their widespread application and further development may become quantifiable sources of power in the future.

While we have found that many of the asserted alternatives presently involve too many unknowns in terms of likely availability, production characteristics or cost to substitute them for additional capacity in the Seabrook project, these alternative sources of capacity or load reduction may well become more viable, cost effective or certain in the future. Therefore, our determination here should not be construed as a diminution of our continued support for the development of alternative technologies and energy saving strategies.

Moreover, we would once again express our interest in seeing that the region's hydro potential is fully utilized. The advantages of additional hydro capacity in the petitioners' system mixes is amply set forth earlier in our discussion. As noted therein, however, we view this source of power as complementary to Seabrook capacity rather than as a substitute for it.

In closing, we would note that, although we have commented that partial deferral of the project's in-service dates would have a positive impact upon petitioners' cash flow positions, we do not feel delay is in anyone's best interest. Without delay, the project is demonstrably less expensive by significant amounts to both petitioners and the consumers they serve. In this instance, the tension between the provision of reliable future capacity at the lowest cost and the strict adherence to financially conservative income and balance sheet criteria appropriate for ordinary times should be resolved in favor of the least costly provision of capacity. The recent forces which have been impinging the electric utility industry are clearly extraordinary when viewed from the perspective of the days when the Department could order reductions in rates subsequent to expansion of capacity.

VIII. ORDER

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

ORDERED: That the acquisition by Montaup Electric Company of a 1 percent interest in the Seabrook project from Public Service Company of New Hampshire and the terms of said acquisition are hereby found to be consistent with the public interest, and the joint petition of Montaup Electric Company and Public Service Company of New Hampshire docketed as D.P.U. 20055 requesting approval of said acquisition and the terms thereof is hereby approved; and it is

FURTHER ORDERED: That the acquisition by Montaup Electric Company of a 1.03542 percent interest in the Seabrook project from Connecticut Light & Power Company and the terms of said acquisition are hereby found not to be consistent with the public interest, and the joint petition of Montaup Electric Company and Connecticut Light & Power Company docketed as D.P.U. 19738 requesting approval of said acquisition and the terms thereof is hereby disallowed; and it is

FURTHER ORDERED: That the acquisition by Montaup Electric Company of 1.06469 percent interest in the Seabrook project from United Illuminating Company and the terms of said acquisition are hereby found not to be consistent with the public interest, and the joint petition of Montaup Electric Company and United Illuminating Company docketed as D.P.U. 20109 requesting approval of said acquisition and the terms thereof is hereby disallowed; and it is

FURTHER ORDERED: That the acquisition by Fitchburg Gas & Electric Light Company of a 0.4349 percent interest in the Seabrook project from Connecticut Light & Power Company and the terms of said acquisition are hereby found to be consistent with the public interest, and the joint petition of Fitchburg Gas & Electric Light Company and Connecticut Light & Power Company docketed as D.P.U. 19743 requesting approval of said acquisition and the terms thereof is hereby approved; and it is

FURTHER ORDERED: That the acquisition by Fitchburg Gas & Electric Light Company of a 0.2609 interest in the Seabrook project from Public Service Company of New Hampshire and the terms of said acquisition are hereby found to be consistent with the public interest, and the joint petition of Fitchburg Gas & Electric Light Company and Public Service Company of New Hampshire docketed as D.P.U. 72 requesting approval of said acquisition and the terms thereof is hereby approved; and it is

FURTHER ORDERED: That the acquisition by New Bedford Gas & Edison Light Company of a 2.1739 percent interest in the Seabrook project from Public Service Company of New Hampshire and the terms of said acquisition are hereby found to be consistent with the public interest, and the joint petition of New Bedford Gas & Edison Light Company and Public Service Company of New Hampshire docketed as D.P.U. 20055 requesting approval of said acquisition and the terms thereof is hereby approved, subject, however, to the condition that New Bedford Gas & Edison Light Company transfer said interest in the Seabrook project to Canal Electric Company at such time as New Bedford Gas & Edison Light Company may acquire said interest.

By Order of the Department,

/s/ DORIS R. POTE

Doris R. Pote, Chairman

/s/ JON N. BONSALL

Jon N. Bonsall, Commissioner

/s/ GEORGE R. SPRAGUE

George R. Sprague, Commissioner

Commissioners participating in decision of D.P.U. 19738, D.P.U. 19743, D.P.U. 20055, D.P.U. 20109, and D.P.U. 72 were: Chairman Pote, Commissioner Bonsall and Commissioner Sprague.

A true copy;
Attest:

CHRISTOPHER C. RICH
Secretary

Appeal as to matters of law from any final decision, order or ruling of the Commission 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 Commission be modified or set aside in whole or in part.

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