COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 19845

RE: Investigation By The Department
Upon Its Own Motion As To The
Propriety of the Response By the
Boston Edison Company to D.P.U.
18810 Regulations 5, 6 and 7
Filed on December 6, 1978

JOINT TESTIMONY OF
PAUL L. CHERNICK AND SUSAN GELLER
ON BEHALF OF
THE ATTORNEY GENERAL

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I. INTRODUCTION AND STATEMENT OF QUALIFICATIONS

Q: Mr. Chernick, would you please state your name, position, and office address.

A: My name is Paul Chernick. I am employed by the Attorney General as a Utility Rate Analyst. My office is at One Ashburton Place, 19th Floor, Boston, Massachusetts 02108.

Q: Please describe briefly your professional education and experience.

A: I received a S.B. degree from the Massachusetts Institute of Technology in June, 1974, in Civil Engineering and a S.M. degree from the same school in February, 1978 in Technology and Policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, to membership in the engineering honorary society Tau Peta Pi, and to associate membership in the research honorary society Sigma Xi. I am the author of <u>Optimal Pricing for Peak Loads and Joint Production: Theory and Applications to Diverse Conditions</u>, Report 77-1, Technology and Policy Program, Massachusetts Institute of Technology. During my graduate education, I was the teaching assistant for courses in systems analysis. I have served as a consultant to the National Consumer Law Center for two projects: teaching part of a short course in rate design and time-of-use rates, and assisting in preparation for an electric time-of-use rate design case. My resume is attached to the end of this testimony as Appendix A.

Q: Have you testified previously as an expert witness?

A: Yes. I have testified jointly with Susan Geller before the Massachusetts Energy Facilities Siting Council and the Massachusetts Department of Public Utilities in the joint proceeding concerning Boston Edison's forecast, docketed by the E.F.S.C. as 78-12 and by the D.P.U. 19494, Phase I. I have also testified jointly with Susan Geller in Phase II of D.P.U. 19494, concerning the forecasts of nine New England utilities and NEPOOL, and jointly with Susan Finger in Phase II of D.P.U. 19494, concerning Boston Edison's relationship to NEPOOL. I also testified before the E.F.S.C. in proceeding 78-17, on Northeast Utilities' forecast, and in proceeding 78-33, on Eastern Utilities Associates' forecast. Most recently, I testified jointly with Susan Geller before the Atomic Safety and Licensing Board in Boston Edison Co., et. al, Pilgrim Nuclear Generating Station, Unit No. 2, Docket No. 50-471 concerning the "need for power".

Q: Ms. Geller, would you please state your name, position and office address.

A: My name is Susan Geller. I am employed by the Attorney General as a Utility Rate Analyst. My office is at One Ashburton Place, 19th Floor, Boston, Massachusetts 02108.

Q: Please briefly describe your professional education and experience.

A: I graduated from Harvard University in June, 1974, with a B.A., magna cum laude, in Economics. In addition, I have a Master's Degree in Public Policy from the John F. Kennedy School of Government, Harvard University, and I have completed the course requirements and passed the qualifying examinations for the Ph.D. in Public Policy. My work experience includes: (1) a summer internship at the Atomic Energy Commission where I collected and analyzed data for the Nuclear Reactor Safety Study (the "Rasmussen Study"); and (2) a research assistantship at the Harvard Business School where I helped prepare a seminar for business executives and public officials on the problems of producing electric power for New England (summer, 1974). My resume is attached to the end of this testimony as Appendix B.

Q: Have you testified previously as an expert witness?

A: Yes. I testified jointly with Paul Chernick in Phase I of D.P.U. 19494 and in E.F.S.C. 78-12, in Phase II of D.P.U. 19494 and in N.R.C. 50-471, as described above. I have also filed expert testimony in two cases before the Massachusetts Energy Facilities Siting Council, in cases involving long-range forecasts of New England Gas and Electric Association (E.F.S.C. 78-4), and Massachusetts Municipal Wholesale Electric Corporation (E.F.S.C. 78-1). One of these cases was decided without full evidentiary hearings; as a result, I was cross-examined only in the NEGEA case.

Q: Would you please summarize the subject matter of your testimony?

A: Yes. We cover the following topics:

1. Our rationale for recommending marginal cost pricing as the basis for time-of-use rate design.
2. General principles and implications of marginal cost pricing for time-of-use rate design.
3. A critique of Boston Edison Company's derivation of time-of-use rates.
4. A critique of the Gilbert Management Consultants' Long Run Marginal Cost Study.
5. A presentation of marginal-cost based rates and their derivation.

II. THE RATIONALE FOR MARGINAL COST PRICING

Q: Do you believe that marginal cost pricing should be the basis for the design of time-of-use rates?

A: Yes. Time-of-use rates (and other utility rates) should be based, as much as possible, on marginal costs. While application of this principle is somewhat limited by problems of definition, uncertainty, equity and technical/administrative feasibility, marginal cost pricing remains the fundamental guiding principle for rate design.

Q: Please explain why you believe that marginal cost pricing should be the guiding principle in ratemaking.

A: The purpose of time-of-use pricing is to convey to the customer the costs of producing electricity as they vary with the time of day and season of the year. Marginal cost pricing provides the proper pricing signal. Under marginal cost pricing, the customer will choose the quantity of kwh such that the "value" (or cost) to the consumer of purchasing (or of foregoing) an additional unit of electricity will just equal the cost of the resources which the utility company will use to produce (or save in not producing) that extra unit of electricity. The consumer's choice of whether to forego or defer additional kwh usage involves more than a determination of the level of usage of existing appliances and equipment. Electricity consumption also depends on decisions about capital investments. The price of electricity figures in the selection of appliance and equipment type, fuel source, size and efficiency. Price is also an important consideration in the customer's decision to make energy-saving and energy-producing investments, including insulation, load control, solar water and space heating, energy storage, and cogeneration. In short, unless rates are designed to reflect marginal cost, investments that could save or produce energy at a lower cost than Boston Edison can produce it will not be made. Marginal cost pricing encourages efficient use of resources.

Q: Please explain why you qualified your endorsement of marginal cost pricing.

A: The application of marginal cost pricing principles will, of course, require approximations and a certain degree of judgment. The value of marginal cost pricing is that it provides a framework for objectivity and a standard for evaluation. The appropriate rate design is the one that accurately signals to the consumer the causal connection between additional kwh usage and resource costs. Since the purpose of marginal cost pricing is clear, the terms of a debate about particular rates are also clear. Prices are "right" if they reflect marginal costs; all that is left is to estimate marginal costs. If the rates must deviate from marginal costs to meet revenue constraints, the objective is still clear: where possible, rate adjustments should avoid altering customer behavior from what it would be under marginal cost prices.

The embedded cost method does not provide a comparably rational framework. The choice of one allocation method over another does not depend on any analysis of the direct causal relationships between consumption and cost, so there is no objective standard by which to judge allocations. Yet, the results of cost of service studies are highly sensitive both to the allocation method and to the assumptions about the load patterns of the various customer classes.

In the case of BECO's proposed time-of-use rates, there is no coherent methodology behind the rate design. BECO's rates are not based on any systematic consideration of time-differentiated cost, so there is no basis for judging the rates against their authors' objectives. In a later section of our testimony, we identify several logical errors and inconsistencies in BECO's workpapers. However, because BECO provides no basis by which to judge the appropriateness of the final results, we cannot say that the correction of these errors will result in "better" rates, even by BECO's standards. We can, however, compare BECO's proposed rates to socially efficient marginal-cost rates, to assess the former's deviations from optimality.

III. GENERAL PRINCIPLES OF MARGINAL COST PRICING

Q: What general principles of rate design can you draw from marginal cost pricing?

A: There are a number of general principles.

1. While local company conditions are occasionally relevant, most rate design considerations should be based on NEPOOL costs, because:

   a. NEPOOL is dispatched as a single system,

   b. NEPOOL determines reserve margins on a pool-wide basis, and

   c. the New England transmission net is integrated and controlled by NEPOOL.

Designing rates from the point of view of the utility company in isolation will reduce the benefits of peak load pricing. In fact, if the summer peaking companies design their rates to encourage winter consumption, and winter-peaking companies encourage summer consumption, the NEPOOL system may end up with even higher capacity needs than they would have had in the absence of peak load pricing.

Designing rates on an individual company basis would result in the following nonsensical situation. BECO customers and their neighbors in the Massachusetts Electric Company's service territory will be served by the same generating facilities and transmission lines; yet the BECO customers will be on a low winter rate when the Massachusetts Electric customers are on a high rate, and vice versa in the summer.

Unfortunately, NEPOOL's capability responsibility formula assigns too much of the capacity requirement to the participant's own peak. We suggest that Boston Edison work with the other NEPOOL members to design a formula which will be consistent with efficient ratemaking.

2. Peak demand is not the primary determinant of capacity-related costs, for several reasons. First of all, capacity is installed to meet a reliability criterion, which is directly affected by many hours of high demand.

Second, the cost of capacity actually installed is determined by the expectation that the capacity will be used more than once per year (or month), so utilities build more durable and efficient facilities than they would provide to meet just peak.

Third, capacity is also installed to accomodate maintenance requirements, which are affected by demand in off-peak weeks and even weekends. In a deterministic system, new capacity may be required by either of two conditions:

1. current capacity is inadequate to meet peak load, or

2. current capacity is adequate to meet peak, but the need for scheduled maintenance of facilities would cause current available capacity to be inadequate in some months.

In a stochastic system, with random plant availability and random demand variation, both constraints may be partially binding. For NEPOOL, the second constraint appears to be more important, and will presumably increase in importance if the plans for construction of large nuclear units, with large maintenance requirements, continue.

These two types of capacity-constraints are illustrated in Figure 1. The system functioning at point A (3300MW peak, 1600MW average monthly peak demand) is peak constrained, since 3300MW are required to meet peak, but only 2000MW are required to meet average monthly peaks. The system functioning at point B, (2600MW peak, 2400MW average) requires 3000MW to meet average demand, but only 2600MW to meet peak demand, and is therefore maintenance-constrained. The solid lines in Figure 1 represent the maximum levels of peak and monthly average demand which can be met by various amounts of 100% reliable capacity/ which requires maintenance 20% of the time. It is further assumed in this illustration that the maintenance can be performed in as small units (of time and MW's) as necessary.

FIGURE 1

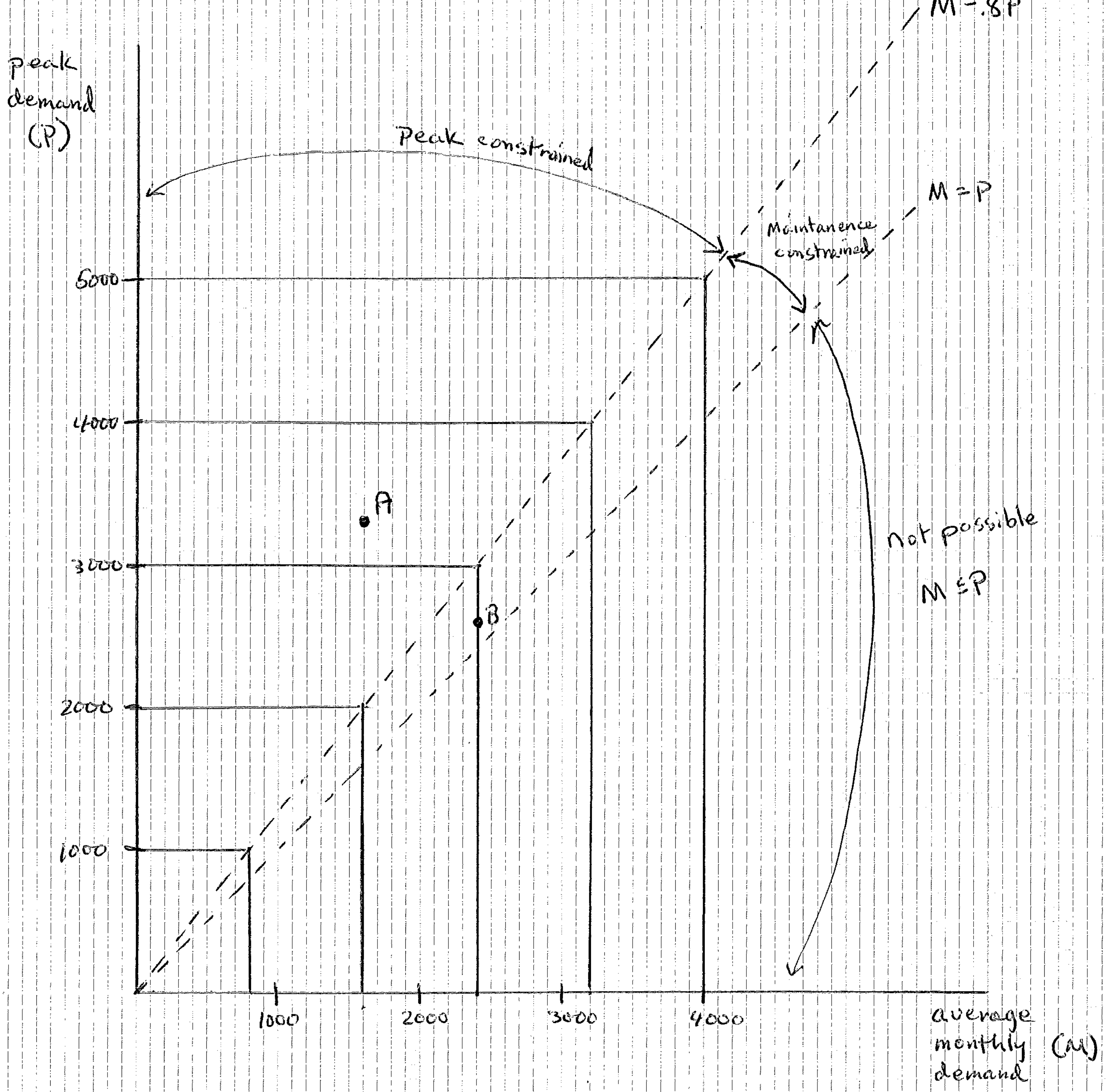

Figure 1: Peak-constrained and maintanenee-constrained Systems

3. Demand charges are clearly unsatisfactory ways of recovering capital costs. Costs related to consumption by all customers (e.g., generation, transmission interconnection) or large groups of customers (e.g., logical transmission, distribution) can be captured by time-of-use rates, or even better by responsive peak rates, but not by demand charges. Demand charges have three major flaws in this regard:

a. Demand charges do not inherently vary with external conditions any better than energy charges.

b. Demand charges are zero for all points in time during which demand is less than a previously established (or forecast) demand in the billing period. (With some of BECO's proposed rates, ratchet provisions effectively make the billing period <u>an entire year</u>.) As a result, demand charges provide no incentive to conserve at those times which are off the customer's peak but which are very much on the utility peak. And if a large portion of the revenue requirements are allocated to the demand charges, the importance of the energy charges is diminished.

c. With demand charges, it may be cheaper for customers, by load shifting, to use more energy in the utility's peak period while cutting their individual peaks. One such customer might find it advantageous to limit loads to 5MW throughout BECO's peak (say 11 a.m. to 5 p.m.), rather than using 6MW for the hour from noon to one p.m. and 3 for the rest. If other customers similarly avoid peaks at the other hours, the result is an average use of 5MW per customer, rather than 3.5MW, throughout the peak period, <u>due to the demand charges.</u>

A different type of cost is incurred when facilities are first provided to allow a customer to draw a certain amount of power. These costs do not vary with the customer's actual demand, but with the demand to which the customer wishes access. Therefore, the costs should be recovered through hookup or customer charges which respond to access, rather than to use. Therefore, there is no class of costs for which demand charges are appropriate, at least for large customers. It is possible that demand charges would be useful for selected smaller weather-sensitive customers for whom responsive rates are still too expensive to administer, but who are large enough to justify demand meters. However, a careful analysis of the efficiency tradeoffs between peak-period energy charges and demand charges would be necessary to demonstrate the superiority of the latter.

4. Any departure from marginal cost pricing, such as adjustments to prevent over-collections, should be accomplished in a manner that least distorts consumer choice; that is, by adjusting charges where demand is least elastic. Customer charges (or other infra-marginal charges) are the appropriate charges to be reduced in the situation of over-collections. Customer charges for basic services do little to maintain efficient allocations, since there is little or no price elasticity for access to electricity. In addition, from the point of view of marginal cost pricing, the determination of the customer component is largely arbitrary. The minimum distribution network is largely a joint, unallocatable, intramarginal investment which is basically a fixed cost of serving an area, rather than individual customers. To put it another way, removal of customers at random from the system has little impact on the distribution cost, other than services, meters, and associated O & M.

The additional costs of providing greater-than-normal service may be reasonably charged in a customer charge, even if basic costs are not. However, the assymetry of customer-related costs (expensive to connect, of little value to disconnect) decreases the allocative value of customer charges.

If reducing the customer charge to zero does not eliminate the excess revenue collection, the next best solution would be to lower the energy charge on an infra-marginal block, for example, the first 100 kwh of the rate P customer's bill. If it is necessary to alter the rate design more drastically, economic efficiency arguments support "the inverse elasticity rule": across classes and across time periods, variable charges should be altered in inverse proportion to the elasticity of demand with respect to price.

5. The ratio of the peak energy charge to the off-peak energy charge is not an adequate measure of the appropriateness of a rate design. The arithmetic difference is an important determinant of the incentives to shift time of use. It is the difference, not the ratio, that determines the customer's savings from a given kwh shift.

Moreover, the objective of time-of-use rate design should be not only to encourage load shifting but also to promote control of non-deferrable loads. Therefore, of course, the absolute magnitudes of the energy charges matter also. Accomplishing a high ratio of peak to off-peak charges may require too high a peak price and too low an off-peak price. It would be economically inefficient, for example, if an artifically low off-peak energy charge encouraged customers to switch from gas or oil home heating to off-peak electric heating, thereby using more fossil fuel.

IV. CRITIQUE OF BOSTON EDISON COMPANY'S DERIVATION OF PROPOSED TIME-OF-USE RATES

Q: What is your understanding of the source of BECO's proposed TOU rates?

A: BECO's rates were not designed through any analysis of time differentiated costs. In particular, the rates are not based in any direct and consistent way on the Gilbert Cost-of-Service Study.

According to the "Response to D.P.U. 18810 Regulations 5, 6, and 7": the "Cost of Service Study was used to determine as many prices as possible for this [Rate P] and other TOUR consistent with the revenue requirements..." This statement is a misrepresentation of the way BECO used the Gilbert Study. BECO certainly did not use the Gilbert study for "as many prices as possible". The revenue requirements cannot prevent BECO from using Gilbert's results, because Gilbert's rates were also calculated to satisfy class-by-class revenue constraints. Yet, of the many rate parameters for all of the TOU rates to be determined, only the customer charge is derived with any consistency from the Gilbert study. Even then, the Gilbert estimates were "fine-tuned" or adjusted by BECO, and in the case of rate T-2, the Gilbert estimate was rejected in favor of Gilbert's estimate for T-3 customers. Moreover, the results of the Gilbert study are actually inconsistent with BECO's rates. The Gilbert study recommends much higher peak charges and lower shoulder charges (Gilbert allocates almost all of the capacity costs to the summer peak.)

Q: Then how were Boston Edison's TOU rates derived?

A: The values for the rate parameters are drawn from a variety of sources, with no apparent rationale for or method behind the choice. Furthermore, in estimating a parameter that is common to several rates, the company frequently employs a different source for each rate.

The sources of parameter estimates, in addition to the Gilbert study, include:

(a) kwh charges under current rates

(b) an average price per kwh for some number of kwh purchased under an existing rate (in the case of rate SP)

(c) some relationship between two current rates (for example, the derivation of TOU rate T-2 from T-3 by applying a "difference" between current rates G-2 and G-3)

(d) components or ratios of components of optional TOU rates

(e) parameters derived for other mandatory TOU rates

(f) algebraic resolution from revenue constraints.

Table 1 summarizes our understanding of the sources of the various rate parameters for four of the TOU rates.

TABLE 1: SOURCES OF BECO'S TOU RATES

Rate	Customer Charge	Off-Peak Energy Charge	Winter and Summer Shoulder Energy Charge	Peak Energy Charge	Capacity Charge
P	Gilbert Cost of Service Study, p. 32-1, 11/15/78	Cost of Service Study - average of summer and winter off-peak charge, adjusted upward to compensate for revenue losses due to kwh shifts	Existing Rate B: ¢ per kwh in the second-to-last energy block	Algebraic resolution of revenue constraint	-------
P-1	Cost of Service Study (with adjustment)	Rate P's off-peak charge (includes adjustment for rate P customers' kwh shifts)	Algebraic resolution of revenue constraint with summer/winter differential from rate P + 0.02¢.	Rate P's peak charge	-------
P-2	Customer charge for Rate P	Same as above	Algebraic resolution of revenue constraint with rate P-1's summer/winter differential	Rate P's peak charge	-------
T-1	Cost of Service Study (with adjustment)	Same as above	? (Values from optional T-1)	Same as shoulder	? (Revenue constraint with adjustment for ratchet)

In the case of the T rates, BECO is apparently unable to locate or duplicate the T-1 rate worksheets, and the T-2 and T-3 worksheets are incomplete. They do not document the calculations described on pages 6 through 9 of BECO's "Response to D.P.U. 18810 Regulations 5, 6, and 7."

In general, Boston Edison presents no cost-based justification for the choice of the source, the derivation of a value from the source, and the basis for any adjustments. We suspect that no underlying rationale exists.

Q: Do you have reason to believe that BECO's rates are not cost-based?

A: Yes. First of all, the algebraic resolution of a revenue constraint is not an appropriate source for estimates of rate parameters. In order to have a cost-based rate, BECO should have derived all the rate charges from an analysis of time-differentiated costs, and corrected for any revenue over- or under-collection by adjusting the rates in a way that least distorts the pricing signal (as discussed earlier in this testimony).

BECO's other sources for estimates are not particularly reliable indicators of time differentiated costs. Present declining block rate structures have not been derived from any cost analysis, let alone a time-differentiated cost analysis. According to the testimony of Mr. Saunders in D.P.U. 19991, the then current rate structures were not cost-based. Indeed, according to Mr. Saunders, the rate redesign proposed in 19991 was an attempt to bring conventional rates more in line with peak load pricing principles. The optional TOU rates were derived prior to completion of the Gilbert time-differentiated cost-of-service study and appear to be based largely on the current rates as well.

Even the estimates taken from the Gilbert time-differentiated cost-of-service appear to be on shaky ground for at least three reasons. First, BECO relied on the preliminary results (dated November 11, 1978) of the study. There are substantial differences between the preliminary and final results (dated November 30, 1978). In particular, as we can see from Table 2, the customer components for some of the rate classes were altered considerably.

Table 2: Comparison of Customer Charges

	P	P-1	T-1	T-2	T-3	SP	Misc.
Gilbert Study preliminary results	6.37	13.61	25.42	52.10	97.29	4.81	3.93
Gilbert Study final results	5.50	12.80	23.54	33.68	40.93	4.75	2.40
BECO TOU rates	6.30	11.50	24.00	102.00	102.00	4.80	--

The preliminary version also makes the unlikely conclusion that the summer off-peak energy charge should exceed the winter shoulder charge. This error was corrected in the final version (see Table 3).

TABLE 3:

A COMPARISON OF BECO'S PROPOSED P AND P-1 RATES WITH RESULTS OF THE GILBERT TIME-DIFFERENTIAL COST OF SERVICE STUDY

	Customer Charge ($)	Summer Peak (¢/kwh)	Summer Shoulder (¢/kwh)	Summer Off-Peak (¢/kwh)	Winter Shoulder (¢/kwh)	Winter Off-Peak (¢/kwh)	Combined W & S Off-Peak (¢/kwh)
Rate P							
Gilbert Preliminary	6.37	20.078	4.089	1.793	1.337	0.636	0.928
Gilbert Final	5.50	17.932	2.766	0.990	2.104	0.975	0.979
BECO Proposed Rates	6.30	15.90	5.73	0.922* (1.06)	4.13	0.922* (1.06)	0.922* (1.06)
Rate P-1							
Gilbert Preliminary	13.61	29.990	7.573	2.102	1.321	0.747	1.201
Gilbert Final	12.80	29.791	5.541	1.25	2.229	1.265	1.260
BECO Proposed Rates	11.50	15.90	9.14	1.06	7.52	1.06	1.06

*Prior to adjustment for anticipated shifts in kwh usage.

Second, the results of the Gilbert study are not directly applicable to BECO TOU rate design, because BECO uses different customer counts in its rate calculations than Gilbert uses in the cost-of-service study. As Table 4 indicates these customer number assumptions differ substantially. Adding to the confusion, BECO presents different customer counts in Exhibit VI-1 from those used in the revenue requirements calculation for Table II-1 of its filing.

TABLE 4: A COMPARISON OF CUSTOMER COUNTS

Rates	BECO Revenue Calculations Worksheets		BECO Filing Exhibit VI-1		Gilbert Cost of Service Study p. 32-1	Calculations from BECO workpapers Response to D.P.U. 1-82
SP	427,908		417,711		438,471	438,471*
P	16,902)	38,551	39,030)	60,735	66,912	66,912*
P-2	21,649)		21,705)		-------	-------
SP-1	38,202)	44,728	39,039)	45,738	-------	-------
P-1	6,526)		6,699)		45,736	45,736
T-1	unknown		17,620		20,591	21,449*
T-2	1,400		1,350		3,017	3,017*
T-3	217		217		715	217
Misc.	?		?		5,799	5,799*
Total			543,371		581,601	

*double counts duplicate customers.

The discrepancies are partly the result of differences in customer classifications. Gilbert uses the customer classifications which BECO used in the workpapers provided in response to D.P.U. information request 1-82. BECO changed its own classification in the course of developing time-of-use rates. For example, BECO separated out the P-2 and SP-1 customers from the P and P-1 rate classes, respectively.

The discrepancies are also the result of error. Amazingly enough, Gilbert must have double counted customers with more than one meter. (Compare columns 3 and 4 in Table 4.) The P-rate customer count of 66,912 includes 26,937 duplicate customers (calculated from the above cited workpapers).

Whatever their source, these discrepancies will affect the applicability of the Gilbert study. It is probable that the estimates of the customer, capacity and energy components depend on the allocation of customers to rate classes. Because the Gilbert methodology estimates different values for each rate class, differences in customer classification certainly affect the applicability of the Gilbert results. Differences in customer classification also lead to differences in the allocation of kwh consumption among the TOU rate classes. There is no evidence of any attempt by BECO to modify the Gilbert results to take these differences into account.

Third, the selective use of the results of a cost of service study raises complications. To the extent that one cost component is dependent on the estimates of the remaining components, errors in the estimates of some components imply misestimatation of others. If BECO intends to use the Gilbert study selectively, yet claim the resulting rates are cost-based, BECO must be careful to maintain consistency and to ensure that the values which it uses are independent of the values which it finds unreliable. For example, if BECO disagrees with Gilbert's estimates of rate P's shoulder and peak energy charges, it should also be skeptical of Gilbert's estimate for the off-peak energy charge. BECO gives no indication that it has done an analysis to check the reliability of rate P's off-peak charge.

Q: Earlier in your testimony, you mentioned that BECO had made errors in the design of its rates. Please describe these errors.

A: There are a number of errors and inconsistencies in BECO's assumptions, calculations, and reasoning. We point out these errors to illustrate how little attention BECO paid to the design of the rates and to encourage more rational rate-setting methods in the future.

In general, BECO offers little or no justification for its selection of values for its rate parameters. The justification that BECO provides is inadequate and at times illogical. One example is BECO's justification of the use of the off-peak and peak energy charges calculated for rate P, for rates P-1 and P-2 also. The purpose is to "line up the rates for future merging." This rationale is quite weak, and it only explains why BECO would want similarities among the three rates. It does not explain the particular choice of rate design, such as the decisions to base all three rates on the P rate and to adjust the shoulder rates to the revenue constraint. If the merger is a serious possibility, then it would make more sense if BECO had first derived a cost-based rate for the consolidated rate group, and from that consolidated rate, tailored three separate rates to satisfy the revenue requirements for the P, P-1 and P-2 classes.

A second example is BECO's reliance on the summer/winter differential in existing rates to justify setting the winter shoulder energy charge lower than the summer shoulder energy charge. It would seem that consistency requires that this existing seasonal differential (if it is believed to be relevant) be applied to the difference between the average summer and average winter energy charges in the TOU rate, instead of the difference between the summer and winter shoulder charges alone. Correcting BECO's calculations for rate P-1 results in a winter shoulder charge that actually exceeds the summer shoulder charge, 8.28¢ and 6.34¢, respectively (subject to some round-off error).

A third example is BECO's frequent reference to the ratios among peak, shoulder, and off peak energy charges as an indication of the effectiveness of the rates. As explained earlier in our testimony, this measure alone is not an adequate indicator of the validity of a rate design.

The rate design and revenue requirements calculations are based on unreliable customer number and load data. The workpapers reveal the following calculational errors and unreasonable results:

(1) BECO's method of splitting the B-020 rate class in order to separate out the customers who are eligible for the P rate is simply incorrect. Both the number of customers and the kwh usage are underestimated. BECO estimates that the number of customers who will qualify for the TOU rate will be the <u>average</u> of the number of bills in the summer months, which BECO calculated to be 16,900 bills. But all customers with a use of 1000 kwh or more in "<u>any</u> month during the summer billing period" [emphasis added] are eligible for the TOU P rate. Therefore the customer number will be at least as great as the highest of the number of bills over 1000 kwh in a summer month. According

to the SP-1 workpapers (see response to information request AG-1-29), the customer number for the P rate should be at least 22,000, the number of August bills. The number will exceed 22,000 if there are additional customers with a greater than 1000 kwh use in some other summer month, but a lower than 1000 kwh use in the August billing period.

The kwh use is similarly miscalculated. It appears that the SP customers' summer kwh use was estimated by summing the kwh in all of the monthly bills that are less than 1000 kwh. Since some of the P customers will have some summer bills of less than 1000 kwh, the SP kwh figure includes some kwh use that should have instead been allocated to the P rate classes. The same error may have been made in calculating winter kwh use.

The validity of these class split calculations is particularly important because the SP, P, P-1, T-1, and T-2 rate classes consist almost entirely of portions of current rate sub-classes. Unfortunately, BECO has provided insufficient documentation by which to evaluate its general method for performing these splits.

(2) According to the workpapers, the BECO's SP-1 rate calculations are based on an assumption that, for the E-1 055 customers who would qualify for the SP-1 rate, the summer kwh use exceeds the total for the year.

BECO also made serious errors in their adjustment of rate P for anticipated shifts in the kwh use of rate P customers.

Q: How did BECO adjust rate P for anticipated shifts?

A: BECO assumed a loss of 10% of the peak kwh consumption, at 15.9¢/kwh, and a loss of 5% of the shoulder kwh consumption in both the summer and winter periods, at 5.73¢/kwh and 4.13¢/kwh respectively. BECO then increased the off-peak energy charge to recover the anticipated revenue losses.

Q: What is wrong with this adjustment?

A: The calculations are faulty on several grounds. First of all, BECO completely omitted the revenues that would be collected from the kwh shifted on to the shoulder period and the off-peak period. Thus, the calculations reflect anticipated conservation, not shifting. As a result of this error, the revenue loss calculated by BECO, $480,511, is overestimated by $139,080 or about 30%. However, this error was counterbalanced by an arithmetic error: in summing the revenue losses, BECO omitted the losses due to shifts off the summer peak, $262,986.

Second, the company provides no justification for applying all of the revenue deficiency to the off-peak rate. If BECO had approached the problem by first changing the underlying load assumptions, the deficiency would have been taken up in the peak charge (because the peak charge was determined through algebraic resolution of the revenue constraint). This inconsistency serves once again to point out the problems with BECO's non-systematic approach to rate design.

It is puzzling that only rate P was designed to take into account anticipated load shifting. It is even more puzzling that BECO believes that except for a "calculation error", the P-2 rate also takes into account anticipated load shifting. (See the Company's response to information request AG-1-60). The rate P-2 calculations were based on the pre-TOU rate, pre-shifting load assumptions. Rate P will overcollect unless the customers shift their consumption; rate P-2 will not.

Q: According to Table II-1 in the Company's filing, the proposed TOU rates will closely maintain the current revenue contributions of the existing sub-rate classes. Is this possible?

A: No, it is not possible. Under existing rate structures different rate classes face very different average prices per kwh. Maintaining revenues would require the designing of separate TOU rates for each current rate class.

Indeed, BECO's proposed TOU rates do not meet the revenue targets for every current rate class and sub-class, not as closely as Table II-1 suggests. Table II-1 is highly misleading. BECO has not documented the source of the sub-group revenue figures (despite DPU information request 1-82). BECO's workpapers present revenue calculations for each TOU rate class as a whole. If the SP-1 rate calculations are any indication, most of the subgroup revenues are merely backed out from the total revenue calculations.

Table 5 compares BECO's Table II-1 revenue figures for the SP-1 customers with our revenue estimates calculated from the disaggregated load data provided in BECO's SP-1 workpapers. (The SP-1 rate class is the only one for which this data is available). Note that the table omits the D041 and P241 customers; these customers were added to the SP-1 class after the SP-1 rates were derived.

TABLE 5
COMPARISON OF REVENUE ALLOCATIONS FOR SP-1 RATE SUBGROUPS

Sub rate class	BECO's Estimate	Our Calculation
G-1 011	10,231,509	10,176,569.95
016	30,560	28,169.882
013	11,201	16,916.215
A-1 110	116,641	138,439.305
E-1 055*	85,079	114,894.742*
	10,474,990	10,474,990.09

*Calculation incorporates BECO's assumption that total winter usage for these customers was negative.

Q: Do you have similar criticisms of BECO's derivation of the synthetic rates?

A: Yes. The purpose of a synthetic rate is to mimic (as much as possible) the aggregate effects of the corresponding TOU rate. Therefore, the energy charges in a synthetic rate should be derived as a weighted average of time-differential costs per kwh, weighted by the time distribution of kwh consumed, (or, if available, by the marginal distribution of kwh consumed as the energy price changes).

BECO's "synthetic" rates are not based in any direct and consistent way on a consideration of time-differentiated costs, nor on the TOU rates, and are thus not authentic synthetic rates at all. For example, if BECO's P-rate were "right" in some way, then the SP energy charges should be the weighted sum of the P-rate energy charges; and any revenue excess should be refunded through a lump sum credit, or a reduction in the energy charge in an infra-marginal block. Instead, BECO derived only the SP customer charge from the Cost-of-Service Study, and derived the energy charges from the current B rate (not the time-of-use P rate).

The SP workpapers reveal a haphazard process through which, after a number of trials and errors, BECO arrived at a set of energy charges that both satisfied the revenue constraints and seemed reasonable by some undisclosed criteria. According to the workpapers, BECO went through the following steps:

1. The structure of the rate was pre-set: two energy blocks in the summer, one in the winter.
2. BECO calculated the average price per kwh of 2.94¢ from the 350 kwh bill under current rates minus the proposed SP customer charge; and applied it to both the first summer block and the entire winter period.

3. Algebraic resolution of the energy charge for the second summer block resulted in too low a charge, 0.0407¢/kwh.
4. Therefore, BECO replaced the 2.94¢ with the average charge for a 300 kwh bill under current rates (minus the SP customer charge), 2.49¢
5. Algebraic resolution of the revenue constraint produced a second summer block charge of 5.67¢.
6. BECO replaced the 5.67¢ figure with 5.73¢ which is the energy charge in the second to last block in rate B (as well as the summer shoulder charge for TOU rate P).
7. Finally, the winter charge was lowered slightly to 2.47¢ to satisfy the revenue constraint.

The source of the SP-1 rate is even more obscure; we could not determine from the workpapers how the rate was derived.

As is the case with TOU rates, the rate design and revenue calculations are based on unreliable customer number and load data. In the case of the SP-rate, as discussed previously, BECO's method of splitting the B-020 rate class to separate out the customers eligible for the P rate is simply incorrect and results in an allocation of too many customers and too many kwhs to the SP rate class.

Q: Is the Controlled/Interruptible Energy Allowance for SP water heating customers a reasonable rate?

A: No. The Allowance does not fully credit the customer with the savings that accrue. It therefore provides too low an incentive to customers to opt for interruptible service. We have the following grounds for believing that the proposed credit understates savings: First of all, the $22/kw-yr is too low an estimate of the cost of additional capacity in the future. We estimate the cost to be about $53 per kw-yr (see Section VI of this testimony).

Second, the restriction of the credit to summer months and to kwh use in excess of 350 kwh limits a customer's savings to at most $13.00 per year (650 kwh/mo. x $.005 x 4 mo.). It appears from the workpapers that BECO assumes that controlling a water heater reduces capacity needs by 1 kw, producing an annual saving of $22 by BECO's own low estimate. Even if, as BECO wrongly assumes, it is only the contribution to summer peak that determines the need for additional capacity, then the water heating should be interruptible only during the summer months, but the customer should be credited with the full $22. However, since as we pointed out earlier, demand in the winter months also contributes to need for capacity, water heating should be interruptible (and credited) all year round. In any case, it should make little difference to the customer whether BECO pays the credit in four monthly credits of $5.50 each ($22 ÷ 4), or in 12 credits of $1.83 each, so long as the full credit is paid.

The placement of the credit in the second energy block is undesirable on economic efficiency grounds. Under BECO's rate design, the credit applies to all end uses, including non-off-peak, non-water heating usage. The credit applies to air conditioning load on the peak, for example. Transferring the credit to the first energy block is preferable; as a general principle, changing prices on an infra marginal block will cause less distortion in consumer consumption and investment decisions.

Q: Are the eligibility requirements for the Controlled/Interruptible Energy Allowance reasonable?

A: No. BECO restricts the credit to customers that have no other source of water heating. In particular, customers with solar water heating equipment do not qualify, because:

> [I]f the customer has solar water heating then the probability is that on a hot summer day there is no electric load associated with the equipment." (response to information request AG. 1-12)

In effect BECO has introduced an end-use type distinction based on the means of load control. A water heating customer on an interruptible rate will be penalized if he invests in naturally off-peak operating solar heating equipment. This discriminatory ratemaking contradicts

BECO's intentions to make rate structures more uniform by phasing out end-use distinctions and merging rates according to voltage levels.

Q: Are there any other examples of discriminatory ratemaking?

A: Yes. The No. 5 Special Off-Peak service charge inexplicably exempts off-peak thermal storage space heating, space cooling and water heating equipment from the calculation of the billing demand of T-1, T-2 and T-3 customers. If the T rates accurately reflected costs, there would be no reason to have any special provisions for off-peak equipment. There certainly is no cost-based rationale for singling out these particular end uses. It appears that BECO is attempting to institute promotional rates for off-peak space conditioning and water heating.

V. CRITIQUE OF GILBERT MANAGEMENT CONSULTANTS' LONG RUN MARGINAL COST STUDY.

Q. Does Gilbert appear to understand marginal-cost pricing theory?

A. No. In many places, the LRMCS does not analyze marginal costs at all; instead, average costs are frequently used. The "traditional theory of peak-load pricing" which Gilbert describes on p. 2 was obsolete seven years prior to the time the LRMCS was performed (Crew and Kleindorfer, 1971). The "recent arguments . . . [which] have cautioned against the blind application of this principle" (p. 2) appear to describe the shifting peak phenomenon, which was described and solved by Steiner (1957) two decades earlier, and has been repeatedly solved for more complex models in the intervening years (Chernick 1977, p. 221).

The lack of familiarity of Gilbert with current marginal cost pricing concepts, as illustrated above, casts serious doubt upon the validity of its LRMCS and the conclusions which it draws therefrom. Its LRMCS does not afford a reasonable basis for evaluating the desirability of marginal cost based time of use rates.

Q. Are there serious errors in Gilbert's LRMCS?

A. Yes. These errors can be divided into several categories:

1. Estimation of marginal generation costs;
2. Estimation of marginal transmission and distribution (T & D) costs;

3. Designation of periods;
4. Assignment of costs to periods;
5. Allowance for losses; and
6. Calculation of running costs.

Q. How does Gilbert estimate the marginal cost of generating capacity?

A. It uses two methods. Its first method, called "Long Run Incremental Cost" (LRIC), consists of weighting the costs of each planned generating unit by the kwh to be produced by that unit in the "planning horizon", which is arbitrarily taken to be ten years. This method is simply incorrect, since it places baseload capacity costs, most of which are related to providing cheap base-load running costs, on the peak period. Gilbert has made more subtle errors as well. Its three "marginal" units include one that is already on line (Wyman 4) and one which is being constructed as an experimental or demonstration unit (the fuel cell); neither of these units is typical of BECO or NEPOOL's response to changes in demand. Other NEPOOL plants are not even mentioned in the analysis even though those units are at least as marginal as the BECO units. The length of the planning horizon determines the share of the weighted average which is allocated to Pilgrim II; no rationale is presented for the ten-year limit.

The second generating-cost method Gilbert uses is the "Peaker Method", which assigns peaking unit costs to the peak period and ignores all other capacity costs. This is the correct pricing mechanism if either of the following two conditions apply:

1. All new non-peaking capacity is intra-marginal, and would be added regardless of any reasonable variation in demand, as an energy-saving measure, or,
2. pricing periods are optimally designed so that new non-peaking capacity causes savings in peak period running costs which approximate such capacity's capital cost to the periods in which it is marginal.

The explanation at the bottom of page 1 of the LRMCS indicates that Gilbert does not understand either the significance of the Peaker Method or its connection with optimal rate design. As a result it did not investigate the propriety of omitting all non-peaking capacity from the study.

Q. Does Gilbert correctly convert generation costs from dollars per KW installed to dollars per KW-year of customer charges?

A. No, for three reasons. First, costs are expressed in January, 1978, dollars, which were already ten months out of date when the LRMCS was written, and will be nearly three years old when time of use rates are first put in place. As a result, all capacity costs (including T & D) are understated.

Second, the carrying charges are incorrectly estimated. Instead of using real constant-dollar costs, Gilbert uses current-dollar charges to BECO rate payers, which include inflation. The effect of using inflated carrying changes is to increase the apparent annual cost of capacity. Levelizing the carrying charge in real terms would recognize the fact that utility accounting charges less for plants (in real terms) as they age; at 7% inflation, a 20-year old plant will only cost the rate payers about a quarter as much as it did in the first year, even if carrying charges are levelized in nominal (current-dollar) terms.

The third error which Gilbert makes in converting generation capital cost to charges per KW-year involves reserve margins. Gilbert simply increases all capacity charges by 20% to reflect current estimates of required reserves. This approach is simply incorrect. For each type of generating unit, based on unit size, forced outage rates (total and partial), maintenance requirements, and power pool characteristics, it is possible to calculate the amount of additional load which can be carried due to the presence of the unit; this additional load is the Effective Load Carrying Capacity (ELCC) of the unit. For large plants with high forced outage and maintenance rates, such as nuclear units, the ratio of ELCC to rated capacity (which ratio we call Effective Load Carrying Ratio or ELCR) is very low, while for small, reliable units (such as gas turbines) it is much higher. Ignoring these differences seriously distorts the relative value of various units, and therefore the prices which are appropriate in various periods.

Q. Are there any other problems in the Gilbert LRMCS' handling of generating capacity costs?

A. There is one striking contradiction with BECO policy. BECO apparently believes that large industrial and commercial customers are much more sensitive to generation and transmission outages than are residential customers (see Tr. p. 10811, DPU 19494, Phase II). Considering that small secondary customer service reliability is generally limited by distribution reliability, this may be a reasonable position. Nonetheless, BECO does not seem to have instructed Gilbert to assign extra generation and transmission costs to large customers.

Q. Did Gilbert properly relate transmission and distribution costs to demand?

A. No. Transmission and distribution (T & D) are included both in capital costs and in O & M expense, but Gilbert's analysis is laden with errors. In general, these errors involve failure to correctly measure costs, failure to identify causality, and failure to consider marginal relationships.

One of Gilbert's fundamental problems is that the LRMCS overlooks the fact that a portion of T & D capital costs (and the associated O & M costs) are area-serving in nature. Even if ninety percent of BECO's customers disappeared, a sizable portion of the company's rights of way, substations, poles, lines, and conduits would still be required; if even a single customer remained at the end of the distribution system, the entire system leading to that point would have to remain. There is an intra-marginal, joint, unallocable, fixed cost of serving an area, which is not responsive to marginal demand, energy use, or customer number. Gilbert assumes that all T & D costs vary directly, and linearly, with either demand or customer number.

Q. Please describe the particular errors in Gilbert's handling of transmission investment.

A. Gilbert completely fails to differentiate between the various purposes for which transmission capacity is added. This is epitomized by Gilbert's unrealistic statement that all transmission is generation-related (Exh. 4) and their equally unrealistic and contradictory assignment of all transmission to demand.

Presumably, BECO knows why it built, or plans to build, various transmission facilities. These reasons would include:

a. connection of generating facilities to the grid;

b. reinforcement of the grid to accommodate the load flows caused by new generation;

c. carrying power from existing generators to areas of expanding retail demand;

d. increasing reliability by upgrading or duplicating facilities;

e. duplicating facilities to allow for scheduled maintenance;

f. allowing increased economy sales (or unit sales or other sales of capacity) from BECO plants to other utilities;

g. allowing increased economy purchases from other utilities;

h. serving particular high-tension customers;

i. reducing losses, at peak or overall; and

j. wheeling power for others.

The costs of these various types of facilities are clearly due to different types of demand. For example, a line serving a marginal base-load generating plant may be either intramarginal or allocable to the base period, just as the rest of the costs associated with that base-load generator are allocated. The redundant line for maintenance may be required by peak monthly demand (in all months) in a portion of the service territory. And the upgrading for reliability may be due to an area annual peak which falls outside the annual peak hour or season, such as a residential area with a 6-8 p.m. winter peak. Therefore, a careful functional analysis should be performed to determine the sensitivity of transmission expenses to demands at various places and times. This would appear to be a very difficult task for anyone other than BECO or a consultant working closely with BECO.

Gilbert did not perform an engineering study of BECO's transmission system; instead they use average values of transmission investment per KW of peak demand growth and of transmission O & M per KW peak demand. The investment analysis is, in a limited sense, a marginal approach, since it compares changes in actual or projected peak demand and investment between 1968 and 1987. However, several aspects of the analysis appear to be seriously deficient.

1. Transmission investments are "net additions"; the subtractions are apparently in the dollars of the year of the original investment, rather than the year to which the cost index is applied. Therefore, if a 20-year old facility which originally cost $1,000,000,

but would cost $2,000,000 today, is replaced by a $3,000,000 facility, the real upgrading is $1,000,000, but on the books (and in Gilbert's analysis) it is recorded as a $2,000,000 increase. An engineering analysis would reveal that half the cost is due to replacement, and only half to load growth (or new generation, or whatever).

2. Gilbert did not correct for reclassification of equipment between transmission and other accounts (See, p. 7, LRMCS).
3. As previously noted, Gilbert made contradictory statements regarding the assumptions under which they assigned transmission investment. Both the "100%-generation" and "100%-annual peak" allocations are highly implausible.
4. The measure of peak demand utilized was territory peak, which omits partial requirements wholesale customers and other loads on peak. Therefore, the peak demand is depressed in the late 70's (by up to 270 MW) due to the departure of Reading and other municipals from the "territory" from 1972 to 1977, even though BECO's lines may have been carrying just as much power to the municipals as before. Due to NEPOOL dispatch, the nature of contractual arrangements (for example, between BECO and Reading)

has no impact on the physical source or flow of power.

5. No adjustments appear to have been made for transmission services provided by BECO to other utilities, or vice versa.

6. No attempt was made to determine whether any of the projected additions would be made, regardless of demand growth, such as to replace obsolete equipment, or whether any of the historical additions were, in hindsight, unnecessary (due to falling load growth, for example).

7. No distinction is made between geographical areas. Given the nature of BECO's service territory, it would not be surprising if increased demand in some areas (such as downtown) might be quite expensive to serve, while other areas (perhaps near major overhead transmission corridors) would be relatively cheap to serve, at least in terms of transmission. While the Commission may determine that it is in the public interest to sacrifice some efficiency to maintain geographical uniformity in rates, it should, at least, know the costs of serving various areas.

Gilbert finds (p. 7) that transmission additions per KW of territory demand were much higher in 1968-1977 than the values projected for 1978-87. At least two significant events occurred in the 1968-1977 period. The first was the formation of NEPOOL/NEPEX, which brought regional economy dispatch and, at least, nominally, regional generation planning, including joint ownership arrangements. Operation of a grid to serve New England may well have required extensive new transmission facilities, which are now largely complete. The second event was the increase in the size of generating plants and units. Wheeling these large blocks of power, and supplying backup for large units, would also have required new transmission facilities. No comparable changes in the dispatch region or in plant or unit size appear to be contemplated in the next decade; it would not be surprising if the rate of new transmission investment falls. Therefore, Gilbert's use of an average of historic and forecast values is suspect, at best.

Q. Do similar errors occur in the LRMCS analysis of transmission O & M?

A. Yes. Transmission O & M is not corrected or adjusted for any of the factors listed in connection with Transmission Investment. Furthermore, Gilbert uses an average 1977 O & M cost of $2.92/KW demand (again, with no credit for transmission used for non-territorial loads), rather than any estimate of marginal cost. Gilbert's justification for using the 1977 average value is that "historic plant investment rates are not indicative of the future and recent data indicates a stabilizing trend". In fact, the 1973-1977 least-squares linear fit indicates that total transmission O & M has been decreasing $29.35 for each KW added. Therefore, in our estimates of marginal cost, we have treated transmission O & M as a sunk intramarginal cost, independent of demand and energy output. This assumption, while reasonable, is not entirely accurate, since increased output, especially at high levels, probably increases O & M, as would transmission facilities added to accomodate new demand load and generators. On the other hand, large portions of O & M (maintaining rights of way, towers) do not increase as quickly as do the capacity of transmission conductors, since several conductors may share common facilities; and increases in demand (or capacity) in some periods or locations may prompt installation of additional transmission capacity, thereby decreasing the O & M which resulted from heavy loadings on existing and perhaps outdated equipment. These are issues which should be addressed in a serious analysis of the causation of transmission-related expenses.

Q. What problems occur in Gilbert's analysis of distribution investment?

A. It evidences many of the same errors which plague its study of transmission investment. Again, accounting net additions are used as the cost measure. Instead of using the correct constant-dollar net additions in the form:

(year t additions in 1978 dollars) - (year t retirements in 1978 dollars)

Gilbert uses

(year t additions in year t dollars) - (year t retirements in various years' dollars),

thereby greatly overstating real costs.

Gilbert also apparently assumes the minimum distribution system is customer-related, rather than area-related. This, and all other aspects of Gilbert's allocations between demand costs and customer costs, are based on an average-cost, embedded-cost study, not on any marginal analysis. This is a totally incorrect procedure. In addition, the assumptions and data underlying the embedded cost study have never been fully documented.

No recognition of any energy-saving, loss-reducing effects of distribution investment is evident. Nor does Gilbert distinguish costs by geographical area or type of service (overhead or underground). In short, Gilbert simply did not attempt to relate marginal distribution investment to the underlying engineering and economic considerations.

A closer look at the breakdown of "incremental" distribution investment (Exh. 6) indicates the shakiness of

Gilbert's estimates. For example, of the 1968-1977 increase in "Total Distribution Plant" 11.1% is due to the substation reclassification in 1972, while 14.8% is due to land, poles, and conduit, whose costs are clearly as related to serving area as to serving demand or customers.

Furthermore, the handling of meter expense (Ex. 19) indicates that Gilbert assumed all customers would be on time of-day rates, while BECO is proposing to leave the great majority of residential and small commercial customers (about 85% of each class) on inexpensive one-dial meters.

Q. Do similar problems arise in Gilbert's handling of distribution O & M?

A. Yes. In its handling of distribution O & M, Gilbert repeats both errors found in the distribution investment section (allocations on the basis of an undocumented, average-cost study, failure to recognize the existence of intramarginal cost, neglect of causality) and errors from the transmission O & M analysis (use of average values, rather than marginal values). Perhaps most remarkably, Gilbert recognizes that distribution O & M has been falling in a period of rising demand and rising customer number, but then proceeds to use 1977 average costs (based on arbitrary allocations to demand and customers) as a proxy for a marginal relationship which is apparently negative, or perhaps only weakly positive and declining over time.

Q. What errors occur in Gilbert's selection of time periods?

A. First, it does not appear that Gilbert actually selected the time periods that they use, for two reasons. First, the time periods are identical to those used in BECO's experimental TOU rates, which were submitted to the DPU on April 3, 1978, seven months before Gilbert sent the LRMCS to BECO. Second, Gilbert's quantitative results belie their purported conclusions.

Q. How does Gilbert claim to have determined the time periods used in their study?

A. The LRMCS mentions four methods which were examined. The first was average running cost, which was rejected because rising fuel costs and a prolonged outage of Pilgrim I distorted the pattern during the year examined. Of course, using marginal, rather than average costs; NEPOOL costs, rather than BECO costs; and simulated or adjusted costs, rather than actual costs, would all make the analysis more relevant, and generally more stable.

The second method Gilbert examined was NEPOOL LOLP data. Gilbert noticed that NEPOOL LOLP and BECO loadshape were not well correlated. Unfortunately, Gilbert chose to ignore the reality of the winter-peaking pool and to unrealistically regard BECO as an isolated summer-peaking utility (perhaps because BECO had instructed them to do so). As a result, no LOLP data was used in the LRMCS.

The third method involved an examination of hourly load profiles. Only some general, qualitative statements resulted from this analysis.

The fourth approach, which seems to be the only quantitative basis for selecting pricing periods, was the probability of exceeding peak (PEP) method (p. 5). This aspect of the analysis is so laden with errors as to nearly defy description. The errors include (but are not limited to) the following:

1. PEP is based on a completely arbitrary and inappropriate NEPOOL allocation formula (see testimony of A. Petrello, Exh. AG-45, pp. 10-13, and of S. Finger and P. Chernick, Exh. AG-43, p. 31, in DPU 19494, Phase II).
2. Hours which have little or no probability of exceeding peak nonetheless can contribute to the need for capacity by directly increasing LOLP, by decreasing time for maintenance, and by exhausting energy-limited capacity (e.g. hydro pondage).
3. NEPOOL, not BECO, is the natural unit for which capacity requirements are determined.
4. The importance of a particular BECO demand level varies within the year, depending on other NEPOOL participants' loads, other pools' loads, temperature-induced reductions in plant output and

transmission capacity, maintenance schedules, and hydro output.

5. PEP assumes a predetermined previous peak, when, for capacity planning purposes, peaks are stochastic (that is, random) in height and timing.

6. In addition to using the NEPOOL formula mentioned above, Gilbert misuses it. Thirty percent of the capability responsibility weighting is based on the average of 12 monthly peaks, which implies that peak demand in each month should have an equal weighting (for this purpose) and hours within the month should be weighted (by Gilbert's reasoning) on the basis of the hours' probability of being monthly peak. Instead, Gilbert inexplicably assigns the 30% weight to the probability of exceeding the average of the last 12 months' peaks, which concentrates responsibility on the peak months. The NEPOOL formula affords no special status to demands which exceed historic averages.

7. Gilbert also errs in applying the 70% and 30% weights to annual and average monthly peak. Capability responsibility is proportional to seventy percent of the participant's annual peak as a fraction of the sum of all participants' (forecast) annual peaks, plus thirty percent of the participant's average peak as a

percentage of the sum of such average from all participants (also forecast).

Since the sum of annual peaks greatly exceeds the sum of averages, the participant's annual peak is divided by a larger number than is the participant's average peak, so a MW of average demand is relatively more important than a MW of peak demand. In fact, for 1984-85 the actual weighting of annual peak will be about 2.02 times that of average peak, rather than the 2.33 implied by the 70/30 weight.

Q. Did Gilbert actually use the results of their analysis of PEP?

A. Amazingly, no. The months of June to September were chosen as peak months, but the LRMCS results in Exh. 1, p. 1, indicate that December, January, February and May make more significant contributions to the need for capacity than does September. In fact, the hourly weightings for May exceed those for September in every (non-zero) hour, those for December exceed September in all but one hour (of seven), and the total weight in the designated peak hours (10-4 EST) for January is twice that of the September peak period. In short, Gilbert's results suggest a three-month peak season of June to August, with a secondary peak season of December and January with, perhaps, some overlap into February and May; certainly, nothing like the period proposed.

Q. How did Gilbert assign costs to periods?

A. For generation costs, they used the PEP methodology, which is discussed above and which is just as inappropriate for assigning costs as for setting periods.

Transmission costs are allocated on the basis of a formula which weights a variant of the PEP methodology 50%, average demand 25%, and the number of hours in the period 25%. This allocation formula is basically illogical. Average demand should be multiplied by hours to measure base use, not added to hours. The method produces illogical results as well: if a period were divided into two similar halves, hours and PEP would be halved, but average demand would not change, and the two new periods would have a higher total weight than the original period. Splitting the summer off-peak, for example, would increase that period's transmission allocation from 8.85% to 11.62%. Clearly, the allocation process should yield the same results regardless of how periods are subdivided and reformed -- Gilbert's method is not invariant with respect to this change.

Distribution costs are allocated monthly on the basis of:

$$\frac{1}{1 - (\text{monthly peak} \div \text{annual peak})}$$

where the relative peak ratio is averaged over nine years. This formula very heavily weights months with peaks very near annual peak; in fact, if one month were always the peak month, it would have an infinite weight. To the extent that the distribution system is sized to minimize the combined cost of the distribution system and attendant losses (Mahoney, 1979) the weighting should follow the loss function, which is generally quadratic.

The monthly peaks used for the distribution allocation are not distribution system peaks, but generation-level system peaks, which include sales-for-resale and losses at the transmission level. The relevant mean peaks would be those of the individual distribution regions; after all, some substations (and other facilities) may experience their peak demands in January, due to space heating, while other peak in December, due to retail activity, and still others in the summer, due to air conditioning. Gilbert's allocation completely misses these differences, and may considerably underestimate the importance of the non-summer months.

The allocation is also sensitive to the definition of "year" used in Exh. 21. The use of calendar year places the summer peaks in the middle of the year, while a power year would put the peaks at the end of the year, and a June-May year would put the summer at the beginning of the year. Since general load growth increases the loads in whatever months are defined to be at the end of the year, the weightings will depend on the year used.

Distribution costs are allocated within months on the basis of extreme days, one in January and one in July. This method exaggerates the importance of the peak period by ignoring milder days in those months, all days in milder months, and weekends. Much less of the allocation would fall on the peak period if a typical cross-section of each pricing period were used in the study. It also seems a little odd that BECO did not simply apply this hour-specific data to the entire year, directly allocating distribution costs to hours, rather than employing the unnecessary and incorrect monthly allocation.

Q. What error does Gilbert commit in applying losses to cost estimates?

A. Gilbert's Loss Adjustment Factors appear to be based on average losses, not marginal losses. Furthermore, the average losses assumed are too low to explain BECO's actual losses, as demonstrated in Technical Appendix 4.

Q: Did Gilbert properly estimate marginal running costs?

A: No. For the LRIC study, Gilbert appears to use average, rather than marginal, costs. This is clearly an underestimate of the cost of increased energy consumption. The derivation of the average costs actually used is rather obscure (even the rank order of the period costs are counter intuitive), but apparently depends on the peculiar weighting process we discussed with respect to capital cost estimates. Gilbert's only justification for using this strange approach is the claim that:

> "to establish rate levels based on system lambda [marginal energy cost] would be to ignore the fuel savings resulting from the utility's choice of more efficient (and more costly) capacity." (P. 15)

This statement is simply incorrect. If new plants are responsible for fuel (and other) savings which exceed their capital costs, the net capital costs for rate design purposes are zero, and the plants should be built regardless of demand. No matter what happens to capital cost, the fuel saving due to a reduction in current consumption is essentially equal to system lambda, the most expensive KWH generated. In developing our rates, we properly apply fuel savings as a credit against nuclear capacity cost; Gilbert erroneously uses the running costs of new units directly, as if they were marginal energy costs, and never calculates any net savings value at all.

For the Peaker Method, Gilbert uses marginal energy costs and a basically correct approach, except that the cost data seems to be from 1977; costs will certainly be higher in 1980.

Q: Does the LRMCS contradict any of the other assumptions that BECO incorporated into their rates?

A: Yes. BECO assumes that their summer shoulder period rates should be higher than their winter shoulder rates. In contrast, the LRMCS indicates that average demand is higher in the winter shoulder than in the summer shoulder (Exh. 20), and that marginal energy costs are higher as well (Exh. 25, case B).

VI. DERIVATION OF MARGINAL COST - BASED RATES

The pricing methodology we use is a fairly simple one, following the results of Crew and Kleindorfer (1975). While we do not take certain factors into consideration, such as demand uncertainty, storage capacity, and shortage or rationing costs, (Crew and Kleindorfer 1976; Nguyen 1976), we include two factors which are generally not considered in the literature: generation reliability and a shadow price on oil use.

The model we use is basically:

(Eq. 1) $P_3 = b_3 + (B_3 \div E_3) \div (h_3 \times N_3)$

(Eq. 2) $P_2 = b_2 + (B_1 - S_1) \div [(h_1 + h_2) \times C_1]$

(Eq. 3) $P_1 = b_1 + (B_1 - S_1) \div [(h_1 + h_2) \times C_1]$

where P_1 = price in period i (before losses)

b_1 = operating (fuel) cost in period i

B_j = annual capacity cost per Kw of type j

S_j = savings due to increased capacity of type j

N_3 = load factor in period 3

C_1 = capacity factor of plant type 1

h_1 = hours in period i

E_j = effective load carrying ratio for capacity types

and,

(Eq. 4) $S_1 = (E_1 \div E_3) \times B_3 + (b_1h_1 + b_2h_2 + b_3h_3 - 8760d_1c_1$

where d_1 = operating cost of capacity type one

Further, the time periods (i) are: 1 base
2 shoulder
3 peak

and the capacity types are: 1 nuclear
3 gas turbine

A few words of explanation are in order regarding the formulation of the above-described model. The base, shoulder and peak periods were selected to match those in BECO's proposed rate structure (although the peak period is actually disaggregated by season in our proposal). Nuclear and gas turbine technology were selected as capacity types for several reasons.

1. These technologies appear to form substantial portions of the preferred expansion plans of BECO and NEPOOL.
2. While BECO appears to take combined cycle plants seriously for the 1990's, NEPOOL does not. Compared to the added effort involved in determining appropriate time periods, capacity centers, effective load carrying ratios, fuel costs, and the like, the benefits of adding a third marginal generation technology to our admittedly simplistic analysis seemed small. In a more comprehensive study, inclusion of combined cycle plants might be justified.

3. Pumped hydro capacity is favored by NEPOOL, but ignored by BECO. Clearly, the suitability of this peaking technology is influenced by the cost, reliability and quantity of baseload capacity installed and by the off peak demand/supply balance. The complications involved in modeling storage options would require considerably greater modeling sophistication than is warranted by the quality of data available in this case.
4. Neither BECO nor NEPOOL currently seems to believe that new coal capacity has any role in optimal expansion plans, although BECO's assessment of coal may be changing.
5. Alternative generation technologies (cogeneration, wind, hydro, etc.) may be cheaper than BECO's (or NEPOOL's) planned additions, but rates should be based on the actual economic impact of increased sales, not on the impacts which would occur under optimal utility policy. Therefore, we utilize only the technologies in which the utilities are currently interested. BECO is planning a 26 MW fuel cell, but this appears to be a demonstration project, rather than a serious portion of BECO's capacity plan.

Q: Please describe the significance of the equations which you presented above.

A: Eq. 1 simply states that the peak period price per KWH should equal the marginal running cost, plus a charge for peak capacity.

This peak capacity charge is simply the annual cost per KW of gas turbine, converted to KW of firm capacity by dividing by the Effective Load Carrying Ratio for turbine and divided over the hours of use per KW (the load factor) in the peak period.

Eqs. 2 and 3 simply state that KWH prices in shoulder and off-peak periods should equal marginal running costs in those periods plus the net annual cost of a KW of nuclear capacity, divided by annual nuclear output in the shoulder/off-peak period per KW of nuclear capacity.

Eq. 4 simply defines the savings due to a KW of nuclear capacity as the cost of gas turbine capacity (of equal load carrying capacity) displaced, plus the excess of present marginal running costs over nuclear running costs.

A. Derivation of Marginal Costs

Q: Please describe the process by which you calculated marginal costs from the equations you present, starting with your selection of pricing periods.

A: For purposes of achieving comparability with BECO's proposal, we use a six-hour peak period and a seven-hour shoulder period. However, we have extended the peak period to all months, in recognition of NEPOOL's maintenance scheduling needs. In order to reflect the different marginal energy costs in various parts of the year, we have somewhat arbitrarily designated the peak periods in two summer months, July and August, and two winter months, mid-December to mid-February, as ultra-peak periods. We have not otherwise altered BECO's selection of time periods; although we recognize that time periods should be based on NEPOOL-level marginal operating costs and capacity requirement effects, we do not have the data needed to set such appropriate time periods. From Exh. 20 of BECO's Long Run Marginal Cost Study (LRMCS), we find that the peak period consists of about 130 hours per month. Therefore, h_3 in the equations described above is about 1560 hrs/yr. (130 x 12). One third of this time (520 hours) would be in the four ultra-peak months. Similarly, 1824 hours of the year are shoulder hours (h_2) and 5376 hours are off-peak (h_1). One other parameter, the load factor in the peak period (N_3), is directly related to the choice of pricing periods. Inspection of BECO's current and forecast load duration curves (from their 1979 filings to the EFSC, and incorporated herein by reference), indicates that the load factor in the 1560 hours of the year with the highest demand is about 79%. Of course, peaking capacity would really be added to meet NEPOOL's load duration curve, which will be less steep than BECO's load duration curve; thus, the peak period load factor would tend to be higher. On the other hand, the definition of the peak period, as is necessary for rate design purposes, is not identical with the actual 1560 highest hours in any given year, so the peak period load factor for rate design purposes would tend to be lower than the actual peak period load factor. By way of comparison, it is interesting to note that BECO's designated summer peak period has a 76% load factor (1536 MW average from Ex. 20 of LRMCS, divided by the 2013 peak for 1977). In sum, we assumed a peak period load factor of 79%, which is subject to modification as better data becomes available.

Q: Please explain how the marginal energy costs were developed.

A: We simply updated the most recent data available to us to 1980 fuel prices. From BECO's response to the Commonwealth's Interrogatory 51 in the Pilgrim 2 construction permit case before the NRC (Docket No. 50-471), we estimated NEPOOL's marginal energy costs this spring as 35 mills in the peak/shoulder period, and 25 mills/KWH in the off-peak period. As explained in Technical Appendix 1, we then increased these costs by the ratio of BECO's oil prices in September to those in March, and added 15% to allow for oil price increases between September 1979 and late 1980, which we assumed would be the mid-point of the applicability of these rates.

Since there appeared to be no difference in energy costs between peak hours and shoulder hours in the spring, we used the same energy charge for both periods. To estimate the marginal energy cost in the ultra-peak periods, we assumed that the marginal supply of energy would be a gas turbine half of the time and an older, oil-fired steam turbine (such as Mystic 4, 5, and 6) half of the time. We then escalated BECO's September 1979 fuel costs by 15% to yield 1980 prices for each type of fuel and used the 1978 heat rates for the older Mystic units and the Medway gas turbine to derive average marginal generating costs for the ultra-peak. The details of this process are explained in Technical Appendix 1.

Q: What are your resulting estimates of marginal operating costs at the generator level?

A: We estimate marginal costs of:

3.7¢/KWH off-peak (b_1)
5.3¢/KWH shoulder (b_2)
5.3¢/KWH peak (b_3)
6.5¢/KWH ultra-peak (b_3)

at the generator level, before losses. As noted below, these costs are subject to a further adjustment to recognize the true cost of oil.

Q: Please explain how you derived the annual capacity costs?

A: For the gas turbine, we used two data sources for capital cost. From BECO Exh. BE-II-107 in D.P.U. 19494, we found a 1985 capital cost of $477/KW. Assuming that this value was based on 1978 costs, escalated at the 7% inflation rate implicit in the Exhibit, we de-escalated the cost to 1978 and then re-escalated it to 1980 at 12% inflation. This produced a 1980 cost of $373/KW.

From Exh. 2 of the LRMCS, we found that BECO estimated that a gas turbine would cost $361/KW in 1/1/78 dollars. Escalating at 8% for one year and 12% for eighteen months yields $462/KW in mid-1980 dollars.

The differences in capital costs in the two estimates are presumably due to different assumptions regarding plant size and site development costs. We assumed that an existing site will be used, but that the plant will consist of a series of small units (yielding some limited economies in joint facilities) and that the cost would be about $400/KW.

We then annualized the capital cost at a 10% real discount rate over an 18-year life, based on the 17.5 year life given in the D.P.U. 19494 Exhibit. The formula used for annualizing the cost is given in Technical Appendix 2; for an 18-year life it gives a 12.2% annual charge. Combining the above figures with \$4/KW-year O+M (from NEPLAN/GTF 1977) gives a total cost per KW-year of \$53, which is the value we use for B_3.

Q: Before you explain the derivation of nuclear capital cost, please elaborate on your choice of escalation rate, annualization method, and base year?

A: Based on recent trends, we assumed that inflation in 1979 and 1980 will average about 12%. This may turn out to be a bit higher than actual CPI inflation (especially on the basis of a mid-1978 to mid-1980 comparison), but construction costs have historically grown at a rate 2% greater than CPI inflation.

The choice of 1980 as a base year for calculating prices is simply predicated on the assumption that these rates are being designed for application in mid-to late-1980. If the application of the rates is to be delayed significantly, further inflation should be included, so that the electric rates are expressed in the same dollars as the prices paid for other goods.

For nuclear capital expenditures, we use real costs (in 1980 dollars) of a plant (Pilgrim II) which is scheduled to be on line around 1985. We selected this unit because it appears to be a bona fide marginal unit for BECO and NEPOOL; crucial decisions regarding its construction will be made in the next year, or so. We believe it is important that consumers, especially when making capital investments, face prices which reflect the real cost of their consumption and the utility's response. Using a cost of a hypothetical 1980 plant, for example, would not have reflected these real costs. For other capital costs, we have simply converted BECO cost estimates to 1980 dollars.

Q: Please explain your choice of a 10% real discount rate.

A: In the late 1960's and into the 1970's, in a period averaging around 5% inflation, large numbers of consumers accepted 18% interest on charge accounts, the common rule of thumb held that industrial investments averaged pre-tax returns of at least 20%, and consumer behavior in purchasing appliances implied a 15 - 25% discount rate (Hausman 1979).

These values imply real discount rates for these groups on the order of 10-15% or more. Since the borrowed funds used for utility construction would otherwise be likely to go to other industrial investment, the return on industrial investment is particularly relevant. On the other hand, not all the capital invested in utility plant is drawn from such high value investments. Some residential customers who have neither high-cost debts to pay off nor high-return investments available to them, and may be spending their money on the basis of a much lower discount rate than 18%. Some industrial and commercial concerns invest in projects with high private return, but low social return, perhaps because the investments (such as advertising or store layout) simply attract business from a competitor, rather than increasing the production of goods and services. Therefore, we use a 10% discount rate, which is both reasonable and round.

Q: Please explain how nuclear capacity costs were derived?

A: We identified four major components of nuclear capacity cost:

1. initial capital cost;
2. additions to capital cost (also known as interim replacements);
3. O & M; and
4. associated transmission costs.

We estimated the first, and largest, component from the statistical results of a study by Mooz (1977). We estimated capital additions, which includes on-going additions and replacements of portions of the plant (such as new or up-graded safety equipment) from actual Pilgrim I expense which was also the source of the O+M estimate.

Associated transmission costs are taken from BECO's testimony to the NRC. Details of these calculations are given in Technical Appendix 3.

Q: What values did you determine for the various components of nuclear capital cost?

A: We found the following costs (in 1980 dollars):

Initial capital cost	$3055/KW	or	$328/KW-year
Additions to capital cost			$ 40/KW-year
O & M (levelized)			$ 20/KW-year
Associated Transmission	$ 39/KW	or	$ 4/KW-year
Total:			$392/KW-year

Q: How were the reliability-related coefficients estimated?

A: In contrast to most theoretical work, which has simply assumed that all capacity is firm, we recognize that a MW of capacity will reliably support less than a MW of demand (at a given reliability level) and will supply considerably less energy than the product of capacity times the number of hours of demand. We will call the ratio of supportable demand to rated capacity the Effective Load Carrying Ratio (ELCR); the ratio of energy output to the product of rated capacity and time is the capacity factor.

For small units, such as 50 MW gas turbines, the ELCR is approximately one minus the outage rate when the unit is needed. From NEPOOL/GTF (1977), the equivalent forced outage rates for gas turbines is 10% and they require 2 weeks annual planned maintenance. Due to the small size, short maintenance period, and scheduling flexibility of the turbines, we assume that only half of their maintenance coincides with periods of capacity constraint, and that the ELCR equals 1-(.10 + 1/52) = 88%.

For large units, such as Pilgrim II, the ELCR is smaller than for small units. There are two basic reasons for this ELCR differential. First, large plants, and particularly nuclear plants, have longer maintenance requirements and higher forced outage rates than gas turbines, resulting in capacity factors of about 60% for larger nuclear units (see Easterling, 1978; Perl, 1978). Second, large units become unavailable in large lumps, so that the total available capacity of a system composed of large units varies randomly over time. Due to this variation, the system can reliably carry only the level of demand corresponding to the minimum (or very unlikely) level of available capacity, rather than the average level. For example, a system composed of three 1000 mw generators, each with a 10% forced outage rate, will be able to carry no load (all three generators being out of service) .1% of the time, or 8.76 days per year. A system composed of sixty 50 MW units of the same forced outage rate would be able to carry some load all but one time in 10^{60}, or less than a second in the life of the universe. While the large-plant system would carry 1000 MW or more 99.9% of the time, the small-plant system would carry 2300 MW 99.93% of the time.

We rather optimistically used an estimate of 65% for nuclear capacity factor and 50% for nuclear ELCR. This value is supported by NEPOOL Executive Committee (1977) which indicates a 44% ELCR for an 1150 MW nuclear unit; and by analogy with Kahn (1978), who derives a 47.50% ELCR for an 800 MW coal plant (70% the size of Pilgrim II) with a 19.7% forced outage rate, no maintenance constraints and total system capacity of 16,354 MW (69% of NEPOOL capacity before Pilgrim II's addition).

In summary, we use values of .88 for E_3, .5 for E_1, and .65 for C_1.

Q: In Eq. 4 you also introduce the parameter which represents nuclear operating costs. How did you estimate this parameter?

A: We simply deflated the last BECO estimate we had seen, of about .779 $/MMBTU (revised testimony on Need for Pilgrim II for NRC Docket 50-4-71) to 1980 at 6%, multiplied by 10510 BTU/KWH (GTF/NEPOOL 1977), to yield .6¢/KWH.

Q: Have you calculated the net cost of nuclear capacity?

A: Yes. From the preceding discussion, the components of net nuclear costs are:

B_1		392
$(E_1 \div E_3) \times B_3 = (.5 \div .88) \times 53 =$		(30)
$b_1\ h_1 = .037 \times 5376 =$	199	
$b_2\ h_2 = .053 \times 1824 =$	97	
$b_3\ h_3 = .065 \times 520 + .053 \times 1040 =$	89	
$8760\ d_1 = 8760 \times .006 =$	(53)	
SUB TOTAL	332	
$\times\ C_1 = 332 \times .65 =$		(216)
TOTAL		$146/KW-yr.

Q: How do these capital costs convert from dollars per KW/year to cents per KWH?

A: Applying the formulae in Equations 1 to 3, we find a peaking capital cost of:

$$53 \div .88 \div (1560 \times .79) = 4.9¢/\text{KWH}$$

and a nuclear capital cost of:

$$146 \div (7200 \times .65) = 3.1\text{c/KWH}.$$

However, we do not use this nuclear capital cost value.

Q: What value do you use for nuclear capital cost, and why?

A: We use only 1¢/KWH for net nuclear capital cost. While this particular value is judgmental, it is based on a reasonable consideration of a factor which we have omitted from our formal analysis of nuclear savings (S_1). The real cost of imported oil, as perceived by decision-makers at all levels, from BECO to the Congress, exceeds its posted price. This difference, this shadow price, results from varying factors, depending on the technical and value judgments of the observer, but it is composed of the expectation of rising real oil prices, of uncertainty in oil supply (due variously to actions of OPEC, nature, or the United States government), of adverse macroeconomic impacts from inflation and a negative balance of payments, of political and military repercussions of vulnerability to foreign suppliers, and of environmental and health costs (or the costs of pollution control) if tight oil supplies force utilities to burn higher sulphur oil. We have assumed that only 1¢ of the net nuclear cost (or $47/KW-yr.) is really attributable to providing capacity to the non-peak periods, and that the rest is due to an implicit shadow premium on oil consumption of 26% (or $99/KW-yr.).

Q: What marginal costs result from your assumption, and how sensitive are the estimated costs to that assumption?

A: Table 6 presents the energy and capacity charges under three nuclear cost interpretations: our preferred option (1¢/KWH, 26% shadow premium), no shadow premium (3.1¢/KWH), and no net capital cost (38% premium). The results for Option 1 represent our current best estimates of generation-level marginal costs for the BECO-NEPOOL system. We should note that Option 3 is not an extreme value, and, while net nuclear capacity cost cannot be negative, the surcharge on oil use could be set much higher. If, for example, the Commission believes that the real cost of oil is twice its posted price, the marginal costs it should use in rate-making are 17.9¢/KWH in the ultrapeak period, 15.5¢ on peak, 10.6¢ on the shoulder, and 7.4¢ off-peak.

Q: Have any attempts been made to estimate the appropriate value of the shadow premium?

A: Yes. The Energy Future report of the Harvard Business School Energy Project (Stobaugh and Yergin, 1979, Ch. 2) estimated that the costs of importing additional oil were $35 to $85 per barrel, based on posted prices of $15 per barrel; these prices are equivalent to a shadow premium of 130% to 470%, or five to eighteen times our 26% premium. Because of the purpose of that study, the effect of anticipated future prices on utility investment decisions was not counted as a cost, nor was there any attempt to place a price tag on "some potentially quite serious social and political problems". (P. 53).

This is the only published estimate of the total cost of continued or expanded oil consumption of which we, or the authors of Energy Future, are aware, and it suggests that our shadow price for oil may be too low. Even the low end of their range of shadow premiums would imply generator-level marginal costs ranging from 8.6¢/KWH for off-peak to over 15¢/KWH for peak periods.

Q: How did you convert your generation-level costs to customer-level costs?

A: Due to our lack of information regarding the relationship of customer demand to transmission and distribution costs, we simply applied marginal loss factors to the generation level costs. Since several unquantified factors have been omitted from our cost analysis, some increase in customer rates above the calculated marginal cost would be justified, if practical. The omitted factors, in addition to transmission and distribution capacity, include rationing or shortage costs due to the possibility of local or regional insufficiency of supply, such externalities as pollution, administrative and regulatory costs (whether borne by the company, government agencies, or other parties), the effects of any underestimates of nuclear costs resulting from the use of historical (pre-Three Mile Island) cost trends, an optimistic capacity factor and an optimistic O & M projection; and the possibility that the proper shadow premium on oil might exceed 26%; slight underestimates of historic marginal energy costs; the use of private, rather than social, AFUDC rates; and recognition of working capital requirements.

In any event, because the revenue constraint imposed upon BECO is generally binding, even for these bare-bones marginal costs, neither these other marginal energy-related cost components nor customer-related charges can be incorporated in rates at this time. Therefore, we do not attempt to estimate their magnitude.

Q: How did you estimate marginal losses?

A: Assuming a simple quadratic-loss model, marginal losses are (input + total losses) ÷ (input - total losses), where input = total input from generators and tie lines. Because the LRMCS, Exh. 23 appears to provide in its energy loss modifier, (input-total losses) ÷ input, it should be possible to calculate marginal losses for each time period and voltage level. Unfortunately, the losses in Exh. 23 appear to be too low compared to BECO's total losses for 1977. We brought Gilbert's average loss figures into reasonable agreement with BECO's actual losses, and then calculated marginal losses. This analysis is contained in Technical Appendix 4, and the results are presented in Table 7, expressed as marginal KWH input per KWH output.

Q: What customer-level marginal costs result from the generation-level marginal costs and marginal losses you have presented?

A: The customer-level marginal costs are set forth in Table 8.

B. Derivation of Rate Design

Q: What remaining steps are necessary to convert these marginal costs to customer rates?

A: Only three basic steps remain. We must account for the effects of the fuel clause, accommodate the rates to the revenue constraint, and analyze whether the rates are equitable and consistent with national and state goals of conservation.

Q: How did you change your rates to reflect the existence of the fuel clause?

A: We estimated the value of the fuel clause in 1980, and subtracted that value from the marginal cost to yield the prices which should be reflected in the base rates. Our estimate that the fuel adjustment will be about 3.3¢/KWH is based on BECO's latest fuel clause (September, 1979 data), 15% projected escalation in #6 oil price to 1980, and a 25% reduction in Pilgrim I output in 1980, due to a scheduled refueling outage and an atypically high output from Pilgrim for most of 1979. The details of the calculation are given in Technical Appendix Five, and the resulting net costs are in Table 8.

	Ultra-Peak	Peak	Shoulder	Off-Peak
¢/KWH				
Basic Energy Costs	6.5	5.3	5.3	3.7
Option 1 Energy +26%	8.2	6.7	6.7	4.7
1¢ Non-Peak Capacity	4.9	4.9	1	1
TOTAL	13.1	11.6	7.7	5.7
Option 2 Energy	6.5	5.3	5.3	3.7
3.1¢ Non-Peak Capacity	4.9	4.9	3.1	3.1
TOTAL	11.4	10.2	8.4	6.8
Option 3 Energy +38%	9.0	7.3	7.3	5.1
No Non-Peak Capacity Charge		4.9	4.9	
TOTAL	13.9	12.2	7.3	5.1

TABLE 6 Total Generation-Level Costs Given Alternative Values of Oil Shadow-Price

PERIOD	VOLTAGE			
	Primary		Secondary	
	High Tension	Low Tension	Large	Small
Ultra-Peak	1.1046	1.2002	1.2642	1.3299
Peak	1.0929	1.1772	1.2331	1.2899
Shoulder	1.0866	1.1647	1.2161	1.2683
Off-Peak	1.0602	1.1130	1.1471	1.1813

TABLE 7 Marginal Loss Multipliers

		VOLTAGE			
		Primary		Secondary	
Period	Generation	High Tension	Low Tension	Large	Small
ultra-peak	13.1	14.5 (11.2)	15.7 (12.4)	16.6 (13.3)	17.4 (14.1)
peak	11.6	12.7 (9.4)	13.7 (10.4)	14.3 (11.0)	15.0 (11.7)
shoulder	7.7	8.4 (5.1)	9.0 (5.7)	8.4 (5.1)	9.8 (6.5)
off-peak	5.7	6.0 (2.7)	6.3 (3.0)	6.5 (3.2)	6.7 (3.4)

Table 8 Marginal Costs in ¢/KWH by customer Level and Period

Notes: From Table 6, Option 1, and Table 7.

Figures in parentheses are net of 3.3¢/KWH fuel charge.

Q: How do the rates you have developed relate to the class revenue constraints?

A: In general, rates based on our estimates of marginal costs result in over-collections, given BECO's estimates of KWH splits between periods (with some modifications to reflect our definition of periods). As shown in Table 9 (and derived in Technical Appendix 6), only the small commercial customers (ASP-1/AP-1) pay less under our initial marginal cost prices than under existing rates. The smallest proportional over-collection is in the residential, non-heating class (AP/ ASP, which we have defined to include water-heating customers, who do not seem to need the special protection that BECO's rate P-2 affords them). Over-collections in the commercial/industrial rates increase with voltage level, while the greatest overcollection is in the residential space-heating rate (AP-2).

Q: What is the significance of these results?

A: It appears that with the possible exception of certain small commercial customers, each customer is now being charged less than the cost of serving him. This is most obvious for space-heating customers, who are now on rates which are admittedly promotional, and which BECO is now proposing to close.

	OVERCOLLECTION (Tech. App. #6)	METERS Ex. V1-1	X $36/YR	WITH METERS
AP/ASP	26,518,577	39,030	(1,405,080)	25,113,497
AP-1/ASP-1	(2,346,804)	6,699	(241,164)	(2,587,968)
AP-2	8,340,588	Meters included in initial calculation, since all customers will be on TOU		
AT-1	31,527,702			
AT-2	44,857,356			
AT-3	50,246,909			
	$159,144,328			$157,489,084

	OVERCOLLECTIONS AS % BASE REVENUE
AP/ASP	25.2%
AP-1/ASP-1	(12.4)%
AP-2	117.8%
AT-1	41.9%
AT-2	53.7%
AT-3	108.9%

Table 9: Over (Under) collections under prices depicted in Table 8.

Note: Rate classes are the same as for BECO's proposed rates, except that P-1 and SP-1 are merged, P and SP are merged, and P-2 contains only heating customers. Base revenue is 1976/1977 normalized revenue x 1.0604 for effects of D.P.U. 19991.

Since most of these customers were attracted to electric heat by various promotional devices in a period of falling electric rates, some special relief seems appropriate; therefore, we have retained BECO's special rate for existing residential heating customers.

Large industrial and commercial customers, especially those served at high voltages, also seem to be receiving power at hefty discounts, compared to the cost of serving them. There is no obvious reason for continuing this mis-pricing.

Since portions of existing rates are collected through customer and demand charges, the differences between the current marginal price of energy and the marginal cost of that energy are even larger than the comparison of total revenues in Table 9 would suggest.

Q: Do these overcollections indicate some basic, intratable problem inherent in marginal cost pricing?

A: No. Marginal cost pricing is the appropriate and efficient basis for rate design. If adjustments to marginal cost are necessary, they should be made so as to distort resource use as little as possible. Unless the analysis starts with estimation of marginal costs, there is no rationale basis for derivation of rates. It is certainly preferrable to stand with optimal rates, and adjust these as necessary, rather than deriving rates from some arbitrary and inefficient methodology.

Q: How can the conflict between the marginal cost results and the class revenue constraints be resolved?

A: There are several options. The most economically efficient approach, in economic terms, would be to set the rates at marginal cost and allow BECO to overcollect on its revenues. The interests of equity can be preserved by transferring the surplus back to the public, for example, as a tax or other payment to local or state government. A mechanism could even be designed to apply the surplus to town-specific, class-specific reductions in real estate taxes, with the surplus collected from units of local government distributed across the state. However, this would appear to be a long-term solution, requiring the cooperation of local governments and the Legislature.

More immediately, and almost as efficiently, it may be possible to charge marginal costs for marginal consumption, but eliminate the anticipated overcollections by intra-marginal credits or discounts, which will impact the consumption of few customers or none. As a last resort, marginal costs can be decreased, if essential to maintain the total revenue constraint. If this option is necessary, we would strongly suggest that the class revenue constraints be relaxed, so that large industrial and commercial rates can be increased above their current revenue levels. This action would be appropriate for two reasons. First, small customers are now paying rates much closer to marginal costs than those paid by large customers, and some (AP-1/ASP-1) may even be paying more than marginal cost. Second, where deviations from marginal cost are necessary, the most efficient deviation is one which shifts prices away from marginal cost in proportion to inverse of the customers' elasticities of demand for the product. In the present case, this principle implies that prices should be closer to marginal cost (and hence higher) for the highly price-elastic large customers than for smaller customers. Since those large customers' rates are now further from marginal cost than small customers' rates, efficiency will be served by shifting some of the latter's revenue responsibility to the former.

Q: Do you have any specific suggestions regarding the mechanism for reconciling revenues and marginal costs?

A: Yes. We believe that, for most classes, a judicious combination of infra-marginal discounts and modest overcollections would be appropriate. The overcollections should be placed into an escrow account, to be disbursed to BECO in accordance with a revenue-protective formula, with the remainder to be used for energy conservation measures, such as audits, low-interest insulation loans, and the like.

Q: Please describe the specific rate adjustments you would propose?

A: Assuming that the information we have received from BECO is accurate and that any omissions, such as the size of transformer ownership credits and load growth to 1978, are not serious, we would suggest the following modifications:

Rate ASP - a credit of 1¢/KWH for the first 250 KWH/month

Rate AP - no credits, and a metering charge of $1 per month

Rate ASP-1 - a 15% surcharge

Rate AP-1 - a 15% surcharge on energy and a $3/mn metering fee

Rate AP-2 - credits of 6¢/KWH on the first B KWH/mn
4¢/KWH on the next 2B KWH/mn
1¢/KWH on the next B KWH/mn

on bills rendered from December 1 through March 1, where

B = 1000 for current rate B022
300 for current rates B023, D041 and D241
600 for current rate D941

Rate AT-1 - a credit of 2¢/KWH on the first 3000 KWH month and of 1¢/KWH on the next 1000 KWH/month

Rate AT-2 - a credit of 2¢/KWH on the first 68000 KWH/month

Rate AT-3 - a credit of 2¢/KWH on the first 282000 KWH/month and a 13.5% discount on the remaining bill

The discounts are designed to apply to less-than-average usage (less than halve the average for the T rates); to avoid discounts in excess of 2¢/KWH, especially where these may be marginal blocks for some customers; to be as simple as possible; and to collect 10% to 15% more than total current revenues. As Table 10 shows, we were successful (regarding revenue level) for Rates P-2, T-1, and T-2. Since rates ASP and ASP-1 would not be on TOU meters, no revenue protection is necessary, and smaller overcollections seem appropriate. The 1.7% for the ASP-1/AP-1 rate may be a little low, but it should be adequate to protect BECO revenue while the vast majority of KWH's in the class are still on synthetic rates; we were reluctant to increase the rates very much more than 15% above our estimates of marginal costs, expecially if some revenue from larger customers can eventually be used to ease the excessive burden on this class.

Rate AT-3 is a real problem. Since it is currently quite heavily underpriced, and since (unlike AP-2) the rate is still open, it is probably essential to increase total collections more than 15% to maintain reasonably cost-based prices. To minimize customer disruption, it may be advisable to move gradually to full marginal-cost pricing, starting with perhaps a 20% increase in rates (which implies base rates 30% less than marginal costs), increasing to full marginal cost in five years or so. We have designed a rate for the 20% level.

Q: To what uses do you propose that the excess revenue collections be applied?

A: We suggest that the excess of collections, over what would have been collected for the same number of KWH under the current rates, be placed in an escrow fund to be used for a variety of energy conservation projects to benefit BECO's customers, including energy audits for all classes (which could also include providing some weatherstripping and similar materials to small customers); studies of customer-owned generation possibilities, such as hydro electric, solar, and cogeneration potential; low-interest loans for energy development projects, insulation, and other major efficiency improvements; installation of heat pumps, storage heating, solar heating, and wood stoves in the homes of AP-2 customers; conversion of master-metered apartments to single meters; and similar improvements in the efficiency of energy use. It would be helpful if BECO developed revenue protection formulae and guidelines for conservation programs promptly, so that the extra funds collected from the customers could be returned to them in energy savings as quickly as possible.

In the long run, the best conservation options will eventually be exhausted, while the revenue surplus will tend to disappear as load curves flatten. It may still be advisable to prepare for disposing of excess revenue by other means, such as real estate tax reduction.

Revenues
($ Millions)

Rate Class	Base	Fuel	Total	Marginal Cost Over-collection	Effect of Modification	Net Overcollection	
						$M	%
ASP/AP	99.5	71.7	171.2	26.5	(14)	12.5	7.3%
ASP-1/AP-1	20.9	8.8	29.7	(2.3)	2.8	.5	1.7%
AP-2	7.1	9.1	16.2	8.3	(6.4)	2.0	12.2%
T-1	75	57	132	31.5	(14.8)	16.7	12.7%
T-2	83.6	73.0	156.6	44.9	(22.1)	22.7	14.5%
T-3*	46.1	60.7	106.8	50.2	(18.4)	31.8	29.8%
T-3**					(10.4)	21.4	20.0%

Table 10 Effects of Modifications to Meet Revenue Constraints.

* with 2¢ credit

** with additional 13.5% discount

Q: Have you prepared a summary of the rates which you are proposing?

A: Yes. The set of rates derived above is summarized in Table 11 and in Table 12, for the TOU rates and the synthetic rates, respectively. These rates are based on our best estimates of BECO cost and load data, on the assumption that the Commission will not allow the current revenue responsibility to be shifted among the major customer groups defined by the rates, and on the assumption that the Commission will wish to establish an escrow fund to protect BECO from revenue losses due to load shifting and to fund conservation programs. If the data can be improved, if the Commission decides to allow revenue shifting (which we endorse insofar as consistent with marginal cost principles), or if the Commission wishes to reduce (or increase) the allowance for revenue protection and conservation, we would be glad to re-evaluate the rates. Therefore, our proposals should be viewed as a reference case, to which adjustments may be desirable and necessary. The same is true, of course, if the Commission indicates that other principles (such as a higher shadow price on oil) should be applied to rate design.

Table 4: Summary of Attorney General's Proposed TOU Rates

Rate Class	AP	AP-1	AP-2	AT-1	AT-2	AT-3
Voltage	small secondary	small secondary	small secondary	large secondary	primary low	primary high
Availability	residential (as TOU meters available and justified)	non-residential	residential heating customers in dwellings on heating rates before 1/1/78	---------unrestricted-------		
Monthly Charge:	$1.00	$3.00				
KWH Charges:						
Ultra peak	14.1¢	16.2	14.1	13.3	12.4	9.7
Peak	11.7	13.5	11.7	11.0	10.4	8.1
Shoulder	6.5	7.5	6.5	5.1	5.7	4.4
Off-peak	3.4	3.9	3.4	3.2	3.0	2.3
Credits (¢/KWH)			6 for B KWH/mn 4 for 2B KWH/mn 1 for B KWH/mn where B=1000 for B022 B= 600 for D941 B= 300 for B021, D041, D241 and AP-2credits apply on bills rendered in Dec. to March	2 for 3000 KWH/mn 1 for 1000 KWH/mn	2 for 68000 KWH/mn	1.7 for 282000 KWH/mn

Table 12: Summary of Attorney General's Proposed Synthetic Rates

Rate Class	ASP	ASP-1
Availability	Small secondary residential; initially including all residential customers; larger customers shifted to AP, and heating customers to AP-2, as meters available and justified	small secondary non-residential initially including entire class; larger customers shifted to AP-1, as meters available and justified
Energy Charges:		
July, August, Dec 15 - Feb 15	6.1¢/KWH	8.5¢/KWH
Other months	5.3¢/KWH	7.7¢/KWH
Credits:	1¢/KWH on first 250 KWH/month	
Source:	See Technical Appendix #6	

Q: Does your analysis suggest rates for interruptible power and for power purchased from customers and other small producers?

A: Yes. Interruptible rates should recognize two types of savings. First, there are capacity savings, since some portion of peak demand can be met by interruption, rather than new units. Second, there are some energy savings, since the interruptible customer will generally be interrupted at the time when NEPEX is dispatching its least efficient plants.

Capacity savings can be recognized by a reduction of the capacity portion of peak and ultra-peak rates in proportion to the customer's ability to mimic the behavior of a gas turbine; that is, to drop load with at least 90% reliability within 15 minutes, for at least the same number of hours/year that the average gas turbine is run. Customers who are less (or more) reliable than gas turbines, or who can tolerate less (or more) interruption, can be credited proportionately, while special weightings would need to be developed for those who require more (or less) lead time than a turbine, or who must impose limits on the length of individual interruptions. Assuming, not unreasonably, that square-root functions are found to describe well the relationship of the last two variables (warning time and interruption length) to the interruptible customer's value to NEPEX, an AT-2 customer who is able to shed load 100% of the time for 300 hours per year, for up to 3 hours at a time, on 30 minutes' warning, would receive a credit on peak-period consumption of:

3.9¢/KWH	difference in price between peaking & base capacity
x1.1772	peak period losses
$\times 1.0 \div 0.90$	100% reliability vs. 90%
$\times 300 \div 1000$	300 hrs/yr vs. assumed 1,000 hours for gas turbine
$\times \sqrt{3 \div 6}$	3 hrs/interruption vs. 6 hr peak period for turbine
$\underline{\times \sqrt{15 \div 30}}$	30 minute notice vs. 15 minutes for turbine
.765¢/KWH	

The fact that the credit is in ¢/KWH is quite convenient. Customers who use little peak-period energy are not apt to have large loads on line at the time of interruption, while those who use much energy will generally have large loads to reduce, so the incentive is proportional to the value of the service rendered by the customer to BECO. To simplify planning, interruptible service should be provided under contracts which require notice before termination at least equal to the lead time for peaking capacity.

The energy credit could be determined in a variety of ways, perhaps the most straight forward being a credit per KWH in the periods subject to interruption of (average marginal running cost in interrupted hours) x(% interrupted hours in period).

Q: What purchased power rates does your analysis suggest?

A: The basic rate in each period would be average generator-level marginal energy cost for that period (actual or projected) plus a capacity credit in peak and ultra-peak hours of:

$$4.9\text{¢/KWH} \times \frac{\text{generator ELCR}}{\text{turbine ELCR} = .88}$$

Where the ELCR of the generator (as operated) can be determined from prospective or retrospective system simulation modeling. Regardless of the results of the proceding calculation, a capacity credit of at least 0.8¢/KWH should be given in all hours, to recognize the generator's role in displacing nuclear capacity.

The rates described above are appropriate for generation, which feeds into transmission lines, as most NEPOOL units do. Units for which output would incur larger-than-normal losses should be paid less than these rates, while a small secondary customer whose excess output will be absorbed by his neighbors, without need for transformation and transmission, should receive as much as 33% higher rates, to reflect the number of generated KWH's displaced. In addition, it may be wise to pay the 26% shadow price on oil to generation which is not fueled by oil or gas, to reflect the advantages of reduced oil use.

Specific guidelines should be established to relate time, voltage level, energy generation and local demand conditions so that marginal KWH generation displacement and hence, purchased power rates, can be readily calculated.

Q: Why is it important to establish standard rules and prices for interruptible rates and for purchased power?

A: If customers are to make long-term capital commitments to enable them to interrupt their consumption or to generate power, they should be assured of receiving fair compensation for their efforts, without protracted and one-sided negotiations with the utility. Had BECO offered a set of straightforward and fair rates, MASCO (the Harvard project) might well be on line already with efficient, low-pollution gas turbines or steam turbines, and Spaulding & Slye could have proceeded with the Burlington Cogeneration Project, knowing exactly how they would be repaid for their surplus generation.

Q: Are backup rates appropriate for customers who generate some or all of their electricity?

A: The only real differences in costs per KWH between normal customers and self-generators is that the latter must spread fixed facilities (service drops, meters) over fewer KWH, and that the latter also have a higher variance in demand. If the revenue constraint ceases to be binding (due to rate increases, decreasing demand, and/or new mechanisms to redistribute excess electric revenue to tax relief), the first difference will be neatly handled by a monthly customer charge; in the meantime, no significant misallocation of resources is likely to result, due to the low elasticity of service connections. The second difference is apt to be of trivial consequence for small customers; either they will be too few to matter to NEPOOL, or they will be so numerous that the distribution of demand will be close to that of normal customers. For very large self-generators, whose demand may abruptly fluctuate by over 50 MW, it would be appropriate to charge for the extra peaking capacity required to meet the reliability criterion with the additional demand variance of the NEPOOL system caused by the customer (net of the average variance of the class, per KWH). Such situations would be quite unusual, and could alternatively be resolved by the customer selling all its output to the utility at purchased power rates (which capture generator reliability) and buying its consumption at normal retail rates. Therefore, special backup rates should rarely, if ever, be necessary.

Q: What effect do your proposed rates have on equity considerations?

A: Equity can be defined in several ways, and we will address a few of these.

The rates are equitable in the sense that they are based on the same principles for all classes and, but for the revenue constraints, the rates would differ only in proportion to the marginal loss ratios. No class or group of customers is allowed to exploit other groups by charging monopoly prices, as suggested by Weintraub (1970) and Bosch-Font (1974). No special incentives, promotions, or discounts are used to encourage particular end uses or patterns of uses; each customer pays as close to the cost of energy which he or she uses as the revenue constraint permits.

The classes which would experience the greatest increases in rates under marginal cost pricing are the classes most heavily protected under the proposed rates. Winter-time credits for the P-2 class and an across-the-board discount for the T-3 class shield these customers from rapid changes in rates; prompt movement toward marginal cost pricing encourages conservation and load management, while providing a revenue surplus to finance the customer's transition. The initial increase in rates is limited to (at most) 20%, before load shifts or conservation; therefore, even the most seriously impacted class (T-3) should not be overwhelmed.

Finally, the rates are equitable in that customers who choose to conserve energy receive more of the benefits of their actions than they do now. Therefore, whether they are motivated by patriotism, by concern for future generations, by environmentalism, by profit goals or by parsimony, those who reduce energy waste are rewarded for doing so. Conversely, those who do not conserve or shift load pay more dearly than they do now for the resources they consume. Our rates "give customers more control over the total size of their utility bills" (Peak Load and Time Differential Pricing, DPU 18810, October 20, 1977), and more control over the amount of oil burned on their behalf.

Q: What effect will your proposed rates have on conservation?

A: Studies which have addressed the issue (BECO Forecast, 1979, p. II-H-10; Taylor, et. al., 1977), have generally found that residential consumption responds primarily to the marginal price of electricity, rather than to fixed charges. The shift of revenue from intra-marginal customer charges and initial blocks to the KWH blocks which are marginal for most consumption will tend to decrease usage. Taylor, for example, found a marginal elasticity of about 0.8, implying that a 10% increase in the marginal price will eventually reduce consumption by 8%; if this elasticity applies to all of BECO's Forecast 1990 consumption, a 10% increase in marginal price would reduce annual consumption by 1032 GWH, saving about two million barrels of imported oil per year.

The replacement of inefficient demand charges, which discourage consumption only at the customer's peak, with energy charges, which discourage consumption in every hour, should produce further reductions in the use of electricity, and hence, of oil. And the conservation escrow fund will facilitate energy-saving investment, further accelerating conservation.

The present instability in the international oil market makes it imperative that we decrease our energy use quickly. New large nuclear and coal-fired units (e.g., Pilgrim II) probably cannot be on line much before 1990, and are therefore of little help in the current situation, even if they do turn out to be cost-effective. As Energy Future states succinctly, "conservation - not coal or nuclear energy -- is the major alternative to imported oil (Stobaugh & Yergin 1979, p. 11). While there are other short-run approaches to reducing the oil consumption of New England's electric generation system (coal conversion, installation of cogenerators, demand-responsive voltage control, intensive insulation and applicance-efficiency programs, conversion of master-metered apartments to single meters, development of wind and hydro resources), none are likely to be more cost-effective than marginal cost pricing, especially since the conservation fund which we propose will finance many of the other cost beneficial measures. Marginal cost pricing is not simply a good idea -- at this crucial juncture, it may be New England's best idea.

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TECHNICAL APPENDICES

TECHNICAL APPENDIX #1

Technical Appendix 1: Estimate of Marginial Fuel Costs

From Interrogatory 51, NRC Docket No. 50-471
average marginal fuel costs (¢/kwh)

date	3/7/79	4/4/79	5/2/79	average
9am - 10pm	3.54	3.84	3.30	3.558
10pm - 9am	2.21	2.75	2.66	2.539

We used 3.5 ¢/kwh and 2.5¢/kwh, on- and off-peak, respectively. This may be a slight underestimate, on the order of 1% to 2%.

From BECo's fuel clause filings (see attachments), it appeared that #6 oil cost 40¢/gal in march 1979 and that #2 oil cost 45¢/gal, with gallons containing 147000 BTU and 137000 BTU, respectively from BECo's 1978 FERC form #1. Assuming that these were the average prices flowed through the various accounting mechanisms to NEPOOL interchange calculations in march to may, the offpeak cost is equal to

2.5 ÷ 40 x 147000 = 9188 BTU/kwh heat rate, #6 oil,

but is probably mostly #6 oil burned at about 9600 BTU/kwh at plants with cheaper oil — certainly 40¢/gallon is not an underestimate of oil price

Similarly, if we solve for the peak price, we find that it will be explained by

#6 oil @ 12862 BTU/kwh - implausibly high,
#2 oil @ 10656 BTU/kwh - implausibly low,
or 83% old steam plant (eg. Mystic 4,5,6) @ 11,800 BTU/kwh
and 17% gas turbine @ 15,000 BTU/kwh

Between March and September, prices rose by

40.5%	Mystic	, #2 oil	
35.6%	"	, #6	
31.0%	L St	#6	
33.0%	L St	#2	(very small amount)
29.5%	New Boston	#6	

again, from fuel clause filings. We took as typical a 40% increase in #2 oil price and a 30% increase in #6.

September off-peak 2.5 x 1.3 = 3.25 ¢/kwh
peak 3.5(.83 x 1.3 + .17 x 1.4) = 4.6 ¢/kwh

For ultra peak, we assumed
½ gas turbine 67.14 ¢/gal. x 14,718 BTU/kwh ÷ 137000 BTU/gal = 7.21 ¢/kwh
½ old oil steam 51.53 ¢/gal x 11,800 BTU/kwh ÷ 147000 BTU/gal = 4.14 ¢/kwh
(7.21 + 4.14) ÷ 2 = 5.67 ¢/kwh in September

Multplying these costs by 1.15 for inflation - matching increases to 1980, yields 3.7¢/kwh off-peak, 5.3¢/kwh shoulder & peak, 6.5¢ ultrapeak, or a bit more.

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TABLE "A"

NEPEX OPERATING COSTS*

Hour End	6/7/78	7/5/78	8/2/78	9/6/78	10/4/78	11/1/78	12/6/78	1/3/79	2/7/79	3/7/79	4/4/79	5/2/79
1	13.80	9.05	19.90	18.84	19.70	18.47	20.90	19.40	20.92	19.13	26.40	25.97
2	12.30	10.40	17.26	18.10	19.70	17.21	20.70	18.50	20.87	19.75	24.90	24.45
3	13.10	13.00	18.25	18.03	19.10	16.22	19.01	15.00	20.94	20.23	23.90	23.61
4	11.00	11.00	18.50	18.20	18.70	15.05	19.29	12.90	20.96	18.61	24.20	22.91
5	9.70	13.00	18.38	18.09	18.60	15.37	19.23	10.80	20.79	18.74	24.10	22.13
6	10.20	13.00	18.35	18.40	19.00	17.48	20.81	15.80	Note 1	20.13	24.90	24.27
7	15.00	16.33	18.70	20.01	20.50	20.69	24.01	19.50	Note 1	21.60	25.40	23.44
8	20.16	Note 1	21.68	22.00	20.10	24.92	32.00	Note 1	30.00	31.00	37.00	26.20
9	26.26	Note 1	23.67	27.00	29.40	33.64	33.43	30.45	30.00	33.00	36.90	37.00
10	34.26	Note 1	26.30	28.50	31.60	34.68	31.67	33.55	29.50	36.60	37.00	37.00
11	31.82	Note 1	28.55	34.00	32.00	36.92	23.68	38.26	30.07	36.20	37.27	37.00
12	30.71	Note 1	29.00	32.60	32.30	36.60	21.41	37.10	32.77	33.80	38.00	31.60
13	33.17	Note 1	27.50	30.50	34.30	37.07	19.54	35.90	36.72	31.50	37.50	31.70
14	33.75	Note 1	25.54	31.50	33.10	35.23	19.64	38.33	30.58	33.30	37.80	31.00
15	30.81	20.20	22.50	32.00	32.00	34.90	20.44	35.26	29.63	35.00	32.41	31.10
16	30.81	23.00	22.50	34.30	32.50	35.20	22.03	35.67	33.81	35.28	42.02	31.18
17	30.17	23.00	22.20	32.40	33.00	35.30	28.00	36.66	39.08	37.27	37.30	31.17
18	27.40	22.30	22.10	32.00	33.00	36.60	30.24	40.00	38.57	39.42	41.56	30.94
19	23.18	20.10	21.20	28.40	32.00	32.70	28.00	40.15	34.12	38.52	41.79	30.29
20	22.44	19.10	20.80	22.97	32.00	29.80	27.90	36.60	38.83	35.79	41.64	29.68
21	29.17	19.30	21.10	23.76	24.18	22.60	25.11	34.50	26.60	34.20	37.40	39.40
22	30.99	19.80	21.00	21.91	22.72	21.60	24.40	32.70	26.08	27.00	31.68	41.41
23	20.07	18.20	20.30	20.68	21.44	20.40	23.27	25.16	25.52	24.86	31.22	31.00
24	17.96	17.63	19.00	19.50	19.59	18.79	20.65	23.77	21.56	21.90	28.38	27.47

Note 1 - Computer Trouble

* Numbers represent cost of last 125 MW generated during on-peak hours and last 250 MW during off-peak hours. Figures are used in pumped storage dispatch. Numbers requested in Question #51 are not available for full period.

FJF/ctm
6/25/79

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FUEL ISSUE REPORT FOR THE MONTH OF MARCH, 1979

ELECTRIC

COST AREA 58

LOCATION	GALLONS	ACCOUNTS		PRICE PER GALLON
		DEBIT	CREDIT 15103	
L STREET STATION				
Station #4 ✓	341347	50102-4	127182.72	37.25907
New Boston ✓	8610	50102-3	3208.01	37.25907
NEW BOSTON ✓	28022339	50102-3	11150352.45	39.79094
#2 OIL ✓	7330	50102-3	3313.45	45.20396
EDGAR STATION				
STATION #75 ✓		50102-2		
#2 OIL ✓		50102-2		
MYSTIC STATION				
STA. #200-UNITS #4-5-6 ✓	8507614	50102-1	3215755.64	37.79856
#2 OIL-UNITS #4-5-6 ✓	172340	50102-1	82350.82	47.78393
STA. #200-UNIT #7 ✓	1644670	50102-7	621661.65	37.79856
#2 OIL-UNIT #7 ✓	67573	50102-7	32289.03	47.78393
		TOTAL	15236113.77	

BECo. Form X4002 Revised 1/77

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FUEL ISSUE REPORT FOR THE MONTH OF SEPTEMBER, 1979

ELECTRIC

COST AREA 58

LOCATION	GALLONS	ACCOUNTS DEBIT	CREDIT 15103	PRICE PER GALLON
L STREET STATION STATION #4 ✓	130403	50102-4	63663.83	48.82083
NEW BOSTON ✓	8610	50102-3	4203.47	48.82083
NEW BOSTON ✓	15745189	50102-3	8113001.46	51.52686
#2 OIL ✓	1850	50102-3	1112.26	60.12216
EDGAR STATION				
STATION #75 ✓		50102-2		
#2 OIL ✓		50102-2		
MYSTIC STATION				
A. #200-UNITS #4-5-6 ✓	3465439	50102-1	1775713.82	51.24066
OIL-UNITS #4-5-6 ✓	181966	50102-1	122168.22	67.13794
A. #200-UNIT #7 ✓	14773714	50102-7	7570149.45	51.24066
OIL-UNIT #7 ✓	122581	50102-7	82298.37	67.13794
		TOTAL	17732310.88	

TECHNICAL APPENDIX #2

Technical Appendix 2 : Annualizing Formula

An infinite annuity of $\$x$ at discount rate r has present value

$$\frac{1}{r} x .$$

If the benefit stream ends in n years, the present value is reduced by the same stream discounted 10 years, and becomes

$$PV = \frac{1}{r} X - \frac{1}{r} X \frac{1}{(1+r)^n} = \frac{(1+r)^n - 1}{r\,(1+r)^n} X$$

$$= \frac{1 - \frac{1}{(1+r)^n}}{r} x$$

To find x, given PV

$$X = \frac{r}{1-\frac{1}{(1+r)^n}} PV \Rightarrow \frac{r}{1-\frac{1}{(1+r)^n}} = \text{carrying change}$$

For

r	n	use	$\frac{X}{PV}$
.1	18	G.T.	12.19%
.1	28	Nuclear	10.75%

TECHNICAL APPENDIX #3

Technical Appendix 3: Nuclear costs

Capital:

From Mooz (1978), we get the following formula for nuclear plant capital cost in 1976 dollars, on p. 32, Table 11.

Variable Name	Meaning	coefficient	Value used	contribution to cost
constant		-8885.5		-8885.5
CPIS	Date of construction permit	141.34	80.33 (April 1980)	11353.84
SIZE	MWe	-0.21943	1150	-252.34
TOWER	Dummy for Cooling Tower	92.04	0	0
LOC1	Dummy for Northeast	128.12	1	128.12
LN	Log of number of LWR's built by A/E	-72.422	ln(48) = 3.87 (from Electrical World 1/15/79)	-280.36

Cost/kw (1976$)	2063.76
construction inflation, 1976-78	x 1.18
contruction inflation, 1978-80, @ 12%	x 1.2544
	3054.75
carrying charge (from Technical Appendix 2)	x .1075
@ 10% real discount rate, 28 year life	328.4

This value is somewhat lower than Mooz's alternative formula, which excludes the marginally significant SIZE variable. Also, April 1980 is an optimistic estimate for a construction permit.

P A3-2

additions to capital cost

Year	Pilgrim I costs in $/1000, from FPC form 1	current dollar additions	1967 construction dollars
1974	235982		
		482	255
1975	236464		
		4976	2488
1976	241440		
		16139	7403
1977	257579		
		4189	1775
1978	261758		
			11921
			÷ 4 years
			2980 $1967
			x2
			5961 $1976

From Mooz, Pilgrim I cost $460.05 million in 1976$
Therefore, annual increase was
5961 ÷ 460050 = 1.3% of capital cost / year
in real terms

For Pilgrim II, 1.3% of 3054.75 is 39.6 $/kw-yr

Nuclear O&M

For Pilgrim 1

year (y+1973)	O&M – refueling (from FPC form 1) $1000 current	deflated by CPI $1967 c
1973	4797	3604
4	7271	4923
5	7341	4554
6	12576	7376
7	12765	7033
8	14186	7343

regressing $c = ae^{by}$ yields

$a = 3886$

$b = .146$

$r^2 = .820$

where refueling expense is

year	cost	x.553 for excess	1967$
1974	4083	2256	1527
1976	7339	4056	2379
1977	4630	2559	1410

averages 1772
@ 20 month intervals
= $1063000/yr (1967$)

The .553 factor is from $\frac{2866}{5186}$ on p A3-6

The 1986 present value of each year's non-refueling O&M is

$$3886 \times \underbrace{1.932 \times 1.21}_{\substack{\text{inflation 1967-78} \\ \text{(CPI) 1978-80}}} \times \frac{e^{.146\,t}}{(1.1)^{t-13}} \quad , \text{ where } t=0 \text{ in } 1973$$

$$= C_{1986} \times \frac{(q^{28}-1)}{q-1} \quad , \text{ when } q = \frac{e^{.146}}{1.1}$$

and C_{1986} is

$$3890 \times e^{.146 \times 13} \times 1.932 \times 1.21 = 60678 \text{ in } 1980\$$$

So the 1986 present value is $60678 \times \frac{1.052^{28}-1}{1.052-1} = 3{,}657{,}595$

\$1000 1980

annualized, this value is $.1075 \times 3{,}675{,}595 = 393{,}192{,}000$

1980 \$/yr

This value is for Pilgrim I; assuming very strong economies of scale - scaling factor of .3 - the cost per kw-yr for Pilgrim II would be

$$393{,}192{,}000 \times \left(\frac{1150}{670}\right)^{.3} \div 1150000 = \$402 / \text{kw-yr}$$

and with a scaling factor of .5

$$393{,}192{,}000 \times \left(\frac{1150}{670}\right)^{.5} \div 1150\,000 = \$447.9 / \text{kw-yr}$$

A linear regression on the same data yields

$$C = 3816.4 + 795.63\,t \qquad t = 0 \text{ in } 1973$$

$$r^2 = .819 \qquad c \text{ in } 1967\,\$$$

For a 1986 present value in 1980 \$ of

$$\sum_{t=0}^{28} \frac{14159.6 + 795.63\,t}{(1.1)^t} = 209{,}412{,}500$$

$\times .1075 = \$22{,}511{,}800\ /\mathrm{yr}$ for Pilgrim I.

Depending on the scaling factor, this becomes

$$22{,}511{,}800 \times \left(\frac{1150}{670}\right)^{.3} \div 1150{,}000 = \$23.0/\mathrm{kw\text{-}yr}$$

or

$$22\,511\,800 \times \left(\frac{1150}{670}\right)^{.5} \div 1150{,}000 = \$25.6/\mathrm{kw\text{-}yr}$$

We use a value of \$20/kw, equivalent to linear O&M growth with perfect economies of scale. We also neglect the annual refueling cost of $1063\,000 \times 1.932 \times 1.21 \div 1{,}150{,}000 = \$2.2/\mathrm{kw\text{-}yr}$, with perfect economies of scale, to \$3.7/kw-yr with a .5 scaling factor. Therefore, our O&M cost estimate is highly conservative in three ways; we use linear growth in cost, perfect economies of scale, and no refueling cost.

PA3-6

BOSTON EDISON COMPANY

Pilgrim Refueling Outages

Test Year Ended December 31, 1978

($000)

Title Col.A	Outage Expenses Operation Col.B	 Maintenance Col.C	 Total Col.D	
Outage Dates:				[illegible] 555
12/28/73 to 3/22/74	$1432	$3410	$4842	
G. E. Credit '75	(242)	(517)	(759)	
	$1190	$2893	$4083	2256
1/29/76 to 6/ 1/76	$2698	$4641	$7339	4056
8/ 6/77 to 11/14/77	$1860	$2770	$4630	2564

Next outage scheduled Jan. 5, 1980 for 14 weeks

Test Year Adjustment:

'77 Outage Expense	$4630	1559 [illegible]
rojected Expense for Next Outage (Line 8 times 112% for inflation)	5186	[illegible] 2742 [illegible]
egular BECO Labor	(970)	
egular BECO Invoices	(1350)	
dditional Cost for Outage	$2866	
est Year Adjustment (Line 12 x $\frac{12 \text{ Months}}{20 \text{ Months}}$)	$1720	7 /

t	C (PV)	t	C (PV)
0	14159,6	15	6246.7
1	13595,7	16	5852.0
2	13017,2	17	5477,4
3	12431,6	18	5122,5
4	11844,9	19	4787.0
5	11262,1	20	4470.0
6	10687,4	21	4171,2
7	10124,1	22	3889.7
8	9574,9	23	3625,0
9	9041,9	24	3376.2
10	8526,6	25	3142,7
11	8030,4	26	2923.8
12	7553,8	27	2718.7
13	7097,6		209412.5
14	6661.9		

$/1000 1980

Calculation of linear O&M growth,
present value

Associated Transmission Cost

From p. A3-9, average (excluding Pilgrim II, which is not complete) is

$28.2M
add 10% for AFUDC (½ of a 2 year construction period @ 10%)
and 25,44% for inflation (1978-80 @ 12%)
and 15% for owner's costs
$44.7M
÷ 1150000 Kw
$38.9 /Kw
x10.75% (assume 28 year life)
$4.2/kw

This estimate excludes Transmission O&M, and is not sensitive to the specific owner's costs or AFUDC estimates.

P, A3-9

TABLE 1

TRANSMISSION CAPITAL COST ESTIMATES (LINE AND STATION COSTS)[1]

	Unit Related Costs To Tie Into EHV Grid	Grid Reinforcements Identified Concurrent With Unit	Total[2]
Pilgrim[3]	$ 2,700,000	$ 500,000	$ 3,200,000
Charlestown	10,700,000	5,100,000	15,800,000
Millstone	19,800,000	(none identified)	19,800,000
Montague	1,500,000	10,300,000	11,800,000
Seabrook	14,900,000	32,000,000	46,900,000
Dunstable (UE&C #1)	4,100,000	34,600,000	38,700,000
Dunstable/Tyngsborough(UE&C #2A)	1,500,000	35,000,000	36,500,000
Tyngsborough (UE&C #2)	3,500,000	35,600,000	39,100,000
Center Hill Pt. (UE&C #18)	4,700,000	4,100,000	8,800,000
Wareham (UE&C #19)	30,000,000	2,000,000	32,000,000
Marion (UE&C #20)	30,600,000	2,000,000	32,600,000

(1) These costs are for comparative purposes and do not constitute the entire development costs (primary difference is in station where extensive development other than circuit breakers is required). 1978 costs do not include escalation, AFUDC, or certain owners costs, but does include direct and indirect engineering costs for transmission lines.

(2) Note these costs are not strictly additive since other benefits may derive to the POOL from the grid reinforcement and thus this cost may also be supported by others.

(3) Monies already spent for Pilgrim 2 are regarded as sunk costs for the purposes of this study and are not included herein.

From: TRANSMISSION COST STUDY FOR

ALTERNATE SITES EVALUATION

Boston Edison Company

August 17, 1978

ECONOMIC DATA ON OUTPUT, PRODUCTION, PRICES AND WAGES - POST WORLD WAR II TO DATE

1967 = 100

Line No.	Year (A)	Consumer Price Index: Index (F)	Consumer Price Index: Annual Increase (G)	Producer Price Index: Index (H)	Producer Price Index: Annual Increase (I)	Construction Cost Index: Index (J)	Construction Cost Index: Annual Increase (K)
1	1946	58.5	- %	62.3	- %	45	- %
2	1947	66.9	14.4	76.5	22.8	54	20.0
3	1948	72.1	7.8	82.8	8.2	60	11.1
4	1949	71.4	(1.0)	78.7	(5.0)	59	(1.7)
5	1950	72.1	1.0	81.8	3.9	62	5.1
6	1951	77.8	7.9	91.1	11.4	67	8.1
7	1952	79.5	2.2	88.6	(2.7)	69	3.0
8	1953	80.1	0.8	87.4	(1.4)	70	1.4
9	1954	80.5	0.5	87.6	0.2	70	-
10	1955	80.2	(0.4)	87.8	0.2	72	2.9
11	1956	81.4	1.5	90.7	3.3	76	5.6
12	1957	84.3	3.6	93.3	2.9	79	3.9
13	1958	86.6	2.7	94.6	1.4	80	1.3
14	1959	87.3	0.8	94.8	0.2	82	2.5
15	1960	88.7	1.6	94.9	0.1	82	-
16	1961	89.6	1.0	94.5	(0.4)	83	1.2
17	1962	90.6	1.1	94.8	0.3	86	3.6
18	1963	91.7	1.2	94.5	(0.3)	87	1.2
19	1964	92.9	1.3	94.7	0.2	90	3.4
20	1965	94.5	1.7	96.6	2.0	92	2.2
21	1966	97.2	2.9	99.8	3.3	95	3.3
22	1967	100.0	2.9	100.0	0.2	100	5.3
23	1968	104.2	4.2	102.5	2.5	105	5.0
24	1969	109.8	5.4	106.5	3.9	114	8.6
25	1970	116.3	5.9	110.4	3.7	122	7.0
26	1971	121.3	4.3	113.9	3.2	130	6.6
27	1972	125.3	3.3	119.1	4.6	139	6.9
28	1973	133.1	6.2	134.7	13.1	148	6.5
29	1974	147.7	11.0	160.1	18.9	173	16.9
30	1975	161.2	9.1	174.9	9.2	189	9.2
31	1976	170.5	5.8	183.0	4.6	200	5.8
32	1977	181.5	6.5	194.2	6.1	218	9.0
33	1978*	193.2	7.2	207.0	7.1	236	10.3

1967-78 = 6.1

67-78 = 8.1%

Source: "Survey of Current Business"

* First nine months.

TECHNICAL APPENDIX #4

Technical Appendix 4 : Marginal Losses

Define $b = \frac{\text{output}}{\text{input}} \Rightarrow 1-b = \frac{\text{losses}}{\text{input}} \Rightarrow \frac{1-b}{b} = \frac{\text{losses}}{\text{output}}$

b is BECo's Loss Adjustment Factor

From Table T4-I, sales weighted $\frac{1-b}{b}$ should be 30% higher. To increase $\frac{1-b}{b}$ by 30%, we want

$$\frac{1-b'}{b'} = 1.3\left(\frac{1-b}{b}\right) \Rightarrow b' = \frac{b}{1.3-.3b}$$

Peak Period b's

			check		peak b *
	b	b'	$\frac{1-b}{b}$	$\frac{1-b'}{b'}$	$1-\left[(1-b')\times\frac{2013}{1536}\right]$ ← 1977 peak ← Ex.20 LRMCS
PHT	.9641	.9538	.0372	.0484	.9395
PLT	.9336	.9154	.0711	.0925	.8891
SL	.9144	.8915	.0936	.1217	.8579
SS	.8956	.8684	.1166	.1515	.8275
source	Ex-23		$\xrightarrow{}$	30% greater	

$$^{*}\text{from}\left[\text{losses} = (\text{input})^2 R \Rightarrow \frac{\partial\,\text{losses}}{\partial\,\text{input}} = 2\,\text{input}\,R\right]$$

$$^{*}\text{from : losses} = \text{input}^2 R \Rightarrow \frac{\text{losses}}{\text{input}} = \text{input}\,R \Rightarrow \text{peak losses}\,\% = \%\begin{pmatrix}\text{peak}\\\text{period}\\\text{losses}\end{pmatrix} \times \frac{\text{peak load}}{\text{average peak period load}}$$

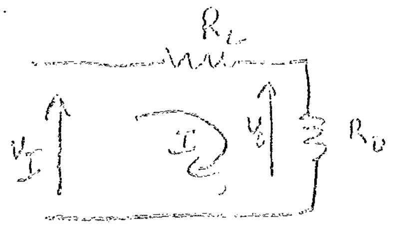
$$\text{Then } \frac{d\,\text{input}}{d\,\text{output}} = \frac{1+\frac{\text{loss}}{\text{input}}}{1-\frac{\text{loss}}{\text{input}}}$$

$$\text{for each period } \frac{\text{loss}}{\text{input}} = (1-b_{\text{peak}})\,\frac{\text{average demand}}{2013}$$

$$\frac{\text{average demand}}{\text{peak}} = \begin{cases} .821 & \text{up} \\ .734 & \text{p} \\ .686 & \text{s} \\ .462 & \text{op} \end{cases}$$

see Table T4-2 for derivation of marginal loss factors by voltage level & period

Derivation of marginal loss formula



$$\text{Losses} = I^2 R_L$$

$$\text{load} = \text{output} = I^2 R_0 = \frac{V_0^2}{R_0}$$

V_0 is constant, as is R_L

$$\text{Input} = \text{output} + \text{losses} = I^2(R_0+R_L) = \frac{V_0^2}{R_0^2}\left(R_0+R_L\right)$$

$$\frac{d\,I_n}{d\,R_0} = -\frac{V_0^2}{R_0^2} - 2\,\frac{V_0^2 R_L}{R_0^3}$$

$$\text{Output} = \frac{V_0^2}{R_0} \Rightarrow R_0 = \frac{V_0^2}{\text{output}} \Rightarrow \frac{d\,R_0}{d\,\text{Output}} = -\frac{V_0^2}{\text{out}^2}$$

$$\frac{d\,\text{Input}}{d\,\text{Output}} = \frac{d\,\text{Input}}{d\,R_0} \cdot \frac{d\,R_0}{d\,\text{output}} = 1 + \frac{2\,R_L\,\text{output}}{V_0^2} = 1 + \frac{2\left(R_L I^2 \cancel{R_0}\right)}{\left(V_0^2\right)}$$

$$= 1 + \frac{2\,\text{losses}}{\text{output}} = 1 + \frac{2\,\text{losses}}{\text{Input} - \text{losses}} = \frac{\text{Input} + \text{losses}}{\text{Input} - \text{losses}}$$

$$= \frac{1 + \frac{\text{loss}}{\text{input}}}{1 - \frac{\text{loss}}{\text{input}}}$$

! ex	losses Gwh
'12	~~X1561~~ 237.1014
87	26.4516
4.	137.2032
6	129.5646
1	55.1131
	585.4339
	11,87
	597.3

597.3 ÷ 8681 = 6.9%

losses ÷ out

78 Forecast

$\rightarrow \frac{8.9}{6.9}$ = 30% increase

Tech

Sept.'7

calcula

co

BECo

Can

Bra

ME

Assum

$\frac{1}{4}$ x

Nov 1979 to

		Primary		Secondary	
Period		High	Low	Large	small
ultra-peak	$\frac{loss}{in}$	.0497	.0910	.1167	.1416
	$1-\frac{loss}{in}$	.9503	.9090	.8833	.8584
peak	$\frac{L}{I}$	.0444	.0814	.1044	.1266
	$1-\frac{L}{I}$	.9556	.9186	.8956	.8734
shoulder	$\frac{L}{I}$	.0415	.0761	.0975	.1183
	$1-\frac{L}{I}$	.9585	.9239	.9025	.8817
off-peak	$\frac{L}{I}$	.0292	.0535	.0685	.0831
	$1-\frac{L}{I}$	.9708	.9465	.9315	.9169

Table T4-2

From these factors, marginal loss ratios can readily be calculated. The marginal losses in the text are similar to those presented in Mass. Electric's marginal cost study.

ASP #P

from P-rate worksheets

57.6% off peak

25.1% shoulder $= \left\{ 42.4\% \times \frac{24.7}{24.7+17.1} \right.$

9.6% peak $= \left\{ 42.4\% - 25.1 - 7.7 \right.$

7.7% ultra-peak $= \left[(\text{July + Aug. peak}) + \frac{\text{July+Aug peak}}{\text{July+Aug p+S}} \frac{2}{3} (\text{Dec+Jan+Feb. P+S}) \right]$

$$= \frac{\left[\left(6569+14332 + \frac{6569+14332}{6569+14332+8064+15659} \times \frac{2}{3} \times (8036+13656+10223) \right) \right]}{265433}$$

↖ assume P/S split same in summer & winter.

Period	Fraction of kwh		SS Cost ¢/kwh		
up	.077	x	14.1	=	1.09
p	.096	x	11.7	=	1.12
S	.251	x	6.5	=	1.63
Of	.576	x	3.4	=	1.96
					5.80 ¢/kwh

Total ASP+AP

from DPU 1-28

current rates	BTCo Prop	Kwh 1976-77	revenue 1976-77	cust # 1976-77 (Ex DI-1)
L-700	P-2	90,735,846	1,853,270	—
L-760	"	4251,733	106,895	—
B-021	"	106,935,268	3,199,571	8,920
B-020	P	265,432,207	9,666,733	18,270 (✓)
B-020	SP	1,705,713,839	79,018,895	438,471
not included	subtract for AP-2	(2431 442	112 834	625)
total -	AP rate	2,172,968,893	93,845,354	465661

p.1 "SP rev"

.058 $/kwh

93,845,354
x1.0604
$99,513,613 1978

126,032,190
-99,513,613
26,518,577 ÷ 465661 = $56.95 /cust/yr = 4.75 $/mo per cust

↖ over

for SP - reduce 1st 100kwh/mn by 2¢/kwh, next200 by 1¢/kwh. ($4/cust/mn)

for P - eliminate meter charge, and give 1¢/kwh credit on 1st 100kwh

ASP - seasonal rates - from P-rate worksheets

peak season - assume July/August period splits

	July + August	%				
ultra peak	10901	20.0	×	14.1	=	2.82
shoulder	13723	25.1	×	6.5	=	1.63
off-peak	29998	54.9	×	3.4	=	1.67
total	54622	100.0				6.12

off-peak season - assume June/September period splits

	June + Sept	%				
peak	5639	13.5	×	11.7	=	1.58
Shoulder	10101	24.1	×	6.5	=	1.57
off-peak	26128	62.4	×	3.4	=	2.12
total	41868	100.0				5.27

SP-1-

Peak months

up   s   OP

$$14126 + \left(\frac{13757}{2} + \frac{24433}{4}\right) + \left(\frac{22586}{2} + \frac{38011}{4}\right)$$

6879 + 6108   11293 + 9503

12987   20796

$$\left.\begin{array}{ll} \text{up} & 14126 \\ \text{S} & 12987 \\ \text{Op} & 20796 \end{array}\right\} \div 47909 = \left\{\begin{array}{llll} ,295 & \times 14.1 & & 4,160 \\ ,271 & \times 6.5 & & 1,762 \\ ,434 & \times 3.4 & = & 1,476 \end{array}\right.$$

7,397 ¢/kwh

x1,15

8.51

Off-peak months

$$\left.\begin{array}{llll} \text{P} & 27439 & = & 27439 \\ \text{S} & 6879+18324 & = & 25203 \\ \text{Op} & 11293+28509 & = & 39802 \end{array}\right\} \div 92444 \left\{\begin{array}{llll} ,297 & \times 11,7 & = & 3,473 \\ ,273 & \times 6,5 & = & 1,772 \\ ,431 & \times 3,4 & = & 1,464 \end{array}\right.$$

6,709¢/kwh

x1,15

7,715

ASP-1/AP-1 Split

P-1 mwH

mwH	UP	P	S	OP
Summer	7495 ←2mn→	7495	13757	22586
Winter	6631 ←2mn 6mn→	19944	24433	38011
Total	14126	27439	38190	60597
÷140352	10.06%	19.55%	27.21%	43,18%

ASP-1 & AP-1

rate	Kwh	Revenue	cust # (VI-1)
P-1	140,352,040	$9,200,357	6526 (6699)
SP-1	124,524,226 12/4 267,892,379 (11/27) ← total	(10,551,590 filing) 10,475,999 12/4 ws 119 741 760 12/29, 11/27	38201 12/4 / 44728 11/29, 11/27 (39039)
use DPU #	↑ # DPU 1-28	19751 947 ← DPU 1-26	→ 45005 total
from v's	264,876266	19,676,356	44727

average rate

.101 x 14.1 = 1.4241

.195 x 11.7 = 2.2815

.272 x 6.5 = 1.768

.432 x 3.4 = 1.4688

6.9424

267,892,379
x .069424
18,598,160

19,751,947
x 1.0604
20 944964
− 18 598160
2346804 under
÷ 45005 = 52^{15}/yr = $4.35/mo

or

2,346,804 ÷ 267,892,379 = .00876 $/kwh

or " ÷ 18 598160 = 12.62% surcharge

AP-2 rev. from worksheet in DPU 1-28

	Kwh	cust	Rev
B022	240 372 535	9384	5,614,384
B023	26 573 349	3401	822,564
D041	2 767 015	306	61,084
241	2516 090	284	60,347
941	500 104	35	6,576
		625	
	272,729,113		6564955
B·020 ≠ D*	2,431,142	—	112 634 (subtract Govt P/SP)
	275,160,255	13410	$6,677,589
	x.0578	x$36/meter-yr	1.0604
		482760	7,080,915

15 904 263

-482 760

-7080 915 (7 563 675)

(8,340,588 over)

discounts

B022 $160/mo x 9384 x 4 = 5,630,400

B023 45 x 3401 x 4 = 612 180

D041/241 45 x 590 x 4 = 106 200

D941 90 x 35 x 4 = 12600

6,361,380

leaving about $2M for audits, loans, & grants {storage, heat pumps, solar, woodstoves, insul.

discount structure

1000 KwhxA @ 6¢
2000 " @ 4¢
1000 " @ 1¢
$150A

where A = {1 B022; .3 B023, D041/241; .6 D941}

* Kwh = 625 ÷ 438471 × 79018893 — 1,705,176,958 kwh — 2,431,1[illegible]

~~Date~~ weighted B022 equivalents

Rate	#	weight	wtd #
B022 ~~9384~~	9384		9384
B023	3401	.3	1020
D041/241	590	.3	177
D941	35	.6	21
			10602

weighted winter bills = 42400

assume we wish to raise per customer

$150 audit + $100 towards loans, grants, etc. for cons. & L.M.

$250 × 13410 = $3.35 M

÷ 42400 = $99 / weighted cust mn

~~lower steps~~ to 4, 2, 1 => $60/old cust mn

8,340,588 ÷ 42400 = 197/weighted cust. mn

B-2

	Kwh total	Kwh summer	Revenue	cust # (VI-1)
B-022	240,372,555	38,621,414	5614384	9331
B-023	26,573,349	3,534,943	822564	3311
D-941	500,104	67154	6576	13 (35)
B-	54720	18088		
	267500728	42,241,599	5,443,524	12655

267500728
-126724797
winter surplus 140775931
÷ 4
35,193,983 /mn
10 580 400
wintertotal ~~45,7543~~83
17.10% /mn
x 4
68.4

42,241,599
x 3
126,724,797
÷ 12
10,580,400 /mn base
3.95% /mn
x 8
31.6 ✓

5,443,524
x 1.0604
5,772,313

$.342 + .079 = .421$

p-p $.17 \times (2 \times 17.1 + 2 \times .0395) = .0716 \times 14.1 = 1.00956$

$.342 + .237 = .579$

p $.17 \times (2 \times .171 + 6 \times .0395) = .0984 \times 11.7 = 1.15128$

$s = .26 \times 6.5 = 1.69$

$op = .57 \times 3.4 = 1.938$

5.79

8022
1000 kwh @ 6¢/Kwh = 60
2000 Kwh x 4¢/kwh = 80
1000 Kwh x 1¢/kwh = 10
150
x 4 mn x 9331 802 = $5,598,600

8023
300 kwh @ 6¢/kwh 18
600 Kwh @ 4¢/kwh 24
300 Kwh @ 1¢/kwh 3
45
x 4 mn x 3311 = $595,960

meters $3 x 12 x 12655 = 455,580
5598,600 (022)
595,980 (023)
6,649,160
17 600
61 7

D - twice 8023 kwh
90 x 4 x 35 = $12,600

P-2

Calculation of
Extra Winter Use

Kwh / cust - yr
P-2

winter surplus (~~F~~ summer)

B-021 11890 1273 337 ÷ 4 = 85 / m

022 25760 " 13343 ÷ 4 = 3300

023 8025 4823 ÷ 4 = 1200 kwh/m D-March

D/B 15852 (assume 35 cust $\overset{\text{on } P2}{}$ - see Ex $\underline{V}$/-)) 85-46 = ~~2~~ 100 /m

P 14528 $\boxed{-1316}$ Summer 5281 × 3 = 15844

SP 3734 ÷ 12 = 311

B-020 $\frac{24311}{\div 625}$ annual using B022 ratio $\frac{3336}{25760}$ = .13 surplus kwh/mn | using D911

D041 9042 + 3890 = 12932 1675 | 1350

241 8859 + 3890 = 12749 1651 | 1322

941 14289 + 3890 = 18179 2354 | 2133

941 Summer use = 67,154 ÷ 35 = 1919/cust
× 3
annual 5757/cust (@ summer levels)
(assume no change in B020 use)

14289
− 5757
8532 winter surplus
÷ 4
2133 /mn
÷ 14289 = 14.9%

winter surplus kwh/mn
× 9042 = 1350
× 8859 = 1322

AT-1

	Average					
	P-1	T-2	T-1		SL	
Pp	10.1%	9.0%	.09.6	x	13.3	= 1.2768
P	19.5	18.2	.18 8	x	11.0	= 2.068
S	27.2	33.7	.30 5	x	5.1	= 1.5555
O	43.2	39.1	.41.1	x	3.2	= 1.315 2
			100.0			6.2155

Kwh 1,728,187,983
x 6.2155
$ 107,415,524

rev. req. $70,967,361
x 1.0604
$ 75,253,790

- 75,253,790 rev.
32,161,734
- 634,032 meters
$ 31,527,702 over

meters 17612
x $36/yr P
634,032

÷ 17612 x 12 = $149.18 /cust mn
÷ 1,728,187,983 = 1.82¢/kwh
÷ 75,253,790 = 41.9% surcharge on rates

Credits 5¢/kwh x1000 kwh
4 x 1000
3 x 1000
2 x 1000
1 x1000
≥ $150 / (cust) mn

8177 kwh/cust mn average

AT-2

P-P/P S O

Summer 184,790,707 229 140477 ~~122 731 643~~

P-P/P + S
41393,184
44.6% 55.4%
92,395,353 92,395,354

,325 231 643

Winter 810 235 647
446.4
11.15 33.45 65.4 %

662,920,075

325,231,643

PP P
90,341,274 271,023,824 448 816 548
Summ 92 395 353 92 395 353 229 140477
182,736,627 363,419,177 678,011,025

988,151,718.04

184.8
229.1
122.7
810.2
662.9
09.7

total Kwh = 2,212,318,549

%

PL

	%				
P-P	18.260	x	12.4	=	1.0242
P	16.427	x	10.4	=	1.7084
S	30.647	x	5.7	=	1.7469
Op	44.666	x	3.0	=	1.3400
	100.000				5.8195 ¢/kwh

÷ 1358x12 = $2753/cust/yr
÷ Kwh = 2.03¢/kwh
÷ 124,746,200 = 34.84% reduction in rates

.058195 x 2,212,318,549 = $128,746,200
− 83 595,561 = 78,833,988 x 1.0604
45,150,684 over
+ 293,328
44,857,356 over net

meters 1358 cust x 12 x $18 = $293,328

KK = 18,835,780

T-2 * allocated on @ T-3 (4/6/78)

Summer

	P	S	O
H	132,99,416	16,491,278	23,406,973
	43,649,816	54,125,771	76,823,675
L	127,841,475	158,523429	225,000,995
	184790707	229,140,477 ✓	327,231,643
	229140477		
	413931184		

	S	O
H	63.314 160	51,802,495
G	201 076 112	164,516,819
L	545,845375	446,600,761
	810235647 ✓	662,929,075 ✓

Demand

H	1,267,837
G	3,023,303
L	2,216,587

} Rate / T allocation

2009,7
203
2212

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AT-3

	U-P/P		S	O
Summer	153,767,750*		190,672,010*	270,631,238*
[P+S]		344,439,760		
[P/o split]	44.64		55.4%	
[Resume P + U-P]	7688,3875	76,883,875		

Winter 674 212 000*

.446 → 300,987,500 .554 → 373,224,500 551,628,000*

2mos → 75,246,875 6mos → 225,740,625

153,130,750	302,624,500	563,896,510	$ 22,259,238

Total Kwh Σ = 1,840,910,998

average bill @ [illegible] = 564, [illegible]

	Fraction of Kwh		HT cost ¢/kwh		
U P	.08264	x	11.2	=	.93
P	.16439	x	9.4	=	1.55
S	.30631	x	5.1	=	1.56
OP	.44666	x	2.7	=	1.21
	1.00000				5.24

.0524 x 1,830,910,998 kwh = 96,445,272

revenue target: 43,[illegible] x [illegible] (96,[illegible])

meters [illegible] ([illegible])

[illegible] overcollection