The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

June 30, 1988

D.P.U. 87-260

Investigation by the Department on its own motion as to the propriety of the rates and charges set forth in the following schedules: M.D.P.U. Nos. 622 Residential R-1, 623 Residential Space Heating, 622/623 Interruptible Rider Applicable to Schedules R-1 and R-3, 624 Residential Time-of-Use, 625 Large Residential Time-of-Use, 626 Optional Controlled Water Heating, 627 Optional Church, 628 Small General Service, 629 Small General Service Time-of-Use, 630 Secondary General Service, 631 Primary General Service, 630/631 Rider A Applicable to Schedules G-1 and G-2, 632 Nonindustrial Primary Service T-4, 633 Industrial Primary Service T-5, 634 Large Nonindustrial Primary Service T-6, 635 Large Industrial Primary Service T-7, 636 Transmission General Service T-9, 637 Street and Security Lighting S-1, 638 Partial Streetlighting Service S-2, 639 Interruptible Service Menu I-1, 640 Intermediate Interruptible Service Menu I-2, 641 Energy Conservation Service Rider, 642 Supplemental Power Service, 643 Primary Firm Back-up and Maintenance Power Service P-2, 644 Secondary Firm Back-up and Maintenance Power Service P-3, 645 Rider Applicable to R-1, R-3, R-4, R-5 and T-1, filed with the the Department on December 17, 1987 to become effective January 1, 1988 by the Western Massachusetts Electric Company.

APPEARANCES: Robert S. Cummings, Esq.
Robert L. Dewees, Jr., Esq.
Duncan S. Payne, Esq.
Peabody & Brown
One Boston Place
Boston, Massachusetts 02108
FOR: WESTERN MASSACHUSETTS ELECTRIC COMPANY
<u>Petitioner</u>

James M. Shannon, Attorney General
By: Joyce Davis, Esq.
Alycia K. Lyons, Esq.
Jerrold Oppenheim, Esq.
One Ashburton Place
Boston, Massachusetts 02108
<u>Intervenor</u>

Andrew J. Newman, Esq.
Rubin and Rudman
50 Rowes Wharf
Boston, Massachusetts 02110
FOR: KIMBERLY-CLARK CORPORATION
MONSANTO COMPANY
MEAD CORPORATION
<u>Intervenors</u>

Robert M. Granger, Esq.
Nicholas J. Scobbo, Jr., Esq.
Ferriter, Scobbo, Sikora, Caruso &
Rodophele
One Milk Street
Boston, Massachusetts 02109
FOR: CITY OF SPRINGFIELD
<u>Intervenor</u>

Roger D. Colton, Esq.
National Consumer Law Center
11 Beacon Street
Boston, Massachusetts 02108
FOR: HAMPSHIRE COMMUNITY ACTION
COMMISSION, INC.
<u>Intervenor</u>

TABLE OF CONTENTS

V. RATE STRUCTURE

A. Rate Structure Goals

Rate structure is the level and pattern of prices that customers are charged for use of utility service. A class' rate structure is a function of the cost of serving that rate class and the design of rates calculated to cover that cost. The Department's goals for utility rate structure are efficiency, simplicity, continuity, fairness, and earnings stability.

There are two steps in developing rate structure: cost allocation and rate design. Cost allocation entails assigning a portion of a utility company's total costs to each rate class. Rate design entails determining a set of prices for each rate class which is projected to produce the allocated revenues.

In order to permit the development of a rate structure which meets the Department's objectives, the allocation process should determine an overall revenue requirement for each class which reflects the costs a company incurs in serving that class. Cost allocation comprises five tasks. The first task is to functionalize costs. In this step, costs are defined as being associated with either the production, transmission or distribution function of providing service. The second task is to classify expenses in each functional category according to the forces underlying their incurrence. Thus, the expenses are classified as demand-, energy-, or customer-related. The third task is to identify an allocator which is most appropriate for costs in each classification within each function.

The fourth task is to allocate all of the company's costs to each rate class based upon the cost groupings and allocators chosen, and to sum these allocations in order to determine the total cost of serving each rate class. The fifth and final task is to compare the cost of serving each rate class to the revenues produced by each rate class during the test period. If the difference between these amounts is small, the total revenue increase or decrease may be allocated among all rate classes to equalize rates of return and to ensure that each class pays for the costs it imposes. If the differences between the allocated costs and test year revenues are great, the revenue increase or decrease may, for reasons of continuity, be allocated to reduce differences in rates of return without equalizing them in a single step.

In order to promote the Department's goals for rate structure, rate design must meet two objectives. First, it should produce a set of rates for each rate class which generate revenues covering the cost of serving that class. Second, rate design should be based on marginal cost. Economic theory indicates that marginal-cost-based prices tend to lead to the efficient allocation of resources.

There are four steps in rate design. First, a company must perform a marginal cost study which accurately determines a company's marginal costs. Second, marginal costs must be converted into rates for each rate class. Third, the marginal-cost-based rates must be reconciled with the total class revenue requirement by adjusting the most inelastic portion of that rate. Fourth, the resulting rate structure must be compared with the existing rates. If it is found to represent a change which violates the goals of continuity, the existing rates must be adjusted to move rate design toward marginal-cost-based rates in a manner which does not violate the goal of continuity. Massachusetts Electric Company, D.P.U. 85-146 (1986). Boston Edison Company, D.P.U. 85-266-A/85-271-A (1986). Western Massachusetts Electric Company, D.P.U. 85-270 (1986). Western Massachusetts Electric Company, D.P.U. 86-280-A (1987).

B. Cost Allocation

1. Load Research

The five-step cost allocation process described above presumes the availability of accurate and reliable load data obtained through load research. Load research is the study of company loads by rate class and for the total system. It enables a company to determine its system peak and individual class peaks. Using load research, a company can develop load profiles for demand and energy for each class and for the company as a whole for each hour of the year. Detailed information about system and class loads in each hour is a necessary input for the probability of dispatch cost allocation method ("POD"), which WMECo used in this case.

The Company collected most of the load data it used in allocating costs to its retail classes during the test year. For rate class G-0 the Company used 1984 load data from a test sample of small commercial and industrial customers with demands between 2 and 50 kilowatts ("KW"). For the G-1 and G-2 classes, the Company used 1985-1986 load data from a test sample of intermediate commercial and industrial customers with demands between 50 and 350 KW. WMECo states that it is currently collecting data on these classes in three separate load research tests and its future cost of service study ("COSS") analyses will be based on class-specific data. The Company has also established new load research samples for the R-1, R-3 and T-2 classes in order to improve the accuracy of future load estimates for those classes (Exh. WM-9, pp. 12-15).

In D.P.U. 86-280-A, the Department found that the Company must verify that its load data are normally distributed and therefore compatible with its POD method of developing capacity and energy allocators; or, if the data are not normally distributed, the Company must modify its method or adjust its data. In the present case, the Company made adjustments to its load data in order to enhance the data's consistency with a normal distribution so they would be compatible with the POD allocation process. Loads for six days of the test year were weather-normalized. In addition, the Company assigned loads occurring on December 24 and 26 to the off-peak or weekend category, in order to account for effects of the holiday season (Exh. WM-9, pp. 11-12).

2. Consolidation of Jurisdictional and Retail COSS

In past rate cases, the Company has filed both an actual test year jurisdictional COSS, segregating the Company's wholesale and retail business, and a retail COSS reflecting rates in effect at test year-end and cost of service adjustments requested by the Company. In this case, the Company states that, because a de minimis portion of its business is wholesale, it filed a single system-wide pro forma COSS which encompasses both retail and wholesale revenues and expenses (Company Brief, p. 97). The Company's witness, Mr. Berthold, explained that the results of a single study would be substantially the same as the results of two separate studies using the same methodology (Tr. XI, p. 12).

In Massachusetts Electric Company, D.P.U. 200, p. 32 (1980), the Department required a jurisdictional cost of service study of companies requesting an inflation allowance. The Department has also stated that companies requesting an inflation allowance would not have to provide a jurisdictional cost of service study if their nonjurisdictional sales were negligible (Boston Edison Company, D.P.U. 906, p. 72 (1982)) and that they would have to provide a jurisdictional cost of service study if nonjurisdictional sales accounted for more than 2 percent of total electric sales revenues (Commonwealth Electric Company, D.P.U. 956, p. 40 (1982)). In Boston Edison Company, D.P.U. 1350, p. 213 (1983), the Department extended use of the jurisdictional cost of service study to allocate all adjustments to revenue requirement, not just an inflation allowance. The Department finds that, in this case, in which WMECo's wholesale business constitutes approximately 0.7 percent of its total business, there would be a de minimis difference between the total retail revenue requirement as determined through a separate jurisdictional COSS and through a single COSS which segregates the Company's wholesale business. It is therefore appropriate to accept a cost of service study encompassing both the Company's retail and wholesale business.

3. Cost of Service Study

In performing its retail cost of service study, WMECo allocated production plant using a modified-peaker POD method similar to that used by the Company in its rate case D.P.U. 86-280. This method is described below. The Company allocated transmission plant using a three-coincident-peak allocator reflecting transmission loads during winter a.m. and p.m. peaks and the summer peak. Demand-related distribution plant was allocated using maximum noncoincident demand at the substation level. Customer-related distribution plant was directly assigned. Conservation program expenses were allocated to those classes eligible to participate based on the number of customers in each class or on the POD demand allocator for each class.

4. The Probability of Dispatch Method

a. Description

The POD method allocates a generating unit's capacity costs and energy costs over all hours in which a unit operates.[4] These costs, in turn, are allocated to customer classes consuming electricity during those hours, in proportion to their load during those hours.

WMECo based its allocation in this filing on a POD model called PRODIS, which was used in its last rate case. The PRODIS model used by the Company in the present case and in D.P.U. 86-280 incorporates an enhancement called the "modified peaker approach," described infra.

Using PRODIS, the Company first allocated NU's capacity costs over all hours of plant dispatch. The Company then adjusted the hourly capacity costs to reflect WMECo's capacity costs as assigned to WMECo under the Northeast Utilities Generation and Transmission ("NUG&T") Agreement. The NUG&T Agreement establishes the method of allocating generation and transmission costs among Connecticut Light and Power Company, Hartford Electric Light Company, Holyoke Power and Light Company, Holyoke Water Power Company, and Western Massachusetts Electric Company. These companies plan, construct and operate

---

4/ The Supreme Judicial Court recently affirmed the Department's decision in D.P.U. 86-280-A approving the Company's use of the POD method. Monsanto Company v. Department of Public Utilities, ______ Mass. ______ (June 13, 1988).

their generation and transmission facilities on a one-system basis, although each of the companies owns or has ownership shares in these facilities individually. Under the NUG&T, capacity costs are allocated to WMECo based on the ratio of WMECo's peak during the most recent sixteen months to the sum of all NU affiliates' sixteen-month peaks.

The Company made several changes to the PRODIS model for this rate case. First, it expanded the number of customer classes which could be analyzed in the model from twelve to twenty-four. Second, it modified the model so that it could compute monthly production revenue requirements for each unit on the basis of each unit's monthly, rather than annual, capacity costs. The Company made this change because the availability of some of NU's units varies significantly across the year because of partial-year sales or purchases (Exh. WM-9, p. 9). Third, WMECo adjusted the POD model to accommodate monthly energy and capacity costs calculated using a separate monthly NUG&T demand percentage and energy percentage. Previously, a single monthly percentage was used in the model to allocate both NU's capacity and energy costs to WMECo.

The Company also changed the way in which it computes capacity costs for the POD. In order to adjust for differences in capacity costs which occur because the Company's units were installed at different times, all capacity costs were expressed in current dollars (Exh. WM-9, p. 2). The Company translated capacity costs into current dollars using the Handy-Whitman index, which provides inflation factors for plant components.

Using PRODIS, the Company performed the following steps in developing its POD capacity allocators (Exh. WM-9, pp. B-6 to B-13):

The Company simplified NU's hourly loads for the test year by modeling 576 typical hours, each typical hour corresponding to one of the 24 hours of a weekday or weekend day in each month. Using the average load and standard deviation of load in each hour, and assuming that loads were distributed normally, the Company developed a load probability distribution for each typical hour.

Next, the Company modified its load estimates to take into account the impact of its Northfield Mountain unit, a 1,000 MW pumped storage hydro facility. WMECo developed a simplified model of Northfield dispatch, using NU system load data, fuel prices, capacity purchases and capacity sales for the test year, and the 1988 WMECo unit performance goals. The model produced a set of pumping requirements and generating output anticipated from Northfield. WMECo subtracted Northfield's generation from NU system load to determine net generating requirements to be satisfied by run-of-river hydro and conventional thermal generation and recomputed hourly load distributions for the net requirement.

The Company used a simplified model of economic dispatch for its generating units to determine a dispatch sequence and to identify the threshold load level at which each unit would be dispatched. Unit maintenance and outages were normalized over the year; each unit then was assigned a continuous capability rating based on its 1988 performance goals. For simplicity, WMECo grouped together a number of smaller peaking units with similar operating costs, treating them as one unit in the dispatch sequence. The Company also grouped together run-of-the-river hydro, power purchases, cogeneration and a minimum load for each nuclear unit as a must-run component to be dispatched in all hours.

Next, the Company compared hourly load probability distributions to the threshold load levels at which each unit would be dispatched according to the economic dispatch sequence, in order to calculate the probability that each unit would be dispatched in a given typical hour. The Company then normalized the probabilities of dispatch so that all probabilities summed to one.

The Company multiplied NU's revenue requirement for each unit by the probability of dispatch in each hour, thus distributing the total revenue requirement of each unit over the 576 typical hours. It then multiplied the resulting hourly NU revenue requirement by the capacity percentage assigned to WMECo in that month through the NUG&T Agreement, thereby deriving for each unit a matrix of revenue requirement associated with each typical hour.

Finally, the Company summed the matrices for all units into a total revenue requirement matrix assigning WMECo's total revenue requirements to the 576 hours. These costs were then allocated to customer classes based on each class's proportion of the load in each hour. To simplify application of the results, the Company summed the appropriate peak and off-peak hours to derive peak and off-peak allocators.

b. The Modified Peaker POD

The PRODIS POD model used by the Company incorporates a modification of the POD called the "modified peaker" approach. In the Company's modified peaker method, generating unit capital costs are segregated into "pure capacity costs," equal to the costs of the least capital-intensive unit which may be used to meet load, in this case a gas turbine, and costs in excess of those of a peaker. The pure capacity component of costs is allocated exclusively to the peak period. Excess costs are allocated among all hours of unit dispatch using the conventional POD method (Exh. WM-9, p. B-14).5/

c. Energy Allocation

To ensure consistency between capacity and energy allocators, the Company used a POD energy allocation process similar to the POD capacity allocation. In order to derive a total energy cost for all units excluding Northfield, WMECo dispatched NU's thermal and conventional hydro resources against

---

5/ The phrase "modified peaker POD" does not have a standardized meaning and may refer to several modifications of the POD method. In its recent rate structure case, Cambridge Electric Light Company used the same phrase to describe an adjustment to the POD in which it allocated pure capacity costs to the hours in which the Company's peaking facilities operated. See D.P.U. 87-221, p. 23 (1988).

system loads, excluding generation used for pumping to Northfield and loads satisfied by Northfield generation. In modeling this base case, the Company used the same dispatch sequence and effective continuous capacity ratings used to develop capacity allocators. WMECo then ran a second dispatch simulation using system loads including Northfield pumping and generation. The inclusion of Northfield resulted in new, lower total-period energy costs. The difference between costs in the two cases constituted the energy savings attributable to Northfield. The total Northfield energy savings amount was multiplied by Northfield generation in each of the 576 time periods and the resulting savings associated with each time period were then subtracted from the thermal system's base-case energy costs to derive total energy costs for each period. The Company multiplied total costs by WMECo's NUG&T energy percentage to derive WMECo's energy costs for each period. Within each time period, costs were allocated to customer classes on the basis of each class's portion of the total system load. Finally, energy cost allocators were summed into peak and off-peak allocators.

d. Parties' Positions

i. Industrial Intervenors

The Industrial Intervenors contend that the COSS presented by the Company is flawed and must be rejected. Specifically, they assert that the Company's POD does not reflect the role of customers' peak demand in determining WMECo's total capacity costs under the NUG&T (Industrial Intervenors Brief, p. 8). First, they argue that the POD method used by the Company fails to reflect changes in customer load. To support this contention they point to a sensitivity study prepared by their witness, Mr. Rosenberg, indicating that if there were a 10 percent reduction of load in each on-peak hour for Rate T-7 and an equal increase in its off-peak load, that class's capacity responsibility would decrease only by 1.44 percent under the POD.

Second, the Industrial Intervenors assert that the Company's modified-peaker POD fails to reflect peak demand costs because it spreads peaker costs over all peak rating hours rather than over the smaller number of hours when a peaker would actually be expected to run. The Industrial Intervenors say this spreads capacity costs to nonpeak hours, thus understating peak costs and overstating off-peak costs (Industrial Intervenors Brief, pp. 9-10).

Third, the Industrial Intervenors claim that WMECo's modified-peaker POD understates embedded peak capacity costs because it fails to increase the cost of pure peaking capacity sufficiently to reflect the effective forced outage rate ("EFOR") of a peaking unit. The Industrial Intervenors state that in the POD dispatch each unit is derated based on its own operating characteristics to determine its cost per KW of load-carrying capability, yet the hypothetical peaker is derated using a system-wide NEPOOL reserve margin of 22.5 percent. According to the Industrial Intervenors, the 22.5 percent margin is not a unit-specific measure and it vastly understates the cost per KW of load-carrying capability of a peaker. They argue that use of an industry-wide equivalent forced outage rate ("EFOR") for a combustion turbine could serve as a reasonable proxy for Company-specific data on turbine performance and should be used, in this case, in place of the NEPOOL reserve (Industrial Intervenors Brief, pp. 10-11).

Fourth, the Industrial Intervenors claim that the POD method filed by the Company fails to reflect the monthly peak load demands of each class. They assert that, under the POD method, variability of loads is critical to proper cost allocation because probabilities of dispatch are a function not only of demand in a time period, but also of the standard deviation of expected demand. They further contend that averaging approximately twenty hourly weekday demands obscures important information regarding the extremes of class demands which actually contribute to the peak weekday in each month. The Industrial Intervenors state, "[t]he averaging process removes the extremes of each class which actually contribute to the peak weekday in each month" (Industrial Intervenors Brief, pp. 11-12) and that "[j]ust because a customer requires less demand on one day this does not lessen the need for power on a peak day" (id., p. 12).

In their reply brief, the Industrial Intervenors agree with Springfield's assertion (see infra) that if two periods have the same mean load, the Company's dispatch algorithm will allocate higher costs to the period in which loads are more variable (i.e., have a larger standard deviation). The Industrial Intervenors also agree with Springfield's judgment that this allocation is unfair. Yet they also state that when two periods have the same mean load, if the POD does not allocate more capacity costs to the hour with the higher standard deviation, the method is not rational because "if two hours have the same mean load, the one with the higher standard deviation has a greater chance of being the annual peak" (Industrial Intervenors Reply Brief, p. 7).

The Industrial Intervenors urge the Department to adopt a COSS presented by their witness, Mr. Rosenberg. Mr. Rosenberg ran the modified-peaker POD model using an EFOR of 53.98 percent rather than the NEPOOL reserve margin of 22.5 percent to calculate the amount of peaker costs to be assigned to the peak periods. He then assigned the peaker costs to the hours when a combustion turbine would be expected to run rather than to all peak hours. In addition, he modified the POD to use class loads on the days of WMECo's monthly peaks to assign class responsibility. The Industrial Intervenors contend that this modification more accurately reflects the NUG&T Agreement (Industrial Intervenors Brief, p. 13).

The Industrial Intervenors state that, notwithstanding the modifications presented by Mr. Rosenberg, the POD continues to overallocate capacity costs to the off-peak hours and to street lighting and large primary classes. The Industrial Intervenors say that the POD overstates off-peak costs because of the way in which it models must-run units. The Company allocates must-run unit costs over all hours, even hours in which load is likely to be less than total must-run capacity. The Industrial Intervenors did not present a specific proposal for reallocating must-run costs, but recommend that such an adjustment be considered in the next WMECo rate case. They also raise the possibility of an adjustment which would recognize typical capacity costs per technology rather than actual unit costs. They assert that through such a method the cost of baseload plants would be standardized and cost differences among baseload plants would not affect the class responsibility of various customer classes (Industrial Intervenors Brief, p. 15).

ii. Springfield

Springfield argues that there are three aspects of the Company's POD method which, because of the specialized, deterministic nature of street and area lighting load, cause the Company's model to overstate the cost responsibility of street and area lighting customers. Springfield contends that this imposes a hardship on street lighting customers because they are "captive" and cannot shift load to other periods or change energy sources.

First, Springfield advocates replacing NU loads and generating resources with a WMECo own-load dispatch in the POD model. According to Springfield, use of NU loads and resources in the POD is premised on the assumption that WMECo's production costs are a fixed percentage of NU's system costs. Springfield contends, however, that WMECo's resources and loads are not a simple pro rata share of NU's resources and loads. Springfield states that the production costs allocated by means of the POD are WMECo's own costs per book, excluding debits and credits associated with the NUG&T, which are reflected in the fuel charge (Springfield Brief, pp. 6-7). Furthermore, WMECo's load characteristics differ from those of NU; NU's loads are relatively greater than those of WMECo during hours when street and area lights are operating. Specifically, Springfield contends that during the test year NU experienced evening peaks in the months of November through February, while WMECo had an evening peak only in December (Springfield Brief, p. 10; Exh. SPFLD-20). Springfield states that actual use of resources by WMECo customers is best reflected by an own-load dispatch. It states that it would be groundless to base an argument that own-load dispatch is inappropriate on the fact that NU resources are planned and dispatched as a system, when in fact all NU system resources are dispatched by NEPOOL (Springfield Brief, pp. 5-12).

Second, Springfield maintains that the Company's must-run modeling of nuclear capacity does not reflect actual operating constraints and distorts the allocation of capacity costs to low-load periods. The Company placed most of the capacity of its nuclear units into the must-run group. Springfield argues that this arbitrarily forces the bulk of nuclear costs into all hours regardless of load requirements. Springfield states that this treatment of nuclear units was not consistent with the way in which the Company models nonnuclear units in the POD, even though the Company's witness, Mr. Stillinger, testified that minimum load levels exist for all units. Springfield contends that, under Springfield's proposed alternative economic dispatch approach, Millstone 3 would be the last nuclear unit to be dispatched, since it has the highest running cost, and its capacity costs would be allocated fully only to those hours in which load equalled or exceeded 2,035 MW. Springfield points out that this is particularly important to street lighting customers since the hours in which full Millstone 3 capacity is not needed under its version of economic dispatch are all hours when street lighting is operating. Springfield says that adoption of a full economic dispatch method will be even more important to street lighting customers as Millstone 3 capacity costs are phased in (Springfield Brief, pp. 13-18).

Third, Springfield states that the Company has failed to demonstrate that its use of the normal distribution is an appropriate means of modeling the probable dispatch of generating resources. Springfield contends that the Company is mistaken in assuming that loads in a given period are normally distributed. Springfield argues that while the Shapiro-Wilk test, which the Company used to test the normality of its data sets, may be capable of identifying nonnormal data sets, data sets not rejected by the test are not necessarily normal.

Furthermore, the Company tested only total system data, while the POD method was applied to total system load less Northfield Mountain generation (Springfield Brief, pp. 20-21).

Fourth, Springfield states that the Company's use of average loads to allocate costs to customer classes discriminates against customers with invariant loads, including street lighting customers. Springfield states that the Company's dispatch algorithm measures only the probability that load will exceed a given load level and that resources higher in the dispatch sequence will be needed. Springfield says the algorithm does not take into account the probability that the load will be lower than a given level and that fewer generating resources will be needed. It therefore concludes that capacity costs isolated for each time period using the one-sided distribution correspond to peak loads in each period (Springfield Brief, p. 22).

Springfield asserts that, at the same time, the Company uses average class loads to allocate costs which it has isolated using peak demand. Thus, according to Springfield, "[c]lasses with variable loads escape the costs they have drawn into the period as a result of that variability" (Springfield Brief, p. 22). Even though street lighting load is stable, street lighting is assigned a portion of capacity costs associated with the variability of demand above average, according to Springfield.

Finally, Springfield takes issue with the Company's use of a deterministic dispatch model, and in particular, use of a deterministic dispatch model combined with probabilistic loads. Springfield states that by assuming that units are always available at their derated capacity, the Company's model understates the use of peaking units and therefore understates on-peak costs. Springfield argues that forced outages are random and normally distributed and hence should be treated in a probabilistic rather than deterministic manner. It favors a POD model in which unit outages are modeled as random variables, and probable loads to be served by a given unit are calculated based on random failures of resources lower in the dispatch. Alternatively, Springfield would favor a dispatch of derated resources against actual test year hourly loads (Springfield Brief, pp. 25-28).

Springfield points out that the Company's current model yields a finite probability that loads will exceed all available resources, although the Company does not associate any cost with a need for exogenous resources and the Company disputes that exogenous resources are actually required (Springfield Brief, p. 28).

For these reasons, Springfield recommends that the Department reject the Company's POD method in favor of an own-load dispatch POD. Springfield has recalculated the POD allocator for street lighting using a WMECo own-load economic dispatch of resources (Springfield Brief, Appendix).

iii. Attorney General

The Attorney General asserts that the POD method is fair and reasonable and should be retained.

The Attorney General opposes the Industrial Intervenors' proposal to adjust peaker costs in the modified-peaker POD method by the typical EFOR of a peaker. The Attorney General claims that the Industrial Intervenors are ignoring the maintenance inefficiencies inherent in other types of plants such as large nuclear baseload units (Attorney General Brief, p. 139).

iv. Company

The Company used a probability of dispatch method in its cost of service study in accordance with the Department's decisions in D.P.U. 85-270 and D.P.U. 86-280-A. WMECo continues to prefer the average and excess demand/twelve coincident peak ("AED/12CP") method and requests that this method be used in the Company's next rate proceeding (Company Brief, p. 105). The Company states that this method is the most appropriate method for allocating costs because it most accurately reflects cost-incurrence on the NU system, including the effects of demand and energy consumption (id.).

In response to Springfield's criticism that WMECo did not demonstrate that its load data were normally distributed, the Company says that only 9.2 percent of 53 of its data sets could not be demonstrated to be normal at the .05 significance level. The Company also states that there is no statistical test which can prove that data are normally distributed. Further, the Company states in its brief, "[t]he loads used for the computations of the allocators in the first piece [i.e., loads modified by Northfield generation] have been tested since and were found to be 90 percent normally distributed at the .02 level" (Company Brief, pp. 127-128).

e. Analysis and Findings

i. Industrial Intervenors' Critique of the POD

The Industrial Intervenors argue that the POD method used by the Company fails to reflect changes in customer load. Mr. Rosenberg's sensitivity analysis of shifts in use from peak to off-peak, however, does not constitute evidence that the POD is inappropriate. The relatively small change in cost allocation given a shift in use from peak to off-peak by proposed class T-7 reflects the fact that WMECo's system includes a large baseload component whose capitalized energy costs are allocated over all hours.

The Company's modified-peaker POD separates out the peaker portion of each unit's costs and allocates it to peak hours on the assumption that it represents pure capacity. The Industrial Intervenors argue that the peaker portion of costs in the modified-peaker method should be spread over fewer hours. The Industrial Intervenors recommend allocating peaker costs only to hours in which peakers are expected to operate. Yet units do serve a capacity function over all peak hours, which are determined by the Company through its analysis of rating periods (described infra). Depending on a utility's load shape and generating system configuration, including its pumped hydro capacity, allocating pure capacity costs only to hours in which peakers operate might restrict pure capacity costs to fewer hours than those having a significant probability of being peak hours. Thus, the Company has chosen a reasonable modeling approach. While the Industrial Intervenors' proposal might be appropriate for some utility systems, it is not necessarily the best method of allocating peaker costs in all situations.

In D.P.U. 86-280-A, the Department invited parties to consider whether pure capacity costs should be calculated in a manner which would take into account peaker reliability. Western Massachusetts Electric Company, D.P.U. 86-280-A, p. 143. In a table summarizing variations of the POD considered for this case, the Company shows that it has calculated POD capacity allocators using the modified peaker and setting peaker costs at twice the actual unit costs to estimate a reserve margin higher than the NEPOOL 22.5 percent margin (Exh. II-3). The Company's witness stated that the Company presented the results of this method to show that it "doesn't really have much of an effect on the results" (Tr. XI, p. 34).

The purpose of the POD is to develop a capacity allocator for embedded costs. WMECo's total embedded costs are a function of capacity installed to meet WMECo's loads plus additional capacity needed to meet the Company's share of NEPOOL's reserve requirement. Thus, total installed capacity and total embedded costs reflect reserve margin requirements. Upward adjustment of pure capacity costs by the EFOR of a peaking unit would not be appropriate since the Company does not determine the timing and size of capacity installations based on its loads adjusted by individual unit reliability. Instead, the Company has used the 22.5 percent NEPOOL reserve margin to inflate peaker costs in order to adjust total capacity costs for the average effect of unit derating.[6/] The Department therefore finds that the Company's method of adjusting peaker capacity costs is appropriate.

A POD based on customer loads on the WMECo monthly peak day does not constitute a probability of dispatch method. A modified-peaker POD allocates unit costs in excess of peaker costs based on all hours of unit operation; the Industrial Intervenors' method would ignore most hours of unit operation and typical loads, focusing only on unit operation and class loads on high demand days. The Department, therefore, does not accept the proposal of the Industrial Intervenors.

ii. Springfield's Critique of the POD

Springfield favors a WMECo own-load dispatch to allocate the costs which it claims are WMECo's own costs per book. Springfield's claim that the production costs which the Company

6/ The Company has not explained its use of the NEPOOL reserve margin rather than the Company's own reserve requirement. In its next filing, the Company is directed to address the appropriateness of using NEPOOL's versus the Company's own required reserve margin to adjust capacity costs in the modified-peaker method.

seeks to allocate by means of the POD method are not a fixed percentage of NU's total costs, but are the Company's own costs per book excluding interexchange, is incorrect. WMECo allocates all costs attributable to the Company, and then, for rate design purposes, deducts costs which flow through the fuel charge, including NUG&T credits and debits. NUG&T credits and debits are included in the COSS and allocated using the POD capacity allocators. Thus, the Company is allocating its total costs net of the NUG&T's effects, and not, as Springfield asserts, its own costs per book.

Springfield points out that the Company's POD model yields a finite probability that loads will exceed resources; but as the Company states, under Springfield's own-load model, average WMECo load net of Northfield generation in some typical hours exceeds available capacity. This result appears to be anomalous for the Company. NU's system is planned and operated as a single system and WMECo's customers are served by plants owned by Connecticut Light and Power Company. Thus, the Company's use of an NU single-system dispatch is more appropriate than Springfield's own-load dispatch since it recognizes that capacity allocation should reflect the actual use of resources by Company customers.

Springfield argues that the Company's modeling of must-run nuclear capacity does not reflect actual operating constraints and distorts the allocation of capacity costs to low-load periods. In D.P.U. 86-280-A the Department found that while the full rating of the must-run component may exceed system demand during certain off-peak hours, the PRODIS model appropriately matches expected loads and derated unit capacity. The large must-run component dispatched in WMECo's model is a function of WMECo's system configuration, which includes a large nuclear baseload component. It is appropriate for the Company to reflect this operational constraint in its POD model, but the Company should explain its method for calculating the must-run portion of each of its units. In this case, the Company's witnesses provided only a general explanation of the Company's approach (Tr. XII, pp. 59-60; Tr. XV, pp. 90-91). The Company's next filing should present a detailed description of the Company's method for determining the must-run component.

The Company is correct in stating that since only 9.2 percent of its data sets could not be demonstrated to be normal at the .05 significance level, this indicates a high degree of normality. The Company is also correct in stating that no statistical test can prove normality.

Springfield is correct in asserting that the Company should test the normality of the load data actually used in the computation of POD allocators--that is, load data net of Northfield generation. While the Company states in its brief that the loads modified by Northfield generation have been tested and 90 percent were found to be normally distributed at the .02 level, the Company did not make this information a part of the record in this case. In the future WMECo must put in evidence a statistical analysis which supports the normality of its load data net of Northfield generation if it continues to use the PRODIS model.

Springfield is incorrect in stating that the Company's use of average loads to allocate costs to customer classes discriminates against customers with invariant loads. The Company's dispatch algorithm computes, for each resource in the dispatch sequence, the probability that load will exceed the dispatch threshold of that given resource. By calculating for each unit in the dispatch the probability that load exceeds the dispatch threshold, PRODIS calculates the probability that each unit will be used. The model therefore also takes into account, in the inverse, the probability that a unit will not be dispatched. Thus, Springfield and the Industrial Intervenors are incorrect in claiming that for two time periods with the same mean load, PRODIS will necessarily allocate higher costs to the period with the larger standard deviation. In practice, in WMECo's application of PRODIS, more variable periods are very likely to receive a higher cost allocation because they are allocated part of the cost of units higher in the dispatch as well as a share of must-run unit costs.

Furthermore, it is a fallacy to say that classes with variable loads "escape the costs they have drawn into the period as a result of that variability" (Springfield Brief, p. 22). The fact that some customers have relatively invariant loads does not relieve them of a proportionate share of cost responsibility for use in periods when the aggregate demand of all classes is high and hence capacity costs are high. Therefore, Springfield's argument that the Company's POD discriminates against customers with invariant loads is without merit.

5. Other COSS Allocation Issues

a. Water Heater Expense

i. Parties' Positions

The Attorney General challenges the Company's treatment of embedded water heater expense (Attorney General Brief, pp. 23-28). The Company's COSS separated the Company's revenues and expenses into two categories, "total retail" and "all other." "All other" includes water heater rental customers and wholesale accounts. Water heater customers are residential customers who lease water heating equipment from WMECo. The Attorney General asserts that the Company allocated customer-related costs to the "all other" category using the allocator for wholesale customers, which reflects only the six wholesale customers and not the 18,893 water heating customers. Thus, the water heating class has not been allocated any expenses for customer accounts and customer service/information in Accounts 903, 905, 908, 909, and 910 (Exh. AG-208). The Attorney General asserts that since these costs are not being borne by the water heating class, they are being borne by all retail ratepayers. The Attorney General rejects what he says is the Company's position, that all water heater customers are residential customers, and as such, are already being charged for the expenses in these accounts and that allocating these expenses to the water heating class would constitute double-billing. According to the Attorney General, billing and customer charges tied to water heater rentals should be borne by those who rent water heaters, not by others (Attorney General Brief, pp. 25-27; Attorney General Reply Brief, p. 15).

The Attorney General further argues that if the Company is allowed to assign only incremental costs to the water heating class, this will promote the use of electricity through electric water heating rentals whose price is artificially low, even if these are not the most energy-efficient appliances.

The Attorney General says that disregarding embedded customer costs for water heating would be inconsistent with the Department's decision in Western Massachusetts Electric Company, D.P.U. 1300, p. 86 (1983), which stated: "In several recent cases the Department has found that water heater rental customers should pay the full cost of serving them." The Attorney General states that in its most recent Commonwealth Gas Company decision, D.P.U. 87-122 (1987), the Department reversed this position, ruling that its "analysis [for above-the-line accounting] will focus [only] on a review of the incremental expenses and revenues" associated with appliance rental. The Attorney General says he has filed a motion for reconsideration of that decision because he believes that the full implications of the decision were not brought out in hearings on that case (Attorney General Brief, p. 23).

The Attorney General cites Exhibit AG-207, a recalculation by Mr. Berthold of the cost of service study which uses the allocator "CU50," based on the number of year-end customers in all classes including water heating, to allocate Accounts 903, 905, 908, 909, and 910. Exhibit 207 shows a revenue deficiency of $905,000 for the water heating program as opposed to a deficiency of $60,000 calculated according to the Company's original allocation method (Attorney General Brief, p. 27; Attorney General Reply Brief, p. 17; Exh. AG-208). The Attorney General concludes that costs allocated to the retail classes should therefore be decreased by $845,000.

The Company responds that only incremental costs should be allocated to water heating customers, as they are already retail customers of the Company. The Company states that allocating embedded customer accounts expenses to rental water heaters, as suggested by the Attorney General, would result in charging the rental water heater customers twice for the same customer accounts expenses (Company Brief, p. 61).

The Company states that its cost of service study does not allocate only incremental expenses to its water heating rental customers. It states that general plant, administrative and general expenses, and operation and maintenance expenses are allocated to rental water heaters in the cost of service study. It asserts that costs in Accounts 908, 909 and 910 have not been allocated because they relate to the economical use of energy, but do not pertain to the rental of water heaters (Company Reply Letter, p. 5).

ii. Analysis and Findings

In Commonwealth Gas Company, D.P.U. 87-122 (1987), the Department distinguished between rental programs treated above and below the line. When an appliance rental program is below the line, its revenues flow to the utility's stockholders, who must therefore bear the program's fully allocated embedded costs. In this case, the Company states that it proposes to treat its water heater rental costs and revenues as above the line. This would result in application of an incremental cost standard, under Commonwealth Gas Company. In fact, in its COSS the Company has segregated water heater rentals and some water heater expenses into an "all other" category, separate from retail revenues and expenses used to derive the Company's retail revenue requirement. Thus, the Department finds that, in this proceeding, the Company is actually treating water heating as below the line for the purposes of setting retail rates. It must therefore allocate a share of the embedded customer costs to its water heating customers. Accordingly, it is unnecessary to reach the Attorney General's argument concerning the proper allocation of costs in the case where a company treats such revenues and expenses above the line.

Accounts 903 and 905 cover records and collections and customer account expenses, expenses which pertain to water heater rentals as well as to the Company's sales of electricity. Under cross-examination by the Attorney General, the Company's witness acknowledged that water heater rental customers might receive customer assistance and information regarding their water heater rentals and that the costs of these customer services would be booked to Accounts 908 and 909 (Tr. XI, pp. 72-74). By extension, it is reasonable to assume that rental water heater customers benefit from services booked to Account 910, miscellaneous customer service and information expense. While an embedded COSS should directly assign costs to customer classes where direct cost causation can be determined, one of the purposes of developing allocators is to assign joint and common costs equitably where such direct assignment is impossible. Based on this record, the Department finds that the costs included in Accounts 903, 905 and 908 through 910 represent costs incurred to provide both electrical and water heater services. Based on the record in this case, the Department therefore finds it appropriate for the Company to allocate embedded costs in Accounts 903, 905, and 908 through 910 using COSS allocator CU50, which represents the number of year-end customers in all classes including water heating, and to reduce its retail revenue requirement accordingly.[7/] In future cases, the Department will consider whether different allocators would be more appropriate. As shown in Exhibit AG-207, an additional $845,000 should be reallocated from "total retail" to "all others."

7/ An argument that the level of such costs is not substantially affected by the presence of the water heater rental program would be relevant only in an incremental analysis, which has been rejected above.

b. Allocation of Distribution Costs to Street Lighting

i. Parties' Positions

Springfield contends that the Company's allocation of certain distribution and customer costs discriminates against street and area lighting customers. First, the Company directly assigned $174,000 of rate base in Account 364, Poles, Towers and Fixtures, to street lighting customers. The Company then divided the balance of the account between primary and secondary facilities and allocated this balance to all customers, including street lighting, on the basis of primary and secondary demands. Springfield claims that the Company was unable to support its decision both to assign part of Account 364 to street lighting and to allocate a portion of Account 364 costs to street lighting, except to state that the direct assignment was consistent with historical treatment of the account. Springfield therefore argues there should not be any direct assignment of Account 364 to street lighting and that street lighting rate base should be reduced by $170,000, representing the $174,000 direct assignment to street lighting less Springfield's allocated share of the $174,000 (Springfield Brief, pp. 30-31).

The Company states that its direct assignment of certain Account 364 costs to street lighting comprises poles and appurtenances which distribute power to an area for the purpose of street lighting. The remainder of the account balance represents investment which serves a distribution function and is allocated to the Company's customers on the basis of noncoincident demand (Tr. IX, pp. 124-128).

ii. Analysis and Findings

Account 364 includes plant which serves to distribute electricity to areas for use specifically by street lighting, as well as plant serving a more general distribution function. The Company witness testified that the Company made a direct assignment of plant used exclusively for street lighting and allocated the remaining portion that is used jointly by all customers, including street lighting. In this case Springfield has presented no evidence to indicate that the street lighting class was bearing a disproportionate share of those costs. The Department finds the Company's allocation method for Account 364 to be reasonable.

c. Allocation of Miscellaneous Distribution Expenses to Street Lighting

i. Springfield's Position

Springfield argues that the Company is wrong in allocating miscellaneous distribution expenses, Account 588, to customer classes on the basis of total distribution plant because total distribution plant includes directly assigned street lighting distribution, Account 373. Including Account 373 in developing an allocator for Account 588 results in an allocation of 6.08 percent of miscellaneous expenses to street lighting when the distribution demand allocators for this class range from 1.33 to 2.28 percent (Springfield Brief, p. 31). Springfield argues that the correct allocation for miscellaneous expenses in Account 588 is distribution plant excluding Account 373. Springfield requests similar treatment for Account 598, Miscellaneous.

ii. Analysis and Findings

The Company's choice of allocators for miscellaneous distribution expenses in Account 588 allocates these costs on the basis of total distribution plant, rather than Springfield's preferred basis of distribution plant less the cost of installed street lighting equipment. Account 588 contains miscellaneous expenses such as the cost of records and maps of the distribution system. There is no evidence on the record that such costs are not proportional to total distribution plant for each class, including street lighting plant booked in Account 373. Similarly, the record does not support a different allocation for Account 598. The Department therefore finds the Company's choice of allocators for Accounts 588 and 598 to be reasonable.

d. Allocation of Customer Expenses to Street Lighting

i. Parties' Positions

Springfield argues that allocation of customer expenses in Accounts 903, 905, 908, 909 and 910 by means of the number of customers at year-end results in double-billing for the 3,500 of the 3,593 street and area lighting customers who take service under another rate. Springfield says that area lighting customers should receive the same treatment as rental water heater customers, who have not been allocated customer expenses. At a minimum, Springfield asserts, area lighting customers should not be allocated collection costs in Account 903 because this means they must pay twice for the preparation, mailing and processing of a single bill.

The Company contends that these are costs related to electricity consumption and hence should be allocated to area lighting customers but not to water heating customers. The Company also states, "[e]ven though the customer sees one bill, separate calculations must be prepared for both street and area lighting service and also for service under the Company's other retail rates" (Company Brief, pp. 137-138).

ii. Analysis and Findings

A street lighting customer who also takes service under another rate may impose costs on the Company in both roles and would therefore pay rates which reflect that fact. Thus it is appropriate that the Company allocate customer expenses in Accounts 903, 905 and 908 through 910 to street and area lighting customers as well as to other classes. Although the parties to this case have not addressed the issue, it is possible, however, that another allocator would more fairly allocate the customer expense accounts. For example, in Cambridge Electric Light Company's last rate design case, D.P.U. 87-221, that company allocated customer service and information expenses based on an analysis of the labor resources expended for each class. In light of the issues presented in this case regarding the proper allocation of customer service expenses, WMECo should investigate alternative allocators for these accounts and present its findings in the next case. Based on the record in this case, the Department finds that the allocators proposed by the Company for Accounts 903, 905 and 908 through 910 are reasonable.

6. Revenue Allocation

a. Parties' Positions

i. Company

In accordance with the Department's Order in D.P.U. 84-25, WMECo proposes to equalize rates of return for all classes except Rates T-2 (comprising proposed Rates T-4 and T-5) and G-3 (comprising proposed nonindustrial Rate T-6 and industrial Rate T-7). The Company asserts that the results of the cost of service study with equalized rates of return would lead to extreme total revenue changes for these classes, ranging from an increase of 13.17 percent for Rate T-6 to a decrease of 2.7 percent for Rate T-5. For continuity reasons, the Company recommends constraining the increase in both Rates T-2 and G-3 to the increase which would result if the two rates were treated as one. Given the Company's proposed total revenue increase, this would lead to a 5.86 percent increase for T-2 and G-3, and a shift of $1,634,000 from G-3 customers to T-2 customers.

ii. Industrial Intervenors

The Industrial Intervenors recommend equalized rates of return for all classes based on their recommended allocation method.

iii. Springfield

Springfield challenges the Company's proposed 13.2 percent increase for street lighting base rates, which is greater than the proposed average retail base rate increase of 12 percent. Springfield claims that this increase is inconsistent with the COSS, which shows that street lighting allocation factors have declined. Also, Springfield says that a 13.2 percent rate increase would have a whipsawing effect and violate the Department's principle of continuity, given the fact that street lighting base rates were reduced by approximately 9 percent as a result of the Company's last rate case, D.P.U. 86-280-A (1987). Springfield therefore proposes that the increase to street lighting be limited to the system average increase (Springfield Brief, pp. 35-37).

b. Analysis and Findings

The Department finds that, in light of the Department's adjustments to the Company's requested revenue requirement, it is possible to equalize rates of return for all classes without unreasonable increases for any particular customer class, and that equalized rates of return will not violate our continuity standard for any rate class. The Company should therefore equalize rates of return for all classes as shown in Schedule 10.

C. Rate Design

1. Marginal Cost Study

a. Selection of Time Periods

The first step in calculating marginal costs is selection of the appropriate daily and seasonal time periods for analysis of costs. These are termed costing periods. The second step is to consolidate hours with similar load and cost characteristics into rating periods, that is, the daily and seasonal periods that are appropriate for setting rates. It is possible to use hourly costing and rating periods which produce a distinct price for each hour in the year. It is more practical, however, to group hours with similar cost characteristics so that rates can be designed to meet the goals of simplicity and efficiency.

i. Company's Proposal

WMECo has reevaluated both its existing daily and seasonal rating periods since its last rate case. In response to a Department directive (see D.P.U. 86-280-A, p. 155), the Company conducted statistical analyses examining hourly variations between its marginal costs. WMECo examined periods based on forecasted hourly marginal costs for the one-year period ending June 30, 1989, to determine the appropriate rating periods. The Company used the "Ontario Hydro" method to investigate its current on-peak and off-peak periods and their stability over time. This method selects the optimal peak period by grouping hours to produce minimum cost variance within periods and maximum cost variance between periods (Exh. WM-14, Exh. CJR-4).

The results of the analyses indicated that 7:00 a.m. to 11:00 p.m., Monday through Friday, are the most representative on-peak hours for the period during which the proposed rates would be in effect. WMECo also reports that, based on the results of the statistical analyses, there were no signs of seasonal variations in costs which would warrant seasonal rates. Therefore, it asserts that a single rating period is appropriate (Exh. WM-14, Exh. CJR-8).

No intervenor took a position on this issue.

ii. Analysis and Findings

The Department has found in the past that identifying the appropriate costing and rating periods is essential in order to develop accurate price signals. Massachusetts Electric Company, D.P.U. 85-146-A (1986); Cambridge Electric Light Company, D.P.U. 84-165-A (1985). We emphasize that the establishment of the proper rating periods is the critical first step in meeting the Department's goals for rate design. Unless the Company has a thorough understanding of how its costs vary with time, it is likely to set rates that give incorrect price signals, and consequently encourage customers to consume when WMECo's costs are the highest.

The Department has reviewed the Company's analysis and finds it appropriate. The results of the study are consistent with WMECo's prior analyses and Department findings in the Company's last rate case. Accordingly, the Department will accept the Company's current rating periods for the purposes of rate design in this case. The Company must evaluate and update its costing and rating periods continuously and file the results in all future cases.

b. <u>Marginal Production Costs</u>

i. <u>Company's Proposal</u>

WMECo's marginal production costs are based on the modified peaker method. This method estimates the future cost of constructing a peaking unit on a per-KW basis in the year it is projected to be needed to meet electricity demand. This cost is then annualized over the life of the unit and discounted back to determine its present value. The Company determined that capacity will be needed in 1999 and calculated in present-value terms the expected annual levelized fixed costs of an 85 MW gas turbine installed in that year (Exh. WM-14, Table B-4). The Company based its estimate of the need for capacity on the assumption that Seabrook 1 will provide capacity starting in 1989, and that conservation, cogeneration and other supply options will provide additional capacity as planned over the next ten years. WMECo used a discount rate in this analysis of 10.68 percent, based on the Company's requested weighted average cost of capital. The Company also adjusted the levelized cost of a gas turbine upward by 22.5 percent to account for the reserve margin required for new capacity (Exh. WM-14, Table B-4). Finally, WMECo adjusted the annual marginal production costs by marginal demand losses to calculate marginal production costs by voltage level.

ii. Parties' Positions

(A) Attorney General

According to the Attorney General, "NEPOOL's new construction value at 1988" is the most appropriate basis for estimating the value of capacity, since NEPOOL is capacity-deficient in 1988 (Attorney General Brief, p. 136). The Attorney General asserts that the NEPOOL shortage has a direct bearing on the Company, "since there is a market for summer peak capacity in 1988, and the Company has none to sell" (id., p. 136). Therefore, the Attorney General argues that capacity rates should be based on the cost of capacity additions in 1988 and not 1999, as proposed by WMECo (id., p. 126).

(B) Industrial Intervenors

The Industrial Intervenors do not question WMECo's use of the modified peaker method in estimating marginal production costs. However, the Industrial Intervenors assert that the marginal production costs should be based on the cost of installing a peaker in 1995 and not in 1999, as the Company proposed (Industrial Intervenors Brief, p. 23).

The Industrial Intervenors refer to D.P.U. 88-19 (1988), an investigation by the Department on its own motion into a purchased power agreement between WMECo and Riverside Steam and Electric Company, where the Department determined that the first year that WMECo would need additional capacity was 1995. Therefore, the Industrial Intervenors argue that since the Company filed this case before the January, 1988 decision in

D.P.U. 88-19, "there is no basis in this record to use any date other than that recently approved in the Riverside case" (id., p. 24).

Finally, the Industrial Intervenors maintain that the levelized cost of a gas turbine should be adjusted by the EFOR of peaker units, which is generally greater than 50 percent, rather than the NEPOOL reserve margin of 22.5 percent (Industrial Intervenors Brief, p. 24).

(C) Company

The Company points out that the Department rejected the Attorney General's argument that NEPOOL's capacity constraint be reflected in the calculation of capacity costs, in the Company's last rate case, D.P.U. 86-280-A, p. 191. Therefore, since no new evidence on that issue has been received in this proceeding, the Company contends that this argument should again be rejected (Company Brief, p. 143). Further, the Company asserts that the year it first needs capacity is 1999 and not 1995, as the Industrial Intervenors contend (Tr. XVIII, p. 101; Company Brief, p. 147).

With respect to the Industrial Intervenors' contention that the marginal capacity costs be adjusted by the EFOR of a peaking unit, the Company argues that such an adjustment is inappropriate because it "is too unit specific" (id., p. 147). WMECo contends that it uses a gas turbine installed in 1999, only because of the low capital costs associated with the unit. However, it does not follow that it actually will be installed, since the Company can choose any of the other options contained in its resource plan. Therefore, WMECo asserts that the NEPOOL reserve margin of 22.5 percent should be used instead of the EFOR.

iii. Analysis and Findings

The Department in the past has found that, when determining marginal capacity costs, it is the capacity situation of the utility, not that of NEPOOL, which is to be used as a measure. Western Massachusetts Electric Company, D.P.U. 86-280-A, p. 190 (1987); Fitchburg Gas and Electric Light Company, D.P.U. 84-145-A, p. 95 (1985); Cambridge Electric Light Company, D.P.U. 84-165-A, pp. 43-44 (1985). We do not find that the Attorney General has raised any new arguments that would require the Department to reconsider its past findings.

For the purpose of determining marginal production costs, the appropriate measure of a company's need for capacity is the first year when the company's capacity will not be met with existing and committed supply and demand management resources.

The next step is to determine what supply and demand management resources should be included in the analysis as existing or committed supplies. In D.P.U. 85-270, the Department found that all existing generating units, purchased power contracts and energy service contracts should be included in the resource mix, for purposes of determining the need for capacity. In addition, all projected repowerings, life extensions, projected conservation investments, forecasted power purchases from qualifying facilities ("QFs") and other uncommitted supply plans were not included in the mix of resources used to meet future load because they represented resources to which the Company had not committed itself. See Western Massachusetts Electric Company, D.P.U. 85-270, pp. 273-274 (1986). Further, the status of Seabrook 1 is sufficiently uncertain that, for pricing purposes, it should not be included in the mix of resources available. See Cambridge Electric Light Company, D.P.U. 87-221-A, p. 60 (1988).

The Industrial Intervenors argue that 1995, and not 1999, is the appropriate in-service date for the peaker, because the Company filed this case before the January, 1988 decision in D.P.U. 88-19, where the Department determined that WMECo would first need additional capacity in 1995.[8/] Setting aside the 1995 capacity deficiency erroneously reported in D.P.U. 88-19, fn. 6, the Department's finding in that case does not necessarily determine the outcome here. The record presented in this case reflects information currently available to the Department.

8/ The finding in D.P.U. 88-19 cited without reference by the Industrial Intervenors appears to be in footnote 6, page 22 of that Order. A review of the record in that case indicates that the analysis relied on by the Department, Response to Information Request I-3, assumes a 1998 capacity deficiency. Thus, although the Department's analysis was based on the correct information, the reference in footnote 6 to a 1995 capacity deficiency is an inadvertent error.

Because of the inherently dynamic nature of the information relied upon to compute future avoided costs, the facts presented to or found by the Department in another case should not be seen as binding for all subsequent cases. Cambridge Electric Light Company, D.P.U. 87-221-A, p. 58 (1988). Therefore, for the marginal cost study, the Department will base the in-service date of the peaker on the record developed in this case. Below is a summary table depicting the year the Company forecasts that it will need new capacity:

	MW Capacity	Capability Responsibility	Surplus/(Shortfall)
1988	5532	5257	275
1989	5879	5524	355
1990	6161	5652	509
1991	6350	6107	243
1992	6674	6108	566
1993	6653	6125	528
1994	6655	6263	392
1995	6577	6447	130
1996	6577	6596	(19)
1997	6577	6753	(176)

(Exh. AG-158)

In the table above, only Department-approved cogeneration contracts were included, since they represent committed resources. Contrary to the Company's approach, we have excluded all projected repowerings, life extensions, uncommitted supply plans and Seabrook 1 from the mix of resources available to meet future load (see Exh. AG-158). We note that in year 1996 there is a 19 MW deficiency. The Department in the past has found this level of deficiency to be insignificant for a company of this size because of the degree of uncertainty associated with a company's load forecast. Western Massachusetts Electric Company, D.P.U. 86-280-A, pp. 157-158 (1987).9/ Accordingly, we find that WMECo is projected to need capacity in the summer of 1997 and not the summer of 1999, as the Company has projected.

WMECo uses NEPOOL's required reserve margin for new capacity of 22.5 percent to adjust the marginal capacity cost in order to reflect the fact that a 1 KW increase in load would require a 1.225 KW increase in generation capacity. The adjustment therefore is to reflect the additional cost of maintaining the same level of reliability after the 1 KW increase in load. The marginal capacity cost is a function of the Company's load forecast adjusted for NEPOOL's required reserve margin and not by a unit-specific performance characteristic such as the EFOR.

The availability (EFOR and percentage of maintenance outage hours) of each unit in the generating mix of NEPOOL contributes to the derivation of the NEPOOL reserve requirement. NEPOOL

9/ In D.P.U. 86-280-A, the Department agreed with the Company's witness that an 8 MW deficiency projected for 1998, relative to a forecasted capability responsibility of 6365 MW for that year, represented an insignificant amount of deficiency. The Department therefore accepted 1999 as the first year that WMECo needed additional capacity. In the instant case, the Department accepts 19 MW as an insignificant level of deficiency for a company of this size. However, the Department directs the Company to address in its next rate case the issue of what standards to use to determine the level of projected deficiency or even projected surplus that is significant for ascertaining the first year the Company needs to add capacity in order to meet forecasted load and reserve requirements.

conducts a loss-of-load-probability ("LOLP") analysis based on existing and planned generating resources and estimated availability rates of each unit to determine the load-carrying capacity of the system and to identify the additional amount of installed capacity needed to meet reserve requirements consistent with a reliability standard that customers not lose service involuntarily more than once every ten years. Thus, assumed availabilities of generating units, along with other factors, lead to an estimate of the amount of load and reserve that can be satisfied by the capacity, rather than vice-versa. If the assumed generating mix and associated availabilities changed, the analysis would result in a different amount of installed capacity needed to meet the reserve requirement for NEPOOL (and possibly also for individual companies). Thus, the Industrial Intervenors are incorrect in implying that the capacity of a peaker that may be relied upon to help satisfy installed capacity requirements should reflect a derating according to the peaker's EFOR, and it would be inappropriate to adjust a company's marginal capacity costs by the EFOR of peaker units. Accordingly, for rate design purposes, we find that the Company's adjustment to its marginal capacity cost by the required reserve margin is appropriate. We note that the Company, in calculating its marginal capacity costs used NEPOOL's 22.5 percent reserve margin, rather than the Company's own reserve requirement utilized to determine its needs for future generation. In its next rate filing, the Company is directed to address the appropriateness of using NEPOOL's versus the Company's own required reserve margin in determining both the marginal capacity costs and future capacity needs.

c. Marginal Transmission and Primary Distribution Costs

i. Company's Proposal

WMECo calculated marginal transmission and primary distribution ("T&D") costs by dividing the projected investments in the T&D systems during the five-year planning period from 1988 to 1992 by the estimated increase in the load-carrying capability that would result from the investments. The Company, for this proceeding, updated the results of a study conducted by ICF, Inc., which was used in the last rate case (Exh. WM-14, Table B-1). WMECo separated projected T&D investments into three categories: those necessary to meet new load, those necessary to maintain the existing system, and those necessary to achieve cost reductions in operation. Only investments categorized as necessary to meet new load were used in the analysis. In addition, the study assumed that all such investments over the period of analysis are designed to meet increases in load for the life of the investments, or 30 years (Exh. DPU-32, p. 19; Exh. DPU-33).

The Company made several modifications to the load projections. First, WMECo separated the annual load growth by voltage level, then adjusted it by a diversity factor to account for the diversity between system peak and peak loads at each voltage level. The NU engineers estimated the diversity factor for the distribution system to be 0.80, and to be 0.94 for the transmission system (Exh. DPU-32, p. 18).[10/] WMECo also adjusted load levels on the distribution system by marginal demand losses for the purpose of the analysis (Exh. WM-14, Table B-1). The Company divided annual levelized transmission costs by each class's incremental coincident peak to determine marginal costs per KW.

For the secondary distribution network, the Company calculated marginal costs separately for the residential, small general service and secondary general service customers. WMECo based its estimates of future secondary distribution investments on actual secondary distribution investment costs in 1986, adjusted for WMECo's policy of requiring certain distribution costs to be paid by new customers. WMECo added these costs to the primary distribution costs calculated above and then divided them by each class's noncoincident peak ("NCP") demand measured at the customers' meters to account for losses (Exh. WM-14, Table B-3). The result was marginal distribution costs per KW by voltage level.

In response to a Department directive (see D.P.U. 86-280-A, p. 161), the Company conducted a LOLP analysis and an expected unserved energy analysis to determine the appropriate allocation

---

10/ A diversity factor is the ratio of the sum of the noncoincident maximum demands of two or more loads to their coincident maximum demand for the same period.

of capacity costs to daily rating periods (Exh. WM-14, pp. 15-17, Exh. CJR-4). Using a production simulation model called POLARIS, hourly LOLP, marginal cost and expected unserved energy values were produced for the time period July 1, 1988, through June 30, 1989. Mr. Roncaioli stated that unserved energy is a better proxy for demand costs than LOLP, because unserved energy, by definition, captures both the magnitude and the likelihood of potential capacity shortages, whereas LOLP considers only the likelihood of potential capacity shortages (Exh. WM-14, p. 15; Tr. XIV, pp. 84-85). Thus, hourly unserved energy results were used by WMECo to establish the costing periods, employing the Ontario Hydro statistical maximization method. The results of the analyses indicated that the period of greatest exposure to unserved load is the period of Monday through Friday, 7:00 a.m. to 10:00 p.m., similar to that of the costing period analysis (Exh. WM-14, pp. 15-17, Exh. CJR-4).

ii. Parties' Positions

(A) Industrial Intervenors

The Industrial Intervenors argue that the Company's construction budget, upon which marginal primary distribution costs are based, is unreviewable since the engineers responsible for preparing it were not presented in this case to verify or justify its contents (Industrial Intervenors Brief, p. 22). The Industrial Intervenors point out that three years ago, in D.P.U. 85-270, the Company had calculated a marginal primary distribution cost of $23.02 per KW per year for the G-3 customers, whereas in this case, the primary distribution charge is estimated to be $48.84 per KW per year. According to the Industrial Intervenors, the variation in marginal primary distribution cost in such a short time "is proof positive that the marginal distribution cost...cannot and should not be used as a basis to design a ratcheted distribution demand charge" (id., p. 23).

(B) Company

The Company argues that its marginal distribution costs are based on a moving five-year horizon. In D.P.U. 85-270, they were based on WMECo's 1986 to 1990 construction program, while in this case, the marginal distribution costs are based on the five-year forecast period of 1988 to 1992. Therefore, it stands to reason that they would differ from those forecasted in 1985. Furthermore, WMECo asserts that there is no reason why "an appropriate price signal may not change from year to year by more than a uniform escalation rate" (Company Brief, p. 146).

No other party took a position on this issue.

iii. Analysis and Findings

The Industrial Intervenors argue that since the Company did not present any witnesses to verify its construction budget, the budget is unreviewable, and thus, the marginal distribution cost estimate in this case should not be used for rate design purposes. However, the Industrial Intervenors did not attempt to call and question Company personnel on this issue, and they have provided no alternative which the Department could consider. Though the Industrial Intervenors have raised an issue regarding the Company's assumptions with respect to its construction budget, the Company's evidence that the reason for the cost difference is the impact of rolling averages cannot be rejected on its face. The Department will accept the Company's updated marginal T&D cost estimates for the purposes of this case. In its next rate case, we direct the Company to submit a report supporting its forecasted T&D investments. The report should document in detail the Company's forecasted T&D investments by project, project costs and cost per KW.

In D.P.U. 86-280-A, p. 161, we directed the Company to perform a LOLP analysis to support its position that T&D costs be assigned to the peak period only. The Company has complied with our directive by conducting statistical analyses to determine the appropriate allocation of capacity costs to daily rating periods. The results of the analyses showed that the period of greatest exposure to unserved load, peak period, is close to the Company's current on-peak period. Therefore, for rate design purposes, and as WMECo has proposed, all T&D costs should be assigned to the peak period.

d. Marginal Energy Costs

i. Company's Proposal

The Company determined short-run marginal energy costs by running a production cost simulation of the NU generating system using fuel prices forecasted for the period July 1988 through June 1989. Hourly marginal energy costs were calculated for the period as the expected value of the MWH generated by the last MW of thermal capacity dispatched. Each hourly marginal energy cost is composed of both fuel and variable O&M costs. Hourly marginal energy costs were summed separately over the on-peak and off-peak periods, and then averaged to yield average annual marginal peak and off-peak energy costs at the busbar. WMECo then adjusted these marginal peak and off-peak energy costs by marginal energy losses to determine costs by time period and by voltage level (Exh. WM-14, Table B-5; Exh. DPU-33).

ii. Parties' Positions

(A) Attorney General

The Attorney General urges the Department to adopt long-run marginal energy costs, not short-run marginal energy costs, as the proper basis for retail rate design (Attorney General Brief, pp. 106-110), and return to the wisdom of its original long-run policy (id., p. 105). The Attorney General reiterates the same arguments made in the Company's last rate case (see D.P.U. 86-280-A, pp. 165-172), namely, that:

a) Electricity energy rates must include a signal about long-run costs in order to put all supply options on the same economic footing and thus prepare consumers and utilities alike for the high cost of future generation expansion.

b) Customer-financed conservation is not accounted for in utility construction and purchase planning and thus costs associated with these options would not be on a least-cost basis.

c) Long-run price signals are essential to stimulate cost-effective customer conservation, because of the customers' short payback periods. Consequently, consumer decisions would be consistent with economic least-cost investments only if prices are based on long-run marginal energy costs.

d) Short-run pricing results in large fluctuations in rate design and provides conflicting price signals to customers.

e) WMECo does not calculate its short-run costs consistently with its theory because it does not include any external costs.

(B) Industrial Intervenors

The Industrial Intervenors assert that the marginal energy costs should be based on the latest available fuel forecast. They state that the Company has revised the calculation of the marginal energy cost based on the DRI February 1988 fuel forecast (Exh. II-28), and this latest forecast should be used as an input to the production cost model for rate design purposes (Industrial Intervenors Brief, p. 25).

(C) Company

WMECo points out that the Department, in the Company's last rate case, D.P.U. 86-280-A, determined that marginal energy costs should be based on short-run marginal costs. The Company contends that the issue of long-run marginal cost pricing was absent from the testimony of any witness who appeared in the present case. WMECo further contends that if the issue is to be reconsidered, new evidence should be brought before the Department and the parties should be given the opportunity to challenge that evidence by cross-examination and rebuttal testimony. "Where the Attorney General attempts to introduce testimony in a brief by way of naked allegations unsupported by evidence, the testimony should be ignored and the Attorney

General's arguments rejected" (Company Brief, p. 142). WMECo maintains that no new evidence has been received in this case and, therefore, the Attorney General's arguments should be rejected.

iii. Analysis and Findings

The Attorney General has revisited the same issues the Department addressed in the Company's last rate case and in the pending motion on reconsideration. We agree with the Company that the Attorney General has not offered new or additional evidence in this case. Accordingly, we will address this issue in the context of and jointly with the pending motion for reconsideration.

The gravamen of the Attorney General's objection to the Department's decision in D.P.U. 86-280-A is that it failed to give sufficient reasons for the reversal of the decision in D.P.U. 85-270. Not finding in the opinion what he would consider sufficient reason for this decision, the Attorney General implies that it amounted to "whim" or "caprice" on the part of the Department.

The Company and the Industrial Intervenors are correct when they state that the decision in D.P.U. 86-280-A amply describes the reasoning leading to the Department's rejection of so-called long-run marginal cost pricing for energy use. Nonetheless, a brief review of the major points on which the decision rests should allay the Attorney General's concern that the Department's decision was whimsical or capricious.

To understand the basis for the reversal of D.P.U. 85-270, we must return to that docket. There the Department set forth certain basic principles that have long informed Department rate design policies. In particular, the Department stated that it had endeavored to reflect marginal costs in rates "in a manner which reflects how the Company incurs them, i.e., capacity costs are incurred in the long run and energy costs in the short run." D.P.U. 85-270, p. 290. As a corollary, the Department further stated that if marginal costs "vary significantly and predictably as a function of time, then more accurate price signals will be given if the rate design reflects those variations." Id., citing Boston Edison Company, D.P.U. 1720, p. 117 (1985). The Department then observed that with the advent of QF contracts with fixed energy rates, "the costs incurred by the Company do vary predictably in the long run." Id., p. 219. The Department concluded that, for those reasons, it was "now appropriate to reflect long-run energy costs in rates." Id.

As the Department found in D.P.U. 86-280-A, the evidence adduced in that docket undermined the premises for the conclusion in D.P.U. 85-270. First, the term "long-run marginal cost" was incorrectly used as a term of art in D.P.U. 85-270. D.P.U. 86-280-A, p. 179. Dr. Ruff explained that the levelized projection of annual avoided energy costs over the planning period was a time average of short-run marginal costs, rather than an estimate of true long-run marginal costs, as the term is understood by microeconomists (Exh. WM-16, p. 4). D.P.U. 86-280-A, pp. 163-164, 180. No party drew this distinction in the prior case. The Department relied on this new testimony in its reevaluation of the use to which levelized long-term avoided fuel and variable O&M costs should be put. D.P.U. 86-280-A, pp. 188-189.

Further, the Department reviewed its conclusion set forth in D.P.U. 85-270 that long-run marginal costs vary with load in a sufficiently predictable way to support energy pricing decisions. Under the light of scrutiny aided by presentations from numerous parties, the Department found no evidence in D.P.U. 86-280-A to support the hypothesis, implicit in the decision in D.P.U. 85-270, that long-term projections of costs result in prices which are necessarily less volatile than short-run marginal cost calculations. D.P.U. 86-280-A, pp. 187-188, 189.

BECo, not a party to the prior case, asked the Department to consider the implications of "long-run marginal cost pricing" on load factor. BECo also pointed out that the demand charge provides a price signal which puts consumers on notice that increased consumption may lead to the need for new and costly sources of supply.

More than one party brought forth in the 86-280 docket arguments rebutting the reliance on the existence of QF bidding and rates as a basis for using long-term avoided costs to price energy. The Department found persuasive the observations that

QFs, unlike retail customers, commit themselves to a contracted output for a term of years. Thus, if prices paid to them based on levelized long-term avoided costs result in overpayments in early years, QFs will make up the difference in later years by delivering energy at less than the annual avoided cost that otherwise would have obtained. Retail customers, by contrast, typically do not enter into long-term contracts, and accordingly would not be shielded from shifting prices based on increasing year-by-year calculations of the time average of short-run marginal costs. D.P.U. 86-280-A, pp. 184-186.

In D.P.U. 85-270, the Department found that long-run marginal energy prices were predictable as a result of the "advent of contracts with fixed energy rates." D.P.U. 85-270, pp. 290-291. This reasoning confused the prices paid by the utility to QFs, fixed upon signing of the contract, with marginal costs. The price is not fixed until the contract is signed, but once the contract is signed, the QF's price becomes an infra-marginal cost to the utility. No increase or decrease in load will affect the cost of a must-run QF to the utility. Increases and decreases in loads will affect only other costs in this instance. These other costs, in turn, are subject to adjustment from computation to computation based on the then-current long-range forecast of significant variables such as oil prices. Even if all energy were purchased from QFs at rates based on long-run cost projections, the next increment of load would have to be priced based on projections of cost which vary from time to time. Certainly some fossil-fuel thermal generation will remain at the margin in projections of marginal cost for some time to come. Accordingly, the increased reliance on QF power at fixed energy prices does not, contrary to the Department's assumption in D.P.U. 85-270, necessarily lead to fixed marginal energy costs in the long term.

Extensive new analyses offered by expert witnesses in D.P.U. 86-280-A deepened the Department's understanding of these issues and led the Department to revise the decision in D.P.U. 85-270. The Department set forth these reasons in D.P.U. 86-280-A. We have elaborated to some extent on these reasons in this Order.

The argument behind the Attorney General's motion for reconsideration, in these circumstances, resolves to the proposition that a Commission may never revisit complex issues, subject them to renewed analysis, and alter its conclusions. The Boston Gas Company case cited by the Attorney General does not stand for that proposition. The Supreme Judicial Court noted that the ratemaking adjustment disallowed by the Department in the case on appeal had been allowed on three preceding occasions, and that the Department in reversing itself had done so "without finding or reporting some facts which would warrant or permit such a change." Boston Gas Company, supra, p. 104. By contrast to the Department's lengthy discussion in D.P.U. 86-280-A of its reasons for return to short-run marginal energy cost pricing, the Department in the Boston Gas Company case had made only a two-sentence statement to the effect that the requested ratemaking adjustment was not proper. Id., p. 100. As the Court pointed out, the Department's decision in that case "does not mean that every decision of the Department in a particular proceeding becomes irreversible in the manner of judicial decision constituting res judicata...." Id., p. 104.

The Department notes that the argument of Business, Industry, Labor and Legislators United ("BILLU"), a party to D.P.U. 86-280-A, in support of the Attorney General's motion for reconsideration is unpersuasive. The decision to return to short-run marginal-cost energy pricing is not responsible for the magnitude of the increase in rates in that docket experienced by the one customer cited by BILLU. As the Company rate-design witness agreed, both short-run marginal costs and the Company's projections of long-run avoided costs were so far apart from average energy costs that significant movement away from marginal costs was required in the development of retail rates, whichever method for calculating marginal energy costs was chosen. Those adjustments were necessary to preserve continuity in rates overall. It may be true that individual customers received unusually high increases, relative to the overall average, or to the average for the class, but these increases were not the result of the decision to use short-run marginal cost pricing.

In sum, nothing in the Attorney General's motion persuades the Department to alter its decision. The motion is denied. Further, in this case, we do not find that the Attorney General has raised any new arguments that would require the Department to reconsider its past findings (see D.P.U. 86-280-A, pp. 177-191).

The Department notes nonetheless that the use of a peaker's costs for setting long-run production costs rather than a next-unit method does not include capitalized energy costs. However, the issue of whether capitalized energy costs should in some way be reflected in rates has not been discussed adequately on this record. The Department directs the Company to address in its next rate case the questions of whether and how future capitalized energy costs should be reflected in the demand and/or energy portions of rates. Accordingly, the Department will base marginal energy costs in this case on short-run marginal costs.

In response to a Bench request in the instant docket, the Company recalculated its marginal energy costs by excluding Seabrook 1 from its production cost simulation model and by using the February 1988 DRI fuel forecast (Exh. II-28). The Department will use these results for rate design purposes, since they represent the most recently available information regarding WMECo's marginal energy costs.

e. Marginal Customer Costs

WMECo calculated marginal customer costs by first analyzing the capital costs for service drops and meters and adjusting the annual capital costs by the annual O&M, property taxes and meter reading and billing costs. The Company used the sum of these costs for each class divided by the number of customers to represent marginal customer costs by class (Exh. DPU-33). No parties disputed the Company's calculations, and they will be accepted in this case.

f. Translating Marginal Costs to Rates

In order to transform marginal costs into class-specific retail prices, WMECo first assigned annual peak and off-peak costs to each rate class based on the voltage level(s) at which customers are served. Then the Company multiplied the annual demand costs by a coincidence factor. The coincidence factor adjusts for the difference between total class KW or peak-period KWH sales ("billing units") and class demands at the time marginal demand costs are incurred by the Company. KWH billing units are used to develop coincidence factors for small general service classes that do not have KW billing units. The coincidence factor generally accepted by the Department for marginal production and transmission costs is the ratio of class average monthly coincident peak ("CP") to class test year billing units. The coincidence factor generally accepted by the Department for distribution costs is the ratio of class average monthly noncoincident peak ("NCP") to class test year billing units. Western Massachusetts Electric Company, D.P.U. 85-270 (1986).

For residential and small general service rates without KW billing units, the Company summed marginal production, transmission, and distribution costs by KWH to develop the demand component of marginal KWH charges. For intermediate and large general service classes the Company summed marginal production and transmission costs to develop a marginal-cost-based demand charge and used marginal distribution costs calculated using the ratio of class NCP to calculate annual maximum KW as its proposed marginal distribution charge. The Company's proposal to introduce two-part demand charges is further discussed below.

2. Implementing Marginal-Cost-Based Rates

Because the marginal-cost-based rates did not produce class total revenue requirement, the Company had to adjust the rates. The Company's general procedure for designing rates which produce class total revenue requirement is to develop energy and demand charges based on marginal costs, then to set the customer charge, the most inelastic portion of each rate, in order to recover the balance of total class revenue requirement. The Company then compares these rates to existing rates to determine whether they satisfy continuity constraints. The continuity guideline used by the Company in this case was minimization of the number of bills that increased by more than twice the overall revenue increase being sought (Exh. WM-14, p. 4).

3. Rate Analysis

a. Residential Rates

i. Company's Proposal

The Company's residential rates are R-1 for regular use, R-3 for all-electric customers, and R-4 and R-5, optional time-of-use rates.

The Company stated that in designing Rate R-1 it sought to set energy charges as close as possible to marginal costs while minimizing the number of customers whose bills would increase by more than twice the Company's proposed 8.8 percent total increase (Exh. WM-14, p. 25). The Company increased the R-1 customer charge by 17.6 percent from $7.00 to $8.25; the remaining R-1 revenue would be collected through a uniform energy charge applied to all KWH. For Rate R-3 the Company proposed to increase the customer charge from $8.00 to $10.00 and to collect the remainder of the R-3 revenue through a uniform energy charge.

The Company proposes to maintain the interruptible rider applicable to Rates R-1 and R-3 for controlled water heating. The rider provides a monthly credit of $2.00 per bill for use of 401 to 600 KWH and a credit of $4.00 per bill for use above 600 KWH. The Company's controlled water heating credit is based on an analysis of the benefits of dual-element water heaters, although the Company states that most water heaters controlled by WMECo are single-element units and that the credits associated with these units are much smaller (Exh. DPU-138).

The Company set energy charges for optional time-of-use ("TOU") Rates R-4 and R-5 equal to marginal energy costs. Mr. Roncaioli stated that the differential between marginal-cost-based R-4 and R-5 energy rates, and R-1 and R-3 energy charges (which are set as residuals), creates an opportunity for customers to save money simply by changing rates, while causing the Company to incur the greater costs associated with TOU metering. Mr. Roncaioli recommended elimination of Rates R-4 and R-5 (Tr. XIV, pp. 127-128). In the absence of the Department's approval for elimination of these rates, the Company proposes to limit availability of Rates R-4 and R-5 to the one customer currently on R-4 and to customers who were not taking service on Rate R-1 as of January 1, 1988.

No intervenor commented on residential rate design.

ii. Analysis and Findings

At this time, because of continuity considerations, the Department finds that it is not possible to implement full marginal-cost-based rates for Rates R-1 and R-3. The Company is directed to set the R-1 customer charge at $7.50 and the R-3 customer charge at $9.00 and to set the energy charge of each rate as close to marginal cost as possible to achieve the allowed allocation. We also find that WMECo's controlled water heater credit provides appropriate savings to qualifying customers. In its next rate proceeding, however, the Company should calculate its water heater credit using the type of water heaters actually controlled by the Company.

The existence of optional time-of-use rates create an opportunity for customers to cross over from regular residential to residential TOU rates. To the extent that these customers have high load factors and relatively high on-peak use, it is appropriate for them to take service on a rate separate from that of other residential customers. However, price differentials between regular residential energy rates and optional TOU energy rates may also create an incentive for uneconomic rate-shifting from regular residential to residential TOU rates. Time-of-use energy charges are set at marginal cost, while regular residential energy charges are set to recover residual revenue requirement after the residential customer charge is established, with due consideration for continuity requirements. Consequently, for many customers, even customers with relatively poor load factors, the regular residential energy charge may be higher than their weighted average TOU peak and off-peak energy charges. Thus, the record in this case demonstrates that the availability of optional residential TOU rates creates the potential for uneconomic rate-switching by poor-load-factor customers with high energy use. The Department therefore finds that, because of the problem of uneconomic rate-switching, it is appropriate for the Company to close its optional residential TOU Rates R-4 and R-5 to new customers at this time.

b. Residential Low-Income Rate

The Company does not presently offer a residential low-income rate of any kind and did not propose one in this proceeding. The Company contends that such a rate would not be cost-based and could be very arbitrary (Exh. DPU-35). The Company states that if it were required to file a low-income rate it would propose a rate limited to recipients of Supplemental Security Income ("SSI"). SSI is a federal means-tested program of income support for low-income elderly, blind and disabled individuals. The Company states it would offer a 50 percent discount on the first 300 KWH of use so that only essential electricity consumption would be subsidized. WMECo indicates that it would favor a rate higher than the regular R-1 rate for use of 300 to 600 KWH so that low-income and regular residential customers using 600 KWH would receive the same size bill. The Company would not favor any discount in the customer charge because the customer charge is intended to reflect fixed costs. WMECo also asserts that use of demand limiters, devices similar to fuses, which limit a customer's maximum demand, might be appropriate for customers on a low-income rate (Exh. DPU-35).

No other party took a position on this issue.

As a matter of policy, the Department recognizes that electricity is a basic necessity of life in modern society. Rigid application of cost-based ratemaking principles in this case could jeopardize the ability of those with poverty-level incomes to retain electric service. A subsidized rate for low-income individuals should be available if the impact of the subsidy on nonparticipants is reasonable. The Department has recognized the unique situation of low-income customers in its regulations concerning the shut-off of electricity and other utility services (220 C.M.R. 25.03). The Supreme Judicial Court has acknowledged that rates may be set to protect low-income ratepayers, even though this requires an exception to the

Department's principle of cost-based ratemaking. American Hoechest Corp. v. Department of Public Utilities, 379 Mass. 408 (1980). Accordingly, the Department finds that the Company should implement a subsidized low-income rate available to low-income residential customers. In its compliance filing the Company must provide an estimate of the expected penetration rate of the new SSI rate and explain how it determined that penetration rate. The Company must calculate the projected total revenue deficiency resulting from the SSI rate and allocate that deficiency among classes in proportion to their share of the total total revenue requirement.

The Department does not accept the guidelines for a low-income rate which were suggested by the Company. First, in Commonwealth Gas Company, D.P.U. 87-122 (1987), the Department found that "[i]n terms of the need of certain residential customers for assistance, there is no basis to distinguish between [SSI recipients] and other low-income customers." However, since the Company has investigated implementation of an SSI rate, and the record does not support a more comprehensive approach, the Company should institute an SSI rate in this proceeding. In its next rate case, however, the Company should propose an expanded rate available to a wider group of low-income customers and an analysis of the rate impact of wider eligibility on nonparticipants.

Second, charging low-income customers more than regular R-1 customers for use at a level between 300 and 600 KWH is inequitable. Instead, the Department finds that a 35 percent discount should apply to all KWH. Furthermore, the SSI rate should include a 35 percent discount on the customer charge; otherwise, low-income customers with very low use will bear the full burden of increases in the customer charge. Since a low-income rate is not designed to be cost-based, the Company's argument that the customer charge is designed to cover fixed costs carries no weight. The Company concedes that it has no experience with demand limiters and has presented no evidence as to why low-income customers should be burdened with them (Exh. DPU-132).

c. General Service Rates

i. Rate 23

Rate 23 is an optional controlled water heating rate available to all nonresidential customers. The Company proposes to raise the customer charge from $10.00 to $12.50 and set the energy charge to recover the balance of required revenue. The Department finds that continuity considerations do not permit institution of full-marginal-cost rates. Therefore, the Company is directed to set the customer charge at $11.00 and the energy charge as close as possible to marginal cost to recover the allowed revenue requirement.

ii. Rate 24

Rate 24 is available to churches for lighting and incidental power in buildings set aside exclusively for public worship. It is available only to customers who are currently receiving service under this rate. In its previous rate case, D.P.U. 86-280, the Company proposed elimination of Rate 24, but the Department found that the Company had not substantiated its recommendation with adequate information regarding class load characteristics and cost incurrence. The Department therefore directed the Company to retain Rate 24 in that case and to provide evidence supporting its recommendation. Western Massachusetts Electric Company, D.P.U. 86-280-A, p. 201. In his testimony in this case, Mr. Roncaioli stated that the Company began metering the demand of Rate 24 customers in March 1987, but because of the demand meter installation schedule, the Company has collected only limited energy and demand data. The Company therefore did not propose elimination of the rate in the current case.

The Company developed its recommendation for Rate 24 by increasing the customer charge from $40.00 to $47.00, and setting the energy charge to recover the balance of required revenue.

The Department finds that the Company's proposed customer charge for Rate 24 would violate continuity constraints. The Department directs the Company to set the Rate 24 customer charge at $43.00 and to set the energy charge so as to recover the allowed allocation for the rate. In its next rate case the Company must present its findings regarding the load characteristics of Rate 24 and the advisability of eliminating this rate.

iii. Rate G-0

Rates G-0, G-1 and G-2 are all general service rates available to customers with demands not exceeding 349 KW. G-0 customers may be served from either primary or secondary voltage levels. Rate G-1 is available to customers requiring use of secondary facilities. Rate G-2 is available to customers requiring use of primary facilities.

In D.P.U. 86-280-A, the Department directed the Company to investigate whether it would be appropriate to consolidate Rates G-0, G-1 and G-2 into two rates, one for primary voltage and one for secondary voltage. In his testimony in this case, the Company's witness Mr. Roncaioli stated that a primary distribution customer is one whose service requires only primary facilities, that is, voltage greater than 600 volts. On the other hand, those customers taking secondary 240/480 or 120/240 volt service whose service drops are connected directly to primary line transformers without any intervening secondary poles, wires or equipment, are also classified as primary customers. Yet if the transformer were moved even one pole away, these customers would become secondary customers. Thus, it is not the use characteristics of these customers which determine whether they are "primary" or "secondary" (Tr. XIV,

p. 136). The Company therefore contends that it is appropriate for all Rate G-0 customers to pay secondary distribution costs. Furthermore, the Company maintains that G-0 customers should remain separate from Rate G-1 and Rate G-2 customers because they do not have, on average, similar use characteristics. The average G-0 customer uses about 1,663 KWH per month versus 21,114 KWH for Rate G-1 and 28,113 KWH for Rate G-2. Rate G-0 has an average load factor of about 30 percent while Rates G-1 and G-2 have load factors of about 40 percent (Exh. WM-14, p. 21).

The Company proposes to increase the G-0 customer charge from $16.00 to $18.81. Presently Rate G-0 includes a demand charge of zero for the first 2 KW of demand and $8.59 for KW above 2. The Company proposes to set the demand charge at zero for the first 2 KW or less and slightly below marginal cost at $9.65/KW for all KW in excess of 2.

The Department accepts continued separation of G-0 customers from customers on Rates G-1 and G-2. The Department finds that for reasons of continuity the Company should set the G-0 customer charge at $18.50 and adjust the energy charge to recover the allowed class revenue requirement.

iv. <u>Rates G-1 and G-2</u>

The Company set the demand charge for the first 50 KW at zero and the demand charge for demand in excess of 50 KW at marginal cost. The Company maintained customer charges of $230.00 for each rate and moved energy rates in the direction of marginal costs. In response to an information request from the Department, the Company stated that a zero demand charge is an historical aspect of Rates G-1 and G-2 and that the Company had not done an analysis of the impact of charging for the first 50 KW of demand (Exh. DPU-37). The Department asked the Company to redesign the rates, including a charge for all KW of demand. The Company provided the requested rates, but stated that it could not support them because they would be much less in accordance with marginal costs than the rates originally proposed. Under cross-examination by the Industrial Intervenors, however, Mr. Roncaioli conceded that the demand charges in the requested rates were actually closer to marginal costs than those in the Company's proposed rates (Tr. XXIII, pp. 52-54). The Company states that under the redesigned rates customers would have an incentive to cross over from G-0 to G-1 at 20 KW and from G-0 to G-2 at 10 KW. The Company predicts that these crossover impacts could be so significant that adoption of these rates could deprive the Company of significant revenues. It argues that if the Department finds that all KW should be billed on G-1 and G-2, then a phase-in across several rate changes would be appropriate (Tr. XXIII, p. 47; Exh. II-30).

The Company has not provided any cost-based rationale for maintaining zero demand charges for the first 50 KW of demand for G-1 and G-2 customers. The Department recognizes the potential adverse effects of eliminating in one step the zero demand charges for the first 50 KW of demand. The Department therefore finds that in its next rate case the Company should present a proposal for the phase-in of demand charges for all KW. In its compliance filing in this case, the Company should set the G-1 and G-2 demand charges at full marginal cost, set the customer charge at $250.00 and adjust energy charges so that the Company will collect its allowed revenue requirement for each class.

v. Proposed Industrial and Non-Industrial Rates

(A) Parties' Positions

The Company's cost of service study distinguishes between industrial and nonindustrial customers currently on Rates T-2 and G-3. WMECo defines industrial customers as those using at least 50 percent of their energy requirements for manufacturing. The Company maintains that its cost of service study shows that the costs of serving industrial and nonindustrial customers differ. The Company's rate design witness, Mr. Roncaioli, testified that "[w]here a customer group has electricity consumption characteristics that are sufficiently unique from any other group so as to impose unique combinations of costs on the Company, that group is a candidate for taking service under its own rate" (Exh. WM-14, p. 12). The Company therefore proposes to separate current mandatory TOU Rate T-2 into nonindustrial Rate T-4 and industrial Rate T-5, available to customers with demands between 350 and 1,000 KW, and to separate current mandatory TOU Rate G-3 into nonindustrial Rate T-6 and industrial Rate T-7, available to customers with demands over 1,000 KW.

Springfield argues that, according to the Company's cost of service study, the costs of serving T-2 and G-3 customers are nearly equal. It contends that the only cost differences between nonindustrial and industrial customers which the Company could identify are transformer ownership and installations on customer premises (Springfield Brief, p. 38). It states that cost differences relating to transformer ownership are recognized in the transformer ownership portion of the rate, while the Company could introduce a dedicated facilities charge to cover the costs of major, one-time expenditures for certain installations on customer premises (Springfield Brief, p. 39).

Springfield also argues that T-2 and G-3 customers have the same marginal production, transmission, distribution and energy costs. Finally, Springfield contends that the present design of T-2 and G-3 rates, and of the proposed T-4, T-5, T-6 and T-7 rates, includes demand, energy and customer components as well as peak and off-peak differentials, and that the Company should therefore be proposing to combine the T-2 and G-3 rate classes (Springfield Brief, p. 39).

The Industrial Intervenors support the proposed separation of industrial and nonindustrial customers as cost-based. They also state that the separation of these classes will make it easier to design cost-based rates without imposing undue hardship on any segment of a rate class (Industrial Intervenors Brief, pp. 25-26).

(B) Analysis and Findings

In D.P.U. 86-280-A, in a discussion of WMECo's proposal to abolish Rate 24, the Department stated that "definition of rate classes by end-use is a crude and potentially misleading method. Similar end-uses may indicate similar load patterns, but it is more appropriate to determine rate classes by grouping customers with similar costs to serve.... Mr. Roncaioli's claim that Rate G-0 serves customers with similar load characteristics to those on Rate 24 is completely unsubstantiated." Id., p. 201. In New England Telephone and Telegraph Company, D.P.U. 86-33-C (1987), the Department stated that a rate class should exist only when the costs incurred in serving one group of customers are measurably different from the costs of serving all other groups of customers. In that Order the Department also found that "[w]here the costs to serve are different between two different customer groups within a customer class...there should be a separation between these two groups." Id., p. 25.

The Company has provided a COSS showing differences in the rates of return for industrial and nonindustrial customers. The rate of return for T-2 nonindustrial customers is now 9.65 percent while the rate of return for T-2 industrial customers is 10.97 percent; the rate of return for G-3 nonindustrial customers is 5.96 percent while the rate of return for G-3 industrial customers is 7.48 percent. The Department finds that the difference in rates of return among customers in Class T-2 is not large. Similarly, the Department finds that the difference in rates of return among customers in Class G-3 is not large. Furthermore, the Company has not supported its request to separate these rates with evidence of the load characteristics which cause these cost differences. The Company has not demonstrated that separating T-2 and G-3 classes into industrial and nonindustrial components is more reflective of cost causation than dividing these classes into some other subgroups (e.g., smaller and larger customers or high- and low-load-factor customers). Thus, the Department finds that the Company's present filing does not meet the Department's standards regarding evidence of load characteristics which cause cost differences. Therefore, the Department will not approve segregation of industrial and nonindustrial rates at this time.

vi. Distribution Demand Charge

(A) Parties' Positions

The Company proposes two demand charges for general service rates G-1, G-2, T-1, T-4, T-5, T-6 and T-7, one for production and transmission, and one for distribution. The Company would bill the production and transmission demand charge based on the customer's current-month peak demand and would bill the distribution demand charge based on the customer's maximum peak during the preceding twelve months. These rates presently have a single demand charge billed using the customer's current month-peak. The Company contends that a separate distribution demand charge is necessary to give customers a more appropriate price signal regarding the marginal cost of distribution capability and the impact of a customer's demand on that cost (Exh. WM-14, p. 8). The Company's witness stated that distribution circuits, especially transformers, can be shared only to a very limited extent and hence must be sized to individual customers' maximum demands. Thus, according to Mr. Roncaioli, low-load-factor customers with a given annual maximum demand impose the same distribution costs on the Company as higher-load-factor customers with the same annual maximum demand. He stated that if the Company cannot assess a separate distribution demand charge, over the course of the year, lower-load-factor customers will pay less than their full distribution costs and these costs must then be subsidized by other customers (Exh. WM-14, pp. 7-14).

In support of its arguments for a separate distribution demand charge, the Company performed a cost of service study of twelve customers with demands over 1,000 KW. Six of these customers had low load factors, ranging from 13 to 33 percent, and six had high load factors, ranging from 58 to 69 percent. The Company states that this cost of service study showed little difference between production investment per KWH for low- and high-load-factor customers and between transmission investments per KWH for low- and high-load-factor customers. On the other hand, the distribution investment per KWH for the six low-load-factor customers was four times the investment for the six high-load-factor customers (Exh. DPU-25; Exh. WM-14, pp. 9-10).

The Company acknowledges, however, that introduction of a distribution demand charge could cause some customers to experience bill increases in excess of 20 percent.

The Attorney General opposes all demand charges, saying that demand charges cannot accurately reflect the cost impact of individual customers' load patterns and, consequently, do not serve the Department's objectives (Attorney General Brief, p. 119). The Attorney General argues that the proposed distribution demand charge is especially inefficient because it is premised on the assumption that at the level of distribution plant the Company realizes no benefits from load diversity. The Attorney General states that the Company has no evidence for this assumption about a lack of diversity benefits.

Mr. Rosenberg, testifying for the Industrial Intervenors, asserted that a demand charge based on a ratcheted noncoincident demand is an appropriate means of collecting the costs associated with distribution facilities that are sized to a specific customer's peak demand. He took issue, however, with the level of distribution demand charges proposed by the Company. First, Mr. Rosenberg contended that the marginal cost of primary distribution of $48.84 presented by the Company in this case is too high. He said that inflating the cost figures developed by a consulting firm for WMECo three years ago at 6 percent per year yields a marginal distribution cost of $27.42 (Exh. II-21, p. 20).

Second, he stated that the Company is proposing general service rate customer charges many times larger than marginal cost, through which it would recover distribution costs. Third, he argued that the Company's proposed distribution charge includes costs which are jointly incurred for jointly-used facilities, such as substations and a portion of transmission costs. Mr. Rosenberg therefore proposed a distribution demand charge in the range of $0.27 to $0.50 (Exh. II-21, p. 21).

In their brief, however, the Industrial Intervenors contend that the Company has not justified the two-part demand charge. The Industrial Intervenors cite previous Department Orders which denied such a charge. They argue that the Company has not shown that a distribution demand charge is necessary and would recover only distribution-related costs which cannot be recovered without a distribution demand charge. The Industrial Intervenors assert that the Company has not provided evidence of any items other than transformers which are customer-specific. They also contend that it is erroneous to base a distribution demand charge on the marginal primary distribution costs, since such costs are derived from equipment which is jointly used and the costs of which are jointly incurred. Furthermore, they suggest that wide fluctuations in the results of the marginal distribution cost study indicate that this study is a poor basis for design of the distribution demand charge; they say the marginal primary distribution cost is based on a construction budget estimate by NU engineers, and that this budget could not be reviewed in this case because the engineers were not presented to testify. Finally, they assert that adoption of a distribution demand charge will tend to discriminate unlawfully against existing and prospective qualifying facilities, contrary to the requirement to encourage cogeneration set forth in the Public Utilities Regulatory Policies Act of 1978 (Industrial Intervenors Brief, pp. 18-21).

(B) Analysis and Findings

It is undisputed that the Company's proposed distribution demand charge constitutes an annual demand ratchet, that is, a demand billing mechanism which is based on a customer's maximum demand in the past twelve months. As the Department has found in the past, when demand charges are ratcheted, a customer that has achieved its annual demand peak has a reduced incentive to control demand. Western Massachusetts Electric Company, D.P.U. 86-280-A, p. 196. The Company has presented no new evidence or argument that would persuade the Department to approve an annual demand ratchet in this case. Accordingly, the proposal to institute the distribution demand charge is denied.

To the extent that transformers and perhaps other portions of the Company's distribution system are sized to the annual maximum demands of individual large customers, the Company will not recover its annual distribution costs from low-load-factor customers. These costs therefore will be spread to other customers. The Company could explore the possibility of using a facilities fee or transformer credit to deal with the problem of recovering distribution costs from those who cause their incurrence.

The Attorney General has presented no new evidence regarding the elimination of all demand charges which would require the Department to reconsider its past findings on this subject. Western Massachusetts Electric Company, D.P.U. 85-270 (1986); Western Massachusetts Electric Company, D.P.U. 86-280-A (1987); Cambridge Electric Light Company, D.P.U. 87-221-A (1988). Therefore, the Company should continue to incorporate demand charges in designing rates.

vii. Time of Use Rates

(A) Demand Threshold for Mandatory TOU Rates

In D.P.U. 86-280-A, the threshold for WMECo's mandatory TOU rates was lowered to 350 KW. Mr. Roncaioli stated that, in accordance with the Department's policy favoring TOU rates, the Company asserts that ultimately all customers with demands greater than 100 or 200 KW should be served on mandatory TOU rates (Company Brief, p. 112). WMECo proposes to maintain the present 350 KW threshold for TOU rates until it can analyze the consumption shifts for new TOU customers having demands in the low end of the 350 KW to 500 KW demand range (Exh. WM-7, p. 7). The Department finds the Company's proposal reasonable.

(B) Rate T-1

Rate T-1 is an optional time-of-use rate for general service customers having demands under 350 KW. There are presently no customers on Rate T-1; consequently, the Company has no billing statistics to use in designing the rate and the Company has used the billing statistics for Rate G-1. As stated above, the Company proposed a two-part demand charge for Rate T-1. Mr. Roncaioli testified that the Company set the T-1 demand charges at marginal cost. The Company increased energy charges in the direction of marginal costs and decreased the customer charge from $601.60 to $345.07.

The Company asserts that because Rate T-1 is designed without its own billing statistics and target revenue, it creates the potential for rate-switching by customers who can save money without any change in consumption. The Company therefore proposes to maintain the rider prohibiting customers who were taking service on a nonresidential rate on January 1, 1988, from receiving service under Rate T-1.

Examination of the Company's workpapers shows that the Company set T-1 demand charges by summing annual marginal production and transmission costs and dividing them by twelve. Thus, the Company did not apply a coincidence factor in calculating marginal costs. In its filing WMECo did not explain its reasons for choosing this method.

The Company did not provide a rationale for its calculation of T-1 demand charges and the Department therefore has no basis for accepting the Company's method. In its compliance filing, the Company should use G-1 billing units to develop a marginal-cost-based Rate T-1, as directed by the Department in D.P.U. 86-280-A. The Company must eliminate the distribution demand charge for Rate T-1. The Company may maintain the T-1 rider at this time in order to prevent crossover.

(C) Rates T-4, T-5, T-6 and T-7

As noted above, the Company proposes to divide Rate T-2 into nonindustrial Rate T-4 and industrial Rate T-5 for customers with demands between 350 and 999 KW and to divide Rate G-3 into nonindustrial Rate T-6 and industrial Rate T-7 for customers with demands of 1,000 KW or more. The Company set demand charges for these rates at marginal cost and moved energy charges in the direction of marginal costs, increasing customer charges to collect residual revenue. Proposed Rates T-4 and T-5 include the provision that customers currently served under those rates may continue to be served under those rates regardless of their demands, at least until the next rate decision. Mr. Roncaioli stated that this provision recognizes the discontinuity which occurs as the demands of customers on Rate T-4 and T-5 grow from just under to just over 1,000 KW. He stated that this provision would give the Company time to work with customers to minimize the impact that a rate shift would have on the customers' billing (Exh. WM-14, p. 32).

In addition to opposing the Company's proposed distribution demand charges for these rates, the Industrial Intervenors oppose the Company's design of Rate T-7, arguing that the Company is not moving toward marginal cost pricing with sufficient speed. The Industrial Intervenors have proposed their own Rate T-7. The Company and the Industrial Intervenors agree that the Industrial Intervenors' proposed Rate T-7 sets energy charges closer to marginal cost than the Company's proposed rate, but the Company objects to the Industrial Intervenors' Rate T-7 for reasons of continuity and because it contends that there should always be a spread between energy charges and marginal energy costs (Company Brief, p. 147). The Industrial Intervenors assert that the problem of continuity for T-7 customers can be handled by transferring customers who would receive increases of more than two times the system average to Rate T-5 (Industrial Intervenors Brief, pp. 26-28). The Company responds that it does not have the billing data and revenue allocation information to accomplish the necessary redesign of Rate T-5 (Company Brief, p. 148).

As discussed above, the Department does not at this time approve the Company's separation of industrial and nonindustrial rates. The Department also rejects the Company's plan to introduce two-part demand charges. The Department therefore finds that the Company must design its T-2 and G-3 rates using total revenue requirement allocated to industrial and nonindustrial customers on these rates, eliminate the distribution demand charge, and set demand charges at marginal cost. Thus, the Department need not comment on alternative proposals for the design of proposed Rate T-7; the Department notes, however, that there is no evidence on the record supporting the Company's assertion that there should always be a spread between energy charges and marginal energy costs. The

Department finds that energy charges for Rates T-2 and G-3 cannot be set according to full marginal costs without producing a customer charge that would violate our continuity goal. We direct the Company to set the Rate T-2 and G-3 demand charges at full marginal cost. We direct the Company to set the T-2 energy charge as close to marginal cost as possible to attain a $900.00 customer charge. We direct the Company to set the G-3 energy charge as close to marginal cost as possible to attain a $4000.00 customer charge.

(D) Rate T-9

The Company proposes to rename Rate G-4 as new Rate T-9. The proposed Rate T-9 is a TOU rate applicable only to customers served at transmission voltage level. Rate T-9 customers must own and maintain all service transformers and associated equipment. Only one customer is served under Rate T-9.

Relative to the existing Rate G-4, the Company's proposed Rate T-9 increases the demand charge above marginal cost, decreases energy charges slightly in the direction of marginal cost, and increases the customer charge from $60,000 to $119,580. The Department finds that implementation of a fully marginal-cost-based rate would result in an increase in the customer charge which would violate the goal of continuity. The Department finds that demand charges for T-9 should be set at marginal cost and the energy charge should be set as close as possible to marginal cost to attain a $120,000 customer charge.

viii. Rates S-1 and S-2, Street Lighting

There are two street lighting rates: S-1, for street, highway and off-street security lighting; and S-2, for municipal street and highway lighting where all street lighting equipment is owned and maintained by the municipality. Rate S-1 present and proposed rates consist of a lamp, luminaire and pole charge. In D.P.U. 86-280-A, the Department accepted a street lighting rate which was designed using high-pressure sodium lights as the marginal cost lights. The Company's proposed rates are designed following the same principle. All base charges for street lighting were increased by approximately 13.2 percent, the proposed overall street lighting base rate increase. Adders for decorative luminaires and ornamental poles were also increased by 13.2 percent.

The Department finds that the Company's proposed street lighting rates are reasonable. In its compliance filing the Company should adjust the rates to achieve the allowed revenue requirement if necessary.

ix. Supplemental and Back-Up Rates

(A) Parties' Positions

The Company proposes a set of new supplemental and back-up power rates, Rates P-1, P-2 and P-3. Rate P-1 is for power intended to supplement the output of the customer's generation capacity where the customer's own generation capacity is less than the customer's maximum load. The Company proposes that the customer must specify the maximum demand or "supplemental contract demand" which it plans to impose on the Company. The customer would then be billed for this service in accordance with the applicable general service tariff appropriate to the size of service taken. The P-1 billing demand would be the lower of the supplemental contract demand or the actual billing demand. Any demands in excess of the supplemental contract demand would be classified as "firm back-up power" available under Rate P-2 or P-3 (Exh. WM-14, pp. 13-14, 84-90).

Rate P-2, Primary Firm Back-Up Demand and Maintenance Power Service, and Rate P-3, Secondary Firm Back-Up Demand and Maintenance Power Service, would be applicable to all partial-requirements general service customers who require firm back-up and maintenance service. Firm back-up power is intended to provide customers with a back-up supply of power when the customer's generating facilities are not in operation or are operating at less than full capacity. According to the Company's witness, these rates require self-generating customers to decide how much, if any, reserve capability such a customer wishes the Company to have to serve it, and require that the customer contribute to the Company's cost of satisfying the largest load specified by the customer (Exh. WM-14, p. 14).

In its initial filing, the Company has proposed that P-2 customers would pay the customer service charge of the applicable general service rate and a distribution demand charge of $3.21 per KW of firm back-up demand. They would also pay a production and transmission demand charge equal to $2.00 for each KW of firm back-up contract demand (a "reservation fee") plus $3.29 (equal to the difference between the full production and transmission demand charge minus the reservation fee) multiplied by $[1-(K/2074)^{12}]$ for each KW of firm back-up demand, where K is the number of on-peak hours during which the facility received any back-up or standby service in the most recent full calendar months of July, August, September, December, January and February. Energy charges would be the same as for the applicable general service rate. The Company's proposed Rate P-3 is essentially the same as Rate P-2, except that the distribution demand charge is set as $3.73 per KW of contracted firm back-up demand, to reflect the fact that P-3 customers would take service at the secondary level.

The Company contends that when a customer uses its own generation to displace energy without reducing the burden of its demand on the Company, that customer's load factor will decrease. If the customer is taking service on a rate in which the energy charge collects revenues above the marginal cost, the customer may pay less than its cost of service (Company Brief, p. 116). Also, if the customer's generation performs well, its billing demand will decrease, as will the revenues it pays to the Company. The Company will not, however, be able to reduce its supply capability because it must be ready to meet previous higher load levels should the customer's generation equipment fail. The Company argues that if it does not have back-up rates it must spread those costs to other customers, forcing them to subsidize the self-generator's "insurance policy" (Company Brief, p. 116).

The Industrial Intervenors argue that the Company's proposed supplemental and back-up power rates must be rejected. They state that proposed Rates P-2 and P-3 are priced according to: (1) the maximum firm contract demand reserved by the self-generator; and (2) the probability that a customer will require back-up service during any of the twelve highest hours of the year. They contend, however, that the demand charges to a supplemental power customer would be the same over a wide range of different scenarios, and that such an outcome is not logical (Industrial Intervenors Brief, p. 30). The Industrial Intervenors' witness Mr. Rosenberg argued that the Company's proposed rates are inequitable because they charge the same rate for back-up as for maintenance power, ignore load diversity, take into account only the number of hours in which back-up power is required and not the amount of power required, and are based on the normal output rating of a self-generator's unit, which is difficult to define (Industrial Intervenors Brief, p. 30).

The Industrial Intervenors recommend that the Department adopt changes to the supplemental and back-up rates proposed by their witness Mr. Rosenberg. One of the changes advocated by Mr. Rosenberg is a different multiplier for Rates P-2 and P-3. The Industrial Intervenors' proposed multiplier equals K/2074. The Industrial Intervenors claim that this factor represents the probability that a partial-requirements customer will require back-up service during any of the twelve highest hours of the year. They argue that the Company's multiplier formula fails to recognize the diversity inherent in outages of self-generators and thus violates requirements outlined by the Federal Energy Regulatory Commission in regulations implementing the Public Utilities Regulatory Policies Act of 1978, 18 C.F.R. 292.305(c). These regulations state that the rate for sales of back-up or maintenance power "shall not be based upon an assumption (unless supported by factual data) that forced outage rates or other reductions in electric output by all qualifying facilities on an electric utility system will occur simultaneously or during the system peak or both" (Industrial Intervenors Brief, p. 33).

Mr. Rosenberg also recommended that the supplemental and back-up rates provide for scheduled maintenance power which would be planned for off-peak periods and provided at a rate reflecting its off-peak and coordinated nature. He stated that firm back-up contract demand should initially be set at the discretion of the customer. He proposed that the Company charge only a minimum "insurance charge" for unserved back-up demand rather than charging the same rate for reserved, but unused, back-up power as for used back-up power (Exh. II-21, pp. 33-41).

(B) Analysis and Findings

When a utility customer installs cogeneration capacity, the utility must still maintain capacity to meet the cogeneration host's power needs if the cogeneration facility is subject to maintenance or a forced outage. It is appropriate for the cogenerating customer to pay for required reserve capacity, taking into account expected diversity among QF outages, so that the cost of this capacity is not imposed on the utility's other customers.

In rebuttal testimony Mr. Roncaioli stated that Mr. Rosenberg's rate proposal "offers certain positive additions to the Company's proposal and with a few changes could provide the basis for the service the Company wishes to have the Department approve" (Exh. WM-23, p. 5). Mr. Roncaioli took issue with Mr. Rosenberg's proposed production and transmission multiplier K/2074. The Company asserts that its multiplier is appropriate, although it should perhaps be weighted by the customer's load each time the customer takes back-up service (Exh. WM-23).

The Department is concerned about several aspects of the Company's proposed supplemental and back-up rates. The Company's proposed rates do not take into account the amount of back-up power actually used, even though the amount of power taken affects the Company's costs. In addition, WMECo has not demonstrated that its back-up rates take into account an appropriate degree of diversity among cogenerators' outages. Therefore, the Department finds that it is not appropriate to accept the Company's current proposal for supplemental and back-up rates. In its next rate proceeding the Company should indicate how back-up and supplemental rates can be designed so that are cost-based and reflect: (1) the amount of back-up power reserved; (2) the magnitude as well as frequency of back-up power taken; (3) the lower cost of providing replacement power for a unit under maintenance when that maintenance is coordinated with the utility; (4) expected diversity among cogenerators' outages; and (5) elimination of ratcheted distribution demand charges. The rate should provide an incentive for customers to estimate accurately their level of supplemental and back-up power needs. Unit rating may be an appropriate basis for estimating the amount of back-up power a cogenerator should reserve.

x. Interruptible Rates

The Company presently offers two interruptible rates; no customers are served under either rate (Exh. WM-14, p. 17). Through Mr. Roncaioli's testimony (Exh. WM-14) and revisions to that testimony (Exh. WM-16), the Company proposes to amend interruptible Rates I-1 and I-2, and to introduce a third interruptible rate, I-3.

The Company's interruptible rates are designed so that customers may specify a level of firm demand and a level of interruptible contract demand. Firm service up to the firm service demand level is provided under the applicable firm service rate and all KWH sales at demand levels up to the firm contract demand are billed under that rate schedule. The customer pays for interruptible demand service in accordance with the relevant interruptible rate. Each interruptible rate includes a customer charge, a primary- or secondary-level "facilities charge" for interruptible contract demand and an energy charge. Under Rates I-1 and I-2, the interruptible customer contracts annually with the Company to set an energy charge level from a menu of energy charges associated with various numbers of hours of interruption (Exh. WM-14, pp. 78-79; Exh. WM-16). Under proposed Rate I-3, the energy charge is set at a level which the Company projects would require the interruptible customer to undergo an estimated 475 to 525 hours of interruption a year; the Company currently proposes an I-3 energy charge of 4.66 cents per KWH (Exh. WM-16). Interruptions are required when the Company's expected cost of energy delivered exceeds the interruptible contract payment level, when the Company's or NEPOOL's reliability is threatened, or when the Company is near its expected peak load. WMECo plans to eliminate control of interruptible loads by switch and to notify customers by phone that they should interrupt loads. The Company proposes that all interruptible rates should have a rolling term of five years (Exh. WM-14, p. 19; Tr. XV, p. 34).

Rate I-1 is available to any primary voltage customer who agrees to interrupt a load of at least 5,000 KW above its firm demand level. During periods when interruption is based solely on the Company's costs, an I-1 customer may avoid interruption by paying the estimated marginal cost of generation, adjusted for losses and an "operating margin," plus 5 mills. The operating margin may vary depending on the speed with which a customer agrees to interrupt load; for example, a customer that could interrupt within ten minutes of receiving notice would have a 2 mill adder while a customer that could interrupt within an hour would have an adder of approximately 8 mills (Tr. XV, pp. 17-20). Thus, those interruptible customers prepared to interrupt on shorter notice would receive a lower total bill for buyback power.

Rate I-2 is presently available to primary or secondary customers who agree to interrupt load of at least 500 KW; the Company proposes that it should be available to customers who agree to interrupt loads of at least 300 KW. Rate I-2 does not include a buyback provision. The Company proposes that Rate I-2 allow customers a six-month trial contract period before the five-year rolling contract goes into effect. In response to customer requests for an orderly method of load reduction, the Company proposes to eliminate load control by Company switch and substitute telephone notification when load reduction is needed (Exh. WM-14, p. 19).

Proposed Rate I-3 would be available to any customer who agreed to interrupt at least 300 KW of load. The energy charge for I-3 would be 4.66 cents per KWH, designed to result in 475 to 525 hours of interruption per year. The Company would reserve the right to change the energy charge once every twelve months if a different charge would be required in order to yield an estimated 475 to 525 hours of interruption. I-3 differs from

I-2 because it offers customers the option of avoiding interruption during periods when the Company's costs exceed the energy charge by purchasing the interruption at a rate of the energy charge plus 10 cents per KWH.

The Company's filing proposes customer charges of $950 for Rate I-1, $577.55 for Rate I-2, and $1,000 for Rate I-3. The Company's analysis of marginal customer costs for these rates indicates that the marginal customer cost for Rates I-1 and I-3 is $925 (Exh. DPU-140) and for Rate I-2 is $577.55.

During December 1987, and January through April 1988, the Company also had in effect a voluntary interruptible rate providing a credit of $2.33 per KW of average interruptible demand provided by a customer in all interruption periods in a month. The rate imposed no penalty for failure to interrupt and provided no credit in months in which the Company requests no interruption (Exh. II-16). The Company's witness stated that the Company did not have a plan to file a similar rate for the upcoming summer period, but would wait for a determination by NEPOOL that such a rate would assist with the regional capacity situation (Tr. XV, p. 42).

The Company's proposed interruptible rates expand the range of options currently available to customers willing to interrupt their loads. The Company's proposed changes in administration of the rates, including the six-month trial period for Rates I-2 and I-3 and interruption by telephone request, appear to be reasonable. The Company should set customer charges at the marginal customer cost, equal to $925 for Rates I-1 and I-3 and $577.55 for Rate I-2.

VII. SCHEDULES

SCHEDULE 1

REVENUE REQUIREMENT AND
CALCULATION OF REVENUE INCREASE

	PER COMPANY	DPU ADJ.	PER ORDER
ELECTRIC COST OF SERVICE			
OPERATIONS AND MAINTENANCE EXPENSE	$135,461,000	($4,560,000)	$130,901,000
DEPRECIATION AND AMORTIZATION	$41,973,000	($2,450,000)	$39,523,000
DECOMMISSIONING	$4,794,000	($274,000)	$4,520,000
GAIN OR LOSS UTIL. PROP.	$0	($467,000)	($467,000)
TAXES OTHER THAN INCOME TAX	$14,270,000	$94,000	$14,364,000
CONN. CORPORATE BUS. TAX	$1,239,082	($291,895)	$947,185
MASSACHUSETTS FRANCHISE TAX	$4,115,144	($969,422)	$3,145,722
FEDERAL INCOME TAX	$24,762,762	($5,856,375)	$18,906,388
RETURN ON RATE BASE	$54,421,792	($4,915,693)	$49,506,099
COST OF SERVICE	$281,036,780	($19,690,384)	$261,346,395
RETAIL COST OF SERVICE	$278,282,620	($20,278,845)	$258,003,774 *
ELECTRIC REVENUES			
ELECTRIC OPERATING REV.	$243,201,000	$0	$243,201,000
OTHER OPERATING REVENUES	$8,580,000	($69,000)	$8,511,000
TOTAL REVENUES	$251,781,000	($69,000)	$251,712,000
RETAIL REVENUES	$249,313,546	$62,290	$249,375,836 **
BASE RETAIL REV. SHORTFALL	$28,969,073	($20,341,135)	$8,627,938
RETAIL REVENUE INCREASE	$28,969,073	($20,341,135)	$8,627,938

Notes to Schedule 1

*The Department has adjusted the retail allocator proposed by WMECo as follows to account for the Company's water heater activities.

Total COS per Co. X Proposed Co. retail allocator (.9902) = Retail COS Per Co.
developed from Exh. WM-5, Sch. A-1

[Retail COS per Co. - $845,000 water heater adj.] ÷ Total COS per Co. = DPU Retail Allocator (.9872)

**Retail Revenues = Total Revenues per Co. X Retail Allocator developed from Exh. WM-10, p. 10-1

SCHEDULE 2

OPERATIONS AND MAINTENANCE
EXPENSES

	EXPENSES PER COMPANY	DPU ADJ.	PER ORDER
O&M PER BOOK	$161,565,000	$0	$161,565,000
ADJUSTMENTS:			
AMORT. NUCLEAR OUTAGE EXPENSE	$1,464,000	$326,000	$1,790,000
AMORT. PREVIOUS DOCKET EXPENS	($15,000)	$0	($15,000)
CHARITABLE DONATIONS	($139,000)	$0	($139,000)
EEI DUES EXPENSE	($151,000)	$0	($151,000)
ELIM. NUG&T CREDIT CAPACITY	$18,468,000	$0	$18,468,000
FUEL ADJ. EXPENSE	($57,744,000)	$0	($57,744,000)
INFLATION ALLOWANCE	$2,889,000	($373,000)	$2,516,000
INSURANCE AT NUCLEAR SITES	$315,000	($54,000)	$261,000
LONG TERM CAPACITY EXPENSE	($352,000)	($100,000)	($452,000)
LONG TERM TRANS. EXPENSE	($754,000)	($7,000)	($761,000)
MAINT. AMORT. NUCLEAR OUT.	$3,272,000	($327,000)	$2,945,000
MAINT. AMORT. PREV. DOCKETS	$1,943,000	$0	$1,943,000
MAINT. LEASING	($2,000)	$0	($2,000)
MAINT. PAYROLL ESCALATION	$958,000	$0	$958,000
MAINT. PAYROLL EXPENSE	$263,000	$0	$263,000
MASS. SAVE & ENERGY CHECK EXP	($407,000)	$0	($407,000)
NON NUCLEAR INSURANCE ADJ.	($338,000)	($426,000)	($764,000)
OPERATIONS LEASING	$221,000	($751,000)	($530,000)
OPERATIONS PAYROLL ESCALATION	$2,393,000	$18,000	$2,411,000
OPERATIONS PAYROLL EXPENSE	$905,000	$0	$905,000
PENSIONS	($57,000)	($2,066,000)	($2,123,000)
REGULATORY EXPENSE	$651,000	($825,000)	($174,000)
POSTAGE EXPENSE	$0	$65,000	$65,000
UNCOLLECTIBLE EXPENSE	$113,000	($40,000)	$73,000
ADJ. TO O&M	($26,104,000)	($4,560,000)	($30,664,000)
O&M	$135,461,000	($4,560,000)	$130,901,000

SCHEDULE 3

DEPRECIATION AND AMORTIZATION
EXPENSES

	PER COMPANY	DPU ADJ.	PER ORDER
DEPRECIATION			
PRODUCTION			
STEAM	$1,198,000	$0	$1,198,000
NUCLEAR	$14,774,000	($661,000)	$14,113,000
HYDRAULIC	$1,550,000	$0	$1,550,000
OTHER	$1,455,000	($1,117,000)	$338,000
TOTAL PRODUCTION	$18,977,000	($1,778,000)	$17,199,000
TRANSMISSION	$2,541,000	$0	$2,541,000
DISTRIBUTION	$7,971,000	$0	$7,971,000
GENERAL	$457,000	$0	$457,000
TOTAL	$29,946,000	($1,778,000)	$28,168,000
ADJUSTMENTS			
BOOKING ERRORS	$124,000	$0	$124,000
ADJUSTMENTS	$124,000	$0	$124,000
DEPRECIATION	$30,070,000	($1,778,000)	$28,292,000
AMORTIZATION			
MONTAGUE INVESTMENT	$0	$0	$0
SITE STUDY	$0	$0	$0
GAS TURBINE RETIREMENTS	$0	$0	$0
MP3 NET OF TAX AFUDC ADJ	($353,000)	$0	($353,000)
MP3 PROPERTY LOSS	$9,165,000	$0	$9,165,000
DEFERRED EXPENSES	$1,440,000	$0	$1,440,000
DEFERRED TAX ADJUSTMENT	($502,000)	($142,000)	($644,000)
ITC	($2,605,000)	($482,000)	($3,087,000)
DEFERRED TAX RES.	($3,414,000)	$0	($3,414,000)
DEFERRED RETURN	$8,172,000	($48,000)	$8,124,000
TOTAL AMORTIZATION	$11,903,000	($672,000)	$11,231,000
DEPRECIATION AND AMORTIZATION	$41,973,000	($2,450,000)	$39,523,000

SCHEDULE 4

RATE BASE AND RETURN ON RATE BASE

	PER COMPANY	DPU ADJ.	PER ORDER
PLANT IN SERVICE	$836,541,000	$0	$836,541,000
ACCUM. DEPR.	$222,724,000	$0	$222,724,000
NET PLANT IN SERVICE	$613,817,000	$0	$613,817,000
ADDITIONS TO PLANT			
DEF. TAX ON NUCLEAR DECOMMISSIONING	$1,375,000	$0	$1,375,000
MATERIALS & SUPPLIES	$7,749,000	$0	$7,749,000
FUEL SUPPLIES	$1,841,000	$0	$1,841,000
CASH WORKING CAPITAL (SCHEDULE 6)	$14,409,666	($8,620,673)	$5,788,993
DEFERRED OUTAGE COSTS	$2,966,000	($2,966,000)	$0
ADDITIONS TO PLANT	$28,340,666	($11,586,673)	$16,753,993
DEDUCTIONS FROM PLANT			
CUSTOMER DEPOSITS	$570,000	$0	$570,000
CUSTOMER ADVANCES	$356,000	$0	$356,000
UNCLAIMED FUNDS	$21,000	$0	$21,000
ACCUM. DEFERRED ITC	$898,000	$0	$898,000
ACCUM. DEF. INCOME TAXES	$110,618,000	$2,443,000	$113,061,000
SPENT NUCLEAR FUEL	$18,824,000	$0	$18,824,000
WESTINGHOUSE CREDITS	$1,780,000	$0	$1,780,000
DEDUCTIONS FROM PLANT	$133,067,000	$2,443,000	$135,510,000
RATE BASE	$509,090,666	($14,029,673)	$495,060,993
COST OF CAPITAL (SCHEDULE 5)	10.69%	-0.69%	10.00%
RETURN ON RATE BASE	$54,421,792	($4,915,693)	$49,506,099

SCHEDULE 7

TAXES OTHER THAN INCOME TAXE

	PER COMPANY	DPU ADJ.	PER ORDER
PAYROLL TAX	($215,000)	($1,000)	($216,000)
PROPERTY TAX	$10,956,000	$95,000	$11,051,000
GROSS EARN. TAX	$3,523,000	$0	$3,523,000
EXCISE TAX	$6,000	$0	$6,000
TAXES OTHER THAN INCOME TAX	$14,270,000	$94,000	$14,364,000

SCHEDULE 8

INCOME TAXES

	PER COMPANY	DPU ADJ.	PER ORDER
RATE BASE	$509,090,666	($14,029,673)	$495,060,993
RETURN ON RATE BASE	$54,421,792	($4,915,693)	$49,506,099
ADD:			
PERMANENT TAX DIFFERENCES	$17,637,000	($3,941,000)	$13,696,000
INCOME ADDITIONS	$17,637,000	($3,941,000)	$13,696,000
DEDUCT:			
WEIGHTED COST OF DEBT	3.53%	0.52%	4.04%
INTEREST LONG TERM DEBT	($17,970,901)	($2,029,564)	($20,000,464)
AMORTIZATION OF ITC	($2,605,000)	($482,000)	($3,087,000)
AMORT. DEFERR. TAX RES.	($3,414,000)	$0	($3,414,000)
INCOME DEDUCTIONS	($23,989,900)	($2,511,564)	($26,501,464)
TAX CREDITS	$0	$0	$0
NET INCOME	$48,068,892	($11,368,256)	$36,700,635
FEDERAL INCOME TAX (FEDERAL TAXABLE INCOME * TAX RATE)	$24,762,762	($5,856,375)	$18,906,388
CONN. CORPORATE BUS. TAX	$1,239,082	($291,895)	$947,185
MASSACHUSETTS FRANCHISE TAX	$4,115,144	($969,422)	$3,145,722
FEDERAL TAXABLE INCOME (NET INCOME / (1 - FEDERAL INCOME TAX RATE))	$72,831,654	($17,224,631)	$55,607,023

SCHEDULE 9

REVENUES

	PER COMPANY	DPU ADJ.	PER ORDER
ELECTRIC OPERATING REV.			
PER BOOK	$267,314,000	$0	$267,314,000
ANNUALIZATIONS	$9,421,000	$0	$9,421,000
TRANSMISSION L.T.	$0	$0	$0
FUEL NORMALIZATION	($33,534,000)	$0	($33,534,000)
OTHER	$0	$0	$0
ELECTRIC OPERATING REV.	$243,201,000	$0	$243,201,000
OTHER OPERATING REVENUES			
OTHER OPERATING REV.			
PER BOOK	$12,676,000	$0	$12,676,000
OTHER REV.			
FUEL NORMALIZATION	($865,000)	$0	($865,000)
OTHER REV. ANNUALIZATION	($398,000)	$0	($398,000)
OTHER REV. L. T. TRANS.	($1,644,000)	($69,000)	($1,713,000)
OTHER ELECTRIC REVENUES	($1,189,000)	$0	($1,189,000)
OTHER OPERATING REVENUES	$8,580,000	($69,000)	$8,511,000
TOTAL REVENUES	$251,781,000	($69,000)	$251,712,000

D.P.U. 86-280, WESTERN MASSACHUSETTS ELECTRIC COMPANY SCHEDULE 10
DATE PREPARED: 6/30/1988

REVENUE REQUIREMENT PER ORDER* $258,003,775+$25,865,932

	RATE CLASS	COSS COST TO SERVE	COSS RETURN & TAXES	PRESENT BASE REVENUE	PRESENT FUEL REVENUE	COSS DEFIC.	PROPOSED FUEL REVENUES	BASE REV. REQ. FROM CLASS % TOTAL COS	PERCENTAGE REVENUE INCREASE W. FUEL
		WM-10, p.36	WM-10, p.36	WM-14, p.107	WM-14, p.107	WM-10, p.36	WM-15, p.77		
Residential	R-1,R-4	$66,301,000	$19,994,000	$67,775,967	$7,039,188	$8,909,000	$5,919,167	$72,553,370	4.9%
Res. Space Heating	R-3,R-5	$27,920,000	$9,414,000	$28,466,808	$3,706,712	$3,995,000	$3,116,963	$30,832,787	5.5%
Small Gen'l Service	G-0	$24,430,000	$8,537,000	$26,649,125	$2,645,212	$2,698,000	$2,224,352	$27,754,258	2.3%
Opt.Cntrl.Wtr.Heat.	RATE 23	$1,097,000	$385,000	$1,211,659	$131,225	$92,000	$110,347	$1,237,313	.4%
Opt. Church	RATE 24	$592,000	$220,000	$667,202	$61,720	$62,000	$51,900	$686,494	1.3%
Opt. Sm. Gen'l TOU	T-1	$0	$0	$0	$0	$0	$0	$0	
Secondary Gen'l Serv.	G-1	$6,018,000	$2,158,000	$6,080,611	$758,422	$1,061,000	$637,755	$6,797,108	8.7%
Primary Gen'l Service	G-2	$23,487,000	$8,153,000	$23,470,021	$3,332,734	$3,671,000	$2,802,487	$25,969,412	7.3%
Primary TOU	T-2	$20,495,000	$7,068,000	$22,782,641	$3,252,506	$409,000	$2,735,023	$22,329,448	-3.7%
Lg. Primary TOU	G-3	$45,992,000	$15,523,000	$46,102,975	$7,169,059	$5,899,000	$6,028,442	$49,910,350	5.0%
Trans. TOU	T-9	$7,161,000	$2,322,000	$7,086,852	$1,253,070	$769,000	$1,053,703	$7,569,683	3.4%
Contract	98	$6,438,000	$2,145,000	$6,562,669	$1,003,390	$733,000	$843,748	$6,961,221	3.2%
Street Lighting	S-1, S-2	$4,924,000	$1,393,000	$5,120,516	$406,762	$674,000	$342,045	$5,402,332	3.9%
				$0					
	TOTAL	$234,855,000	$77,312,000	$241,977,046	$30,760,000	$28,972,000	$25,865,932	$258,003,775	4.1%

*Revenue requirement equals base revenue requirement per order from Schedule 1 plus proposed fuel revenue.

WESTERN MASSACHUSETTS ELECTRIC COMPANY SCHEDULE 11
CALCULATION OF MARGINAL COSTS BY VOLTAGE LEVEL
DATE PREPARED: 6/29/88

CAPACITY COSTS		PRODUCTION	TRANSM.	PRIMARY DIST.	SECONDARY DIST-LGS	SECONDARY DIST-SGS	SECONDARY DIST-RES
1.	PROD. PW $/KW-YR @ GENERATOR (1997)	$53.62					
2.	ADJUST. FOR RESERVE REQUIREMENT	1.225					
3.	DEMAND LOSS FACTORS	1.00	.983	.951	.917	.917	.917
4.	TOTAL PROD. PW $/KW/YR	$65.68	$66.82	$69.07	$71.63	$71.63	$71.63
5.	TRANS. $/KW-YR @ TRANS. VOLTAGE		$4.92				
6.	DEMAND LOSS FACTORS		.983	.951	.917	.917	.917
7.	TOTAL TRANS. PW $/KW/YR	4.92	$5.01	$5.17	$5.64	$5.64	$5.64
8.	PROD. & TRANS. PER CP KW/YR	$65.68	$71.83	$74.24	$77.27	$77.27	$77.27
9.	DISTRIBUTION PER NCP KW/YR - LOSS ADJ.			$48.84	$60.41	$69.48	$72.86
10.	TOTAL MARGINAL CAPACITY COST	$65.68	$71.83	$123.08	$137.68	$146.75	$150.13
ENERGY COSTS							
11.	MARG. ENERGY PEAK LOSS FACTORS	1.0000	.983000	.951000	.917000	.917000	.917000
11. A	MARG. ENERG. OFF-PEAK LOSS FCTRS	1.0000	.977000	.961000	.927000	.927000	.927000
12.	PEAK MARGINAL ENERGY COST	.034960	.035565	.036761	.038124	.038124	.038124
13.	OFF-PEAK MARG. ENERGY COST	.026670	.027298	.027752	.028770	.028770	.028770
14.	SYST. WEIGHTED AVE. MARG. ENERGY COST	.030434	.032134	.033122	.034607	.033382	.033382
15.	LESS PROP. FUEL ADJUSTMENT CHARGE	.00732	.00732	.00732	.00732	.00732	.00732
16.	SYSTEM MARGINAL ENERGY RATE	.023114	.024814	.025802	.027287	.026062	.026062

NOTES:

1. EXH. DPU-118
2. EXH. WM-14, TABLE B-4
3. EXH. WM-14, TABLE B-1, P. 1
4. (ROW 1 * ROW 2) / ROW 3
5. EXH. WM-14, TABLE B-3
6. EXH. WM-14, TABLE B-1, P. 1
7. ROW 7 / ROW 6
8. ROW 7 + ROW 4
9. EXH. WM-14, TABLE B-3
10. ROW 8 + ROW 9
11. EXH. WM-14, TABLE B-5
12. EXH. II-28, ROW 12 / ROW 11
13. EXH. II-28, ROW 13 / ROW 11. A
14. ROW 12*PEAK % + ROW 13*OFF-PEAK %
15. EXH. WM-14 AT EXH. CJR-3
16. ROW 14 - ROW 15