Determination of the Marginal Costs of Providing Service on the Delmarva Power & Light Company System and the Conversion of Marginal Costs into Rates

Final Report

to

The Public Service Commission of Delaware

and

The National Regulatory Research Institute

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This report was prepared by J.W. Wilson & Associates, Inc. for the National Regulatory Research Institute (NRRI) under contract No. EC-77-C-01-8683 with the U.S. Department of Energy (DOE), Economic Regulatory Administration, Division of Regulatory Assistance. The opinions expressed herein are solely those of the contractor and do not necessarily reflect the opinions nor the policies of either the NRRI or DOE.

The NRRI is making this report available to those concerned with state utility regulatory issues since the subject matter presented here is believed to be of timely interest to regulatory agencies and to others concerned with utilities regulation.

The NRRI appreciates the cooperation of the Public Service Commission of Delaware with the contractor in preparing this study.

Table of Contents

PREFACE

This report was prepared by J. W. Wilson & Associates, Inc., as an account of work sponsored by the National Regulatory Research Institute (NRRI). The report contains the findings and reflects the views of the consultant. The distribution of this document does not imply an endorsement by NRRI, Delmarva Power & Light Company, or the Public Service Commission of Delaware.

In February of 1978, the National Regulatory Research Institute established a Regulatory Assistance Program designed to offer technical assistance to state regulatory authorities and their staffs in areas where expertise was lacking. The State of Delaware applied for assistance under this program to investigate electric rate design issues of importance to the state. In response to this request, NRRI provided funds for this project and selected J. W. Wilson & Associates, Inc. to perform this analysis.

Three specific objectives have guided the activities of J. W. Wilson & Associates, Inc., under this project:

1. To assist the Delaware Public Service Commission in analyzing initiatives to encourage electric utility companies to institute rate structures that reflect the long-run marginal costs of power production, and that help to enable the achievement of improved system load factor;

2. To develop for implementation, a suitable electric utility rate structure for a major electric utility in Delaware that is reflective of marginal power production costs and time-of-use costs differentials; and

3. To assess the prospective impact of marginal cost time-of-use electric rates on utility companies and consumers in Delaware.

To achieve these objectives, three substantive tasks were included in the JWWA workplan. The first task required interviewing regulatory, utility, and public officials in Delaware to determine the objectives and perceived problems of key individuals in the state with regard to electric utility rate structure design. The results of this survey are provided in a the final section of this report. Second, the workplan called for a review of the existing rate structures for a major electric utility company in Delaware. This analysis of the current rate structure of the Delmarva Light & Power Company was provided in a previous report by J. W. Wilson & Associates, Inc.

Finally, the workplan called for the design of an efficient and practical marginal cost based rate structure with appropriate time-of-use rate variations for a major electric utility in Delaware. The first part of the report presents a generic discussion of the methodology and the techniques underlying the JWWA time-of-day rate design. The second part of this report provides in testimony form, a time-of-day rate design based on marginal costs for the Delmarva Power & Light Company.

Procedures for Determining Marginal
Costs and Their Conversion
into Time Varying Rates
Applied to the
Delmarva Power & Light Company

TASK 4 REPORT
TABLE OF CONTENTS

Introduction

The procedures for calculating marginal costs and for constructing time varying rates are explained in eight steps. Briefly, these eight steps are as follows:

1. Choose the rate periods in which the time varying rates will be different.

2. Determine the marginal cost of the demand and energy components of bulk power supply.

3. Calculate the costs related to other functions and functional services provided by electric utilities.

4. Construct the billing determinants needed to establish time varying rates.

5. Bring the foregoing data together to construct a preliminary set of time varying rates.

6. Adjust the preliminary time varying rates to meet a revenue requirement established independently by the regulatory authority.

7. Determine what markups are needed for energy losses between the generators and the customers.

8. Determine class revenue responsibilities by distributing the functional components of the total cost of service among the customer classes in accord with the use by those classes of the different functions.

This report applies these procedures to Delmarva Power & Light Company more generally than the specific application contained in the Task 3 testimony format. It is hoped that this report will explain marginal costing procedures and methodology in a manner allowing more general application by the Commission staff and other parties to rate case proceedings in the State of Delaware.

Step 1: Choosing Rate Periods

A. General Considerations

If time-of-use rates are to be instituted, then the first step is division of the year into two or more rate periods, during which the rates will be different. The rate periods must be chosen so that consumers can comprehend them easily. This means no more than two or three rate periods in any one day or week, and not more than four seasons, preferably fewer, when the rates or rate periods are different.

The most important aspect of the choice of rate periods is the selection of the hours against which capacity charges shall be levied. The principle of peak responsibility pricing requires that the marginal cost of system generation and transmission be charged against the electricity use or users responsible for the system's peak, because it is demand in the peak period that determines how much capacity the system must have.

The peak hours should ideally be determined with reference to hourly loss-of-load-probability (LOLP) curves, because they show best when the demands are taxing a system's generating capacity. In practice, reference to daily load curves is a feasible approach. Reference to load curves is practical, because the general pattern of the load curves is likely to be reflected in the LOLP curves. Also, the need for comprehension by users restricts the choice of rate periods to simply defined time blocks, and the regularity of load curves facilitates simplicity.

One important consideration in choosing the peak rate period is the seasonal pattern of peak loads and the way maintenance schedules relate to this seasonal diversity. If seasonal diverstiy is so limited that optimized maintenance scheduling equalizes LOLPs across seasons, then all seasons should have peak hours. But wide seasonal diversity may indicate that the off-peak seasons not have any peak-period hours or (more likely) that these hours not share fully in capacity charges levied in the peak season.

A second consideration in selecting rate periods is differences in marginal running cost (system lambda). Where these differences are large, as between oil-burning peaking units and base load coal, it is proper that they be reflected in rates. And the rate periods ideally should be chosen so that system lambda is homogeneous within each period, but different between periods. In practice, this principle is again compromised by the requirement that rate periods be easily comprehended by the ratepayers.

A related point is that the peak hours for allocation of generating capacity charges are defined by LOLPs, that are different in concept from the marginal running cost differential required to operate peaking plants. For example, it may be most economical on some systems to serve the region between 85 to 90 percent on the load duration curve from peaking capacity rather than to install enough base load capacity to meet 90 percent of the load, but this need not mean that demand in these hours is responsible for the system capacity requirement.

There is important and systematic variation in the electricity demand for DP&L by the hour of the day, the day of the week, and the season of the year. The seasonal fluctuations are due primarily to changes in the normal seasonal weather conditions, including the number of daylight hours. But, in addition, the weather within one season also varies from day to day, and these less predictable daily weather changes also have a major impact upon electricity demand.

The variation in electricity demand by time-of-day is illustrated by the four daily load curves in Schedule 1. These curves show that the aggregate demand on the Delmarva system remains stable at a high level from early in the morning until well into the evening on weekdays. There is a deep valley in the nighttime hours of approximately midnight through 7 a.m., and a very rapid change in the demand level in the brief time between the valley and the plateau.

Loads also vary systematically by the day of the week. Loads on Saturdays and Sundays are generally far below the plateaus established on working days.

When the hours of the year are grouped into rate periods that have relatively homogeneous demand levels, the following periods result:

<u>Peak hours</u>:

Winter months (October-May),
8 a.m. to 10 p.m. on workdays

Summer months (June-September)
9 a.m. to 11 p.m. on workdays

<u>Off-peak hours</u> (all other times):

Winter months, 10 p.m. to 8 a.m.

Summer months 11 p.m. to 9 a.m.

All day Saturday, Sunday, throughout the year

Some statistics describing these periods and the loads in them are shown in Schedule 2.

The peak period includes those hours of the day in which the demand is generally above 90 percent of the daily peak. These are the hours within which the daily peak is likely to occur, or into which the peak might be shifted if the hour were excluded from the peak period for ratemaking purposes.

Some typical values of system lambda for PJM are shown in Schedule 2. As expected, marginal running costs are substantially higher during the peak period than during the off-peak periods. Winter lambdas are higher than summer lambdas primarily because baseload units are planned to be on-line at time of system peak with maintenance being performed at other times during the year.

Hourly integrated PJM lambdas are the marginal cost of energy on the Delmarva system, since Delmarva dispatches its own system in response to PJM lambdas. That is, when Delmarva can buy energy more cheaply from the PJM pool than it can produce energy itself, Delmarva will be in a buying mode. However, when another pool member would incur self-generation costs higher than Delmarva's cost of providing additional power, Delmarva will be in a selling mode. Hence, efficient operation of the Delmarva system results in a cost of additional energy being that of the pool marginal cost. These pool marginal costs are available for each hour on the PJM system, making the marginal energy cost over a given time period readily available.

Step 2: Marginal Cost of Bulk Power Supply

After the rate periods have been chosen, the next task is to determine the costs of providing electric service in each of these several rate periods. The determination of these costs should be made first at the system generation level, and this determination requires two steps in the total procedure. The first of these two steps is the determination of the marginal costs of bulk power supply in each of the rate periods. Then in Step 3, the appropriate cost rates for the other functional components of the provision of electric service will be considered.

The costs of bulk power supply are in two parts: the cost of having sufficient generating capacity available to meet the loads; and the cost of running that capacity to generate sufficient energy. The costs appropriate for time-of-use rates are marginal costs, rather than the embedded cost levels used to establish a revenue requirement for cost-of-service purposes. However, except for this difference, the marginal capacity and running cost are essentially the same as the demand and energy components of the total power production costs in a conventional cost-of-service study.

A. Marginal Running Costs

Marginal running costs are the simpler of the two components of total bulk power supply cost, and it is more convenient to begin with them. Marginal running costs can generally be associated with system lambda. Where data on system lambda are not explicitly available as such, one may rely instead upon the individual plant and generating unit estimates of running cost per kilowatt-hour that are used in the dispatching algorithm for scheduling generation. In this event, the <u>marginal</u> running cost at any time is the dispatching cost of the least expensive unit <u>not</u> fully loaded at that time. Since the PJM system lambdas are readily available for each hour, a separate calculation of marginal energy costs is unnecessary.

The marginal running cost for any rate period should generally be taken as the average of the marginal running costs during all of the different hours in that rate period. If the rate periods have been chosen to minimize the within-period variation in system lambda--as the discussion in Step 1 explains they should be chosen--then the use of a single average value for system lamba throughout an entire rate period is consistent with the proposition that the rates charged to the users should at each hour reflect the marginal costs of that particular hour.

The data on marginal running costs of DP&L are presented in Schedule 2 that was discussed in Step 1. These marginal running costs are PJM system lambdas and represent the additional cost of providing additional energy on the Delmarva system during various time periods.

B. Marginal Costs of Meeting Demand

The second part of the bulk power supply cost analysis is the calculation of the marginal cost of generating capacity and associated transmission required to meet an additional kilowatt of demand. It is now generally accepted that the marginal cost of meeting a kilowatt of demand in the peak period is properly based on the cost of a peaking unit. An alternative calculation--to so-called Turvey computation--is the cost of a baseload generating unit less the fuel savings realized when that unit is run instead of a peaking plant during the peak hours. However, it has been demonstrated that this calculation yields the same result as the cost of a peaking unit, provided that the length of the peak period is defined for this purpose as the number of hours that peaking plants would be in use on a system with an optimally designed mix of peaking and other plants.*

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*The reason for this equality is that baseload capacity should ideally be built exactly to that point on the load-duration curve where the fuel savings precisely offset the higher capital cost of the baseload plant compared to peaking capacity. If the baseload plant cannot be run enough hours for these fuel savings to offset its extra capital cost, there is too much baseload plant. And if all baseload plants--even the marginal baseload plant--can be run more than enough hours to offset the extra capital cost, there is not enough baseload plant.

The calculation of the marginal cost for meeting an additional kilowatt of demand during the peak period is shown in Schedule 3. The original cost per kilowatt of capacity is the $185.00 incurred by DP&L to purchase and install a combustion turbine unit.

The annual capital carrying cost rate of 15.32 percent is developed on pages 3 and 4 of Schedule 3. The return requirement is based upon the current cost of new long-term debt and preferred stock and DP&L's proposed return on equity, so that it reflects the marginal cost of capital. Income taxes are included at the full nominal rates of taxation. The benefits from income tax deferrals due to rapid depreciation and the effect of the investment tax credits are included in the carrying cost rate determination. The return requirement is translated into a levelized annual payment for recovery of the initial cost of the plant plus a return on the unrecovered balance. This approach, which is akin to the calculation of a mortgage payment for principal and interest, is a slower means of revenue recovery than straight-line depreciation plus a return on the undepreciated balance of plant. This means that the levelized annual payment is less than the revenue that would be required in the first year of the life of a new plant, although it is of course higher than the traditionally calculated revenue requirement late in the life of the plant.

The annual carrying cost per kilowatt of capacity is \$28.34, obtained by multiplying the 15.32 percent carrying cost rate times the \$185.00 original cost per kilowatt of generating capacity. Annual maintenance costs of \$1.33 per kilowatt of capacity are included. The sum of the annual carrying cost per kilowatt of capacity and the annual operation and maintenance costs is the total marginal cost per kilowatt of generating capacity.

The final element in the calculation of the marginal cost of meeting a kilowatt of demand is the addition of a margin for the reserve requirement. The reserve requirement of 20 percent represents the margin of installed capacity required above expected peak demand generally required of PJM member utilities. If this margin is to be maintained, then an increase of one kilowatt of expected peak demand requires an increase of 1.20 kilowatts of generating capacity, and the cost per unit of capacity must therefore be increased by this factor to reflect fully the capacity costs of meeting additional demand.

When the marginal cost of \$29.67 per kilowatt of generating capacity is multiplied by 1.20, to allow for the required reserve, the result is a total annual marginal cost of $35.60 for meeting a kilowatt of demand.

Schedule 4 converts the cost of associated transmission investment into an annual marginal cost. DP&L estimated the outlet cost of a peaking unit at $19.00 per Kw. Applying the annual carrying cost rate of 15.32 percent to this investment, then adding O&M expenses of $.57 and reserve requirement yields a $4.17 cost of transmission associated with an increase of 1 Kw of demand during peak periods.

Step 3: Other Functional Cost Components

Bulk supply is only one (or three, if capacity, transmission, and energy are counted separately) of the many functional services provided by electric utilities. The marginal costs of power production, whose determination was discussed in the preceding Step 2, reflect only a part of the total cost picture of electricity supply. Since time varying rates are intended to reflect the entire spectrum of electric utility costs, the analysis of the marginal costs of power production must be supplemented by an accounting for the other costs of electricity supply.

These other costs fall into three major categories:

transmission, below 230 Kv

distribution

customer costs

In conventional ratemaking, the analysis of these functional cost categories enters into the determination of the rate structure through a class cost-of-service study, the object of which is the establishment of separate class revenue responsibilities for the different customer classes. The individual cost elements of each functional service are distributed among the customer classes in accord with the classes' use of the service, and thus the class revenue responsibilities do reflect class usage characteristics. But the functional cost totals are submerged into the class revenue responsibilities, and the rate structure within each class is generally constructed without specific regard to the functional cost structure.

In developing time-of-use rates, it is important that the total costs for each function be accumulated and preserved, so that a single price per unit of the functional service can be calculated and applied to all users (in all customer classes) on the utility system. Preservation of totals for the functional cost categories rather than for class revenue responsibilities is also a necessary first step towards the design of rates that recover these costs from the specific times of use (peak and off-peak) and part of the rate schedule (demand, energy, customer charge) to which each cost properly applies.

Development of the functional costs for functions other than power supply can be done either on a marginal cost basis or with reference to embedded average costs as traditionally calculated. As a matter of economic theory, marginal costs for these other functional services are the proper basis for pricing, just as marginal costs are the proper basis for the pricing of power supply demand and energy. But the determination of marginal costs for lower level transmission, distribution, and customer costs is much more difficult and less precise than for power supply, and it is not clear that the benefits are sufficient to justify the effort. This is especially true where the object is to refine the time structure of electric rates in support of load management objectives that relate primarily to power production costs and fuel use rather than to the other functional activities of electric utilities.

In contrast to marginal costs, the determination of the embedded total or average costs for the other functional services is familiar to those who have worked in or with traditional electric utility ratemaking. Use of embedded average costs for these other functional activities can also be justified as probably a good approximation to the theoretically preferable marginal costs, and it is the approach here. The functionalized costs of providing service on the Delaware jurisdictional portion of the Delmarva system are shown in Schedule 5. These results are derived from the conventional class cost-of-service study performed by DP&L for forecast test-year 1978. Page 3 shows the functionalization of O&M expenses. Depreciation expenses are functionalized on page 4, and taxes other than income taxes are functionalized on page 5. Income taxes and proposed cost increases above book levels are functionalized on page 2 of Schedule 5.

Step 4: Billing Determinants for Time-Varying Rates

To construct a set of utility rates, one needs information about billing determinants as well as about costs. For costs that are developed initially on a per unit basis, such as the marginal costs of power supply in Step 2, the number of billing units to which these prices are applied is the determinant of revenue, and thus it is needed for comparison of the revenue from the time-varying rates with the system revenue requirement. For other functional activities for which costs are developed on a total system basis, as in Step 3, it is necessary to know how many units of service were provided by the utility incurring those total costs, so that an average cost per unit can be obtained by division and applied as the unit price for the relevant service.

For three-part time-varying rates, with demand, energy, and customer charges, the billing determinants are billing demands, energy used in each rate period, and the number of customers.

In general, data on energy usage in each rate period (at system level) and on the number of customers can be obtained directly from the records of the company. Hour-by-hour data on energy usage at the system level are generally available from the system dispatch logs, and indeed they are likely to have been developed as a by-product of the selection of rate periods in Step 1. Data on the number of customer bills to which a minimum charge or customer charge is applicable should also be readily available.

Data on billing demands are likely to be much more of a problem, because demands are routinely metered only for some customer classes and not for others. Estimates of billing demands can be derived from load study data, preferably from the system for which time-varying rates are being determined, but, if necessary, by use of detailed load study data from other comparable systems. Estimates of billing demands are often made for use as allocation factors in class cost-of-service studies, and these data and estimating procedures are therefore not unknown to electric utility rate analysts.

Billing determinants at the generation level for the Delmarva Power & Light Company for 1978 are shown on pages 1 and 4 of Schedule 6. The generating capacity requirement is determined by the highest retail demand in the year that for DP&L was 901 megawatts. Power supply demand costs are recovered by billing against the sum of the monthly billing demands through the year. These demands total 15,524 megawatts, or 17.2 times the annually peak demand on the system. The ratio of billing demands to the annual peak demand exceeds a factor of 12, because the billing demands are the sum of the noncoincident maximum demands of all the customers in each month; and the sum of the noncoincident maximum demand of the individual customers is substantially greater than the maximum coincident demand during the month. Owing to this diversity, the price to each customer for each kilowatt of his own maximum demand in any one month need be only approximately one-seventeenth of the annual cost to DP&L of meeting one kilowatt of demand, rather than the one-twelfth that each customer would have to pay if there were no diversity.

Footnote 3 on page 2 of Schedule 6 explains the derivation of the 15,524 Mw of billing demands. This number represents the sum total of monthly Kw meter readings that would occur on customer meters throughout the year, but stated at the magnitude associated with measurement at generation level. The noncoincident billing demands at generation level are increased by a factor of 9.7855. This represents the relationship of annual billing demands to those during the peak month. Each monthly peak for nonpeak months is below the annual peak; therefore, annual billing Kw are not 12 times the noncoincident demands in the peak month, but a lower amount. The sum of the monthly peaks on the DP&L system is 9.7855 times the annual peak, and this is the factor used to convert a monthly noncoincident demand into an annual noncoincident billing demand.

In addition to power supply demands, the demands upon the distribution system must also be measured, because they are the basis against which some of the distribution costs are recovered. Since the necessary size and capacity of the distribution network are determined at each point on that network by the maximum localized loads there, an appropriate basis for recovering the distribution costs is the sum of the noncoincident maximum demands of each customer for service taken from the distribution system. For DP&L, the distribution system is defined as the system for providing service at voltages below 69 kilovolts, and the demands on this system must be calculated excluding the billing demands of all customers taking service at transmission level voltages. The sum of the noncoincident maximum demands of all customers taking service from the distribution primary system is 14,805 megawatts for the 12 months of 1978, while the comparable determinant at secondary voltage levels is 11,149 Mw.

These 14,805 Mw demands are calculated by removing the Rate Q and Transmission noncoincident demands from the total noncoincident demands shown on page 4 of Schedule 6 and annualizing the result by applying the 9.7855 factor. The 11,149 Mw figure is the result of removing the primary demands in a similar calculation.

Energy usage at generation level, before losses, is obtained directly from DP&L proposed test-year levels reflected in the Company's class cost of service study. Loads during each hour of the monthly peak days, typical days, and weekend days were used to develop system level energy usages by rate period. The retail energy usages by customer class were taken directly from DP&L's class cost of service study, as were the weighted customer totals by customer class.

Step 5: Time-Varying Rates at System Generation Level

The first three steps in the development of time-varying rates concern the separation of the total costs of providing service into components associated with the several different functional aspects of that service: power supply demand; energy furnished at different times of the day, week, and year; demands upon the distribution system; and customer-related costs. Step 4 explains how the quantities of service furnished in each of these functional areas can be measured. The purpose of Step 5 is to bring together these data calculated in the four preceding steps, to determine a rate per unit of service for each of the functional services provided by electric utilities.

In general, the energy charges in each rate period are simply the marginal running costs developed in Step 2 that are already expressed on a per kilowatt-hour basis. The demand-related costs of power production can be met either by charges against the noncoincident monthly billing demands measured during the peak rate period, which are a proxy for the individual customer contributions to the coincident system peak, or by charges against the energy used in the peak rate period. A combination is also possible, with some of the demand-related costs recovered by charges against billing demands and some of the cost recovered by charges against energy usage in the peak period. The power supply demand charge is levied only against billing demands and/or energy usage in the peak rate period, because high rates of energy use in off-peak periods, when generating capacity is idle, do not affect the demand-related costs incurred by the utility furnished service.

Transmission costs should generally be recovered in the same way that the demand-related costs of power production are recovered, because transmission serves the functional purpose of integrating the power supply centers and connecting them to the major load centers. Since the size and cost of the transmission network are governed by the maximum demands placed upon the network, these costs are related to capacity rather than to energy.

The size and cost of the distribution system are also related to demand rather than energy, but--like power supply demand costs--they may be recovered either from demand charges, or from energy charges, or from a combination of the two. If distribution costs are recovered from demand charges, these charges should be applied to the maximum noncoincident demands for service from the distribution system, without regard to the rate period in which the maximum occurs for any individual customer. The power supply demand charge is limited to the peak period, because customers should not be charged additionally for high rates of energy use in off-peak periods, when generating capacity is idle; but the required capacity of the distribution system depends upon the maximum localized demand, whenever it occurs, and that is why the distribution charge is levied against the maximum noncoincident demands measured without regard to rate periods. If distribution costs are recovered through energy charges, it is similarly appropriate to assess these charges against energy use in all rate periods, rather than limiting these charges to energy used in the peak rate period.

Finally, customer costs should be recovered by charges against the weighted number of monthly customer bills, so that each customer bears a proportionate share of the total customer-related costs.

Calculation of the time-varying rate components for the Delmarva Power & Light Company in test-year 1978 is shown in Schedule 6, page 1. The demand component of the cost of bulk power production is $39.77 per kilowatt per year. To recover $39.77 for each kilowatt of required generating capacity, DP&L must bill its customers only $2.31 per month for each kilowatt of noncoincident demand used during the peak rate period. This is because the sum of the monthly noncoincident demands is 17.2 times the annual peak, even though there are only 12 months in the year, owing to diversity among the customers. The difference between one-twelfth of $39.77 per kilowatt per year ($3.15) and $2.31 per kilowatt of billing demand per month is the benefit of diversity, which is shared by all the users on the DP&L system, in the unit cost determination developed in Schedule 6.

The energy charges of 30.61 mills and 19.41 mills for the two rate periods are based upon average system lambdas for the PJM pool, weighted by rate period hours.

The unit rates for lower level transmission, distribution, and customer costs are based upon the functionalization of actual total system costs, as developed in Step 3; and they are simply the average costs per unit of service for each of these functional categories. The transmission costs ($13,166,000), distribution costs ($14,773,000 and $5,912,000), and the customer costs ($24,435,000) are taken directly from Schedule 5, page 1. The number of billing units of service provided in each of these categories is developed on Schedule 6, page 1, or taken directly from Schedule 6, page 4, as explained in Step 4. The costs per unit are then obtained by division of the number of billing units into the total dollars of cost.

Step 6: Adjusting Time-Varying Rates to Meet the Established Revenue Requirement

If the time-varying rates determined in Step 5 are applied to the billing determinants at system generation level, as developed in Step 4, the result is a definite amount of revenue. This revenue amount may, by chance, equal the revenue requirement established by other means for the electric utility in question, but it is possible (indeed, likely) that it will not. In the procedures used in this study, some parts of the time-varying rates are indeed developed from an analysis of the embedded total system costs, as these costs would be viewed in determining a revenue requirement. But only the lower level transmission, distribution, and customer costs are so treated in this presentation; whereas the prices for both the demand and the energy components of power supply are based upon marginal rather than upon embedded average costs.

The purpose of Step 6 is to explain how the rates determined in Step 5 can be adjusted to meet an established revenue requirement. To make adjustments, it is first necessary to know what the revenue requirement is. This is not likely to be a problem in a complete rate investigation, where the rate structure can be established for the same test-year that is used in the determination of the revenue requirement by the regulatory authority. In other circumstances, it will be necessary to calculate the revenues that would have been obtained if the currently approved rates had been in effect for the entire year used in developing the billing determinants for setting the time-varying rates. If the currently approved rates were actually in effect during this entire year, then this calculation simply involves adding up the actual revenues; but if a rate change has occurred since the beginning of this base year, the revenues actually collected during the year must be adjusted to reflect the new rate levels most recently approved.

The revenue requirement adopted for use on the DP&L system is that equal to the $229,511,000 total costs of providing service as proposed by the Company. Retail rates for electric service are responsible for $225,170,000 of the total cost of service.

In working with a revenue requirement, it is also important that the established requirement include fuel adjustment revenues as well as revenues from base rates. The reason is that the marginal running costs reflect current or recent fuel prices, not the fuel prices of some past period that may happen to be the base for the fuel adjustment procedure; and thus it cannot reasonably be expected that revenues based upon current running costs should equal the revenue requirements developed using a hypothetical base period fuel cost. Finally, if this approach is used, the base fuel cost for the fuel adjustment procedure must be revised to that actually experienced during the year for which the running costs are reflected in the time varying rates.*

Schedule 7 develops the revenues produced from application of marginal cost-based rates and compares these revenues to those required. Since lower level transmission, distribution, and customer costs are recovered on an average basis, these functional costs will be recovered exactly when unit costs are applied to billing determinants. Power production revenues from marginal cost-based rates are $151,229,000, however, while the embedded cost of power production is $164,592,000. The $13,363,000 difference shown on Schedule 7 is the amount by which total revenues produced at marginal cost-based rates must be increased to produce the total costs of service at DP&L proposed rates.

There are several different ways that time varying rates can be adjusted to meet an established revenue requirement.

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*If it is desired to retain the same base fuel cost for the fuel adjustment procedure, the difference between the fuel cost in the year used to develop the time-varying rates and the base fuel cost can be subtracted from the marginal running costs that would otherwise be used, and application of the fuel adjustment procedure on the old base will restore the energy prices to the desired level. Alternatively, the marginal running costs could be adjusted to what they would be if fuel prices were at the base level of the fuel adjustment procedure instead of at the levels actually observed during the year from which the time varying rates are developed; but this is likely to be a more complicated calculation.

Six different approaches are discussed in the following paragraphs.

1. Uncertainty in the marginal cost calculations--The estimation of marginal energy and capacity costs is invariably subject to some uncertainty. Marginal running costs differ from hour to hour, even within a single rate period, and this variation defines a plausible range for the kilowatt-hour charge. Rates can be adjusted upward or downward to one extreme or the other of this range, where that is necessary to meet a preestablished revenue requirement.

In principle, economic advice is likely to suggest that the best point estimate be chosen from a range of uncertainty, and that there is great peril in using the admitted imperfections in one's methods and techniques as an excuse for reaching a result that one may for other reasons want to achieve. On the other hand, there is considerable debate over the correct way to establish prices based on marginal costs in the first place, and it would be difficult to object in practice to the use of external constraints as a device for helping to resolve some of this controversy.

2. Aberrations in the data for a single utility--The determination of costs for a particular utility may involve the use of data that are atypical of representative cost conditions. For instance, if a given system is far out of balance with regard to its plant program, its actual marginal running costs during the off-peak period may not reflect relative costs that will be incurred in the future as new construction optimizes the plant program. Since one of the objectives of marginal cost pricing is to give consumers stable signals as to the real cost of producing energy as it is consumed (or forgone) at the margin, the use of a more long-term equilibrium cost, rather than a more short-term cost aberration, may be justified on a rational basis, as well as aiding in the achievement of a given revenue requirement.

3. Redefinition of rate periods--A third approach is to shift hours from high-price to low-price rate periods, to reduce the revenue obtained from given rates, or in the opposite direction with the opposite effect. In other words, the boundaries of the peak and the off-peak periods will generally be selected with reference to the load curves and the dispatching system, but where these two do not mesh perfectly, there is a need to apply judgment and practical considerations. One such practical consid-

eration can be the amount of revenue that is required, and this can be used to decide whether a particular borderline hour belongs in a high-priced or a low-priced rate period.

The same practical considerations apply to this approach as to adjustments made within the range of uncertainty about what the marginal costs themselves are.

4. Flat percentage adjustment to some or all components of a multipart rate structure--A flat percentage adjustment to all parts of the multipart rate structure is another practical way to remove any difference between the revenue requirements and the revenue that would be generated from rates set at marginal costs. If the adjustment is small, this approach has much to recommend it. (And if the adjustment is a large one, then no approach is likely to be very good.) This approach has the appeal of apparent fairness, and its results are likely to be very much like those that are obtained when the first approach is applied. As far as economic merit is concerned, the question is how this approach compares with the more finely tuned ones to be discussed in the following two paragraphs.

5. Adjustment only to customer charges-- Adjustment only to the customer charges is likely to be appropriate and

practical only if the adjustment is downward. The principal argument in favor of adjusting customer charges is that they are the part of the rate structure to which the demand response is likely to be least elastic. In other words, modest reductions in the customer charge are not likely to have any impact on the number of customers, whereas adjustments in any other part of the rate structure are likely to impact electricity usage to some extent. This argument also applies to upward adjustments of customer charges if they should become necessary, but it is likely that any such action would be interpreted as a regressive shift of revenue responsibility onto customers with lower incomes or lesser abilities to pay.

6. <u>The inverse elasticity rule</u>-- The inverse elasticity rule for making revenue adjustments can be applied in either of two very different ways. One approach is to use elasticity estimates as a criterion in deciding what parts of a multipart rate structure should be changed. For example, this is the principle on which the customer charge is best defended as the most appropriate candidate for revenue adjustment when that becomes necessary.

A very different use of the inverse elasticity rule is its application to adjust differently the prices paid by different classes of customers. This approach is defended only on the grounds of economic efficiency, and even economic principles recognize that questions of equity must also be considered in public policy decisions such as electricity pricing. Since it is extremely difficult in practice to determine the elasticity of demand for any one customer or customer class, there are extreme difficulties likely to be encountered in attempting to implement the principle of inverse elasticity for choosing among customers and deciding how much to adjust the rates of each customer or customer class.

The adjustment process shown on Schedule 8 resembles Method 4 above. The marginal costs of generation, transmission, and energy are increased proportionately by 8.8 percent to achieve the total revenue target. Functional costs determined on an average cost basis have not been altered (since they are not responsible for the need for adjustment, and because the cost methodology used to arrive at the cost of these functions has been approved by the Delaware Commission in past rate cases). The proportionate adjustment maintains the relative peak, off-peak cost ratios, as well as the demand/energy cost determination at marginal cost levels. More speculative methods, such as adjustment via the inverse elasticity rule are avoided.

Step 7: Time Varying Rates at Customer Level Marked Up for Loss Factors

After rates have been determined at system generation level consistent with a revenue requirement, one further step is necessary in the derivation of retail rates. The rates at system generation level must be marked up to reflect both demand and energy losses that occur between the generation level and the delivery of electricity to ultimate consumers. Since losses vary with the delivery voltage level and rate period during which service is taken, loss estimates should vary accordingly.

The adjustment of rates from system generation level to customer level, to reflect transformation and distribution losses, is extremely straightforward, as illustrated in Schedule 9. This schedule shows the development of retail rates for two customer classes: those customers served at primary voltage levels, and customers served at secondary voltage levels. The rates at generation level are shown in the first line of the table, which is taken directly from the unit costs shown on page 1 of Schedule 6, or the adjusted costs shown on Schedule 8. The second line contains the loss factors, associated with service at primary. Once the loss factors have been determined, all that remains is multiplication of the costs at generation level times the loss factors, to obtain the actual rates applicable at sales level. Resulting primary rates are shown on the third line. The process is repeated with loss factors for secondary service shown on the fourth line, with resulting retail rates at secondary shown on the last line.

Determination of the appropriate loss factors for each customer class requires the combination of engineering judgment with available statistical information. Average loss factors for total system energy for all classes can be determined by comparing total energy sales recorded at meters against total energy recorded at the system level in the system dispatch logs. Loss factors at peak periods would generally be higher, owing to Ohm's law. Loss factors also differ by delivery voltage level, and engineering judgment is likely to be required to establish the appropriate differentials in the loss factors. The loss factors shown in Schedule 9 are those determined by DP&L and used in their class cost of service study.

Having determined the cost of each functional component of providing service, all that remains is to collect the functional rate components and restate them in tariff form. Schedule 10 illustrates rates for secondary and primary customers. The source of the rate elements is Schedule 9. Separate charges for customer, energy, and demand components are shown. Appropriate losses for primary and secondary customers are reflected in the demand and energy charges. In addition, customers taking service at secondary voltage levels are responsible for all secondary distribution costs (as well as their proportionate share of primary distribution costs), while primary customers bear no cost responsibility for the secondary distribution cost requirement.

An alternative method of determining rates is to recognize class diversity of demand. Classes exhibiting a great deal of diversity in their usage of electricity will contribute much less to system peak for each unit of billing demand than will customers exhibiting little diversity of demand. Since billing demands are a proxy for a measure of contribution to system peak, a given contribution will be spread over more billing Kw for customer groups having greater diversity than other customer groups. The result will be a lower cost per billing Kw the greater the diversity.

Schedule 11 explicitly recognizes diversity in the rate determination. Each class is assigned its share of the marginal costs of capacity. That share is then unitized over each class's billing determinants. The resulting retail cost of capacity per billing determinant is shown on page 1 of Schedule 11.

Schedule 12 shows rates for the Residential, secondary and primary General Service customers when each class retains the diversity associated with the particular class. The capacity charge is taken from Schedule 11, with the energy and distribution charges taken directly from Schedule 9. Lower capacity charges are associated with greater class diversity.

Schedule 13 confirms that rates based on marginal costs (as adjusted in Schedule 8) generate revenues consistent with the total costs of service as proposed by DP&L. The process involves the multiplication of each rate element times the jurisdictional billing determinant and summing the resulting revenues.

Step 8: Deriving Class Revenue Requirements and Conventional Rates from Marginal Costs

The implementation of time varying rates, as described in the preceding steps, can only be accomplished where time-recording meters are (or already have been) installed. Since metering costs are very high, even for a relatively simple time-varying rate with only two rate periods for kilowatt-hour charges and a single demand charge, the introduction of time-varying rates must necesssarily proceed very slowly; and for some types of customers, time varying rates may never be worth the cost. Conventional kilowatt-hour rates and two-part demand and energy rates will therefore continue to be used.

However, this continuing use of conventional rate forms is not a bar to the reliance on marginal costs in establishing some aspects of the rate structure. In particular, it is possible to use marginal costs rather than embedded average costs to derive the class revenue responsibilities that underlie conventional rates.

If the complete time pattern of loads for each customer class is known for the test-year, then it is possible to apply the time varying rates derived in Step 7 to each class as a whole, to determine its class revenue responsibility on the basis of time-varying marginal cost principles. The class load patterns may be known from load studies on a sample of customers in each class, or they may be partly estimated using load study data from comparable utilities.

If the time pattern of the class loads is not known, then it is necessary to rely on some data from a conventional class cost of service study to allocate revenue responsibility to the customer classes. However, it is still possible to apply these conventionally determined class allocation factors to a functionalization of total system costs based on marginal rather than on embedded average costs. Since a functionalization based on marginal cost principles is likely to assign greater cost to the energy function than an embedded cost approach, but less of the total system cost to peak demand and perhaps some other functions, the use of these marginal cost principles tends to assign greater revenue responsibility to those customers that use relatively more energy than capacity or other functional services. Specifically, marginal costing methods are likely to assign greater revenue responsiblity to classes with high load factors than these classses are assigned under fully distributed average cost approaches.

Schedules 14 and 15 illustrate class revenue requirements resulting from application of the rates shown on Schedules 10 and 12. DP&L has estimated class energy usages by rate period. The demand billing determinants have been estimated as described earlier in this report. Retaining diversity benefits shifts revenue requirements from classes with greater diversity towards classes exhibiting lower levels of diversity.

Once class revenue responsibilities have been determined, the process of designing conventional rates to recover these revenues proceeds along the conventional path. However, classes with two-part rates may have a lower demand charge and higher energy charge than under a conventional fully distributed embedded cost-of-service, because the functional components of revenue responsiblity for each class will be more heavily weighted towards energy when marginal costing concepts have been used. This is a most important practical effect of applying marginal cost principles to rate structure.

Model Testimony on the Determination of Marginal Cost-Based Rates for the Delmarva Power & Light Company Delaware Jurisdiction

Testimony of Richard A. Galligan

Q. WOULD YOU PLEASE STATE YOUR NAME, OCCUPATION, AND ADDRESS FOR THE RECORD?

A. My name is Richard A. Galligan. I am a Senior Economist with J. W. Wilson & Associates, Inc. My office is at 1010 Wisconsin Avenue, N.W., Washington, D. C. 20007.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I have two degrees from the University of Wisconsin, including a masters degree in Economics, and, in addition, I completed two years of graduate study at the University of Minnesota, where I fulfilled all of the course work requirements for the Ph.D. degree.

Q. WHAT IS YOUR ACADEMIC EXPERIENCE?

A. I have taught Economics at the University of Wisconsin and the University of Minnesota. I served on the faculty of Mankato State University as an Assistant Professor of Economics for seven years, attaining tenure status after my third year. I also served as an Adjunct Professor of Economics for Webster College. In these positions, I taught a wide range of courses covering all aspects of economics.

Q. WHAT IS YOUR EXPERIENCE IN UTILITY MATTERS?

A. In January 1975, I joined the staff of the Minnesota Public Service Commission at the commencement of commission responsibility over gas and electric utility operations in the State of Minnesota. My responsibilities as a senior staff member included the analysis of utility rate filings, preparation of testimony regarding rate design matters, cross-examination of company and intervenor witnesses, preparation of substantive briefs, serving as Rate Case Manager, preparation of cost-of-service studies, participating in the development of Commission rules and regulations related to annual filing requirements, serving as Commission support staff, and numerous other activities related to utility regulation in the areas of gas, electric, and telephone rates and rate structures. In August of 1976, I assumed my present position at J. W. Wilson & Associates, Inc.

Q. HAVE YOU PUBLISHED IN THE SUBJECT AREA OF UTILITY ECONOMICS?

A. Yes. An article of mine, "Rate Design Objectives and Realities," appeared in the May 6, 1976 Public Utilities Fortnightly.

Q. HAVE YOU BEEN INVOLVED IN, AND TESTIFIED ON, UTILITY RATE MATTERS?

A. Yes. I was the principal member of the Minnesota Participating Department Staff in the 1975 Northern States Power Company rate case, Docket ER-2-1. I also testified for the Minnesota Commission Staff in the Interstate Power Company 1975 electric and gas rate cases, Dockets ER 1-1 and GR 1-1, respectively. In addition, I was Rate Case Manager and testified in the Anoka Electric Cooperative rate case, Docket U-75-103 and also testified in the Minnesota Power & Light Company rate case, Docket E015/GR-76-408. All of these matters were before the Minnesota Commission. Since joining J. W. Wilson & Associates, Inc., I have testified in additional regulatory proceedings before the Regulatory Commissions in California, Connecticut, Maryland, Minnesota, Missouri, Michigan, North Carolina, South Dakota, Montana, and Rhode Island. I have also served as a special staff consultant to the Connecticut PUCA in conjunction with that authority's generic rate structure case and the Connecticut Power & Light, and Hartford Electric Light Company electric and gas rate cases.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My purpose is to analyze the costs of providing electric service on the Delmarva Power & Light Company (DP&L) electric system, to determine whether these costs are higher at some times of the day, month, or year than at other times. Having made such determination, I then calculate the cost differentials by time of use. The costs of providing service have been determined on the basis of DP&L's proposed jurisdictional test-year cost levels in its current rate case filing before this Commission in Docket No. 923.

Q. WHY ARE RATE STRUCTURE CONSIDERATIONS A PARTICULARLY IMPORTANT ASPECT OF PUBLIC UTILITY REGULATION?

A. In a market economy such as ours, it is the price system that allocates resources, encourages producer and consumer efficiency, and, in general, serves as a disciplinary force in determining what is produced, in what volume, and how it is distributed. Prices in this system are the incentives. The prices of various goods and services in our economy constitute a graded system of incentives affecting both the producer and the consumer. By his willingness to pay various prices for various goods, the consumer signals his preferences to producers. By their willingness to sell various goods at various prices, the producers, in turn, signal costs to consumers. When certain conditions are present, especially those associated with the ideal of perfect competition, the price system forces each individual producer and consumer, while working purely in his own interest, to contribute to the welfare of society as a whole. Under these conditions, available resources are used in the most efficient way to produce the largest possible quantity of goods and services, and these are distributed so as to maximize aggregate economic satisfaction.

In the competitive market, prices tend to reach an equilibrium when equal to marginal costs. Should the price of additional units of output exceed the costs of producing such units, production would expand to capture the excess of price over cost on all such units. Expansion of output would continue as long as the price received for additional output exceeds the additional cost of that output. Similarly, should the price of additional units of output be less than the costs of producing those units, firms would have the incentive to cut back on production and save more in costs than they lose in revenue. This would continue as long as the additional cost of producing a unit exceeds the market price at which that unit can be sold.

Society has an interest in seeing that resources are not used to produce units of output that cost more at the margin than the value society places on those units reflected in market price. Similarly, it is in the public interest to have resources put to use in areas where society values the output more highly than the resources it takes to produce that output. Hence, the competitive market leads to a channeling of resources to that production that is in the public interest.

Q. DO THESE SAME MARKET FORCES PROMOTE ECONOMIC EFFICIENCY IN BOTH COMPETITIVE AND REGULATED INDUSTRIES?

A. Unfortunately, the characteristics of competition are often not present in the case of public utilities that are typically franchised monopolies facing only limited forms of market rivalry. In such instances, in the interest of technical efficiency, society is frequently best served by permitting a single utility, such as Delmarva Power & Light Company, to function as a monopoly within a defined service area, subject to rate regulation by this Commission. In this way, to some degree, the discipline of the market can be simulated through the regulation of rates. But, if the public utility sector is to realize its full potential for increasing the welfare of society, the structure of rates charged must present essentially the same system of incentives to producers and consumers as those that would prevail in a competitive market. Since each consumer responds only to the prices and charges that he is required to pay, it is likely that consumer behavior will be at least as sensitive to changes in rate structure design as to changes in rate level. In general, that is why rate structure design is a particularly important consideration, as reflected in the

Phase II proceedings of the current docket dealing exclusively with the matter of rate design.

Q. WHAT IS THE PROPER BASIS FOR DESIGNING ECONOMICALLY EFFICIENT ELECTRIC UTILITY RATES?

A. Electric utility rates should reflect economic costs to the fullest extent possible. To achieve efficiency of production, these economic costs should be the costs associated with the units of production at the margin of production.

Q. WHY DO YOU QUALIFY YOUR STATEMENT THAT THE MARGINAL COSTS SHOULD BE REFLECTED IN PRICES "TO THE FULLEST EXTENT POSSIBLE"?

A. A long-recognized objective standard of utility regulation is the emulation of results in the competitive market. In that competitive market, not only do prices equate to the costs of providing service at the margin of production, but competitive prices also prevent firms from realizing excess profits. This twofold objective is achieved in the public utility industry through effective regulation. Should application of marginal cost-based rates yield revenues inconsistent with the objective of recovering total costs of production (including a return to capital investment), the prevention of economic profits or losses to the utility requires adjustment of rates to prevent such rate level results. It is in recognition of this rate level objective that I have qualified my previous answer.

Q. WHY ARE COST-BASED RATES ESSENTIAL?

A. To the extent that prices diverge from costs, consumption during certain time periods would be forced to subsidize consumption at other periods of time. That, of course, follows from the fact that total revenues must match up with total costs plus the required rate of return if the utility enterprise is to be economically viable. Therefore, if rates charged at certain times fail to cover the costs of such service, service at other times will have to be priced above costs to make up the deficit.

Q. WHAT IS OBJECTIONABLE ABOUT THAT TYPE OF CROSS-SUBSIDIZATION?

A. Aside from the obvious inequity of overcharging some usage and undercharging usage at other times, that type of cross-subsidization would result in a system of inefficient economic incentives that would encourage all customers to undertake undesirable courses of action. Electric service that is underpriced at times will be overconsumed, while service that at times is overpriced will be underconsumed. Both results are undesirable from an efficiency standard.

Q. ARE RATES BASED ON "VALUE OF SERVICE" RATHER THAN ON "COST OF SERVICE" A REASONABLE ALTERNATIVE?

A. No, they are not. To allow value of service to become a cornerstone in regulatory rate determinations would be totally inconsistent with the fundamental purpose of regulation. Value of service, after all, is the ceiling price in an unregulated monopolized market. Value-of-service pricing is therefore the antithesis of responsible price regulation. Even an uncontrolled monopolist is unable to sell his product or service for more than its value. Utility rate regulation was established in the first place to guard the public interest against such monopolistic abuses. Adequate protections against this type of abuse are furnished by the market mechanism in competitive, unregulated markets.

In competitive markets, the interplay of free market forces holds prices down to a level equivalent to costs plus a minimal fair rate of return. Unregulated monopolies, on the other hand, would be free to extract a price from consumers based on commodity value. Driving a wedge between the costs of providing service and the price of that service destroys both efficiency and earnings level results that would prevail in the competitive sector. Curbing that type of potential abuse, which can arise only in noncompetitive markets, is precisely the reason for instituting price regulation. In keeping with those purposes and objectives, electric utility rate regulation should be cost-based if just, reasonable, and efficient prices are to prevail.

Q. IF THE CONDITIONS THAT DESCRIBE PERFECT COMPETITION DO NOT PREVAIL IN THE DELAWARE MARKET FOR ELECTRIC SERVICE, IS THE APPLICATION OF SUCH A STANDARD AT ODDS WITH THE INTERESTS OF DELAWARE CONSUMERS OF ELECTRICITY?

A. No. Even though the ideal of perfect competition does not prevail in the Delaware electric power market, the application of marginal cost-based electric rates will achieve numerous objectives in the interest of Delaware consumers, among which are the following:

1. Provides a given amount of service at the lowest, overall possible costs.

Without the time differentiation of prices based on time differentiated costs of production, the opportunity for a consumption response to such prices will be foregone. As consumers respond quite naturally to traditional nontime-variant rate structures, which price peak service below cost and off-peak service above cost, consuming more peak service than otherwise, the overall costs of production for any given amount of energy required will cost more than would otherwise be the case. Application of marginal cost based time-of-use rates would result in consumers facing the same cost consequences (reflected in their electric bills) as they impose on the utility, and both consumption and production decisions would be made in accordance with the same economic variable. This does not happen with traditional type pricing, where high cost peak energy is averaged with low cost off-peak energy and then reflected in one price for both peak and off-peak energy. Under such traditional pricing, consumers are led to increase peak-period consumption and incur a price below cost, while forcing the utility to incur costs in excess of the price at which such additional energy is sold.

Similarly, the traditional average cost-based price of off-peak energy during off-peak periods discourages such sales, resulting in greater cost saving for consumers than for the utility. Marginal cost-based prices, which disaggregate the averaging contained in traditional, nontime differentiated price structures, will alter consumption patterns in a direction that allows a consumer to substitute low-priced energy consumption for high-priced energy consumption, with attendant reduction in production costs, thus reducing the total cost of providing energy. Deviation from marginal cost-based time-variant rates will leave foregone these overall cost benefits available to Delaware consumers.

2. Provides net income stability to utilities.

Growth in demand for electric service during peak periods, priced to reflect the average costs of providing service at all times, fails to generate revenues sufficient to cover the costs of meeting such service. Obviously, selling peak-period energy below costs causes net income to deteriorate as those sales grow (and growth will be stimulated to the extent such sales are priced below cost). Marginal cost-based rates help to stabilize net income in such circumstances as they result in more revenues (than average cost-based rates) when peak period usage is priced in a manner more reflective of the costs of meeting additional peak period consumption.

3. Reduction in the frequency of rate cases.

This result follows almost as a corollary to item 2 above. Net income is one ingredient in an overall revenue requirement. To the extent changes in demand for electric service result in changes in revenues matched to attendant cost changes for such service, the need for rate relief is lessened.

This reduction in case load is beneficial not only to the Commission and its staff but also to consumers who will receive a more stable set of prices for electric service than those faced as a result of more frequent rate cases before the Commission.

4. Allows consumers the opportunity to reduce their bills by altering consumption patterns.

There is no reason for consumers to defer present peak-period consumption to off-peak periods under the price structures that now prevail, since off-peak energy is priced at the same level as peak period energy. A consumer's only choice now affecting his bill for electric service is to consume or not to consume. Time-differentiated pricing allows another choice in the determination of a customer's bill--when to consume. Prices unreflective of time-differentiated costs at the margin of production destroy possible billing impacts of responses to time-variant costs, lessening a customer's ability to determine his own bill for electric service.

5. Increase the choices available to consumers in the electric market.

Delaware consumers now face a one product market for electric service, i.e., a kilowatt-hour. (Demand-metered customers really face a two-product market, buying energy and demand, but again, primarily undifferentiated by diurnal cost differences.) Should Delaware consumers be provided with the opportunity to purchase electricity based on the costs of providing service at the margin of production, when that service is demanded, those consumers will, in actuality, be provided with several products in the market for electric service. Marginal cost-based pricing creates a ready substitute for relatively high-priced peak-period electric service, namely, relatively low-priced off-peak electric service. Consumer welfare is a direct function of the number of products available in the marketplace. As the number of products and prices faced by consumers increases, the bias must be toward an increased level of benefits available to society. Marginal cost pricing increases available electric service consumption choices and is thus associated with increased consumer benefits.

6. Conservation benefits will be more reflective of the values of such conservation than under traditional type pricing structures.

A consumer who refrains from the consumption of energy enjoys a billing impact dependent on the price paid for such energy. If that price is low compared to the costs associated with the provision of such service, the incentive to conserve is low; and the conservation may be foregone. This is especially critical, and likely to be the experience, during peak periods. A consumer who faces prices during the peak period below the associated marginal costs will be led to consume more than if peak-period prices reflected peak-period marginal costs. The prime reason for this would be the low "reward" from conservation activities, which reward is reflected in current average cost-based prices. Similarly, a customer responding to marginal cost-based prices by shifting electric consumption from peak to off-peak periods also generates conservation benefits. While all resources are scarce, some are more scarce than others. A shift of consumption from peak to off-peak periods, while still requiring a conversion of energy from one form to another, conserves most on our scarcest of energy resources, shifting demand to our relatively abundant energy sources. Prices, unreflective of marginal cost conditions, stop short of inducing conservation activities, resulting in waste of energy. This, of course, is neither in the interest of the U.S. economy nor of the State of Delaware that imports virtually all of its energy requirements.

7. Prevents time-related energy consumption subsidy.

Prices that reflect an average of high costs and low costs of providing electric service underprice such service during peak periods and overprice service during off-peak periods. Consumers requiring relatively more service on peak than other consumers are thus subsidized by such other consumers. Subsidy of on-peak consumption appears hardly in the interest of Delaware consumers.

Time preference of electricity consumption is now a free good to Delaware consumers; i.e., a given amount of consumption costs the customer the same amount regardless of when, during the day, electricity is consumed. However, time patterns of consumption impose different costs on the DP&L system, which costs, if not reflected in rates, give rise to a subsidy to those customers who find it convenient to opt for relatively high peak-period consumption. Marginal cost-based prices will eliminate this intertemporal cost subsidy reflected in rate structures falling short of basis in marginal costs.

8. Provides appropriate stimulus for development of alternative energy sources.

Alternatives for electrical energy consumption are dependent on the price of electricity. A familiar example is the increase in insulation activity as a result of overall increasing energy prices. These prices for electric service are costs to the homeowner, and as these costs increase, the cost savings associated with insulation increase, often providing a handsome return on an insulation investment. Either insulation or increased energy consumption can be used to maintain internal space temperatures at desired levels. As the price of a substitute, energy, increases, the demand for its substitute, insulation, is directly affected.

What is true of energy consumption alternatives as a whole is also true of time-related energy alternatives. Development of storage heating devices, capable of storing energy when cheap energy is available, is deterred when off-peak energy is sold at a price in excess of its marginal costs (largely to provide the dollars to subsidize peak-period electrical consumption). The reason is obvious. The return to the storage investment is the cost difference between peak and off-peak electric service times the amount of such service stored. Such return is nonexistent absent reflection of time-differentiated costs in electric rates. The greater the wedge between prices and costs of providing additional energy at various times, the less the incentive to develop facilities that can store energy and allow the substitution of cheap, low-cost off-peak energy for high-cost, peak-period electric service.

Similarly, solar devices, which would tend to have their greatest output on the long, hot, sunny days in Delaware, are retarded in their development by subsidized peak-period electrical consumption. By reflecting marginal costs of providing electricity in rates faced by consumers, facilities allowing the substitution of off-peak energy consumption, facilities allowing substitution of alternative energy sources, will be stimulated to the benefit of all Delaware residents.

Q. ARE THESE RESULTS ENUMERATED ABOVE DEPENDENT ON THE THEORY OF PERFECT COMPETITION?

A. No. These results are all benefits to be gained by implementing marginal cost-based rates. In a very real sense, the cost to DP&L customers of not adopting such rates is these above enumerated benefits, which will be foregone in that event, or achieved to a lesser extent as prices deviate from a marginal cost basis.

Q. HAVE YOU ANALYZED THE COSTS OF PROVIDING SERVICE FOR DELAWARE CUSTOMERS ON THE DP&L SYSTEM?

A. Yes.

Q. DO THE COSTS OF PROVIDING ELECTRICITY FOR CUSTOMERS ON THE DP&L SYSTEM VARY BY TIME OF DAY, WEEK, AND YEAR?

A. Yes, they do.

Q. WHY DO THESE COST VARIATIONS EXIST?

A. The demand for electricity is higher at some times of the day (and the week, and the year) than at other times. Since electric energy cannot conveniently be stored on a large scale, an electric utility must have sufficient generating capacity to meet the highest demands imposed upon the system. But these high demands are experienced only during some of the hours in a year, and during other hours, much of the utility's generating capacity sits idle.

If the demand for electricity increases during one of these off-peak hours, the cost to the utility of meeting the additional demand is only the running cost--principally fuel--needed to operate generating units that otherwise would be idle. Since this generating capacity is required anyway to meet the higher demands imposed upon the system during peak hours, only an insignificant part of the cost of this capacity is properly chargeable against the off-peak usage, and the costs of providing off-peak electricity are therefore relatively low.

In contrast, if there is an increase in the demand at the time of the system peak, when the utility has planned to have no idle capacity (beyond the reserves required for outages and system protection), then more generating capacity is needed to meet this higher level of demand. The cost of generating capacity is therefore properly chargeable against electricity usage at times when demand is relatively high, and thus the cost of electricity is higher during these peak hours than during the off-peak hours.

One purpose of my testimony in this proceeding is to examine in more detail the time pattern of electricity demand and costs. In the course of this examination, I shall address the following questions:

- How does the demand for electricity change with the time of day, the day of the week, and the cycle of seasons?

- How do the costs of supplying electricity vary in accord with these changes in the demand for electricity?

Q. PELASE OUTLINE THE MAJOR PARTS OF YOUR ANALYSIS.

A. My analysis contains the following steps:

(a) I shall begin with an analysis of the time patterns of electricity usage on the DP&L system, as revealed in the load curves for the Delmarva Power & Light Company. The purpose of this analysis is to identify a small number of time periods within which the electricity demand and cost levels are relatively homogeneous, but between which there are substantial cost differentials due to differing demand levels.

(b) The second step in my analysis is the determination of the approximate marginal costs of bulk power supply for DP&L. I calculate the marginal cost of generating capacity required to meet an additional kilowatt of demand, and the marginal cost of transmitting that capacity. The additional running costs required to generate an additional kilowatt-hour of electricity in each of the time periods identified in the first step of my analysis have been determined from the system lambda analysis on the PJM system. The DP&L system is dispatched on the basis of additional costs on the PJM system, and it is these costs that reveal the additional cost of additional consumption to DP&L customers.

(c) Third, I determine the costs that DP&L incurs in providing the other functional elements of electricity service besides bulk power supply, namely transmission below 230 Kv, distribution, and customer service. I make this determination from the Company's proposed test-year cost of service, and it resembles a conventional class cost-of-service analysis.

(d) Fourth, I modify the results from the third step to reflect the marginal costs of bulk power supply, as derived in my second step, rather than the embedded average costs that are developed in the third step. This yields a functionalized cost of service.

Q. PLEASE BEGIN WITH YOUR ANALYSIS OF THE TIME PATTERNS OF ELECTRICITY USAGE.

A. My analysis of the time patterns of electricity usage is based upon the load curves for the Delmarva Power & Light Company in 1977. The daily load curves for the seasonal peak days and the typical weekdays and weekend days are shown in Schedule 1. These load curves describe the typical DP&L experience.

Q. WHAT KIND OF VARIATIONS DO THE DP&L LOAD DATA REVEAL?

A. They show important systematic variation of electricity demand by the hour of the day, the day of the week, and the season of the year. The seasonal fluctuations are due primarily to changes in the normal seasonal weather conditions, including temperature levels and the number of daytime hours. But, in addition, the weather within one season also varies from day to day, and these less predictable daily weather changes also have a major impact upon electricity demand.

(a) The load curves in Schedule 1 illustrate some of the effects of weather. The hourly loads on a typical day emulate the peak day hourly loads in pattern, albeit at a lower absolute level of demand. Such differences are due in large part to weather differences.

(b) Loads also show some systematic variations by the day of the week. Loads on weekends are generally far below the levels established on working days.

(c) The aggregate demand on the DP&L system has a rounded peak experience in the summer months: there is a deep valley in the nighttime hours of approximately midnight through 7 a.m., and a very rapid rise in the demand levels in the morning hours from 7 a.m. to noon.

(d) The winter load experience exhibits a bimodal peak characteristic, with the dominant peak typically occurring in the early evening hours. The nighttime valley and the early morning increase are again readily observable; however, the absolute magnitude of the daytime loads is somewhat below that of the summer experience.

Q. BASED ON YOUR ANALYSIS, WHAT TIME PERIODS HAVE YOU SELECTED FOR COSTING PURPOSES?

A. Functionalized costs of providing service are determined for a broad based peak period from 8 a.m. to

10 p.m. on weekdays (EST), with 10 p.m. to 8 a.m. and weekends being responsible for off-peak costs. Schedule 2 shows load characteristics on the DP&L system by time period.

Q. AFTER DETERMINING THESE PERIODS, HOW DID YOU PROCEED WITH YOUR COST ANALYSIS?

A. The marginal costs of bulk power supply were next determined, including both marginal running costs and the cost of meeting increases in peak-period demand.

Q. WHAT IS THE MARGINAL RUNNING COST?

A. At any hour of the year, the marginal running cost, or system lambda, is the additional cost that would be imposed upon the generating system if one additional kilowatt-hour of electricity had to be generated. The marginal running cost consists primarily of the cost of the fuel required to power the generators for an additional kilowatt-hour of generation during any clock hour. The marginal running cost changes from hour to hour.

Q. WHY IS THE MARGINAL RUNNING COST DIFFERENT AT DIFFERENT TIMES?

A. Some generating units use less expensive fuel, such as nuclear fuel or coal, than other generating units, that may use residual fuel oil or diesel oil. And even for generating units that use the same type of fuel, some units make more efficient use of that fuel than other units. The result is that some generating units have higher fuel costs per kilowatt-hour than other generating units.

An electric utility dispatches the available generating units so as to minimize the total running cost for generating the required amount of electricity. Units with low running costs are used first and most intensively, while units with higher running costs are only brought on-line when the demand exceeds the output that can be generated with the lower cost units. When demand is high, the marginal running cost therefore tends to be higher than it is when demand is low, because the high level of demand forces the Company to put the less efficient, and therefore the more expensive, generating units on line.

Q. WHAT ARE THE MARGINAL RUNNING COSTS ON THE DP&L SYSTEM?

A. The marginal running costs for the peak and off-peak periods on the DP&L system have been determined on the basis of the PJM running rates. Although Delmarva is not yet a full member of the PJM pool, it does respond to the pool running rates in the dispatch of its own plants.

When a pool participant can purchase additional power from the pool more cheaply than it can generate such additional power on its own units, it will do so. Hence, the pool running rates represent the cost of such additional power. Similarly, a pool member will supply power to the pool anytime its own generating units can supply an increment of power at a cost lower than that of the remaining pool member generating units. Again, the pool running rate becomes the measure of additional cost incurred to meet additional demands for power of pool participants.

These costs of additional energy demands on the pool (and hence, on the Delmarva system) are shown on Schedule 2. The results show the peak-period marginal cost of energy to be 3.332¢ in the winter and 2.532¢ in the summer. Off-peak marginal costs of energy are 2.062¢ in the winter and 1.696¢ in the summer. These costs are the additional costs of providing a kilowatt-hour of electricity at various times on the Delmarva system. These costs will ultimately be converted into one element of time-varying rates.

Q. IN ADDITION TO THE ENERGY COSTS OF BULK POWER PRODUCTION, HAVE YOU ALSO DETERMINED THE MARGINAL RUNNING COST OF MEETING A KILOWATT OF DEMAND DURING THE PEAK DEMAND PERIOD ON THE DP&L SYSTEM?

A. Yes, I have. My calculation of the annual marginal cost of meeting an additional kilowatt of demand during the peak period is shown on Schedule 3. The key elements in this calculation are the original construction cost per kilowatt of capacity, the annual cost of capital, and the reserve requirement. (An alternative calculation--the so-called Turvey computation--is the cost of a base load generating unit less the fuel savings realized when that unit is run instead of a peaking plant during the peak hours. However, it has been demonstrated by others that this calculation yields the same results as the cost of a peaking unit, provided that the length of the peak period is defined for this purpose as the number of hours that peaking plants would be in use on a system with an optimally designed mix of peaking and other plants.)*/

(a) The original cost per kilowatt of capacity that I have used is an estimate of $185 per kilowatt installed. This estimate was provided by the Company and represents the per kilowatt cost of a 25Mw peaking unit including foundation, building, fuel tank, pumps, fencing, and step-up transformation.

(b) The annual carrying cost rate of 15.32 is developed on pages 3 and 4 of Schedule 3. This return requirement is based on the Company's test-year-end capital structure and proposed cost of equity capital in Docket No. 923 presently before this Commission. Debt costs reflect current market conditions. The tax effects of accelerated depreciation and investment tax credit are reflected in tax expense calculations. A revenue requirement covering depreciation, return, and taxes is calculated for each year of plant life. This stream of revenue requirements is discounted at the overall cost of capital and compared with the present value

*/ See: Turvey, Ralph, Optimal Pricing and Investment In Electricity Supply, George Allen and Unwin, Ltd., 1968.

of investment requiring such return to yield the overall carrying cost rate of 15.32 percent.

(c) The reserve requirement of 20 percent represents the change in installed capacity required above expected peak demand for PJM pool members. To maintain this margin, an increase of 1 kilowatt of expected peak demand would require an increase of 1.20 kilowatts of generating capacity, and the cost per unit of capacity must therefore be increased by this factor to reflect fully the capacity costs of meeting additional demand.

On the basis of the calculations shown in Schedule 3, I find that the marginal cost of meeting additional demand is $35.60 per kilowatt per year, including both the carrying cost of capital and the operating and maintenance needed to maintain the generating capacity in operating condition.

Q. HAVE YOU CALCULATED THE MARGINAL COSTS ASSOCIATED WITH THE TRANSMISSION OF CAPACITY REQUIRED TO MEET AN ADDITIONAL KILOWATT OF DEMAND DURING THE PEAK PERIOD?

A. To complete my analysis of the marginal costs of bulk power supply, I made a determination of the marginal costs of transmission associated with the operation of a peaking plant. This results in a complete and consistent approach in the marginal cost determination of providing bulk power on the DP&L system.

Q. WHY DID YOU CALCULATE THE MARGINAL COSTS OF PROVIDING TRANSMISSION ASSOCIATED WITH A PEAKING PLANT RATHER THAN BASING SUCH DETERMINATION ON ALL OF DP&L'S TRANSMISSION FACILITIES?

A. Much of the cost that is classified as transmission is incurred for reasons other than the movement of capacity associated with system peak. These reasons include the movement of electrical energy from a plant site to a load center (rather than locating the plant near the load center and saving on transmission cost but incurring higher fuel transportation expense), interconnections for system reliability, or in lieu of constructing generation capacity, or for area reliability.

The marginal cost of transmission is the cost of moving the capacity related to additional demands during peak periods into the existing grid. The Company's cost estimate of such service is $19.00 per kilowatt of peaking demand located at a substation site immediately adjacent to the existing transmission network. Schedule 4 converts this investment amount into an annual marginal cost.

Q. WHAT ELECTRICITY SUPPLY COSTS ARE THERE BESIDES BULK POWER SUPPLY?

A. The other functional cost components that I have identified besides power supply are:

transmission, below 230 Kv
distribution
customer costs

These are the generally recognized major functional categories, though they do not go to the most detailed level found in some cost-of-service studies.

Q. HAVE YOU BEEN ABLE TO DETERMINE MARGINAL AND TIME-VARYING COSTS FOR THE OTHER COMPONENTS OF THE COST OF ELECTRIC SERVICE, BESIDES BULK POWER PRODUCTION?

A. I have not made an attempt to determine the marginal costs of any of these other components directly, but I believe that the average costs of the other components are a satisfactory approximation to the marginal costs. With regard to time variation, I suggest, as a reasonable approximation, that the entire cost of transmission, below 230 Kv, including both plant associated costs and operating expenses, be treated as a capacity cost and charged against electricity demand in the peak period.

The cost of the distribution system may also properly be viewed primarily as a capacity or customer-related cost, but it would not be correct to charge the capacity part entirely against usage during the peak period. The reason is that the peak usage on any part of the distribution network, which is the determinant of the required capacity for that part of the distribution network, need not generally coincide with the peak hours of demand on the system as a whole. Owing to the diversity of loads on the distribution system, I find it impractical to devise different rate periods that would properly reflect, for each group of customers, the time-varying impact of their demands upon the distribution network costs. Finally, customer costs have no time dimension at all.

Q. HOW HAVE YOU DETERMINED THE FUNCTIONAL COSTS OF SERVICE FOR THE TRANSMISSION, DISTRIBUTION, AND CUSTOMER COST FUNCTIONS?

A. For the most part, these functional costs are taken directly from DP&L's class cost-of-service study in its current rate case, based on a forecast test-year ending December 1978. Schedule 5, page 1 summarizes these costs.

Transmission costs have been separated to allow recovery of the EHV component based on the marginal cost of transmission determination. Distribution costs are separated into a primary and secondary component to allow cost determination by the voltage level at which service is provided.

Q. HAVE YOU INCORPORATED YOUR ANALYSIS OF THE MARGINAL COSTS OF POWER PRODUCTION ON THE DP&L SYSTEM INTO THE FUNCTIONALIZATION OF THE COST OF SERVICE?

A. Yes, I have. My general approach is to substitute cost levels based upon marginal costs for the functions of bulk power supply rather than to use the embedded costs for these functions.

Q. WHAT RESULTS ARE TO BE EXPECTED WHEN BULK POWER SUPPLY COSTS CALCULATED AT THE MARGIN OF PRODUCTION ARE COMPARED TO AVERAGE COST CALCULATIONS?

A. In general, one should expect marginal energy costs to be higher than average energy costs, because the marginal running cost at any hour of the day is the cost of running the most expensive unit on line at that time. The marginal running cost at any hour is, therefore, higher than the average running cost at that hour, and therefore the revenues that would be derived by pricing all energy at its marginal running cost will exceed the average cost assigned to the energy function. This is especially true for usage in the peak periods, where all energy should be priced at the substantially higher cost of energy from the peaking units.

In contrast, one may generally expect that the marginal cost of meeting an additional kilowatt of demand will be less than the average embedded cost. The most important reason for this is that the marginal cost of capacity is properly based upon the cost of a peaking unit, whereas the embedded average cost reflects also the much higher costs per kilowatt of baseload capacity. This reassignment of some of the costs of power production from the demand component calculated on an average embedded basis to the energy component is a proper reflection of the economic factors that cause electric utilities to incur costs to provide electric service.

Q. HOW DO YOU CONVERT THESE FUNCTIONALIZED COSTS INTO A SET OF UNIT COSTS?

A. The first step is to unitize the functional costs on the basis of the appropriate billing determinants at generation level. This process is illustrated on Schedule 6.

Capacity costs are recovered in the peak period. This, of course, does not mean that off-peak energy users get a "free ride" as far as demand cost responsibility is concerned. I have already mentioned above that energy prices should reflect marginal costs rather than an average of energy costs. Since the cost of supplying energy at the margin is always greater than the average cost of energy up to the margin, by charging rates that reflect this difference, a contribution is available to defray demand related costs. It can be shown that for a system of optimal mix, by charging the marginal cost of energy and capacity in each rating period, total capital costs will be fully recovered.

Application of the marginal cost of meeting capacity, $39.77, to the Delaware jurisdictional peak at generation level yields a cost responsibility of $35,838,517.

Over the course of one year, 12 months' worth of peak-period demands will be recorded. These billing demands at generation level total 15,524,148 Kw and are more than 12 times the contribution to system peak due to diversity. Relating this $35,838,517 to the 15,524,148 Kw yields a unit cost on a marginal basis at generation level of 2.3086.

Transmission costs below 230 Kv are unitized by taking the functional cost and relating it to peak-period billing demands. Distribution costs are unitized in the same manner by relating the functional cost of distribution to the sum of the maximum annual billing demands to reflect the local nature of demands placed on the distribution system. The primary and secondary cost components of distribution are stated separately for each level of service. Energy unit costs are simply the marginal costs of energy differentiated by time period.

Customer costs on a unit basis reflect functionalized customer costs related to the weighted number of customers.

[Aside: The billing units I have developed represent the sum of the maximum meter readings that would occur each month. Virtually all of these maximums would occur during the peak period. Company load data or a reasonable estimate of the excess of maximum demand meter readings over peak-period maximum demands for those few customers exhibiting this characteristic should be incorporated into the final rate design authorized by the Commission.]

Q. WOULD THE DIRECT APPLICATION OF THE UNIT COSTS BASED ON YOUR MARGINAL COST STUDY RESULTS GENERATE THE EXACT REVENUE DP&L HAS REQUESTED IN THE CURRENT DOCKET NO. 923 PROCEEDINGS?

A. No. Schedule 7 indicates direct application of unit costs based on the marginal cost study results would produce $13,363,000 less than DP&L's proposed total costs of service.

Q. CONVENTIONAL WISDOM SUGGESTS THAT MARGINAL COSTS MUST BE GREATER THAN AVERAGE EMBEDDED COSTS, YET YOUR STUDY SHOWS THE OPPOSITE TO BE THE CASE. WHY IS THAT?

A. I can't explain conventional wisdom, but I do know that reasoning that ceases after concluding that because current costs exceed historic costs, marginal costs must be higher than the average of those past historic costs, is just too shallow a reasoning process.

I have already mentioned that at the margin energy is expensive compared to its average cost, and demand is cheap (compared to an average cost of a Kw that includes high-cost baseload plant in the average cost determination). The net effect on system costs of these two functional cost considerations can, in itself, explain results at odds with conventional wisdom.

Several other reasons why marginal cost determinations may be consistent with total costs below those proposed by the Company are:

(1) The Company's proposed costs of service are just that--proposed. Only this Commission can determine what the actual Delaware jurisdictional costs of service are. In the current rate case, the Company has presented what it believes its costs of service to be, but only after a full airing of all the revenue, expense, accounting treatments, tax, and return issues will the Commission authorize rates to yield revenues consistent with <u>its determination</u> as to what the actual costs of service are. Hence, the cost level against which the adequacy of marginal cost determinations is compared is itself a variable amount. The magnitude of any difference between marginal costs and average costs will be affected by the total cost of service determination arrived at by this Commission.

(2) My determination of the marginal costs of meeting additional peak-period demand contains a 20 percent reserve margin. If actual reserves are above that level, this would influence the average cost of demand but not the marginal cost.

(3) The levelized carrying cost rate developed in my marginal analysis is below the cost of servce in the early years of plant life. Traditional rate-setting

practice is to determine cost levels in the current year (that would then have to be periodically adjusted downward as rate base depreciated, all other things being equal). If the average Delmarva plant is less than halfway through its depreciation life (due, say, to plant coming on line in a dollar amount at a rate that exceeds the dollar amount of depreciation on existing plant), the total cost of service, as traditionally determined, could exceed the marginal cost of service as I have determined the carrying cost rate.

(4) Finally, by using the peaker method of calculating marginal costs of meeting peak period demand, I am implicitly assuming an optimal plant mix on the DP&L system. Any inefficiency on the DP&L system regarding plant mix (either too much or too little baseload plant compared to total plant, for instance) would result in a higher actual cost of service than would be the case with optimal plant mix.

Hence you can see there are numerous factors at work in the determination of both marginal and average costs, and preconception regarding comparison of marginal and average cost results is totally meaningless.

Q. HOW DO YOU PROPOSE TO RECONCILE YOUR MARGINAL COST RESULTS TO THE LEVEL OF COSTS PROPOSED BY DP&L?

A. Schedule 8 illustrates the process. Increasing functional components, which are based on marginal costs, by 7 percent reconciles the difference in total revenues at DP&L proposed costs to those generated by application of marginal cost based rates.

Q. WHY HAVE YOU ONLY ADJUSTED THE FUNCTIONAL COMPONENTS COSTED ON A MARGINAL BASIS RATHER THAN ADJUST ALL FUNCTIONAL COST COMPONENTS?

A. The difference between DP&L's proposed total costs and revenues at marginal cost based rates arises entirely within the functional components costed on a marginal basis. As Schedule 6 indicates, I used the functional components based on the Company's average cost study (as a proxy for their marginal costs) in the development of my unit costs. Since the costing methodology used to derive these cost components has been used by DP&L in past rate cases and is not at issue, I have restricted my adjustment process entirely within the cost components determined on a marginal basis.

Q. IS AN AVERAGE COST STUDY MORE ACCURATE THAN A MARGINAL COST STUDY, SINCE THE NEED FOR ADJUSTING AVERAGE COST STUDY RESULTS IS NOT APPARENT?

A. No. For purposes of my marginal cost study, I have accepted the Company's jurisdictional total cost of service level proposed in Docket No. 923. When a Commission determines the test-year revenue requirement, it is actually determining total test-year costs of providing service (and allows revenues sufficient to cover total costs). Should the Commission determine that a level of costs different from that proposed by the Company represents the actual costs of providing service in Delaware, rates based on the average costs of providing service will have to be adjusted.

The average cost of service study appears to require no adjustment to rates, because it literally starts with the answer, i.e., total costs, and allocates that total to function and class. Any change in total costs from those proposed will necessitate adjustment of average cost based rates. For example, should the Commission decide to continue to include AFDC on the Salem Unit #2 and Indian River #4 construction projects, the cost to be recovered from DP&L rates will fall by $7,502,000 from DP&L proposed costs of service. In fact, every dollar of DP&L proposed cost disallowed by the Commision is a dollar of adjustment necessary to DP&L proposed rates, but is one dollar less of adjustment required for the marginal cost based rates.

The point of all this is merely to demonstrate that there is no inherent standard of accuracy in the performance of an average cost study that makes the rates based thereon free from adjustment. Typically, both marginal and average cost based rates require adjustment to produce revenues consistent with Commission determined total costs of providing service.

Q. AFTER YOU ADJUSTED YOUR UNIT COSTS CONSISTENT WITH DP&L'S PROPOSED TOTAL COSTS, HOW DID YOU CONVERT YOUR UNIT COSTS INTO A SET OF RETAIL RATES?

A. This process is shown in Schedule 9. There, the unit costs at generation level are increased by the appropriate loss factor for service at primary and secondary voltage levels. A Kw or a Kwh demanded at retail requires DP&L to produce more than that unit of service at the generation level. Line losses and transformation losses will occur as the unit of service leaves the generation busbar and travels to its ultimate point of consumption. These loss factors vary by the voltage level at which service is provided, and Schedule 9 converts costs at generation level into rate elements at retail.

Q. HOW ARE THE FUNCTIONAL COMPONENTS OF RATES ASSEMBLED TO PRODUCE A RATE SCHEDULE?

A. Customers served at primary voltage levels make use of the generation, transmission, and primary distribution network. Primary customer rate schedules would thus include a rate component for each of these functions plus a customer charge, and, of course, charges for peak and off-peak energy.

Rate schedules for secondary customers would include all the functional components of the primary customers, plus a charge for use of the secondary distribution network. Schedule 10 assembles and restates the functional retail costs of service shown in Schedule 9 for both primary and secondary customers.

Q. WHY HAVE YOU DEVELOPED A SECOND SET OF UNIT COSTS, CONSISTENT WITH MARGINAL COSTS, AS SHOWN IN SCHEDULE 11?

A. The rates shown in Schedule 10 are based on the same unit costs for each customer, regardless of the class to which the customer is assigned. Rates differ between primary and secondary customers only because of the differing loss factors and functional cost components required in the provision of service by voltage level.

Schedule 11 develops unit costs reflecting the differing diversities among the Residential and General Service primary and General Service secondary customer classes.

Q. WHAT IS THIS DIVERSITY YOU REFER TO?

A. Some customer classes are fairly constant in their use of the demands they place on DP&L while other customer classes use the demands they place on the system in a rather intermittent sporadic fashion. Diversity is a measure of this lack of consistency in usage of demand.* Customer classes that have relatively high diversity will exhibit more billing Kw on their meters per contribution to system peak demand than will customers exhibiting lower diversity.

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*Technically, diversity is defined as the ratio of the sum of individual maximum demands to coincident maximum demand.

Schedule 11 recognizes this additional factor in the determination of unit costs. Each customer class is assigned its proportionate share of its contribution to system peak (just as in the average cost study allocation process). The cost responsibility of each class share of the marginal capacity costs of meeting peak demand is then unitized by relating the class cost responsibility to the billing Kw of the class. The costing procedure shown on Schedule 11 retains diversity benefits within class, in contrast to the costing process shown on Schedule 6 that spreads diversity benefits among all customers. When diversity benefits are retained within class, those classes with relatively greater diversity than other classes exhibit a lower cost per billing Kw than do classes with less diversity.

Q. AFTER UNITIZING COSTS IN THIS MANNER, WHICH RETAINS DIVERSITY BENEFITS WITHIN CLASS, HOW DID YOU PROCEED?

A. The process of converting unit costs as determined is identical to that described earlier. Schedule 12 shows the retail rates for three classes--Residential, General Service primary, and General Service secondary, when diversity of each class is explicitly recognized and retained within each class.

Q. WILL YOUR RATES GENERATE REVENUES CONSISTENT WITH THOSE PROPOSED BY DP&L?

A. Yes. Schedule 13 demonstrates that application of the proposed marginal cost-based rates is consistent with the total costs of providing service at DP&L proposed rates.

Q. HAVE YOU DETERMINED THE RESULTING CLASS REVENUE REQUIREMENTS FROM THE APPLICATION OF MARGINAL COST-BASED RATES IN THE DP&L DELAWARE JURISDICTION?

A. Yes. Schedule 14 develops and compares class revenue requirements at marginal cost rates when diversity benefits are shared equally by all customers.

Schedule 15 shows class revenue requirements when each class retains the diversity of demand associated with that class.

Q. WHY HAVE YOU NOT INCLUDED ANY SEASONAL RATE DIFFERENTIALS IN YOUR PROPOSED TIME-OF-USE RATE SCHEDULES?

A. The 1977 winter peak for DP&L was 88 percent of the 1977 summer peak. This is a rather mild seasonal peaking characteristic. A look at Schedule 2 indicates that additional energy consumption during the winter months is more costly on the DP&L system than during the summer. The main reason for this appears to be the accomodation of planned maintenance on the PJM system. Utilities plan to perform maintenance on their efficient, baseload units during times of the year when the capacity associated with such units is least required. During these times, more inefficient units will have to be brought on line to provide energy requirements. This results in a higher cost of energy at the margin of production during the winter months, than during the summer for DP&L. The extent of seasonality in a time-of-use rate design on the Delmarva system should be based on an analysis of demands placed on the system in relation to available capacity. This analysis should also extend to the PJM pool loads and available pool capacity, depending on the extent of the integration of pool members in the operations of their own systems. Absent the results of such a study, I have expressed rate element charges on an annual basis.

Q. WHAT ADDITIONAL INFORMATION WOULD BE USEFUL TO THE COMMISSION AS IT DELIBERATES ON THE TYPE OF TIME-OF-USE RATES THAT MAY BE APPROPRIATE ON THE DELMARVA SYSTEM IN DELAWARE?

A. Some additional analysis regarding the desirability of seasonality in the Delmarva rate structure would be useful. A loss of load probability study would yield useful information regarding the magnitude of Delmarva loads in relation to available capacity at each hour during the year. Since loads vary, and plant availability varies due to planned and forced outages, such a study is most useful in defining exactly when, during the year, demand growth would be responsible for needed expansion of bulk power supply facilities.

Q. DOES THIS END YOUR TESTIMONY?

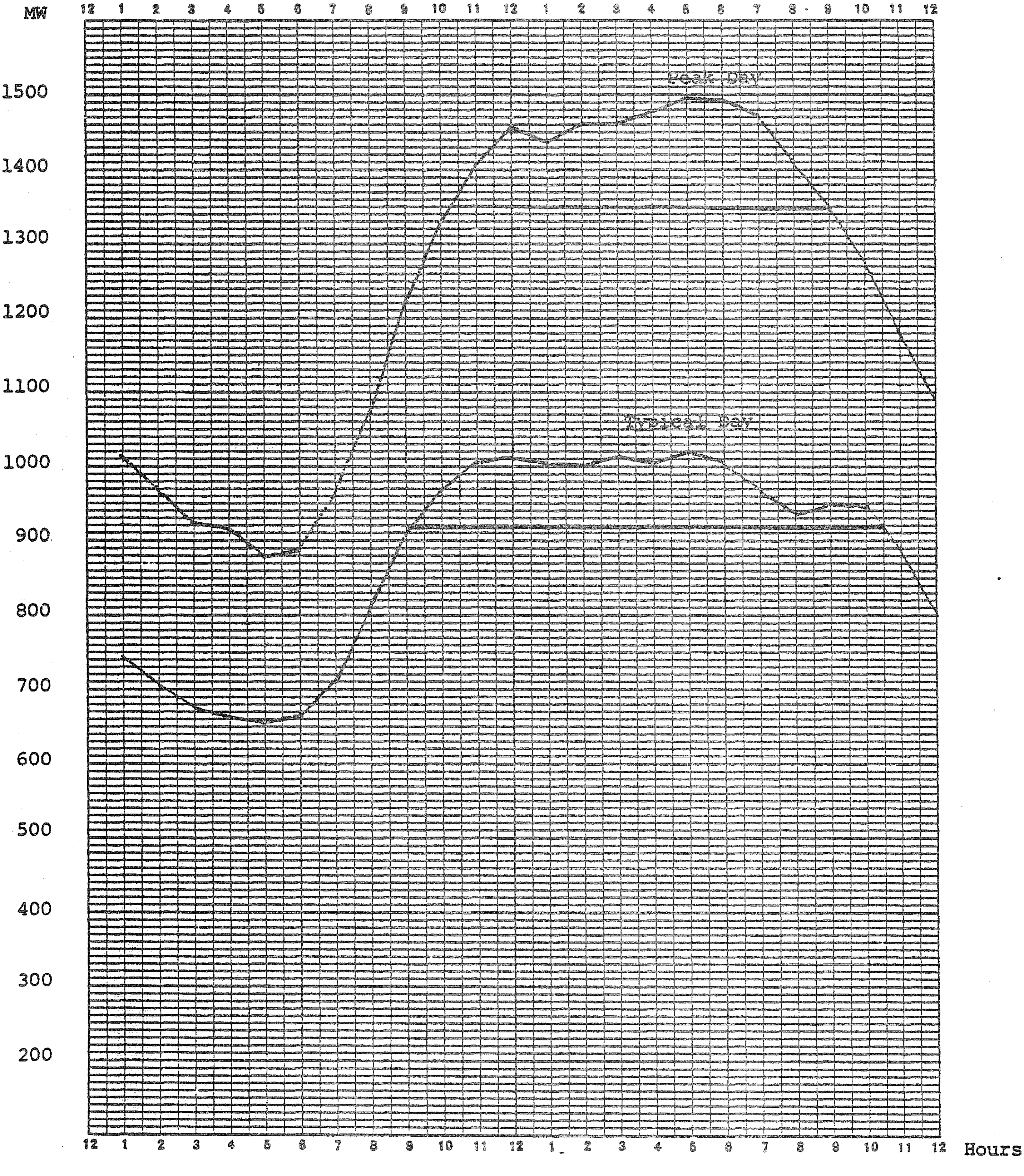
A. Yes, it does.

Schedules Accompanying the Model
Testimony on the Determination of
Marginal Cost-Based Rates
for the
Delmarva Power & Light Company
Delaware Jurisdiction

DELMARVA POWER & LIGHT COMPANY

Daily Load Curve

Summer 1977

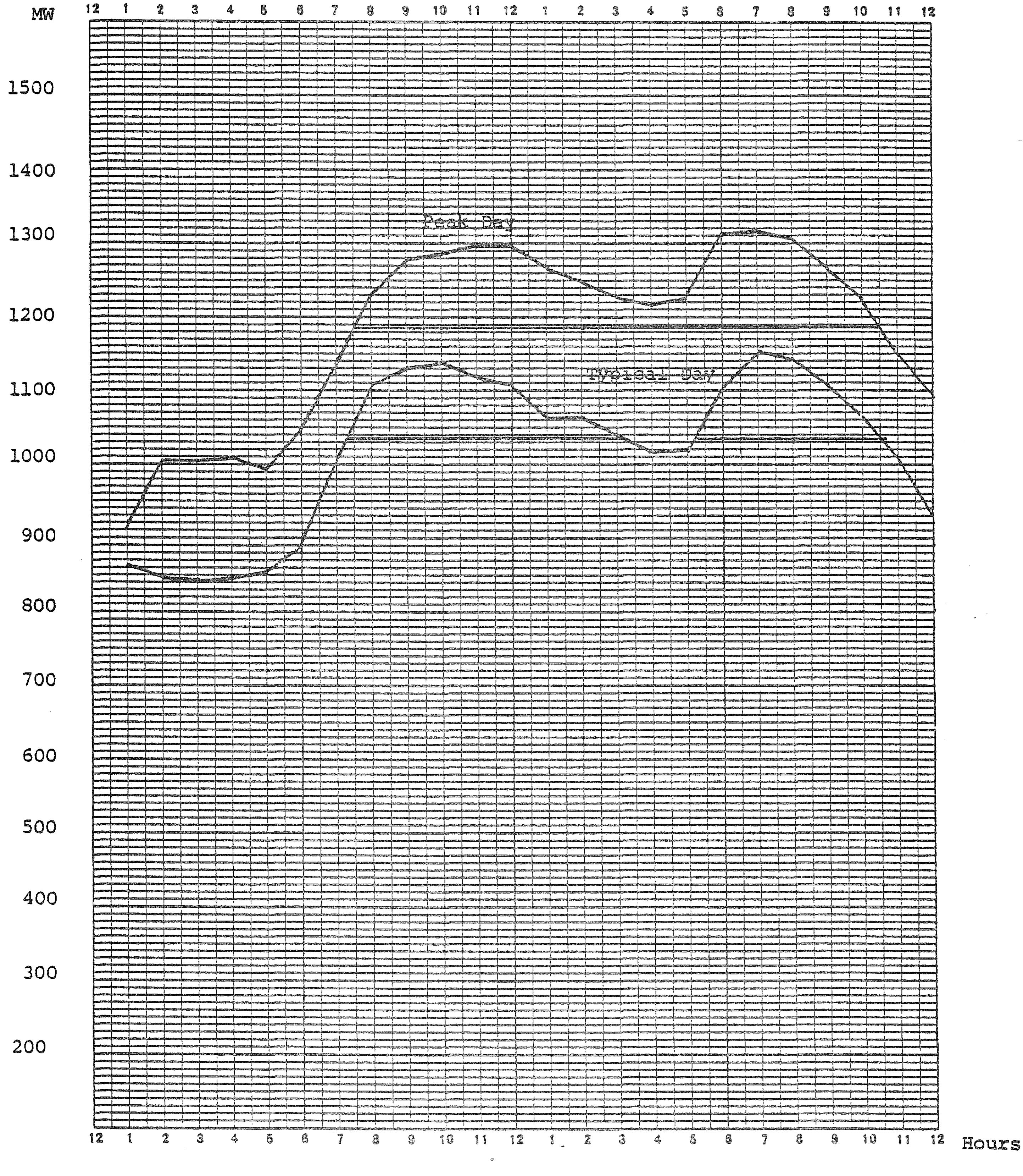


JULY

DELMARVA POWER & LIGHT COMPANY

Daily Load Curve

Winter 1977



JANUARY

DELMARVA POWER & LIGHT COMPANY

Marginal Energy Costs and Analysis of Net Loads by Proposed Rate Period, 1977

	Marginal Energy Costs (mills/kwh)[1]	Clock Hours			Net Energy Available at Generation Level			Average Hourly Load (MWH)
			Percent of Total			Percent of Total		
		Number	Season	Annual	Quantity (MWH)	Season	Annual	
Summer								
Peak Period, 9 am-11 pm weekdays	25.32	1,232	42.08	14.06	1,366,879	48.63	17.08	1,109
Off-peak Period, 11 pm-9 am; and weekends	16.96	1,696	57.92	19.36	1,443,941	51.37	18.04	851
Total Summer		2,928	100.00	33.42	2,810,820	100.00	35.12	1,003
Winter								
Peak Period, 8 am-10 pm weekdays	33.32	2,408	41.29	27.49	2,411,197	46.42	30.12	1,001
Off-peak Period, 10 pm-8 am; and weekends	20.62	3,424	58.71	39.09	2,782,559	53.58	34.76	813
Total Winter		5,832	100.00	66.58	5,193,756	100.00	64.88	891
Total, All Periods		8,760	-	100.00	8,004,576	-	100.00	914

[1] PJM system lambdas

Schedule 2

DELMARVA POWER & LIGHT COMPANY

Marginal Cost for Meeting Demand During Peak Periods

1.	Original cost per kilowatt of capacity	$185.00 1/
2.	Annual carrying cost rate for capital including depreciation and taxes (see Schedule 4, page 4 of 4)	15.32
3.	Annual carrying cost per kilowatt of capacity	$28.34
4.	Annual maintenance cost per kilowatt of capacity 2/	1.33
5.	Total marginal cost per kilowatt of generating capacity	$29.67
6.	Reserve requirement @ 20%	5.93
7.	Annual marginal cost per kilowatt of demand	$35.60

1/ Cost estimate of 25 combustion turbine installation.

2/ Source: One-half gas turbine O&M less fuel, per Kw.

DELMARVA POWER & LIGHT COMPANY

Total Capitalization

Type	Percent 1/	Cost Rate Percent	Weighted Cost Percent
Debt	48.93	9.15 2/	4.48
Preferred	12.77	9.15 2/	1.17
Common Equity	38.30	14.50 3/	5.55
	100.00		11.20

1/ Source: Witness Hammond,
Schedule JLH-4; Docket No. 923.

2/ Single A bond rating in May 1978 from Standard & Poors, June 1978 Bond Guide.

3/ DP&L proposed rate of return to common equity in Docket No. 923.

1

DELMARVA POWER & LIGHT COMPANY
CALCULATION OF REVENUE REQUIREMENTS RELATED TO INCREMENTAL CAPITAL INVESTMENT

	MEAN ANNUAL SURVIVORS	BOOK DEPRE-CIATION	RETIRE MENTS	BOOK DEPRE-CIATION RESERVE	MEAN NET BOOK INVEST MENT	ADR DDB DEPRE CIATION	DEFERRED INCOME TAX	DEFERRED TAX RESERVE	INVESTMENT TAX CREDIT		
									CREDIT	AMORTI ZATION	RESERVE
							.5252* (6)-(2)				
YEAR	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	1000.	40.00	0.	0.00	1000.00	125.00	44.65	0.00	100.	4.00	100.00
2	1000.	40.00	0.	40.00	960.00	107.38	36.44	44.65	0.	4.00	96.00
3	1000.	40.00	0.	80.00	920.00	95.70	29.26	81.09	0.	4.00	92.00
4	1000.	40.00	0.	120.00	880.00	83.74	22.97	110.34	0.	4.00	88.00
5	1000.	40.00	0.	160.00	840.00	73.27	17.47	133.32	0.	4.00	84.00
6	1000.	40.00	0.	200.00	800.00	64.11	12.66	150.79	0.	4.00	80.00
7	1000.	40.00	0.	240.00	760.00	56.10	8.46	163.45	0.	4.00	76.00
8	1000.	40.00	0.	280.00	720.00	49.09	4.77	171.91	0.	4.00	72.00
9	1000.	40.00	0.	320.00	680.00	42.95	1.55	176.69	0.	4.00	68.00
10	1000.	40.00	0.	360.00	640.00	42.95	1.55	178.23	0.	4.00	64.00
11	1000.	40.00	0.	400.00	600.00	42.95	1.55	179.78	0.	4.00	60.00
12	1000.	40.00	0.	440.00	560.00	42.95	1.55	181.33	0.	4.00	56.00
13	1000.	40.00	0.	480.00	520.00	42.95	1.55	182.88	0.	4.00	52.00
14	1000.	40.00	0.	520.00	480.00	42.95	1.55	184.43	0.	4.00	48.00
15	1000.	40.00	0.	560.00	440.00	42.95	1.55	185.98	0.	4.00	44.00
16	1000.	40.00	0.	600.00	400.00	42.95	1.55	187.53	0.	4.00	40.00
17	1000.	40.00	0.	640.00	360.00	0.00	-21.01	189.08	0.	4.00	36.00
18	1000.	40.00	0.	680.00	320.00	0.00	-21.01	168.07	0.	4.00	32.00
19	1000.	40.00	0.	720.00	280.00	0.00	-21.01	147.06	0.	4.00	28.00
20	1000.	40.00	0.	760.00	240.00	0.00	-21.01	126.05	0.	4.00	24.00
21	1000.	40.00	0.	800.00	200.00	0.00	-21.01	105.04	0.	4.00	20.00
22	1000.	40.00	0.	840.00	160.00	0.00	-21.01	84.03	0.	4.00	16.00
23	1000.	40.00	0.	880.00	120.00	0.00	-21.01	63.02	0.	4.00	12.00
24	1000.	40.00	0.	920.00	80.00	0.00	-21.01	42.01	0.	4.00	8.00
25	1000.	40.00	0.	960.00	40.00	0.00	-21.01	21.00	0.	4.00	4.00

READY.

YEAR	MEAN NET INVESTMENT	EQUITY RETURN	INTEREST	TAXABLE INCOME	INVESTMENT TAX CREDIT	INCOME TAX	PROPERTY TAX	REVENUE REQUIREMENT	$1 AT .11199	MEAN ANNUAL SURVIVORS	REVENUE REQUIREMENT
	(1)-(4)-(8)	6.722% (12)	4.477% (12)	[(2)-(6)+(7) -(10)+(13)] /(1-.5252)		52.52% (15) -(16)	1.00% (1)	(2)+(7)-(10) +(13)+(14)+ (16)+(17)+(18)		(1)*(20)	(19)*(20)
YEAR	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)
1	1000.00	67.22	44.77	48.16	100.	-74.70	10.00	227.93	.89929	899.29	204.98
2	915.35	61.53	40.98	51.80	0.	27.21	10.00	212.16	.80872	808.72	171.58
3	838.91	56.39	37.56	54.65	0.	28.71	10.00	197.91	.72727	727.27	143.94
4	769.66	51.74	34.46	56.81	0.	29.84	10.00	185.01	.65403	654.03	121.00
5	706.68	47.50	31.64	58.36	0.	30.65	10.00	173.27	.58816	588.16	101.91
6	649.21	43.64	29.07	59.38	0.	31.19	10.00	162.56	.52892	528.92	85.98
7	596.55	40.10	26.71	59.94	0.	31.48	10.00	152.75	.47566	475.66	72.65
8	548.09	36.84	24.54	60.09	0.	31.56	10.00	143.72	.42775	427.75	61.47
9	503.31	33.83	22.53	59.89	0.	31.46	10.00	135.37	.38467	384.67	52.07
10	461.77	31.04	20.67	54.00	0.	28.37	10.00	127.63	.34593	345.93	44.15
11	420.22	28.25	18.81	48.12	0.	25.28	10.00	119.88	.31109	311.09	37.30
12	378.67	25.45	16.95	42.24	0.	22.19	10.00	112.14	.27976	279.76	31.37
13	337.12	22.66	15.09	36.36	0.	19.10	10.00	104.40	.25159	251.59	26.27
14	295.57	19.87	13.23	30.47	0.	16.01	10.00	96.66	.22625	226.25	21.87
15	254.02	17.07	11.37	24.59	0.	12.92	10.00	88.91	.20346	203.46	18.09
16	212.47	14.28	9.51	18.71	0.	9.83	10.00	81.17	.18297	182.97	14.85
17	170.92	11.49	7.65	55.77	0.	29.29	10.00	73.43	.16454	164.54	12.08
18	151.93	10.21	6.80	53.09	0.	27.88	10.00	69.89	.14797	147.97	10.34
19	132.94	8.94	5.75	50.40	0.	26.47	10.00	66.35	.13307	133.07	8.83
20	113.95	7.66	5.10	47.71	0.	25.06	10.00	62.81	.11967	119.67	7.52
21	94.96	6.38	4.25	45.02	0.	23.65	10.00	59.27	.10762	107.62	6.38
22	75.97	5.11	3.40	42.33	0.	22.23	10.00	55.73	.09678	96.78	5.39
23	56.98	3.83	2.55	39.64	0.	20.82	10.00	52.19	.08703	87.03	4.54
24	37.99	2.55	1.70	36.95	0.	19.41	10.00	48.65	.07827	78.27	3.81
25	19.00	1.28	.85	34.26	0.	18.00	10.00	45.11	.07038	70.30	3.18
										8300.85	1271.54

15.3182%

READY.

DELMARVA POWER & LIGHT COMPANY

Marginal Cost for Meeting Transmission Associated with an Increased Demand for Capacity During Peak Periods

1.	Original outlet cost, per kilowatt for peaking plant a/	\$19.00
2.	Annual carrying cost rate for capital	15.32%
3.	Annual carrying cost per kilowatt	\$ 2.9108
4.	Transmission maintenance cost per kilowatt (\$4.9148 x .1154 b/)	\$.5669
5.	Total Marginal Cost per kilowatt of additional peak period demand	\$3.4777
6.	Reserve Requirement @ 20%	.6955
7.	Annual marginal cost per kilowatt of demand	\$4.1732

a/ Current estimate, DP&L

b/ (\$19 x 1,064,000 kw) ÷ \$175,281,154

DELMARVA POWER & LIGHT COMPANY

Transmission Maintenance Cost per Kilowatt

1.	O&M Transmission Expenses a/	$5,229,200
2.	Total Electric Peak at Generation b/	1,064,000 kw
3.	Expense per Kw	$4.9148

a/ DP&L cost of service study

b/ Provided by DP&L

DELMARVA POWER & LIGHT COMPANY

Total Costs of Service at Company Proposed Rates
($000's)

			Transmission			Distribution			
						Demand			
Total All Functions	Demand	Energy	Total	230 KV & Above	Below 230 KV	Primary	Secondary	Customer	Special Assignment
225,169	60,981	80,693	36,084[a/]	22,918	13,166	14,773	5,912	24,435	2,291

[a/] Allocated on basis of total cost of transmission line per pages 442 & 443 of 1977 FERC Report 1. See Schedule 6, page 3.

Schedule 5
Page 2 of 5

DELMARVA POWER & LIGHT COMPANY

Development of Total Costs of Service by Function
at DP&L Proposed Rates
($000's)

	Total, All Functions	Power Production Demand	Power Production Energy	Transmission	Distribution Demand Primary	Distribution Demand Secondary	Distribution Customer	Special Assignment
Operations & Maintenance	110,982	483	79,917	7,598	5,982	1,918	14,569	520
Depreciation	19,741	12,039		3,437	1,648	755	1,856	6
Taxes, Other than Income	5,065	1,144	879	874	445	167	839	716
Income Related Taxes 1/	10,232	5,249		2,829	800	367	861	126
AFDC	8,636	7,579		799	99	47	104	8
Earnings on Present Rates 1/	46,045	23,623		12,732	3,601	1,650	3,874	565
Total Costs as Adjusted on Present Rates	200,701	50,117	80,796	28,269	12,575	4,904	22,103	1,941
Adjustment to Total Costs at Proposed Rates 1/	28,806	14,779		7,965	2,253	1,032	2,424	353
Total Costs at Proposed Rates	229,511	64,896	80,796	36,234	14,828	5,936	24,527	2,294
Less Other Operating Revenue								
a/c 456	3,832	3,832						
a/c 454 2/	193			104	36	16	37	
a/c 451	24						24	
Interdepartmental 3/	293	83	103	46	19	8	31	3
Total Costs to be Recovered From Rates of Electricity	225,169	60,981	80,693	36,084	14,773	5,915	24,435	2,291

1/ Allocated on basis of netplant in service.
2/ Allocated in proportion to T&D plant.
3/ Allocated in proportion to total costs at proposed rates.

DELMARVA POWER & LIGHT COMPANY

Disaggregation of Electric O&M Expenses into Functional Components
(000's)

O&M Expenses	Total, All Functions	Power Production Demand	Power Production Energy	Transmission	Distribution Demand Primary	Distribution Demand Secondary	Distribution Customer	Special Assignment
Power Production								
Demand	9	9						
Energy	79,755		79,755					
Transmission	4,426			4,426				
Distribution								
Primary - Substations	1,716				1,716			
Lines	3,846				1,829		2,017	
Secondary - Substations								
Lines	840					840		
Line Transformers	580					290	290	
Services	561						561	
Meters	1,292						1,292	
Lighting	265							265
Specifically Assigned	42							42
Customer Accounts	3,679						3,679	
Customer Service & Information Expense	483						483	
Sales Expense	373						373	
Administrative & General								
Plant Related	891	473		222	75	34	79	8
Payroll Related[1/]	12,005			2,935	2,350	750	5,766	204
Subtotal	110,763	482	79,755	7,583	5,970	1,914	14,540	519
Revenue Related A&G	219	1	157	15	12	4	29	1
Total O&M	110,982	483	79,917	7,598	5,982	1,918	14,569	520

[1/] Allocated in proportion to O&M less power production.

DELMARVA POWER & LIGHT COMPANY

Disaggregation of Depreciation Expense Into Functional Components
($000's)

	Total, All Functions	Power Production Demand	Power Production Energy	Transmission	Distribution Demand Primary	Distribution Demand Secondary	Distribution Customer	Special Assignments
Depreciation								
Production	11,467	11,467						
Transmission	3,269			3,269				
Distribution 1/	3,994				1,591	729	1,674	
General 2/	318	169		79	27	12	28	3
CIS Amortization	122						122	
Amortization of L.T. R/W	213	213						
Common 2/	358	190		89	30	14	32	3
Total Depreciation	19,741	12,039		3,437	1,648	755	1,856	6

1/ Allocated in proportion to Distribution plant in service.

2/ Allocated in proportion to Plant in service.

DELMARVA POWER & LIGHT COMPANY

Disaggregation of Taxes, Other Than Income Into Functional Components
($000's)

	Total, All Functions	Power Production Demand	Power Production Energy	Transmission	Distribution Demand Primary	Distribution Demand Secondary	Distribution Customer	Special Assignments
Payroll Related	1,016			248	199	64	488	17
Net Plant Related	227	116		63	18	8	19	3
Specifically Assigned	672							672
Property Related	1,928	1,023		479	162	74	172	18
Subtotal	3,843	1,139		790	379	146	679	710
Revenue Related[1/]	1,221	5	879	84	66	21	160	6
Total	5,064	1,144	879	874	445	167	839	716

[1/] Allocated in proportion to O&M.

DELMARVA POWER & LIGHT COMPANY

Cost per Unit of Functionalized Service at Generation Level

Bulk Power Supply

Capacity Cost: $35.60 per Kw x 901,072 Kw 1/	$32,078,163
Transmission Cost: $4.1732 per Kw x 901,072 Kw 2/	3,760,354
Total bulk power supply $39.7732 per Kw x 901,072 Kw	35,838,517
Monthly billing Kw 3/	15,524,148
Cost per Kw per month	$2.3086

Transmission (below 230 KV)

Cost 4/	$13,166,000
Monthly billing Kw	15,424,148
Cost per Kw per month	$.8536

Primary Distribution

Cost 5/	$14,773,000
Monthly billing Kw 6/	14,805,139
Cost per Kw per month	$.9978

Secondary Distribution

Cost 5/	$ 5,912,000
Monthly billing Kw 7/	11,148,934
Cost per Kw per month	$.5303

Customer

Cost 5/	$24,435,000
Weighted Customers 8/	275,524
Cost per weighted customer per month	$7.3905

Energy 9/

On Peak	30.61 mills
Off Peak	19.41 mills/Kwh

1/ Marginal cost of capacity times forecasted Delaware 1978 annual retail system peak for 1978.

2/ Marginal cost of transmission times forecasted Delaware 1978 annual retail system peak for 1978.

[Footnotes continued on next page]

[Footnotes continued from previous page]

3/ 9.7855 times the sum of noncoincident billing demands for the forecast peak month from Schedule 6, page 4. 9.7855 is the ratio of the sum of the 12 monthly system peaks to the annual peak for 1977.

4/ 36.486% of total transmission costs from Schedule 4, page 1. 36.486% is the share of transmission plant below 230 KV from Schedule 6, page 3.

5/ Source: Schedule 5, page 1.

6/ Total annual billing demands less General Service-transmission and Rate Q.

7/ Total annual billing demands less General Service-transmission, Rate Q, and General Services Primary.

8/ Source: Schedule

9/ Schedule 2 lambda weighted by seasonal hours.

DELMARVA POWER & LIGHT COMPANY

Separation of Transmission Plant into EHV and Below

1.	Total line cost of all transmission line 230 KV and above 1/	$ 93,581,298
2.	Total line cost of all transmission lines 1/	$134,623,125
3.	Line 1 as percent of line 2	63.514%

1/Source: 1977 FERC Form 1.

DELMARVA POWER & LIGHT COMPANY

Billing Units for the Forecasted Year 1978
(at Generation Level)

Customer Class	Contribution to Retail System Peak 1/		Noncoincident Billing Demand for Forecast Peak Month 1/	Energy1/	Weighted Number of Customers
	(Kw)	(% of total)	(Kw)	(Mwh)	(No.)
Residential	358,033	41.431%	869,238	1,391,421	155,598
General Service					
Secondary	160,504	18.573	259,926	777,446	111,469
Primary	283,962	32.860	373,635	1,614,487	2,509
Transmission	41,373	4.788	52,254	306,210	
Rate Q	18,790	2.174	21,223	542,500	20
Public Authorities	946	.109	1,532	4,580	983
Lighting	558	.065	8,636	35,721	4,945
Total Retail System	864,166	100.000%	1,586,444	4,672,365	275,524

1/ Source: Exhibit No. PSG-1, Schedule No. 15, page 1.

2/ Source: Exhibit No. PSG-1, Schedule No. 15, page 2.

DELMARVA POWER AND LIGHT COMPANY

Calculation of the Excess of Power Production Costs Over Revenues Resulting from Application of Marginal Cost Based Rates

Power Production Revenue at Marginal Cost Rates	$151,229,000
Cost of Power Production from Average Cost Study	164,592,000
Excess of Functionalized Power Production Costs Determined on an Average Cost Basis over Power Production Costs Determined on a Marginal Cost Basis	$13,363,000

DELMARVA POWER AND LIGHT COMPANY

Revenues from Marginal Cost Based Prices for Power Supply

Function	Marginal Cost	Billing Determinant at Generation Level	Revenue at Marginal Cost Based Rates
Bulk Power Supply Capacity	$39.7732	901,072 Kw 1/	$35,838,517
Energy			
Peak	30.61 mills	2,205,356	67,505,947
Off-Peak	19.41	2,467,009	47,884,645
Total Energy		4,672,365 2/	115,390,592
Total Power Supply Revenues at Marginal Costs			$151,229,109

1/ Source: Schedule, 6 page 4.

2/ From Schedule 6, page 4. Allocated in proportion to period energy consumption.

DELMARVA POWER & LIGHT COMPANY

Marginal Cost-Based Rate Revenue Adjustment Generation Level

Function	Before Adjustment	Adjustment[1/]	After Adjustment
Bulk Power Supply Capacity	$2.3086	1.0884	$2.5126
Energy			
On Peak	30.61 mills	1.0884	33.31 mills
Off-Peak	19.41	1.0884	21.13

1/ Adjustment factor = 13,363,00 ÷ $151,229,000

DELMARVA POWER & LIGHT COMPANY

Conversion of Rates at Generation Level into Rates at Retail

	Capacity	Transmission below 230KV	Primary Distribution	Secondary Distribution	Peak Period Energy	Off-Peak Period Energy	Customer (Weighted)
Cost per unit at generation level	$2.5126	$.8536	$.9978	$.5303	33.31 mills	21.13 mills	$7.3905
Loss factor to primary service level	1.06263	1.06263	1.06263	NA	1.05253	1.05253	--
Cost per unit at primary service level	$2.6700	$.9071	$1.0603	NA	35.06	22.24	
Loss factor to secondary service level	1.13717	1.13717	1.13717	1.13717	1.10936	1.10936	
Cost per unit at secondary service level	$2.8573	$.9707	$1.1347	$.6030	36.95 mills	23.44 mills	$7.3905

Schedule 9

DELMARVA POWER & LIGHT COMPANY

Monthly Retail Rates for Service at Secondary Voltage Level

A.	Customer Charge	$7.39 per month	
B.	Energy Charge		
	Peak Period	3.695¢ per Kwh	
	Off-peak Period	2.344¢ per Kwh	
C.	Demand Charge		
	Capacity	$3.83 per peak period Kw	
	Distribution	$1.74 per maximum billing Kw	
D.	Minimum Charge	The customer charge	
E.	Rating Periods	Summer	Winter
	Peak Periods	9 a.m. to 11 p.m. weekdays	8 a.m. to 10 p.m. weekdays
	Off-Peak Periods	All other times	All other times
F.	Season Designation	June, July, August, September	All other months

DELMARVA POWER & LIGHT COMPANY

Monthly Retail Rates for Service at Primary Voltage Level

A. Customer Charge — $7.39 per month

B. Energy Charge

Peak Period	3.506¢ per Kwh
Off-peak Period	2.224¢ per Kwh

C. Demand Charge

Capacity	$3.58 per peak period Kw
Distribution	$1.06 per maximum billing Kw

	Summer	Winter
D. Rating Periods		
Peak Period	9 a.m. to 11 p.m. weekdays	8 a.m. to 10 p.m weekdays
Off-peak Period	All other times	All other times
E. Season Designation	June, July, August, September	All other months

DELMARVA POWER & LIGHT COMPANY

Marginal Cost of Capacity Recognizing Class Diversity of Demand
Retail Level

	Residential Class	General Service Primary	General Service Secondary
MC per KW per month at generation level 1/	$1.8999	$3.5056	$2.8483
Loss Factor from generation level to service level voltage	1.13717	1.06263	1.13717
MC at retail	$2.1605	$3.7252	$3.2390

1/ Source: Schedule 11, page 2.

DELMARVA POWER & LIGHT COMPANY

Marginal Cost of Capacity Recognizing Class Diversity of Demand
Generation Level

	Residential Class		General Service Primary		General Service Secondary	
MC at system level 1/		$35,838,517		$35,838,517		$35,838,517
Ratio 2/	358,033KW/864,166KW	41.431%	283,962/864,166	32.860%	160,504/864,166	18.573%
Class cost responsibility		$14,848,272		$11,776,414		$6,656,389
Monthly billing KW	(869,238)(9.7855)	8,505,928	(373,635)(9.7855)	3,656,205	(259,926)(9.7855)	2,543,506
Cost per KW per month		$1.7456		$3.2209		$2.6170
Adjustment consistent with total costs of service and proposed rates		1.0884		1.0884		1.0884
Adjusted cost per KW per month		1.8999		3.5056		2.8483

1/ Source: Schedule 6, page 1
2/ Source: Schedule 6, page 4

DELMARVA POWER & LIGHT COMPANY

Monthly Retail Rates for Residential Class
Recognizing Class Diversity of Demand

A.	Customer Charge	$7.39 per month	
B.	Energy Charge		
	Peak Period	3.695¢ per Kwh	
	Off-peak Period	2.344¢ per Kwh	
C.	Demand Charge		
	Capacity	$2.16 per peak period Kw	
	Distribution	$1.74 per maximum billing Kw	
D.	Minimum Charge	The customer charge	
E.	Rating Periods	Summer	Winter
	Peak Periods	9 a.m. to 11 p.m. weekdays	8 a.m. to 10 p.m. weekdays
	Off-Peak Periods	All other times	All other times
F.	Season Designation	June, July, August, September	All other months

DELMARVA POWER & LIGHT COMPANY

Monthly Retail Rates for General Class Served at Secondary Voltage Level Recognizing Class Diversity of Demand

A.	Customer Charge	$7.39 per month	
B.	Energy Charge		
	Peak Period	3.695¢ per Kwh	
	Off-peak Period	2.344¢ per Kwh	
C.	Demand Charge		
	Capacity	$3.24 per peak period Kw	
	Distribution	$1.74 per maximum billing Kw	
D.	Minimum Charge	The customer charge	
E.	Rating Periods	Summer	Winter
	Peak Periods	9 a.m. to 11 p.m. weekdays	8 a.m. to 10 p.m weekdays
	Off-Peak Periods	All other times	All other times
F.	Season Designation	June, July, August, September	All other months

DELMARVA POWER & LIGHT COMPANY

Monthly Retail Rates for General Service Class Served at Primary Voltage Level Recognizing Class Diversity of Demand

A.	Customer Charge	\$7.39 per month	
B.	Energy Charge		
	Peak Period	3.506¢ per Kwh	
	Off-peak Period	2.224¢ per Kwh	
C.	Demand Charge		
	Capacity	\$3.73 per peak period Kw	
	Distribution	\$1.06 per maximum billing Kw	
D.	Rating Periods	Summer	Winter
	Peak Period	9 a.m. to 11 p.m. weekdays	8 a.m. to 10 p.m. weekdays
	Off-peak Period	All other times	All other times
E.	Season Designation	June, July, August, September	All other months

DELMARVA POWER & LIGHT COMPANY

Revenue Verification from Application
of Marginal Cost-Based Rates

Function	Billing Units	Rate	Revenue ($000's)
Bulk Power Supply			
Capacity	15,524,148 Kw	$2.5126 a/	39,006
Transmission, below 230 KV	15,524,148 Kw	.8536 b/	13,251
Distribution Primary	14,805,139 Kw	.9978 b/	14,773
Distribution Secondary	11,148,934 Kw	.5303 b/	5,912
Energy			
On Peak	2,205,356 Mwh	33.31 mills a/	73,460
Off-Peak	2,467,009	21.13 a/	52,128
Total Energy	4,672,365		125,588
Customer	275,524 Cust	7.3905 b/	24,435
Special Assignment Revenue			2,291
Total			$225,256
Total Costs of Service at DP&L Proposed Rates c/			$225,170

a/ Source: Schedule 8, page 1.

b/ Source: Schedule 6, page 1.

c/ Source: Schedule 5, page 1

DELMARVA POWER & LIGHT

Major Class Revenue Requirements at Marginal Cost Based Time-of-Use Rates When Diversity Benefits are Shared

	Residential Class			General Service Secondary		General Service Primary		
Function	Rate	Billing Units	Revenue	Billing Units	Revenue	Rate	Billing Units	Revenue
Customer Charges	$7.39	1,867,176	$ 13,789,431	1,337,628	$ 9,885,071	$7.39	29,796	$ 220,192
Demand Charge								
Capacity	$3.83	7,479,909	28,648,051	2,236,701	8,566,565	$3.58	3,440,709	12,317,738
Distribution	$1.74	7,479,909	13,015,042	2,236,701	3,891,860	$1.06	3,440,709	3,647,152
Energy								
Peak Period	36.95 mills	619,063 Mwh	22,874,378	386,369	14,276,335	35.06 mills	797,631	27,964,943
Off-peak Period	23.44 mills	635,195 Mwh	14,888,971	314,437	7,370,403	22.24 mills	736,275	16,374,756
Total Revenue at Marginal Cost-Based Rates			$93,224,873		$43,990,234			$60,524,781
Total Revenue Responsibility					$41,707,033			$68,411,013

DELMARVA POWER & LIGHT

Major Class Revenue Requirements at Marginal Cost Based Time-of-Use Rates When Diversity Benefits are Retained Within Class

	Residential Class			General Service Secondary			General Service Primary		
Function	Rate	Billing Units	Revenue	Rate	Billing Units	Revenue	Rate	Billing Units	Revenue
Customer Charges	$7.39	1,867,176	$13,798,431	$7.39	1,337,628	$ 9,885,071	$7.39	29,796	$ 220,192
Demand Charge									
Capacity	$3.13	7,479,909	23,412,115	$4.21	2,236,701	9,416,511	$4.63	3,440,709	15,930,483
Distribution	$1.74	7,479,909	13,015,042	1.74	2,236,701	3,891,860	$1.06	3,440,709	3,647,152
Energy									
Peak Period	36.95 m	619,063	22,874,378	36.95 m	386,369	14,276,335	35.06 m	797,631	27,964,943
Off-peak Period	23.44 m	635,195	14,888,971	23.44 m	314,437	7,370,403	22.24 m	736,275	16,374,756
Total Revenue Requirement at Marginal Cost-Based Rates			$87,988,937			$44,840,180			$64,137,526
Proposed Revenue Responsibility			$86,433,766			$41,807,033			$68,411,013

Results of Interviews with Delaware Officials on Time-Of-Use Pricing

Results of Interviews on Time-of-Use Pricing

Time-of-use pricing of electric power in Delaware would involve a major break with traditional electric utility pricing structures. Although time-of-use electricity pricing has not been used previously in Delaware, it has been instituted in various other states in recent years, first on an experimental basis and then operationally. In addition, time-of-use rates have been operative in several European countries for many years. Experience in the U.S. and abroad has shown that time-of-use pricing of electric power improves the cost reflectiveness of utility tariffs and provides consumers with price incentives designed to achieve improved economies in the electric power industry together with optimal levels of energy conservation.

The time-of-use rates computed in this study are reflective of the Delaware Power & Light Company's costs of production. If consumers are required to face these price signals, then they will make consumption decisions by comparing the value they place on an extra kilowatt hour of electric energy with the true cost of supplying of that energy. If this is done, it will lead to efficient allocation of available resources. By contrast, traditional rates without time-of-use differentials often structure prices so as to induce overconsumption of high cost on-peak power and underconsumption of low cost off-peak power. Time-of-use pricing would rectify this distortion and would properly encourage rational economic choices while, at the same time, providing for a fairer distribution of electric utility costs.

In addition to encouraging greater economic efficiency in the allocation and use of limited resources and improved incentives for conservation, an important by-product of the efficiency of a time-of-use rate structure is fairness. Under traditional, nontime-variant rates, part of the cost of serving relatively heavy peak users is imposed on the rest of the system. Thus, some consumers subsidize others. With cost-reflective time-of-use pricing, each consumer will pay according to the cost burden he imposes on the electric utility system. He will neither subsidize others nor be subsidized himself.

Pricing power by time-of-use is unquestionably one of the most significant proposed reforms in the regulation of electric utilities. The implementation of time-of-use electric rates depends, in turn, on the perceptions of utility regulators and other public decision-makers both as to the logic of the conceptual arguments favoring such reform and as to any possible practical problems associated with implementation. Thus, the views of these decision-makers are of great interest.

Task one of this project was to ascertain the attitudes and perceptions of state officials and others who have significant input into the regulatory process in Delaware. This information is useful for public policy debate in that it identifies areas of consensus and disagreement. In addition, it helps to highlight areas of misunderstanding that must be addressed. Only as perceptions of possible problems are identified, can these problems be systematically examined.

<u>The Survey Instrument</u>

Delaware officials were interviewed to determine their attitudes on the general subject of rate design, Delmarva Power & Light's current rate structure, and the advantages and disadvantages of time-of-use rates. The interviews were quite informal, and the subjects were given an opportunity to discuss the issues as fully as they desired, to digress, to expand on, or to avoid the question. A survey instrument was designed and used for the convenience of the interviewer to make sure the same questions and subject areas were covered in each interview. This also has the advantage of facilitating comparison among the subjects interviewed. Many of the survey questions were deliberately openended, both to encourage full expression on the part of the interviewees and to avoid leading them to pre-established conclusions.

On August 2, 1978, interviews were conducted in Wilmington, Delaware. While personal interviews are preferred, since they tend to elicit the clearest and least inhibited responses, that was not always possible. Because of travel, work, and hearing schedules, the Commission members were unable to attend the August 2 interviews, and they (along with citizen intervenor, Victor Singer) were interviewed by telephone. One commissioner could not be interviewed over the phone but submitted written responses to the questionnaire.

A copy of the questionnaire is presented below.

RATE DESIGN QUESTIONNAIRE

1. What social objective or considerations should be reflected in the design of electric power rate structures?

2. With respect to the effects of electric power rate structures, indicate what you feel ought to be the priority of each of the following indicated below:

   a. Equity or fairness - Should one or more classes of customers "subsidize" another? Should higher income customers subsidize lower income customers? Large customers subsidize smaller customers?

   b. Economic development - Are you concerned about rate structure impacts on employment opportunities? Industrial growth?

   c. Load flattening - Is it important to design rates which would encourage the reduction of peak usage?

   d. Energy conservation - Should reducing total energy usage be an important goal?

   e. Environmental - Are there any considerations or concerns regarding environmental quality in the design of rates?

   f. Other - Do you have in mind any other social goal which can be affected by rate design?

3. What is your general assessment of DP&L's current rate structure? (Summarize if subject is unfamiliar with it).

4. How well do they reflect the priorities discussed earlier? What specific problems are there?

5. Should special discounts be given for specific usage, like electric space and water heating? Why?

6. As a general proposition, do you believe that electricity rate structures should be based upon the costs of providing services?

   Many rate design experts are proposing seasonal and time-of-day rates. The costs of producing electricity vary according to when electricity is used. During periods of very high demand, the cost of generating additional energy is very high since it must be generated by the least efficient plant (i.e., a peaking unit). Since costs vary by time-of-use, prices should vary by time-of-use.

7. How would such a rate structure reflect the priorities or objectives discussed earlier?

8. On balance, do you think such a rate structure is preferable to DP&L's current rate structure?

9. What do you perceive to be possible problems or objections to time-of-day pricing?

10. Time-of-day pricing requires additional metering. Would you expect the flattening induced by time-of-day metering to be worth the cost of this additional metering?

11. Which of the following would be your policy recommendation on seasonal and time-of-day rates?

    a. I am against it.

    b. I favor seasonal but oppose time-of-day pricing.

    c. It deserves further study, but no policy actions should be taken until its impacts are fully analyzed.

    d. It is appropriate for certain customer classes (indicate) but not others.

    e. It should be implemented on a voluntary basis.

    f. It should be implemented on an experimental basis.

12. Any additional comments on rate design issues?

Survey Responses

An attempt was made to obtain viewpoints from those individuals and institutions that directly or indirectly have influenced rate design issues in Delaware. Those interviewed represent a fairly diverse cross-section of viewpoints in the State. The subjects included Governor DuPont, the five commissioners, citizen intervenor Victor Singer, Gordon Smith of Associated Utilities Services (consultants to the Commission), Kenneth Jones of Delmarva Power & Light, and Mr. Ernest Thorn of the Governor's Resource Management Commission. Their responses to the questionnaire are summarized below.

Governor DuPont

Governor DuPont feels that rate reform can and should be concerned with both the problems of fair cost allocation, energy conservation, and load flattening. He indicated that the State's economic well-being and environmental protection were also proper rate design concerns. He questioned whether Delmarva's current rate structure reflects these concerns adequately, while desiring the development and availability of better factual evidence, he appeared to expect that time-of-use rates would be a major improvement. The Governor clearly supported the concept that electric rates should be cost based. He recognized that because time-of-use rates would bring about changes in cost allocation, there would probably be some political resistance by those interests that are now being subsidized under conventional rates. The Governor expressed optimism about the potential for load flattening and the eventual economies and cost reductions that time-of-use rates can achieve. While favoring the development of further factual information, Governor DuPont evidently supports expeditious efforts toward rate reform, and unless subsequent evidence contradicts the apparent desirability of time-of-use rates, he favors the near term implementation of such rates in Delaware, at least on an experimental basis.

The Delaware Commission

All five members of the Commission were interviewed, four by telephone and one by submitting written responses. They seemed to agree generally that energy conservation and load flattening are important rate structure related issues. Other less frequently mentioned priorities included environmental quality, economic development, and subsidizing the poor. The commissioners expressed considerable diversity of views in their evaluation of Delmarva's current rate structure, with two commissioners being critical, two being quite favorable, and one refusing comment. There was some reservation, but they generally approved of Delmarva's current discounts for electric space and water heat.

Despite a degree of approval on the part of the commissioners for Delmarva's current rate structure (including special discounts), the commissioners unanimously approved of the concept of cost-based rates. In several cases, the commissioners indicated that they found the general idea of pricing by time-of-use appealing, but they wanted to give the matter more study. Although cost-based rates were appealing to the commissioners, there was considerable doubt as to whether time-of-use rate reforms would constitute an improvement over the prevailing rate structure. The problems that the commissioners envisioned with the time-of-use rates included metering costs, rate structure complexity, impacts on particular customer groups (especially farmers and the poor), and the difficulty of adjusting to changes. Only one commissioner expressed confidence that time-of-use rates would produce a substantial amount of load flattening. Despite these widespread misgivings, all five commissioners seemed interested in time-of-use rates on an experimental study basis.

Citizen Intervenor

Mr. Victor Singer has been an enthusiastic advocate of time-of-use, marginal cost rates for several years as a citizen intervenor in Delaware electric utility rate cases. He favors such rates, because he believes that they are efficient and fair. Rate design, according to Singer, should not be a discretionary tool to accomplish political or social goals. Rates should reflect costs. Singer believes that cost based rates will, by their very nature, serve to achieve results consistent with reasonable social objectives. The objectives themselves, according to Mr. Singer, need not be used as explicit rate design criteria.

Mr. Singer was very critical of DP&L's current rate structure. To him, that structure is archaic and self-serving. He believes that time-of-use rates would be vastly superior, although he expects that not all customers will initially benefit, and there will be a period of adjustment. Mr. Singer recommends that time-of-use pricing be accompanied by an effective educational campaign to ease the adjustment. He expressed confidence that time-of-use rates will ultimately produce enough load flattening to pay for the costs of implementation. Mr. Singer, therefore, favors immediate, systemwide, mandatory time-of-use rate implementation. Mr. Singer characterized his own present electricity consumption pattern as essentially wasteful, and he expressed an expectation that implementation of time-of-use rates would, at least in the shortrun, increase his own electric bills.

Staff Consultant

Gordon Smith of AUS (Associated Utilities Services), consultants to the Commission staff, was also interviewed. He expressed a mixed but generally favorable attitude toward the concept of time-of-use rates, recognizing that there is room for improvement over the current rate structure of DP&L. However, his preferred concept of time-of-use rates does not necessarily embrace the economic principles of marginal cost pricing and, other than opposing water and space heat discounts, he is not extremely critical of DP&L's rates. Mr. Smith's misgivings about time-of-use rates included doubts as to whether load flattening benefits would outweigh costs of implementation. Because of implementation costs, Mr. Smith felt that time-of-use rates would be more appropriate for some customers than others.

Delmarva Power and Light

Mr. Kenneth Jones represented the Company at the interview session. His responses were similar to Mr. Smith's. Mr. Jones expressed support for the concept of cost based pricing, and he expressed an apparently open and favorable attitude toward rate structure reform -- even Delmarva's. Mr. Jones foresees certain problems with time-of-use rates, including the cost of implementation, impacts on Company revenue, and customer acceptance. He also feels that partial implementation of time-of-use rates might be desirable, at least for those customers for whom load shifting might be feasible. Mr. Jones expressed some dissatisfaction with the continuous debate and study of rate reform that has been characteristic in the industry in recent years, and appeared to believe that some reform is appropriate, and we should "get on with it."

Governor's Resource Management Commission

Mr. Ernest Thorn, the Commission Chairman, believes that the central focus of rate reform should be load management and energy conservation. In contrast to the view conveyed by Mr. Jones -- that Delmarva would like to "get on" with the implementation of rate reform -- Mr. Thorn felt that Delmarva has been "foot dragging." In that regard, he feels Delmarva's current rates are clearly inefficient, and rates based on time-variant costs would be an enormous improvement. He does not foresee any major problems with time-of-use rates (other than complexity) and, like Mr. Singer, he strongly believes that the load flattening benefits would exceed implementation costs. Mr. Thorn favors experimental implementation and, pending evidence to the contrary, would then favor permanent, systemwide, implementation. Consistent with his interest in energy conservation, he favors long-run incremental pricing.

Summary and Conclusions

These interviews produced a broad based consensus of opinion: everyone favors in some degree some sort of positive policy action on rate reform. There is, however, some disagreement as to what that policy action ought to be, although load flattening, conservation, and cost relatedness were generally recognized as conceptually attractive rate design objectives.

On a practical level, there was widespread disagreement about what sort of problems would accompany time-of-use rate implementation and how serious those problems would be. There was substantial concern as to whether the benefits of time-of-use rates would exceed implementation costs. Some were concerned about impacts of rate reform on certain consumer groups and would even go as far as to exempt them from new rate design approaches. Most recognized that there would be an adjustment period related to rate comprehension, persistence of consumption habits, and the long-term nature of expected economies. A common recommendation was that if time-of-use rates are implemented, it would be important to accompany them with an education program so as to minimize consumer adjustment difficulties.

In summary, it was the interviewer's perception that the Governor, Mr. Singer, Mr. Thorn, and the Chairman of the Commission, unless they are shown evidence that it doesn't work, support the implementation of time-of-use rates. The other individuals interviewed find the concept appealing but are more wary of it in practice. No one was wholly resistant to rate reform nor rejected the concept of time-of-use rates as a valid consideration in the State of Delaware.