Final Report

on

ELECTRIC UTILITY TIME-OF-USE AND INTERRUPTIBLE RATEMAKING AND POWER POOLING ISSUES IN COLORADO

Russell J. Profozich

Daniel Z. Czamanski

Roger K. McElroy

G. Timothy Biggs

Timothy Pryor

Whitfield A. Russell and Associates

THE NATIONAL REGULATORY RESEARCH INSTITUTE
2130 Neil Avenue
Columbus, Ohio 43210

prepared for the

Colorado Public Utilities Commission

August 1981

TABLE OF CONTENTS

INTRODUCTION

This report contains a collection of five individual reports that were prepared by The National Regulatory Research Institute (NRRI) for the Colorado Public Utilities Commission (PUC). The Colorado PUC requested that the NRRI perform a series of analyses in relation to various electric utility costing and pricing issues and power pooling arrangements. These areas of inquiry resulted from a generic regulatory proceeding held by the Colorado PUC (Case No. 5693) during which the commission explored the above mentioned topics. The selected areas of inquiry are also a natural outgrowth of the federal government's implementation of the Public Utility Regulatory Policies Act of 1978 (PURPA). This act covers essentially the same topics as those of the Colorado PUC's generic proceeding. Therefore, an investigation of the topics presented in this report served the Colorado Commission in meeting its obligations under PURPA as well as aiding the commission in implementing the decision that concluded its generic regulatory proceedings.

The Request for Technical Assistance

On July 13, 1976 the Colorado PUC initiated a generic proceeding to consider a number of issues relating to jurisdictional electric utilities' rate structures. The commission concluded its generic proceeding with Decision No. C79-1111 issued on July 27, 1979. In the interim, the United States Congress enacted PURPA which requires consideration and determination of various electric utility rate standards by state public utility commissions. Substantial progress was made in the Colorado decision toward full compliance with the PURPA rate standards. However, the commission noted in its decision that a considerable amount of additional information, methodology studies, and training of commission staff would be needed before it could properly implement its decision.

In that regard, the Colorado PUC contracted with the NRRI to complete a series of reports dealing with the certain electric utility rate structure issues. These issues include development of a method for selecting costing periods for electric utility time-of-use rates, development of a method for determining the costs and benefits of electric utility time-of-use rates, assessing the reasonableness of interruptible rates proposed by Colorado electric utilities, and a review of power pooling arrangements of major Colorado electric utilities.

Development of the Reports

Over the past year, the NRRI has worked with the staff of the Colorado PUC to collect data and information and to develop reports dealing with each of the above mentioned issues. Various members of the NRRI staff and its consultant have also traveled to the Colorado commission to provide training to the commission's staff in the areas of methods for selecting costing periods for electric utility time-of-use rates, a method of determining the costs and benefits of electric utility time-of-use rates, and a method for assessing the benefits of Colorado electric utility power pooling arrangements.

The following sections of this report contain the individual reports prepared for, and presented to, the Colorado PUC. The NRRI is presenting these reports as a single volume because it is felt that the issues involved are sufficiently generic in nature to provide useful information to the various state public utility commissions and to the regulatory community.

Section I contains the report Selecting Costing Periods for Electric Utility Time-of-Use Rates in Colorado. This report contains summaries of four methods for selecting costing periods for electric utilities that were developed for the Electric Power Research Institute Rate Design Study. It also presents a method for selecting costing periods developed by the NRRI which uses a NRRI developed computer model. This method requires the identification of specific practical restrictions on the selection of costing periods and involves a computer analysis of utility system hourly load data as a basis for selecting seasonal and daily costing periods. These costing periods are a basis for developing electric utility time-of-use rates.

Section II contains the report The Load Frequency and Duration (FRED) Data Analysis Program User's Manual. FRED is a computer model developed at the NRRI that can be used in selecting costing periods for electric utility time-of-use rates. The user's manual provides necessary information and documentation so that FRED can be utilized at a commission's own computer facilities to aid in the selection of electric utility costing periods. The FRED program may be used alone or in combination with the method developed by the NRRI and presented in Section I of this report.

Section III contains the report A Method for Computing the Main Benefits and Costs of Time-of-Use Rates for Colorado Electric Utilities. The method developed in the report is based on estimated changes in consumption patterns following the introduction of electric utility time-of-use rates. Specifically, the analysis contained in the report considers capacity and energy cost savings and metering costs occasioned by the implementation of time-differentiated electric rates. Capital and energy cost savings per kilowatt-hour are estimated with the help of the Cicchetti, Gillen, and Smolenski computer program. Data requirements for, and sample output of, the computer program are also presented.

Section IV contains the report Assessing the Reasonableness of Interruptible Rates for Colorado Electric Utilities. The interruptible rates offered to industrial customers by various electric utilities throughout the United States are summarized in this report. Also, several methods for estimating the costs upon which to base rates for interruptible electric service are presented in the report. These include two methods based on estimates of the "avoided costs" associated with interruptible service, a "cost plus margin" approach which assumes that the peak period load of interruptible customers is provided for entirely from the idle reserve capacity of regular service customers, and a "peak responsibility" method which determines the capacity charge for interruptible customers based upon these customers' contribution to the annual system peak demand.

Section V contains the report A Review of Power Pooling Arrangements of Major Colorado Electric Utilities. This report was prepared for the Colorado PUC by Whitfield A. Russell & Associates on behalf of the NRRI. The report describes the power pooling and power brokering arrangements of major Colorado electric utilities as well as for other major electric utilities in the west and southwest sections of the United States. Also described are the power pooling and power brokering arrangements of several major power pools in the United States. The report presents an approach for evaluating and comparing the pooling arrangements of Colorado electric utilities with those of the several major power pools.

FINAL REPORT

on

SELECTING COSTING PERIODS FOR ELECTRIC UTILITY TIME-OF-USE RATES IN COLORADO

Russell J. Profozich
Senior Institute Economist

G. Timothy Biggs
Graduate Research Associate
in City and Regional Planning

THE NATIONAL REGULATORY RESEARCH INSTITUTE
2130 Neil Avenue
Columbus, Ohio 43210

prepared for

The Colorado Public Utilities Commission

in partial fulfillment of

Contract No. 900342

June 1981

EXECUTIVE SUMMARY

Time-of-use pricing, a form of peakload pricing, is generally instituted to achieve the goals of economic and engineering efficiency. In addition to efficiency, regulatory commissions must also consider other goals of regulation including revenue sufficiency and stability, customer acceptance and understandability of rates, energy and capital conservation, and equity requirements.

The Colorado Public Utilities Commission has determined that electric utility rates in that state should track the costs of providing service as closely as possible. The commission also determined that at least for the present until more reliable data are available, rates should track the variation in average costs of service by time of use. Since these costs vary by season of the year and time of day, the commission has initiated a study into the feasibility of time-of-use pricing for Colorado utilities. A basis for time-of-use pricing is the selection of proper costing periods upon which to set rates.

There are several advantages and disadvantages associated with time-of-use pricing. The advantages include cost reductions occasioned through a reduction in growth of peak demand, regulatory benefits resulting from a closer correlation of prices with costs of service, consumer benefits realized through lower utility bills as demand is shifted to off-peak periods, and technological advancement resulting from the demand for load management and energy storage technology.

The disadvantages of time-of-use pricing include implementation costs, mainly metering and administrative costs; industrial considerations necessitating a gradual movement to time-of-use pricing; and price stability considerations resulting from the fact that price affects demand and therefore rates must be designed carefully to take into account demand elasticity.

Four methods for selecting costing periods upon which to base time-of-use rates have been developed. These are the Ebesco method, the NERA method, the Ontario Hydro method, and the LILCO method. Available information on each of these methods is summarized in this report for informational purposes. For each case, a lack of complete documentation of the procedures employed and assumptions made in applying the method prevents it from being applied to the Colorado circumstance.

All four of the methods rely on an analysis of utility load characteristics as a basis for selecting costing periods. While some of the methods use fairly sophisticated statistical analyses to develop a set of costing periods, all include a significant amount of judgment necessitated by those nonquantifiable factors that must be included in any costing methodology. These factors include customer acceptance and understandability, customer ability to respond to price differentials, and pricing and revenue stability.

The National Regulatory Research Institute (NRRI) has developed a computer program for analyzing electric utility hourly system load data to produce a set of hourly average load curves and hourly peakload curves upon which to base costing periods. This program may be used in conjunction with explicit restrictions on the selection of these periods, which take into consideration the nonquantifiable aspects of ratesetting, to develop appropriate costing periods for time-of-use rates.

The example procedure for selecting costing periods using the NRRI computer program, which is presented in the last chapter of this report, is similar to the Ontario Hydro method. It requires the identification of specific practical restrictions on the selection of costing periods and involves a computer analysis of system hourly load data as a basis for selecting seasonal and daily costing periods. The periods selected through this process may be checked for accuracy by analyzing system hourly marginal running costs or by comparing them with similar costing periods and average or marginal cost of service information required to be filed by certain utilities under section 133 of the Public Utility Regulatory Policies Act of 1978.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

PREFACE

This report was completed under a National Regulatory Research Institute (NRRI) contract with the Colorado Public Utilities Commission (Contract #900342). The Colorado commission requested, as one part of the contract, a study covering methods of selecting costing periods for electric utility time-of-use pricing within the state of Colorado. This report summarizes various methods of selecting costing periods and relates these methods to the purposes of time-of-use pricing. This report was prepared by Russell J. Profozich, Senior Institute Economist, and G. Timothy Biggs, Graduate Research Associate, under the direction of Dr. Kevin A. Kelly, Associate Director.

CHAPTER 1

INTRODUCTION

The purpose of this report is to develop a method for selecting costing periods for electric utility time-of-use (TOU) pricing in Colorado and to relate this method to the purposes of time-of-use or peakload pricing.[1] Summaries of four methods for selecting costing periods are also presented for informational purposes. Peakload pricing is generally instituted to achieve the goals of economic and engineering efficiency. Economic efficiency is achieved through the price mechanism by ensuring that prices for electric service adequately reflect the costs of providing service. Engineering efficiency is achieved through the construction of optimum size facilities and the optimal utilization of these facilities to meet consumer demand.

As in most instances where a particular policy (in this case peakload pricing) is intended to achieve simultaneous goals, the achievement of both economic and engineering efficiency may tend to become contradictory. That is, by achieving a greater degree of economic efficiency through the implementation of time-of-use pricing, a commission may forego some level of engineering efficiency, and vice versa. In these cases, commissions must balance the competing goals of utility regulation that in addition to efficiency considerations include revenue sufficiency and stability for the utility, customer acceptance and understanding of the rates, energy and capital conservation, and equity in rates.

---

[1]There are various methods available for instituting peakload pricing. Time-of-use pricing, the method with which we are concerned here, is one type of peakload pricing. Other methods such as the familiar demand ratchet provisions of electric utility tariffs or interruptible rates for various types of service have been in use for some time. See, for example, The Development of Various Pricing Approaches: Topic 1.3, prepared by Ebasco Services, Inc., for the Electric Utility Rate Design Study (Palo Alto, Calif.: Electric Power Research Institute, March 1, 1977).

The Occasion

The Colorado Public Utilities Commission has held a generic regulatory proceeding (Case No. 5693) during which it explored various costing and pricing alternatives for electric utilities operating within its jurisdiction. The commission issued a decision at the end of the generic proceeding (Decision No. C79-1111) in which it stated its position with regard to time-of-use (TOU) pricing. Although rejecting marginal cost analysis as a basis for determining costs upon which to establish rates (at least for the present), the commission stated that rates, to the extent possible, should track the costs of providing service. Thus, when average costs of service vary by time of use, electric rates should track that variation as closely as possible.[2] The commission also noted that such rates will place the cost burden of supplying electric service on those responsible for the costs and will encourage, over time, consumers to shift some portion of their consumption to off-peak periods, thereby contributing to capital and energy conservation. The commission also stated that even if time-of-use rates do not induce consumers to shift a part of their demand to off-peak periods, time-of-use rates based on variations in average costs will adequately reflect the cost of service so that those consuming electricity on-peak will pay an appropriately higher price. Thus, the commission seems to have established economic efficiency as the primary purpose for instituting time-of-use pricing.

By way of contrast, if the commission wanted to achieve a very flat load so as to minimize generating costs, the goal then would have been to promote engineering efficiency.

The commission in its Decision C79-1111 has also established certain criteria for the implementation of TOU pricing in Colorado.[3] These criteria state that TOU rates must accomplish the following:

---

[2]Decision No. C79-1111, Colorado Public Utilities Commission, Case No. 5693, July 27, 1979, p. 108.

[3]Ibid., Appendix E, p. 183.

1. Be simple and easy to apply.
2. Result in rates easily understood by the customer.
3. Track costs.
4. Be equitable.
5. Encourage conservation of energy.
6. Encourage conservation of capital.
7. Take into account time periods and cost variations among those periods.

In regard to costing periods, the commission has stated that electric utility costs of service vary by season of the year and by time of day due to the nature of the loads placed on the system and the generating mix required to meet those loads. Variations in rates, then, should coincide with variations in costs of service (criteria 3 and 7 as listed above). In order to comply with the simplicity and understandability criteria (criteria 1 and 2), however, the commission recommends that seasonal costing periods be as few as possible given the need to track costs.

As the basis for seasonal variation in rates, the commission recommends that a utility's load curves be used to determine the seasonal load cycles. Because of the variation of load curves from year to year, a 5-to-10 year average load curve is recommended for use, with the average cost of meeting load during each seasonal period employed as the cost basis upon which to design seasonal rates.

Within each seasonal costing period, costs of service will vary almost on an hourly basis. In order to comply with its costing criteria as outlined above, that is, in order to achieve a balance between precision in tracking costs of service and simplicity and understandability of rates, the commission recommends that time-of-day costing periods should be grouped into periods with similar costs. Two or three daily costing periods should provide an adequate balance between precision and understandability, according to the commission.

Advantages and Disadvantages of Time-of-Use Pricing

Time-of-use pricing charges higher prices for electric service during peak hours than during off-peak hours. Although time-of-use pricing is generally associated with a marginal costing methodology, average costs of service are also appropriate for the implementation of this form of peak-load pricing. There are, however, advantages and disadvantages associated with time-of-use pricing that should be considered when implementing this form of pricing. They may be outlined as follows:[4]

Advantages

1. Cost reductions: At present, the growth in peak demandis priced below its time-differentiated average (or marginal) cost. Peak demand growth and the need for additional capital expenditures are likely to be reduced when prices follow variations in costs of service. As a result, both capital and operating costs would grow at a slower rate, thereby contributing to both capital and energy conservation.

2. Regulatory Benefits: The frequency of rate cases should be reduced due to the closer correlation of prices with costs of service. Also, the regulatory criterion of equitableness will likely be enhanced, since those consumers most responsible for expansion of facilities will pay an appropriately higher price.

3. Consumer Benefits: Consumers may be able to reduce their utility bills provided that time-of-use prices are structured in a manner that is easily understood and easily applied. Customers can realize the benefits of time-of-use pricing by shifting a portion of their energy consumption to off-peak hours.

---

[4]Daniel Z. Czamanski, J. Stephen Henderson, Kevin A. Kelly, Electric Pricing Policies for Ohio, vol. 1. (Columbus, Ohio: The National Regulatory Research Institute, October 1977), pp. 49-58.

4. Technological Advancement: Time-of-use pricing is likely to stimulate research and development in energy storage and other load management techniques by providing greater incentives to store or use electricity during off-peak hours.

5. Economic Efficiency: Economic efficiency will be enhanced because prices for electricity will more accurately reflect the costs of service. Consumers, then, will pay a price that reflects the cost to society of providing electric service.

6. Engineering Efficiency: Engineering efficiency is also likely to be improved through time-of-use pricing, especially over the long run, as greater utilization of facilities occurs as a result of a shift in demand from peak to off-peak hours. Care must be taken in the design of time-of-use rates, however, so that a shift in consumer usage does not result in less, rather than more, efficient utilization of facilities.

Disadvantages:

1. Implementation costs: Prohibitive expenses may be incurred if new customer meters are required for time-of-use pricing. However, in those markets of larger users, the benefits should outweigh the costs because the necessary metering is already in place. Also, with the development of various low cost metering techniques that can be expected in the future, time-of-use pricing is likely to be beneficial to residential customers as well.

2. Industrial considerations: If industry finds peak load pricing too expensive, it is argued that out-of-state movement may occur. Therefore, if and when TOU pricing is implemented, consideration might be given to coordination of efforts with utility commissions in other states in the surrounding region if possible. Also, the commission could give assurance to customers that this pricing

method will not discriminate or impose undue hardship on one customer class over another.

3. Price stability considerations: There is a causal relationship between the price of, and demand for, electric service. Since time-of-day pricing will likely result in some portion of consumer demand being shifted from peak to off-peak periods, care must be taken in designing such rates so that rate instability does not result.

Overall, the benefits of time-of-use pricing should outweigh the costs. A decisive step in ensuring this relationship (i.e., benefits over costs) is selecting costing periods that accurately reflect costs of service. These costing periods form the basis for time-of-use pricing. The following chapter contains summaries of four methods for selection of costing periods that have been experimented with recently. The summary of each method will point out the significant steps that each group used in developing the specific method. These groups, which have applied their method of selecting costing periods for TOU rates with varying degrees of success, are the following:

1. Ebasco Services, Inc. (Ebasco).
2. National Economic Research Associates (NERA).
3. Ontario Hydro (Ontario).
4. Long Island Lighting Company (LILCO).

It should be noted that in each of the four methods summarized, less than full documentation of the procedures employed and the assumptions made in applying the method to a specific utility is available. This lack of full documentation is due to the experimental nature of each of the methods and the fact that judgment plays a crucial role at various points within each method. Unfortunately, the various factors that contribute to the judgmental process are not always well defined by the developer of each method.

Summaries of the four methods are provided for informational purposes. The reader is referred to the various sources of information on each of the methods footnoted throughout the chapter for additional information.

CHAPTER 2

FOUR COSTING PERIOD SELECTION METHODS

The material contained in this chapter is derived from various sources as noted in the footnotes, however, much of the material is taken from A Review and Evaluation of Methods for Selecting Rating Periods, prepared by Gordian Associates, Inc., for the Electric Utility Rate Design Study. This publication offers a fairly detailed summary and review of the four approaches to selection of costing periods. These approaches, or methods, developed by the identified parties (i.e., Ebasco, NERA, Ontario Hydro, and LILCO) have been applied in time-of-use pricing proceedings in several jurisdictions throughout the country. The remainder of this chapter contains abbreviated descriptions of the four methods, including comments on their usefulness in selecting costing periods and adaptability to the Colorado circumstance.

None of the four groups provides full documentation of all of the data requirements, procedures, or assumptions used in applying its method to the selection of costing periods. These omissions are partially due to the fact that costing methods for time-of-use rates are still in the development state. Also, costing methods necessarily rely to a considerable degree on judgment and unquantifiable criteria that prevent any particular method from being applied to a specific utility without some degree of alteration. These factors, along with data limitations and the unique characteristics of each utility to which the costing methodology was applied, resulted in only a general presentation of each method by its developer. Unfortunately, this type of presentation sometimes resulted in vagueness or omission of certain important aspects of the method itself.

All of the methods surveyed use hourly system load data to determine costing periods on the assumption that variations in costs of service follow variations in system load. This assumption, although generally accepted as a means for determining costing periods, is partially necessitated by the lack of available data on hourly system generation costs and hourly system transmission and distribution costs. Although potentially harmful to the analyses, the effects of this assumption are largely nullified by the fact that the final selection of costing periods is tempered by the need to take into consideration the many nonquantifiable aspects (or goals) of utility regulations. These goals contribute to broadly defined costing periods that attempt to strike a balance between accuracy in reflecting actual costs of service and general understandability and usefulness of the rates that result from the costing period selection process. As a result, periods that reflect similar system loads (the proxy for system costs of service) are combined into a single costing period on both a seasonal and daily basis. The final result of this process is the selection of from two to four seasonal costing periods and two to four daily costing periods within each season upon which to base time-of-use rates.

Although useful in developing a method for the selection of costing periods, the assumption that variations in system load follow variations in costs of service may or may not result in rates that adequately reflect the actual cost of providing service. This may be particularly true for a utility with a considerable amount of hydroelectric generating capacity or for a utility that is a member of an established power pool where a large amount of sales among the various members of the pool takes place. In these cases, the accuracy of the selected costing periods (i.e., accuracy in reflecting actual costs of service) may be verified through a comparison with a second set of costing periods developed using hourly system running costs (fuel and variable operating and maintenance expense), and taking into account the exchange of energy among members of a pool and assigning the replacement cost of hydrogeneration or pumped storage generation to the appropriate time period.

The Ebasco Method

The Ebasco peakload-pricing method is basically an embedded (i.e., accounting) cost approach, although Ebasco asserts that it can be used for determining marginal costs as well. Ebasco states that this method, based on seasonal or time-of-day distinctions, creates the basis whereby customers begin to realize how costs are incurred by the utility. This realization (or in other words, price signal) allows customers to change their electric usage habits in order to reduce peakload or conserve energy.[1]

Underlying Theory

Costs must be defined by seasons and/or time of day in order for Ebasco's method to be applied. Ebasco's guiding principles, used as a basis for the allocation of costs to periods, emphasize that greater portions of fixed costs per load unit are associated with those periods of greater system load and that greater proportions of variable costs per consumption unit are also associated with those periods of greater system load.

Since Ebasco assumes that high-load periods are also periods of high-fixed and variable costs, this method analyzes system hourly loads to determine the "high-load" hours. These hours are labeled "peak" hours. Such a determination necessitates time of day and seasonal examination of hourly load data for a historical or projected time period.

Data Requirements

The Ebasco method uses data from a preselected test year, usually the most recent 12-month period, to form the basis for selecting costing

---

[1]Ebasco Services Inc., Costing for Peak Load Pricing: Topic 4, prepared for the Electric Utility Rate Design Study (Palo Alto, Calif.: Electric Power Research Institute, May 4, 1977), p.6.

periods. The specific data requirements used in selecting costing periods are listed below:[2]

1. Monthly system peak demands.
2. Daily load curve (at a minimum, the daily curve for the peak day of each season).
3. A list of generating units classified by type of use (i.e., baseload, intermediate, peaking) and their capacity ratings.
4. A list of firm interchange agreements with other utilities.
5. A schedule of planned maintenance for all generating units.
6. A weighted-average forced outage rate for baseload units on an annual basis.
7. Seasonal capability factors reflecting changes in available generation capability due to seasonal weather effects.

Procedures for the Ebasco Method

Seasonal Costing Periods

Although no specific seasonal costing period selection method was presented, Ebasco makes some generalizations about seasons. In explaining the methodology behind its base, intermediate, and peak (BIP) method, Ebasco notes that judgment plays a major role in period selection. In the United States, all system peaks, with few exceptions, are weather sensitive and are mainly caused by air conditioning or space heating. For this reason, Ebasco assumes that categorical seasonal groupings can be made for all utilities based on variations in monthly system peak demands where these variations are due to weather effects. These groupings are as follows: summer peaking, winter peaking, leap-frogging peaks, or nonpeaking. Ebasco's selection of seasonal costing periods follows the normal seasonal ranges based on weather variation perceptions during the course of the 12-month period.[3] Ebasco ignores formal statistical methods

---

[2]Gordian Associates, Inc., A Review and Evaluation of Methods for Selecting Rating Periods, prepared for the Electric Utility Rate Design Study (Palo Alto, Calif.: Electric Power Research Institute, February 8, 1980), p. 10.

[3]Ibid., p. 11.

in its selection of costing periods and relies on the use of judgment based on experience and pragmatism in the selection of seasonal and daily periods. The ratio of highest to lowest monthly system peak demand is calculated to determine the seasonal costing periods. If the ratio is greater than 1.4, Ebasco states that a great degree of seasonal variation is present. If the ratio falls between 1.2-1.4, seasonal variation may be present, but to a lesser degree. No rationale for the selection of these ratios was presented in the report.

The levels of monthly demand across the year are then examined and grouped into seasons if, based on the ratio findings, variation is present. Next, a retrospective examination of previous years' data is made to determine those months where annual system peaks have taken place. Adjustments are made in the seasonal costing period definitions if the historic data warrant it.

Daily Costing Periods

The determination of off-peak and on-peak hours of the day relies upon an analysis of hourly load data. This type of analysis, when considering time-of-use rates, was found to be used by a majority of 42 electric utilities that were investigated in a 1977 survey.[4]

The initial step here is to decide whether to separate weekdays from weekends and holidays. Ebasco compares the average daily load levels of weekends and holidays to the peakload levels of weekdays in the same season. This is accomplished after a careful evaluation of historic load characteristics. The guide that Ebasco presents to determine the proper daily costing periods involves the ratio of maximum to minimum daily loads expressed as a percent of daily peakload for each costing period.[5] Based

---

[4]Task Force No. 4, Comments on Two Costing Approaches for Time-Differentiated Rates, prepared for the Electric Utility Rate Design Study (Palo Alto, Calif.: Electric Power Research Institute, March 8, 1977), pp. 84-87.

[5]Ebasco Services, Inc., op. cit., pp. 9-10.

on these comparisons, and also taking into account operating requirements such as scheduled weekend maintenance, Ebasco determines whether or not weekends and holidays should be included in the off-peak period.

Off-peak hours are defined in the Ebasco method as those periods during which the utility has some degree of certainty that the load can be satisfied by baseload units. Baseload units are defined as those units having the lowest operating costs that are capable of operating continuously for long periods of time.[6]

The process for developing daily off-peak hours is as follows:[7]

1. Determine and plot the monthly available baseload capacity. (Planned outage schedule, firm interchange arrangements, seasonal capacity factors, and allowances for forced outages should be accounted for.)
2. Determine and plot on the same graph the monthly system peak demands.
3. For the peak month in each season, compute the percentage of maximum peakload that can be supplied by the baseload capacity (i.e., the results from step 1 divided by the results of step 2).
4. For each season, plot the result of step 3 on a graph of the daily load curve normalized for weather conditions for the day of maximum seasonal demand.
5. The hours falling below the percentage of maximum peakload supplied by baseload capacity are considered as daily off-peak hours for each season. The system load during these hours represents the portion of seasonal peakload that can be supplied by baseload capacity.

---

[6]Task Forces and Edison Electric Institute, Glossary: Electric Utility Ratemaking and Load Management Terms, prepared for the Electric Utility Rate Design Study (Palo Alto, Calif.: Electric Power Research Institute, September 11, 1978), p. 7.

[7]Gordian Associates, Inc., op. cit., pp. 13-14.

The next step is to define the daily on-peak hours. Ebasco defines on-peak periods as those periods when system demand exceeds the system's secondary peak. Although this definition is intuitively appealing, Ebasco provides no specific reason for its selection.

Peak hours are identified through the use of a ratio comparing secondary season to primary season peak demands. The procedural steps are as follows:[8]

1. Determine the annual peakload (primary peak).
2. Determine the next highest load level that occurs in another season (secondary peak).
3. Compute the ratio of secondary peak to primary peak expressed as a percentage.
4. Plot this percentage on the graph of the normalized daily load curve for the day of maximum system peak.
5. Identify those hours where the system demand exceeds the secondary-peak to primary-peak ratio as the daily on-peak hours.

The hours that fall between the daily on-peak and off-peak periods represent daily intermediate hours for the peak season only; that is, there is no intermediate period determined for the off-peak season. Ebasco states that a daily intermediate period is not warranted in all cases, particularly where it would be of relatively short duration. Elimination of the intermediate period also serves to simplify rate design, lessen metering requirements, and enhance consumer understandability.

The NERA Method

NERA's objective in establishing costing periods is to recognize both the major differences in marginal costs over the load cycle and the practical limitations on the number of periods for which rates can be set. The NERA method relies on the probability of load exceeding available capacity to measure cost variations and to define costing periods. This

---

[8] Ibid., p. 13.

probability, or risk measure, is the hourly system loss of load probability (LOLP). The NERA method also uses variations in system load to define costing periods. This information is used in addition to the LOLP, or as a substitution for LOLP, when sufficient data are not available from the company being analyzed.

Underlying Theory

NERA's primary standard for developing costing periods is the presence of systematic time-related differences in the probability that load will exceed available capacity. Combined with this is the notion that "the expected marginal capacity costs and the marginal energy costs will vary with one another over the load cycle."[9] The NERA method relies on differences in marginal costs to select costing periods. This method, however, may be applied using average costs rather than marginal costs.

Data Requirements

Data needed for the selection of costing periods under the NERA method are as follows:[10]

1. Historical or forecast monthly peakloads.
2. Weather characteristics information.
3. Some hourly measure of marginal capacity cost responsibility for a forecast study period.
4. Typical daily load profiles (preferably forecast).

Procedures for the NERA Method

NERA segments its procedures into two steps, the selection of seasons and the selection of daily (diurnal) costing periods.

---

[9]National Economic Research Associates, Inc., How to Quantify Marginal Costs: Topic 4, prepared for the Electric Utility Rate Design Study (Palo Alto, Calif.: Electric Power Research Institute, March 10, 1977), p. 25.

[10]Gordian Associates, Inc., op. cit., p. 26.

Seasonal Selection

In the ideal situation, NERA believes that the selected periods should contain elements of relatively homogenous cost characteristics. However, it should be kept in mind that these periods and their associated costs must be comprehensible to the consumer.

It is implied by the NERA costing method that the use of LOLP for capacity cost allocation and for the selection of seasons is preferred. The use of LOLP to define seasons is tempered by the normal definition of seasons based on weather variation and other considerations such as consumer response impact.[11]

The steps for selecting seasonal periods are summarized as follows:[12]

1. Calculate the monthly risk measures or capacity cost allocation factors (e.g., LOLP), preferably over a forecast period.
2. Analyze the variations in risk levels across the months of the year.
3. Select seasonal costing periods based on variations in risk levels.

Daily Costing Periods

NERA recommends using the probability of load exceeding capacity to determine the hourly costing periods. However, if hourly risk measures are not available (e.g., hourly LOLP), historic system hourly loads may be used. Also, costing periods should be broadly defined in order to avoid peak chasing and customer confusion. Therefore, quantitative data are necessary for the establishment of the costing period foundations, but

---

[11]National Economic Research Associates, Inc., op. cit., p. 31.

[12]Gordian Associates, Inc., op. cit., pp. 26-27.

subjective decisions should determine the final selection. Subjectivity also plays a role in the selection of seasonal periods. For instance, NERA recommends that if one month of the winter season has lower costs than the other winter months, much confusion can be avoided if that month has the same charges as the other months in the season. In the four studies conducted by NERA, only two of the companies had available hourly system LOLP data and only for selected days. The selection of costing periods for those companies without LOLP data was based on variations in hourly system load data. In each of the four studies, only two daily costing periods were selected; peak and off-peak. The daily peak periods were broadly defined, ranging from 11 to 15 hours duration.

NERA does not provide specific guidelines for the selection of daily peak and off-peak periods nor for the treatment of those hours of the day where cost levels (or hourly system loads) may lie between the peak and off-peak periods. The final selection of daily costing periods is largely a judgmental determination of what NERA determines is feasible, based on considerations of consumer comprehension and rate stability.

The NERA method procedures for selecting daily costing periods are given below:[13]

1. Compute hourly LOLP levels for typical days of the year.
2. Plot daily load curves for typical days of the year.
3. Determine the hours of greatest risk (through analysis).
4. Select daily rating periods that are broad enough to avoid peak chasing and limited in number so that consumers can understand them.

In terms of documentation, the Gordian report points out that the theoretical basis of the NERA method is fairly well defined.[14] However, there is a lack of sufficient documentation in describing the process of costing period selection (i.e., how the theory is applied). Several

---

[13]Ibid., p. 32.

[14]Ibid., p. 35.

aspects of NERA's method require judgment. NERA does not always provide sufficient guidance concerning those judgmental factors to be considered or their relative importance within the analysis.

The information necessary to apply the NERA method as originally defined is often not available from utility companies. Obtaining the necessary information requires a production cost model that computes hourly system LOLP. The cost of obtaining this information, including the cost of developing or purchasing the model, can be significant.

The Ontario Hydro Method

Information on the Ontario Hydro method derived from the Gordian report is based on a study performed by Ontario Hydro and presented before the Ontario Energy Board. The method developed by Ontario Hydro is a preliminary approach to the selection of costing periods intended only to identify a possible alternative to proposed costing periods submitted to the Ontario Energy Board that were based on the NERA method.

The Ontario Hydro approach is related to marginal costs, although it is general enough to be used with embedded cost data. In selecting the costing periods, explicit specification of many constraints (i.e., limits on the number of daily or seasonal periods) is called for. The Ontario method requires the use of computer programming in the determination and ranking of the costing periods. Although judgment is required at certain steps, this method allows for sensitivity analysis and the development of separate costing periods based on varying levels of consumer understanding and adaptability to various rate classes.

Underlying Theory

Ontario Hydro states that its basic purpose for the application of time-of-use rates is to provide a closer relationship between production costs and demand value by establishing a correspondingly high-price structure when demand is high and a low-price structure when demand is low.[15]

---

[15]Ibid., pp. 41-45.

Ontario also states that TOU rates based on the selection of costing periods may be simplified by grouping periods of similar cost characteristics into a single costing period where a uniform price may be charged for all consumption within that period.

Ontario states that ideally its method would relate the choice of costing periods to those hours representing similar value to the consumer. Also, these same hours should represent similar costs, equal to the value placed on them by the consumer. However, such information is not available, and Ontario Hydro has to rely solely on cost variations as a determination of costing periods.

Ontario Hydro's overall objective in developing costing period selection is to minimize cost variances within periods while simultaneously maximizing cost variances among periods.

Data Requirements

Although Ontario Hydro utilizes a computer program for determining costing periods (based on marginal energy and capacity costs) for a chosen test period, data limitations necessitate that the test period be only 12 months in duration. Also, hourly loads were substituted for hourly marginal demand costs due to this data limitation.

Procedures for the Ontario Hydro Method

Ontario Hydro's sequence of steps for developing time-of-use costing periods, which are explained in further detail below, is as follows:[16]

1. Determine practical period formation restrictions.
2. Perform a quantitative cost analysis under existing conditions (select costing periods).
3. Formulate costing periods and rate structures.
4. Evaluate consumer response.

---

[16] Ibid., p. 43.

5. Determine effects on the generation system.
6. Evaluate changes in system costs and any effects on system constraints.
7. Perform a quantitative cost analysis under projected conditions.
8. Return to step 3 if pricing periods need to be reformulated due to results of steps 4 through 7--otherwise stop.

These steps are recommended given no data constraints. The actual study undertaken by Ontario does not go beyond step 3. Additional detail on the first 3 steps is presented below.

Determination of Costing Periods

Peak chasing, administrative ease and feasibility, consumer comprehension, stability in the rate structure, metering cost, and capability are all underlying restrictions that Ontario Hydro considered in the determination of practical costing periods. Ontario developed a set of seasonal, weekly, daily, and general restrictions that it believes are necessary to ensure that consumers understand the costing periods. These restrictions will be slightly different for each utility depending upon its specific load characteristics. These restrictions are listed below:[17]

Seasonal

1. A maximum of four seasons each composed of consecutive months.
2. A minimum duration of one month.
3. Each season starts at the beginning of a month.
4. January must be in one season and July in another.

Weekly

1. Each week within a particular season must be treated identically.
2. A maximum of three periods within the week.
3. At least Monday through Thursday must have hours in the peak period.

[17] Ibid., p. 45.

Daily

1. Each day with hours in the peak must be treated identically.
2. The daily peak period must have a minimum duration of two hours.
3. Only one peak period of consecutive hours per day is permissible.
4. The shoulder period does not have to be symmetrical.
5. The hours from 1:00 a.m. to 5:00 a.m. are grouped into a single period.

General

1. Holidays are disregarded.
2. Rating periods do not overlap.

Quantitative Cost Analysis

The object here is to have groupings of hours that are both homogeneous and unique in regard to production costs. Subject to the previously outlined constraints, alternative costing periods are developed using marginal energy and marginal demand costs as the relevant characteristics. Ontario states that depending upon the configuration of the generating system variations in capacity costs and energy costs may or may not be closely related. This is especially true for a system like Ontario Hydro's that has a significant amount of hydroelectric generation. Accordingly, two separate sets of costing periods are developed: one based on marginal energy costs, and one based on system load levels (the surrogate for marginal demand costs). These two sets of costing periods may then be combined to produce one set of costing periods that meet the restrictions outlined above.

The following procedures within the quantitative cost analysis are performed with the use of a computer program.[18] Specific documentation of the method of analysis employed within the computer program used by Ontario Hydro is not provided in the report.

---

[18]Ibid., pp. 46-49.

1. Determination of all possible seasonal subgroups satisfying the previously mentioned restrictions.
2. Calculation of the F-statistic for each seasonal subgroup.
3. Determination of all possible diurnal and weekly subgroups with the highest F-statistic.
4. Calculation of the F-statistic for each diurnal and weekly subperiod within a particular season so that those periods with the highest F-statistic may be chosen.
5. Calculation of the F-statistic for each permutation of best seasonal choice and best respective diurnal and weekly choices, using data for the entire year.

The F-statistic is a measure of the degree of variability of data within a data set (which in this case is a costing period) and between data sets (between costing periods). Ontario uses this statistic to test whether or not the degree of variability in system load or in marginal-running costs is greater among possible costing periods than it is within those costing periods. This statistical test is used to assure that the selection of costing periods accurately reflects variation in the cost of service.

The F-statistic is computed as the ratio of the variance between groups of data (costing periods) to the variance within groups of data.[19] Ontario Hydro does not claim that the ratio it computes for its costing methodology has an F-distribution. The use of the term F-statistic by Ontario Hydro is for descriptive purposes only because the number computed is identical in equation form to the F-statistic.

This statistical analysis is performed separately for marginal running costs and for hourly system load levels. The result of this process is a series of possible costing periods all of which satisfy the prescribed restrictions as outlined above. The next step in the Ontario method is the selection of the best set of costing periods from the series of possible costing periods.

---

[19]See: Gordian Associates, Inc., op. cit., appendix D.

Costing Period Formulation

This step considers factors other than those taken into account by the computer analyses. Because adequate statistical information is not available, this step becomes a qualitative attempt to select a set of costing periods that take into account the following considerations:[20]

1. Metering and administrative costs.
2. Likely rate structure effects on customer demand patterns.
3. Peak chasing possibilities.
4. Consumer response effects on the transmission and distribution system and the cost impacts of that response.

In this process of costing period formulation, Ontario Hydro acknowledges that informed judgment plays a significant role in the selection of costing periods; due largely to the nonquantifiable nature of much of the data needed for the analysis. The development of restrictions on the potential costing periods, is subjective and highly dependent upon the load characteristics of the individual utility. This process, however, represents a more precise specification of constraints on costing period selection than do the previous two methods.

The LILCO Method

This method was presented by LILCO in a generic rate design proceeding before the New York Public Service Commission. The method considers variations in marginal energy costs as well as the demand-related costs of generation, transmission, and distribution in selecting costing periods. Also, alternative costing periods can be provided for specific customer classes based on differing levels of consumer understanding.

Underlying Theory

LILCO believes that the creation of specific costing periods must be directly related to the existence of electric supply cost differences

---

[20]Ibid., pp. 49-50.

across hours, days, and months of the year[21] the allocation of costs to hours is inseparable from costing period formation, LILCO uses an approach that ties together both the relative likelihood of having "no excess" generating capacity available at each hour and the relative likelihood of each hour being one that approaches a peak period level for both the voltage level and the geographic area of service. Given this, five criteria are defined by LILCO for establishing costing periods. These criteria are listed below:[22]

1. Match costing periods with metering requirements.
2. Match costing periods with "standing" (capacity) kilowatt accountability.
3. Match costing periods with "running" (fuel) kilowatt-hour accountabilty.
4. Match costing periods with consumer understandability and acceptance.
5. Maintain consistency among costing periods.

The allocation of capacity costs to hours in the LILCO approach consists of two separate but related procedures. These are given below:

Procedure A: The determination of the relative likelihood of having no excess capacity at each hour.
Procedure B: The determination of the relative likelihood of each hour being an hour that approaches a peakload level.

Data Requirements

Data requirements for the two procedures are outlined below.[23]

---

[21]Richard W. Bossert, "Criterion for Defining Electricity Time-of-Use Rating Periods," Comments on Two Costing Aproaches for Time Differentiated Rates, prepared for the Electric Utility Rate Design STudy (Palo Alto, Calif.: Electric Power Research Institute, March 8, 1977), pp. 88-103.

[22]Gordian Associates, Inc., op. cit. p. 57.

[23]Ibid., pp. 60-62.

Procedure A:

1. Hourly system load data for a 12-month period.
2. Daily available system generation capabilities[24] for the same 12-month period including (a) a tabulation of the capabilities of all units operating during the day; (b) the capabilities of units off-line during the day that could have been brought on-line, if required; (c) the net megawatts of of firm capacity transmitted and received under interconnections

Procedure B:

1. Hourly system load data for a 12-month period.
2. A high- average megawatt (MW) system demand level (called the "MW delimiter"). This number is chosen as representative of an expected high-average demand during a peak period of the year.

The selection of the MW delimiter is largely a subjective process. The value chosen is intended to represent that level of system demand which represents an approaching peak condition on the system. LILCO computed the MW delimiter as the average of the peak demand levels experienced on its system during the peak season of the year.

Procedures for the LILCO Method

Both procedures A and B involve calculations based on a normal probability distribution; that is, it is assumed that the data used in these procedures (hourly system load data) follow a normal distribution. The next step in both procedures is to select a set of rational subgroups for the year, based on a common sense approach to subdividing the year for easy review. For the LILCO study, each month's weekdays were established as an individual subgroup. Saturdays and Sundays were grouped separately on a seasonal basis.

---

[24]Capability is defined as the actual generating capacity in MW available from a unit at a particular time. Due to prevailing conditions on the system at any particular time, available capacity (i.e.,

Procedure A

As an example of LILCO's procedure A, taken from the Gordian Associates report, data for the subgroup consisting of all weekdays in June 1975 are shown in table 2-1. The first column of the table shows the hours of the day from 1:00 a.m. to 12 midnight. The second column shows the average system demand in megawatts for each hour for all weekdays in June. Column 3 labeled "Demand Sigma" shows the standard deviation of the individual demand levels around the computed "Demand Average" for each hour listed in Column 2.

The 4th column shows the "Excess Capability Average" for each hour that is defined as the difference between the daily system capability and the demand level at each hour. Column 5, labeled "Excess Capability Sigma," is the standard deviation of the excess capability for each hour across all weekdays in June (i.e., it is a measure of the variability of available excess capacity during each hour of the weekdays in June). The data in columns 4 and 5 are used to compute the probability of excess capability being less than or equal to zero, expressed as a percent and labeled "Probability of No Excess" in column 6. The Gordian Associates report does not explain how this computation is performed. This number for each hour is multiplied by a correction factor to account for the varying number of weekdays in each subgroup (e.g., the number of weekdays in June relative to the number of weekdays in the other subgroups) in order to derive the "Frequency Adjusted Probability" as shown in column 7.

Column 8 in table 2-1, labeled "Relative Weightings," is derived by summing the hourly frequency adjusted probabilities in column 7 across all subgroups for the year and dividing each hourly frequency adjusted probability by that sum. It is these "Relative Weightings" that are used to assign cost responsibility for generating plant costs to each hour. This is accomplished by multiplying total system generating plant costs by the relative weightings for each hour for weekdays in each month as listed in column 8. Thus, the hours from 1:00 a.m. to 10:00 a.m. for weekdays in

---

capability) from any generating unit may vary significantly from the unit's rated or maximum capacity.

TABLE 2-1

SAMPLE PROBABILITIES OF DEMAND EXCEEDING
AVAILABLE CAPABILITY FOR LILCO
FOR WEEKDAYS, JUNE 1975

HOUR	DEMAND AVERAGE (MW)	DEMAND SIGMA (MW)	EXCESS CAPABILITY AVERAGE (MW)	EXCESS CAPABILITY SIGMA (MW)	PROBABILITY OF NO EXCESS (%)	FREQUENCY ADJUSTED PROBABILITY (%)	RELATIVE WEIGHTINGS (%)
100	1198.9	167.5	1487.8	179.9	0.0	0.0	0.0
200	1077.6	148.5	1609.1	170.9	0.0	0.0	0.0
300	1005.5	134.9	1681.2	166.8	0.0	0.0	0.0
400	974.4	122.5	1712.3	162.8	0.0	0.0	0.0
500	959.1	114.7	1727.6	160.7	0.0	0.0	0.0
600	956.1	101.2	1730.6	158.2	0.0	0.0	0.0
700	1055.0	90.7	1631.7	157.6	0.0	0.0	0.0
800	1316.5	87.5	1370.2	163.1	0.0	0.0	0.0
900	1574.0	116.7	1112.7	173.4	0.0	0.0	0.0
1000	1767.8	161.8	918.9	189.8	0.0	0.0	0.0
1100	1883.9	186.4	802.8	204.2	0.0000	0.0000	0.03
1200	1941.3	214.6	745.4	222.0	0.0004	0.0004	0.31
1300	1948.2	235.5	738.5	235.4	0.0004	0.0008	0.68
1400	1969.0	249.8	717.7	248.6	0.0019	0.0019	1.55
1500	1982.6	262.3	704.1	257.2	0.0031	0.0030	2.47
1600	2003.0	266.9	683.7	262.6	0.0046	0.0045	3.68
1700	2013.6	261.8	673.1	261.0	0.0050	0.0048	3.96
1800	2009.0	251.5	677.7	254.7	0.0039	0.0038	3.12
1900	1934.9	231.8	751.9	236.9	0.0008	0.0007	0.60
2000	1851.2	212.4	835.5	218.7	0.0001	0.0001	0.05
2100	1878.0	180.6	808.7	199.9	0.0	0.0	0.0
2200	1866.3	183.2	820.4	208.8	0.0000	0.0000	0.03
2300	1683.0	186.3	1003.8	211.3	0.0	0.0	0.0
2400	1435.6	172.9	1251.1	197.9	0.0	0.0	0.0

Source: Gordian Associates, Inc., A Review and Evaluation of Methods for Selecting Rating Periods, prepared for the Electric Utility Rate Design Study (Palo Alto, Calif.: Electric Power Research Institute, February 8, 1980), table 6

June would have zero generating plant cost responsibility. The hours of 11:00 a.m. for weekdays in June would be assigned 0.03 percent of total generating plant costs, and so on.

Procedure B

Table 2-2 shows an example of LILCO's procedure B.[25] A MW delimiter was selected by LILCO that corresponds approximately to the average of system peak demands experienced by LILCO during the peak months of the year. The selection of a MW delimiter is critical to the analysis. Too large or too small a number will yield results that are not useful for developing time-differentiated costs. The precise specification of the MW delimiter is largely a function of judgment. It should represent a high-average system load during the peak months, not the system peakload itself. LILCO does not explain the factors entering into the selection of the MW delimiter other than to state that it should represent an approaching peak condition on the system.

Column 1 of table 2-2 shows the hours of the day from 1:00 a.m. to 12 midnight. Column 2 shows the average system demand for each hour for all weekdays in June. Column 3 shows the standard deviation of the individual hourly demand levels around the computed "Average" listed in column 2. Data in columns 2 and 3, together with the preselected MW delimiter, are used to calculate the probability of system demand in each hour exceeding the level of the MW delimiter. These probabilities called "Excess Probability" are listed in column 4. As before, the Gordian Associates report does not explain how this calculation is performed. These probabilities are then multiplied by an adjustment factor to account for the differing number of days in each subgroup. They are listed as "Frequency Adjusted Probability" in column 5.

"Relative Weightings" are then computed in the same manner as in table 2-1, that is, the hourly frequency adjusted probabilities in column 5 of table 2-2 are summed across all subgroups of the year, and each hourly

---

[25]Ibid., pp. 64-65.

TABLE 2-2

SAMPLE PROBABILITIES OF SYSTEM LOAD APPROACHING A PEAK LEVEL FOR LILCO FOR WEEKDAYS, JUNE 1976

(1) HOUR	(2) AVERAGE (MW)	(3) STANDARD DEVIATION (MW)	(4) EXCESS PROBABILITY (%)	(5) FREQUENCY ADJUSTED PROBABILITY (%)	(6) RELATIVE WEIGHTINGS (%)
100	1277.1	129.1	0.0	0.0	0.0
200	1142.8	112.8	0.0	0.0	0.0
300	1071.3	102.7	0.0	0.0	0.0
400	1037.9	93.7	0.0	0.0	0.0
500	1023.3	87.5	0.0	0.0	0.0
600	1023.8	82.9	0.0	0.0	0.0
700	1127.9	84.8	0.0	0.0	0.0
800	1403.2	13.8	0.0	0.0	0.0
900	1683.3	148.5	0.0001	0.0001	0.00
1000	1891.3	183.8	0.0255	0.0258	0.10
1100	2007.2	195.5	0.1071	0.1084	0.42
1200	2064.0	215.9	0.1945	0.1968	0.76
1300	2067.9	224.2	0.2083	0.2108	0.81
1400	2082.3	234.2	0.2369	0.2398	0.93
1500	2088.3	243.0	2.2528	0.2558	0.99
1600	2096.9	252.6	0.2722	0.2754	1.06
1700	2111.8	247.0	0.2880	0.2914	1.13
1800	2117.1	237.5	0.2879	0.2914	1.13
1900	2030.3	225.3	0.1648	0.1667	0.64
2000	1952.7	211.1	0.0795	0.0804	0.31
2100	2003.4	195.5	0.1036	0.1048	0.41
2200	2003.6	198.4	0.1072	0.1084	0.42
2300	1794.9	173.5	0.0044	0.0044	0.02
2400	1525.3	149.0	0.0	0.0	0.0

Source: Gordian Associates, Inc., A Review and Evaluation of Methods for Selecting Rating Periods, prepared for the Electric Utility Rate Design Study (Palo Alto, Calif.: Electric Power Research Institute, February 8, 1980), table 7 frequency adjusted probability is divided by that sum. These relative weightings as shown in column 6 are used to assign hourly cost responsibilities for transmission capacity-related costs and distribution capacity-related costs in the same manner as generating plant costs were assigned in table 2-1.

Matching Costing Periods with Running Costs

Before rating periods are selected, LILCO states that marginal running costs (fuel and variable operation and maintenance expenses) must be determined for the test year. Because of the need to group these costs into potential costing periods, an attempt is made to determine those periods where running cost variations within potential costing periods are less than variations among potential costing periods.[26] Hourly marginal-running costs are determined by LILCO for the 12-month period, using a system cost simulation model. Weighted average hourly marginal running costs are then computed for those groups of hours (costing periods) that represent similar hourly marginal running costs. These potential costing periods are then combined with those determined by the "standing" cost accountability criteria (procedure A) in order to accomplish the selection of the final costing periods. These periods are used to assign hourly cost responsibility for generation plant. The costing periods defined through procedure B are used to assign hourly cost responsibility for transmission and distribution demand-related plant.

LILCO states that the final selection of costing periods under procedures A and B is a subjective process based on the five selection criteria as outlined above.[27] LILCO decided at the beginning of its analysis that three costing periods (on-peak, off-peak, and intermediate) would provide sufficient differentiation of customer cost responsibility, satisfy the metering constraint, and be comprehensible to customers. The results of methods A and B and of the hourly marginal running cost analysis

---

[26]Richard W. Bossert, op. cit., p. 99.

[27]Gordian Associates, Inc., op. cit., p. 67.

were analyzed in terms of their relative levels across the 24-hour daily cycle and across the various subgroups of the year. Periods with relatively low capacity cost responsibility and relatively low-running cost responsibility were defined as off-peak. Periods with relatively high-cost responsibility were grouped as on-peak. All other times were defined as intermediate. In addition, past experience and company forecasts indicated an increasing likelihood of Saturdays during June through September having a peak potential. Thus, the company concluded that the on-peak period should be expanded to include Saturdays.

LILCO states that costing periods should be understandable so that customers have an opportunity to respond. LILCO also recommends that costing periods be broadly, rather than narrowly, defined because (1) narrow periods are less stable in their relative costs, and (2) broadly defined periods, in the long run, are more likely to give correct relative price signals.

Several sets of costing periods may be established through the LILCO method according to the load curves of individual customer classes. These sets of costing periods may be offered simultaneously within and between customer classes to improve diversity, especially in costing period "fringe" hours where system load shifting may otherwise occur.

The rating periods in the LILCO study are summarized as follows:

ON-PEAK:	10:00 a.m.-10:00 p.m., Monday-Saturday, June-September
OFF-PEAK:	Midnight-7:00 a.m., all days, year-round
INTERMEDIATE:	All remaining times 7:00 a.m.-10:00 a.m., 10:00 p.m.-midnight, Monday-Saturday June-September

7:00 a.m.-midnight, Monday-Saturday, October-May
7:00 a.m.-midnight, Sundays, year-round.

Costing Period Selection: An Overview

All of the methods for selecting costing periods for time-of-use rates outlined in this chapter state that the selection of costing periods should be related to, and accurately reflect, underlying differences in costs of service. The reflection of actual costs of service, however, should be tempered by the additional criteria that practical ratemakers need to take into consideration. These criteria include metering and administrative costs, customer acceptance and understandability, customer response to price differentials, and pricing and revenue stability. These criteria necessarily introduce judgment into the costing process.

The four methods of selecting costing periods use various devices to measure the costs of service during peak and off-peak hours. The Ebasco method analyzes daily and seasonal system load curves as a surrogate for costs of service in conjunction with information on available generating capacity and firm interchange power to derive costing periods. The NERA method relies on variations in hourly loss-of-load probability as a measure of capacity-related costs of service. However, since hourly LOLP data are seldom available, NERA relies on hourly system load data as a substitute. The NERA method apparently does not consider generating capacity availability in its selection of costing periods. Neither NERA nor Ebasco considers variations in marginal running costs.

The Ontario Hydro method computes two distinct sets of costing periods. One is based on variations in marginal energy costs and another on variations in marginal capacity costs by using hourly system load data as a substitute. The resulting sets of costing periods from these two analyses are then combined to produce one comprehensive set of periods on both a seasonal and daily basis.

The LILCO method selects costing periods based on three measures of system costs of service. First, it determines the probability of having no excess generating capacity based on variations in generating costs and available generating capacity. But again, since data on hourly generating costs are generally not available, this procedure relies on variations in system load. The second procedure determines the probability that each hour during the year will approach a peak demand level. This analysis also relies on system load data and the selection of a MW delimiter. This procedure is used to allocate transmission and distribution-related costs to the periods.

The third measure of system costs of service relies on hourly marginal running (variable) costs to compute possible costing periods. The results of this analysis are combined with those of the first procedure to derive costing periods for the allocation of generation capacity-related and energy-related costs.

The above discussion points out that all of the four methods of selecting costing periods rely on variations in system load as a substitute for variations in generating capacity costs. All four methods also use a considerable amount of judgment in the final determination of costing periods in order to take account of various nonquantifiable costing criteria. The Ontario Hydro and LILCO methods use statistical analysis to assure that the variation in costs between potential costing periods is greater than the variation within these periods. However, where nonquantifiable criteria such as revenue stability and customer understandability and acceptability are taken into consideration, it is uncertain that these statistical methods produce results that are more reliable than those of the Ebasco or NERA methods that rely less on statistical measures.

The Ontario Hydro method also states specifically the practical restrictions it considers in the selection of costing periods. Although this procedure does not eliminate the use of judgment within the analysis, it does provide a basis upon which to judge the final selection of costing periods.

Several of the methods take into consideration available generating capacity in determining costing periods, although it is never specified exactly how this factor is considered within the analysis. Also, several of the methods consider variations in marginal-running costs in addition to system load characteristics in selecting costing periods. Because variation in marginal-running costs generally follow variations in system load, and since costing periods are usually defined broadly to avoid peak chasing and to provide revenue and rate tariff stability, the analysis of variations in marginal-running costs, may be an appropriate mechanism to test the accuracy of costing period selection based on variations in hourly system load data. An added benefit is that hourly marginal-running cost data is generally available to commissions.

The LILCO method is the only one of the four that considers transmission and distribution capacity-related costs of service. These are allocated to costing periods on the basis of system load reaching a peak condition. The LILCO method does not specify why this procedure is an appropriate way to assign these costs to selected costing periods.

The Ontario Hydro and LILCO methods rely on computer programs to measure the variability of costs or system load within and between sets of possible costing periods. This reliance may present a problem to those commissions which do not presently have the necessary computer equipment or expertise to perform the analysis. Also, as noted above, at the conclusion of the statistical analysis, both of these methods rely on various judgmental factors for the final selection of costing periods. Since the use of nonquantifiable criteria is a necessary part of the costing process, much of the gain in precision achieved through the computer analysis may be lost once these criteria are taken into account.

CHAPTER 3

SELECTING COSTING PERIODS USING THE LOAD FREQUENCY AND DURATION (FRED) DATA ANALYSIS PROGRAM

Although system load data may be analyzed for the purpose of establishing costing periods for time-of-use rates without the use of a computer program, the NRRI has developed a program for this purpose that is both easy and inexpensive to operate. This computer program analyzes hourly system load data to compute hourly average load curves and hourly peakload curves.[1] These curves, in combination with other costing criteria, may be used to derive seasonal and daily costing periods for use as a basis for TOU rates.

This program, known as the Load Frequency and Duration Data Analysis Program, or FRED, may be used with either a marginal or average costing methodology. By specifying certain restrictions on the selection of costing periods similar to those used in the Ontario Hydro method that take into account the nonquantifiable criteria of utility ratemaking, a commission may use the output from FRED in conjunction with these restrictions to derive costing periods. This combination has the benefit of simplicity of computation and explicit statement of those nonquantifiable but practical restrictions placed upon the selection of costing periods. If deemed necessary, the results of this process may be checked for accuracy by analyzing system hourly marginal-running costs and comparing the costing periods derived from this analysis with those produced using FRED. This additional step would help assure that those costing periods selected accurately reflect actual differences in costs of service.

An example of this proposed method follows after a description of the operation and output of the FRED program.

---

[1] S. Nakamura, et al., Electric Utility Analysis Package (Columbus, Ohio: The National Regulatory Research Institute, October 1977), chap. 2.

Description of the FRED Program

The FRED program was developed by the NRRI at The Ohio State University (OSU) to calculate and plot the load frequency, load duration, and load probability curves of an electric utility system for specified periods of time. FRED also computes hourly average load curves and hourly peakload curves for use in selecting daily costing periods. The hourly system load data in the Edison Electric Institute (EEI) format is the basic source of data input. The FRED code provides the means of analyzing the characteristics of the electric load and also provides inputs for other computer programs that were developed at The Ohio State University and available at the NRRI for further analysis of electric utility operating characteristics.[2] The FRED program is placed in disk storage for use at the time-sharing option (TSO) terminals at the Ohio State computer facilities or can be used at a commission's own computer facilities.

The input to the FRED code consists of daily hourly load data in megawatt-hours for a 12-month period. These data are stored in disk memory by company and year. The names of the hourly load data sets stored in the disk space are printed during the execution of the program. The user of the code has the option of using data from one hour of any day to data for the full year. The load frequency and load duration curves are calculated by arranging the data in order of load magnitude, that is, the data are ordered from the lowest hourly usage to the peak hourly usage, regardless of the time of day when the usage occurred.

The load frequency curves show megawatt-hours on the x-axis, ranging from just below the minimum hourly load to just above the peak hourly usage. On the y-axis, the number of hours for which the system load was greater than or equal to the x-axis load value but less than the next x-axis load value is given. The load duration curve shows on the x-axis

---

[2]These computer programs are the MARC-3a, MARC-3B, WASP and LOAD CONTROL programs. For a discussion of these programs and their uses, see S. Nakamura, et al., op. cit., chaps. 3 and 4.

the number of hours during which the system load exceeded the load value on the y-axis.

The load probability curve displays megawatts of system load on the x-axis and the probability of meeting or exceeding that load on the y-axis. Since the loads are ordered from the lowest hourly usage for a particular period (baseload) to the highest (peakload), the probabilities range from one to nearly zero. For ease of printing, the load probability curve is shifted so that the loads increase and the probabilities decrease from the top to the bottom of the page.

The FRED code can be used to calculate and display the following:

1. For the given period, determine the peak system demand and the month, day, and hour it occurred, the load factor for the period, and the megawatt-hours generated for the period.
2. List the hourly load data for a given period.
3. Calculate and plot the load frequency curve for a given period.
4. Calculate and plot the load duration curve for a given period.
5. Calculate and plot the load probability curve for a given period.
6. Calculate, list, and plot the average hourly load for each day of the week for a given period.
7. Calculate, list, and plot the peak hourly load for each day of the week for a given period.

The user has the option of selecting any combination of outputs 2 through 7; output 1 is always given.

In specifying the period for analysis, the user has several options. These are listed below:

1. Specify the starting month and day of the period and the ending month and day (these are inclusive days).
2. Within that period, specify the days of the week to be included in the calculations.

3. Specify the range of hours within each day to be used in the calculations (these are inclusive hours).
4. Specify a range of hours within those hours specified in item 3 not to be included in the calculations (these are exclusive hours).

For example, using these four options, the user could choose to analyze hourly load data for the period May 15 through August 10, for weekdays only (excluding holidays), for the hours starting at 10:00 a.m. and ending at 7:00 p.m., excluding the hours of 12 noon and 1:00 p.m.

In summary, the many options for selecting output and specifying the periods for analysis give FRED much versatility.

Example Procedure for Selecting Costing Periods Using FRED

The remainder of this chapter contains an example procedure for the selection of seasonal and daily costing periods for an electric utility using the FRED computer program. The data analyzed by the FRED program consist of hourly system load data (in megawatt-hours) supplied by the Public Service Company of Colorado for the 12-month period, June 1979 through May 1980. This example procedure is intended to illustrate how a comprehensive set of costing periods may be derived for an electric utility based on an analysis of hourly system load data in conjunction with a set of practical restrictions or criteria designed to take into consideration those nonquantifiable aspects of utility rate setting.

A set of criteria or restrictions for the selection of costing periods, similar to those outlined in the Ontario Hydro method, may be selected by the Colorado commission staff. These restrictions are intended to reflect the actual load characteristics of the particular utility, and while based largely on judgment, reflect the analyst's knowledge of the company and its service territory. These restrictions are intended to aid in the selection of a set of costing periods that adequately reflect variations in costs of service while at the same time are understandable and equitable to customers and produce rate stability and revenue stability for the company.

The selection of costing period criteria is not a part of the FRED program itself but rather allows the analyst to establish a framework within which he may analyze company load data. These criteria apply to both seasonal and daily costing period selection and might include the following:

Seasonal Restrictions

1. A maximum of two seasons each composed of consecutive months.
2. A minimum duration of four months.
3. Each season starts at the beginning of a month.
4. The summer peak day must be in one period and the winter peak day in the other.

Weekly Restrictions

1. Each week within a particular season must be treated identically.
2. A maximum of three periods within the week (peak, off-peak and shoulder).
3. Weekends and holidays are considered to be off-peak.

Daily Restrictions

1. Each weekday must be treated identically.
2. The daily peak period must have a minimum duration of four hours.
3. Only one daily peak period of consecutive hours is permissible.
4. Costing periods may not overlap.

The selected restrictions should reflect a common sense approach to the task of establishing costing periods. These restrictions should be decided upon at the outset of the analysis but may be changed during the course of the analysis if it is found that they do not adequately reflect the load characteristics of the company.

For example, the first seasonal restriction listed above states that there may be only two seasonal costing periods, each composed of consecutive months. These criteria may have been selected because the analyst feels that a seasonal peak and off-peak period adequately reflects the differences in costs of service of the company and that additional seasonal periods would only serve to confuse ratepayers. However, upon examination of the utility's annual load curve, the analyst may discover a pronounced peak, off-peak, and intermediate load pattern. The analyst, then, may alter the seasonal restricts and include one or more intermediate seasonal costing periods in the analysis if it is felt that the revised restrictions more accurately reflect actual service territory characteristics without causing undue harm to customer acceptance and understandability.

The remaining restrictions outlined above also reflect an attempt to balance the various goals of rate setting. For example, the requirement that each season start at the beginning of a month reflects the fact that most customers are billed on a monthly basis and would receive mixed price signals if rates were altered in the middle of a billing period. The requirement that each week and weekday in a period be treated identically is intended to avoid customer confusion at the risk of sacrificing some accuracy in reflecting costs of service since daily load patterns often vary over the course of the week. The minimum duration restrictions on seasonal and daily costing periods are designed to provide customers with enough time to react to the price variation between periods and at the same time define the periods broadly enough to avoid peak chasing and revenue instability.

Selection of Seasonal and Daily Costing Periods

The FRED program can be used to calculate and display the system peak demand, the day and hour at which it occurred, and the total megawatt-hours generated for a particular period. If these data are calculated on a monthly basis, they can be used to select the seasonal costing periods in conjunction with the seasonal restrictions outlined above.

Once the seasonal costing periods are selected, FRED can be used to calculate, list, and plot the average and peak hourly load for each day of the week for the two seasonal periods. From these data and curves, the daily peak and off-peak hours can be determined as explained below. This selection of daily costing periods would also take into consideration those practical restrictions outlined by the commission staff.

Table 3-1 shows sample output data derived from the FRED computer program for the Public Service Company of Colorado (PSCO) for the 12-month period, June 1979 through May 1980. Input data for the FRED program, from which these sample output data were derived, consist of hourly system load data for the 12-month period supplied by PSCO. Table 3-1 lists for each month in the period being analyzed the system peakload in megawatts, the day and hour of the month when the system peak occurred, the monthly system load factor, and the total megawatt-hour (MWh) sales for each month.

These data show that PSCO experienced its maximum annual peakload of 2,755 MW on August 6, 1979. According to the restrictions outlined above, this summer peak must be included in one of the selected seasonal costing periods. The data in table 3-1 also indicate that PSCO experienced its secondary or winter period system peakload of 2,675 MW on January 28, 1980. Again according to the costing period restrictions, this secondary peak must be included in a second seasonal costing period.

Figure 3-1 is a plot of the monthly system peakloads listed in table 3-1. This figure demonstrates that for the 12-month period under analysis PSCO's monthly system load increased from June through August 1979, at which time it reached its maximum, and then declined through September and October 1979 before again increasing to a secondary peak level in January 1980, after which it again declined through the remainder of the period.

Based on this annual system load curve and the seasonal restrictions outlined above, two seasonal costing periods were selected for PSCO. The

TABLE 3-1

SAMPLE OUTPUT DATA FROM THE FRED COMPUTER PROGRAM FOR PUBLIC SERVICE COMPANY OF COLORADO FOR THE 12-MONTH PERIOD, JUNE 1979 THROUGH MAY 1980

Month	System PeakLoad (MW)	Day and Hour of Occurrence	Monthly System Load Factor (%)	Total Megawatt-Hour Sales
June 1979	2,588	June 28: 4:00 p.m.	72.0%	1,341,324
July 1979	2,678	July 13: 4:00 p.m.	74.2	1,478,564
August 1979	2,755*	Aug. 6: 5:00 p.m.	70.2	1,438,667
September 1979	2,529	Sept. 10: 2:00 p.m.	72.1	1,313,057
October 1979	2,499	Oct. 29: 6:00 p.m.	72.4	1,345,550
November 1979	2,562	Nov. 26: 6:00 p.m.	76.2	1,406,100
December 1979	2,618	Dec. 11: 7:00 p.m.	74.1	1,442,606
January 1980	2,675**	Jan. 28: 7:00 p.m.	75.6	1,505,251
February 1980	2,552	Feb. 7: 7:00 p.m.	77.5	1,376,521
March 1980	2,469	Mar. 3: 7:00 p.m.	78.2	1,436,896
April 1980	2,372	April 1: 8:00 p.m.	77.2	1,318,089
May 1980	2,244	May 22: 3:00 p.m.	77.4	1,291,525

* System annual peakload (summer period).
** System secondary (winter period) peakload.

Source: System hourly load data provided by company and FRED computer program

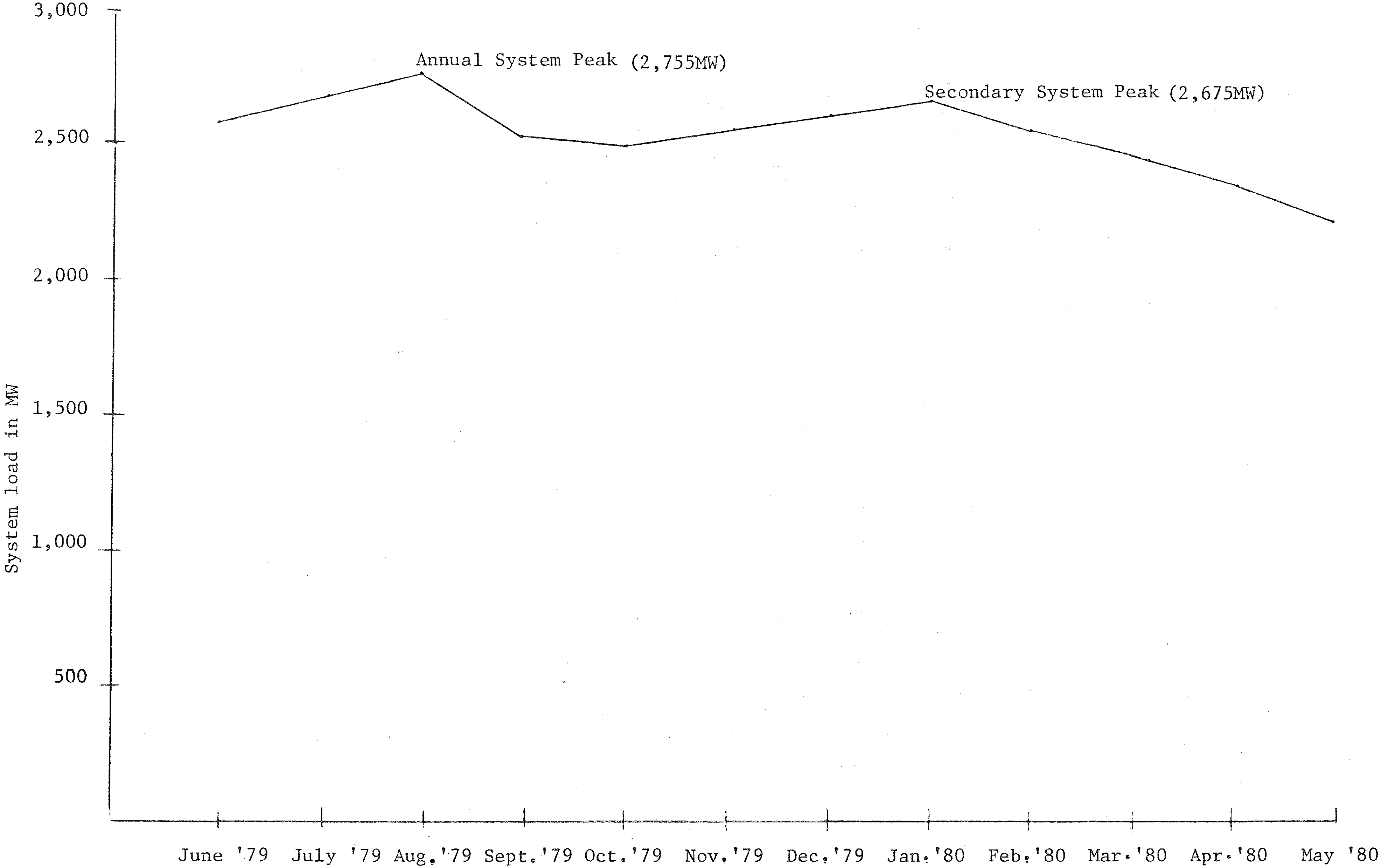


Figure 3-1 Monthly system peakloads for Public Service Company of Colorado for the period June 1979 through May 1980

Source: System hourly load data supplied by the company and the FRED computer program seasonal restrictions require that the months of the annual system peak and the secondary system peak each be in separate seasonal costing periods. The months of October and November appear to represent a transition between the summer (peak) and winter (off-peak) seasons, since system load reaches a minimum here and then rises again for several successive months. The same is true for the months of May and June. On this basis, a peak season costing period consisting of the months of June through October and an off-peak season period consisting of the months November through May were selected for PSCO. Sample logon and execute operations for FRED, using a TSO computer terminal, and sample output data for several months in the annual period from which the data in table 3-1 and figure 3-1 were derived are contained in appendix A.

With the seasonal costing periods selected, the next step is to select the daily costing periods within each season. The FRED program is used to print and plot the hourly average load data and hourly peakload data for each day of the week for the months in which the system annual peak and the system secondary peak occurred. FRED prints and plots separately the data for each day of the week, Monday through Sunday. FRED also provides separately the hourly load data for holidays, for all weekdays, and for all weekend days. Sample logon and execute procedures using a TSO computer terminal and sample output data for PSCO for August 1979 (the month of the system annual peak) and for January 1980 (the month of the system secondary peak) are provided in appendix B. From these data, the daily costing periods for each seasonal costing period may be derived.

Before using these data to select daily costing periods, a system peak condition load level must be defined. The system peak condition load level is essentially the same concept as the MW delimiter used in the LILCO method discussed earlier. It is not the actual annual system peakload but an estimate of that level of system load that represents a peakload condition being approached on the system.

The selection of a system peak condition load level is largely a matter of judgment. It should represent that level of system load which accurately describes an approaching peakload condition. This load level may be estimated through various methods such as an average of system peaks experienced by the company during the peak months, the system load level reached when the next-to-last peaking unit is placed on-line, the system load level reached when power purchased from another system is necessary to supply additional system load, the load level reached when the revenue derived from additional peak period sales is less than the cost of additional generation, or some other rule of thumb such as when the system load is 90 percent of the annual system peak.

For the purpose of this example, the system peak condition load level was selected as that load level representing 90 percent of the annual system peak. The annual system peak for the 12-month period being analyzed is 2,755 MW. Therefore, the system peak condition load level is 2,480 MW. In selecting the daily costing periods, all hours of the day when the system load is 2,480 MW or greater are defined as peak hours.

In reviewing the hourly system load data, the analyst should be conscious of those hours during the day when the system load data demonstrate a rapid build up or drop-off of system load. These hours represent a natural transition among peak, off-peak, and shoulder costing periods. When selecting daily costing periods, the peak condition load level selected for use in the analysis should correspond fairly consistently with the actual build up and drop-off of load experienced on the system. That is, if the hourly load data indicate that a rapid increase in system load occurred between the hours of 9:00 a.m. and 10:00 a.m., but the selected peak condition load level indicates that a peak condition was reached at 8:00 a.m., a review of the method used to select the peak condition load level may be necessary. That is, these natural transitions among system load levels should be taken into account when selecting the MW delimiter.

A review of the daily load curves for August 1979 contained in appendix B in combination with the selected peak condition load level produces a set of daily peakhours and off-peak hours as listed in table 3-2. That is, those hours of the day when the peak system load is 2,480 MW or greater are selected as peakhours. All other hours of the day are considered as off-peak hours.

TABLE 3-2

PEAK SEASON DAILY PEAKLOAD AND DAILY PEAK AND OFF-PEAK HOURS
FOR PUBLIC SERVICE COMPANY OF COLORADO BASED ON
HOURLY SYSTEM LOAD DATA FOR AUGUST 1979

Day of Week	Peakload (MW)	Time of Occurrence	Daily Peak Hours	Daily Off-Peak Hours
Mondays	2,755	5:00 p.m.	11:00 a.m. to 9:00 p.m.	9:00 p.m. to 11:00 a.m.
Tuesdays	2,752	4:00 p.m.	11:00 a.m. to 9:00 p.m.	9:00 p.m. to 11:00 a.m.
Wednesdays	2,744	4:00 p.m.	10:00 a.m. to 6:00 p.m.	6:00 p.m. to 10:00 a.m.
Thursdays	2,548	3:00 p.m.	12:00 p.m. to 6:00 p.m.	6:00 p.m. to 12:00 p.m.
Fridays	2,615	3:00 p.m.	11:00 a.m. to 6:00 p.m.	6:00 p.m. to 11:00 a.m.
Saturdays	2,308	2:00 p.m.	None	All Day
Sundays	2,203	6:00 p.m.	None	All Day
All Weekdays	2,755	5:00 p.m.	10:00 a.m. to 9:00 p.m.	9:00 p.m. to 10:00 a.m.

Source: Hourly system load data supplied by PSCO and FRED computer program

A review of the daily load curves for weekdays in August 1979 shows that the system load increases rapidly between the hours of 10:00 a.m. and 12 noon, remains at a peak condition level during the afternoon, and drops off rapidly in the evening between 6:00 p.m. and 9:00 p.m. to a less than peak condition level. These transition hours also correspond rather consistently with the selected peak condition load level. That is, a rapid buildup and drop-off of system load occurs at about the 2,480 MW level.

The load curves for weekend days also indicate a rather consistent load pattern. However, the peakload for these days does not reach a peak condition level. Therefore, all hours of the day on Saturdays and Sundays are considered to be off-peak.

A review of the daily load curves for January 1980, the month of PSCO's secondary (or winter) peak, reveals a less consistent load pattern than that for August. For Mondays during January, the system load builds to a peak condition at 10:00 a.m., remains at that level until 11:00 a.m., and then drops off to a level just below a peak condition for the afternoon before again increasing to a peak condition level between 5:00 p.m. and 9:00 p.m.

For the remaining January weekdays, the system peak load builds up rapidly in the morning to a point just below a peak condition level, remains at that level or drops off slightly during the afternoon, and then rises in the evening to a peak condition level for a short time before dropping off to a lower level. Table 3-3 shows the daily peakload for all weekdays, weekend days, and holidays in January 1980, the table also shows the time of occurrence of the peakload and the daily peak and off-peak hours determined by using the selected peak condition load level in combination with a review of the daily load curves. Since the hourly system load during Saturdays, Sundays, and holidays never reaches a peak condition, these days are considered to be off-peak.

Recall that the costing period restrictions established for daily costing periods require that all weekdays be treated identically, that a

TABLE 3-3

OFF-PEAK SEASON DAILY PEAKLOAD AND DAILY PEAK AND OFF-PEAK HOURS FOR PUBLIC SERVICE COMPANY OF COLORADO BASED ON HOURLY SYSTEM LOAD DATA FOR JANUARY 1980

Day of Week	Peakload (MW)	Time of Occurrence	Daily Peak Hours	Daily Off-Peak Hours
Mondays	2,675	7:00 p.m.	10:00 a.m. to 11:00 a.m. and 5:00 p.m. to 9:00 p.m.	9:00 p.m. to 10:00 a.m. and 11:00 a.m. to 5:00 p.m.
Tuesdays	2,610	7:00 p.m.	6:00 p.m. to 8:00 p.m.	8:00 p.m. to 6:00 p.m.
Wednesdays	2,548	7:00 p.m.	6:00 p.m. to 8:00 p.m.	8:00 p.m. to 6:00 a.m.
Thursdays	2,534	6:00 p.m.	6:00 p.m. to 7:00 p.m.	7:00 p.m. to 6:00 p.m.
Fridays	2,489	7:00 p.m.	6:00 p.m. to 7:00 p.m.	7:00 p.m. to 6:00 p.m.
Saturdays	2,422	7:00 p.m.	None	All Day
Sundays	2,362	6:00 p.m.	None	All Day
Holidays	2,039	8:00 p.m.	None	All Day
All Weekdays	2,675	7:00 p.m.	10:00 a.m. to 12:00 p.m. and 5:00 p.m. to 9:00 p.m.	9:00 p.m. to 10:00 a.m. and 12:00 p.m. to 5:00 p.m.

Source: Hourly system load data supplied by PSCO and FRED computer program minimum daily peak period of four hours be established, and that only one daily peak period of consecutive hours be established. On the basis of these criteria and the data contained in tables 3-2 and 3-3, sample daily costing periods for all days in the peak (summer) and off-peak (winter) seasons were selected. These sample daily costing periods are displayed in table 3-4.

Table 3-4 shows that the same daily costing periods were selected for both seasons of the year despite the difference in the daily load curves for the two seasons. Also, only peak and off-peak daily costing periods were selected, that is, no shoulder daily costing period was selected for either season. This selection was made for several reasons.

The daily load curves for August reveal a consistent build up and drop-off of system load during weekdays with no intermediate (or shoulder) period. Also once reached, the system load remains at a peak condition throughout the day before declining to an off-peak level at night.

For January, the daily load curves display a less consistent pattern. However, a pronounced shoulder period is still not evident. Hourly system load remains at a level just below a peak condition during a large part of most weekdays. If these hours were characterized as shoulder or intermediate load hours, a small shift in customer load might cause these hours to become peakload hours. This would lead to tariff and revenue instability and contribute to customer confusion if the established daily costing periods were continuously changed to reflect the varying customer load. Also, the slight variance in customer load between the peak and the possible shoulder periods would likely lead to such a minor difference in rates charged during these two daily costing periods as to make the addition of a daily shoulder period for the winter season nonproductive. Finally, since on at least one day of the week the system load reaches a peak condition in the morning and in the evening, an intermediate shoulder costing period would violate the selected costing period criteria requiring that only one peak period per day be selected and that all days of the week be treated identically.

TABLE 3-4

SAMPLE DAILY COSTING PERIODS FOR THE PEAK AND OFF-PEAK SEASONS FOR PUBLIC SERVICE COMPANY OF COLORADO BASED ON HOURLY SYSTEM LOAD DATA FOR THE PERIOD JUNE 1, 1979 THROUGH MAY 31, 1980

Season of the Year	Daily Peak Hours	Daily Off-Peak Hours
Peak Season		
(June through October) Monday through Friday	10:00 a.m. to 9:00 p.m.	9:00 p.m. to 10:00 a.m.
Saturday, Sunday, and Holidays	None	All day
Off-Peak Season		
(November through May) Monday through Friday	10:00 a.m. to 9:00 p.m.	9:00 p.m. to 10:00 a.m.
Saturday, Sunday, and Holidays	None	All Day

Source: Hourly system load data supplied by PSCO and the FRED computer program

The variance in hourly system load data for the winter costing period does give rise to some concern, however. Additional customer load data and analysis, perhaps including hourly system load data for several years rather than for one year as was used in this example, may be necessary to determine more accurately if a daily shoulder costing period could be included for the winter period.

After the selection of seasonal and daily costing periods is completed, if deemed necessary, the commission staff may check the selection of costing periods for accuracy (i.e., accuracy of reflection of actual variation in costs of service) by analyzing system hourly marginal running costs. This information is generally available from utility companies, since it is used to dispatch generating facilities to meet system load based on the availability of the lowest cost generating plant.

Hourly marginal-running costs for each seasonal period can be grouped into daily periods that represent similar costs on the system. This process would again take into consideration those practical restrictions for costing period selection determined by the commission staff. The set of costing periods derived from this analysis can be compared with those determined from the FRED analysis in order to assure that the final selection of costing periods accurately reflects the costs of service.

A second method of checking the accuracy of costing period selection using FRED, is to compare these costing periods with those determined by the utility company as a part of its filing requirements under section 133 of the Public Utility Regulatory Policies Act of 1978 (PURPA). Under rules and regulations established by the Department of Energy, Federal Energy Regulatory Commission (FERC), electric utilities with annual retail sales exceeding 500 million kilowatt-hours are required to file with the FERC and jurisdictional state regulatory commissions certain information and data regarding average cost of service and marginal cost of service by costing periods.[3] Included in this information are two tables, one displaying

---

[3]"Collection of Cost of Service Information under Section 133 of the Public Utility Regulatory Policies Act of 1978," Federal Register 44, no. 198 (Thursday, October 11, 1979): 58687-708.

average costs of service by costing period and voltage level for generation, transmission, and distribution facilities, and for energy costs; and a second table displaying the same information using marginal (rather than average) costs of service. A description of the method used to compute the costing periods and cost of service data is also required to be filed. Although the costing periods presented in this data filing may not exactly coincide with those chosen through use of the FRED code, due to variations in the methods used or in the restrictions placed on period selection, this information may be helpful in judging the reasonableness of costing periods determined through the example procedure presented in this report.

APPENDIX A

SAMPLE FRED LOGON AND EXECUTE PROCEDURES AND SAMPLE OUTPUT FOR MONTHLY PEAKLOADS

This appendix contains sample logon and execute operations for the FRED program, using a TSO computer terminal to compute sample output for monthly peakloads using hourly system load data for PSCO for the period June 1979 through May 1980.

```
logon
USERID? ts1780
PASSWORD? [redacted]
TERMINAL ID? ar60
UNIVERSITY ID? [redacted]
PROCEDURE NAME? fortuser
TS1780 LOGON IN PROGRESS AT 10:54:50 ON MAY 8, 1981
READY
term linesize(133)
READY
ex fred2.clist
```

****** FRED ******

LOAD FREQUENCY, LOAD DURATION, LOAD PROBABILITY
PEAK DAY, AND AVERAGE DAY CODE, SEPT., 1976
THE OHIO STATE UNIVERSITY
NUCLEAR ENGINEERING DEPARTMENT
COLUMBUS, OHIO 43210

REVISED BY THE NATIONAL REGULATORY
RESEARCH INSTITUTE.   4/81

FOR INFORMATION CONTACT :
JEFFREY SHIH
THE NATIONAL REGULATORY RESEARCH INSTITUTE
THE OHIO STATE UNIVERSITY
2130 NEIL AVENUE
COLUMBUS, OHIO 43210
(614) 422-9404

```
IF YOU WISH TO EXECUTE FRED VIA TERMINAL,
ENTER YES;
OTHERWISE ENTER NO TO CREATE AN INPUT FILE
FOR BATCH EXECUTION.
yes
YES
ENTER COMPANY NAME AND YEAR OF DATA
XXXX 19XX
psco 79
PSCO 7900
THE INCLUSIVE TIME PERIOD OF INTEREST IS SPECIFIED BY TYPING THE
STARTING MONTH AND DAY AND THE ENDING MONTH AND DAY IN THE FORMAT
--/--/--/--. FOR EXAMPLE, TO SPECIFY JUNE 1 THROUGH OCTOBER 15 TYPE
06/01/10/15 THEN PRESS RETURN.
01/01/01/31
 1/ 1/ 1/31
DO YOU WISH TO SPECIFY THE DAYS OF THE WEEK FOR WHICH
THE CALCULATIONS ARE TO BE MADE?
no
NO
DO YOU WISH TO SPECIFY THE HOURS OF THE DAY FOR WHICH
THE CALCULATIONS ARE TO BE MADE?
no
NO
DO YOU WISH TO SPECIFY A RANGE OF HOURS DURING THE DAY
WHICH ARE NOT USED IN THE CALCULATION?
no
NO
DO YOU WISH TO SEE THE SELECTED DATA?
no
NO
DO YOU WISH TO SEE THE LOAD FREQUENCY PLOT?
no
NO
DO YOU WISH TO SEE THE LOAD DURATION CURVE?
no
NO
DO YOU WISH TO SEE THE LOAD PROBABILITY CURVE?
no
NO
DO YOU WISH TO HAVE AN AVERAGE AND PEAK DAY CALCULATED
FOR EACH DAY OF THE WEEK?
no
NO


          PEAK MW            MO/DA/HR
           2675.              1/28/19

           THE LOAD FACTOR IS 75.6%

           THE TOTAL MEGAWATT-HOUR SALES ARE    1505251.
```

```
DO YOU WISH TO EXAMINE A DIFFERENT CASE WITHIN THE SAME YEAR?
yes
YES
DO YOU WISH TO ANALYZE THIS CASE FOR  THE SAME
DAYS, HOURS, AND OUTPUT OPTIONS AS IN THE LAST
CASE?
yes
YES
THE INCLUSIVE TIME PERIOD OF INTEREST IS SPECIFIED BY TYPING THE
STARTING MONTH AND DAY AND THE ENDING MONTH AND DAY IN THE FORMAT
--/--/--/--. FOR EXAMPLE, TO SPECIFY JUNE 1 THROUGH OCTOBER 15 TYPE
06/01/10/15 THEN PRESS RETURN.
02/01/02/29
 2/ 1/ 2/29


        PEAK MW          MO/DA/HR
          2552.           2/ 7/19

         THE LOAD FACTOR IS 77.5%

         THE TOTAL MEGAWATT-HOUR SALES ARE   1376521.



DO YOU WISH TO EXAMINE A DIFFERENT CASE WITHIN THE SAME YEAR?
no
NO
NORMAL EXIT FROM INTERACTIVE EXECUTION OF FRED CODE
SESSION ENDED

READY
logoff
OEF201I CSU=  4  CPU=00:00:07.34  SYSO=  0  DSK=  320  CNCT=01:48
TS1780 LOGGED OFF TSO AT 14:43:37 ON MAY 9, 1981
```

APPENDIX B

SAMPLE LOGON AND EXECUTE PROCEDURES AND SAMPLE OUTPUT FOR THE FRED COMPUTER PROGRAM

This appendix contains sample logon and execute procedures for the FRED computer program using a TSO computer terminal. Sample output data from FRED for PSCO for August 1979 (the month of the system annual peak) and for January 1980 (the month of the system secondary peak) are also provided. These data and load curves are used in the selection of the daily costing periods for each season of the year for PSCO.

```
logon
USERID? ts1780
PASSWORD? [redacted]
TERMINAL ID? ar60
UNIVERSITY ID? [redacted]
PROCEDURE NAME? fortuser
TS1780 LOGON IN PROGRESS AT 11:23:58 ON MAY 20, 1981
READY
term linesize(133)
READY
ex fred2.clist
```

```
                    **** FRED ****


      LOAD FREQUENCY, LOAD DURATION, LOAD PROBABILITY
      PEAK DAY, AND AVERAGE DAY CODE, SEPT., 1976
              THE OHIO STATE UNIVERSITY
              NUCLEAR ENGINEERING DEPARTMENT
              COLUMBUS, OHIO 43210

              REVISED BY THE NATIONAL REGULATORY
              RESEARCH INSTITUTE.     4/81

              FOR INFORMATION CONTACT :
              JEFFREY SHIH
              THE NATIONAL REGULATORY RESEARCH INSTITUTE
              THE OHIO STATE UNIVERSITY
              2130 NEIL AVENUE
              COLUMBUS, OHIO 43210
              (614) 422-9404
```

```
IF YOU WISH TO EXECUTE FRED VIA TERMINAL,
ENTER YES;
OTHERWISE ENTER NO TO CREATE AN INPUT FILE
FOR BATCH EXECUTION.
yes
YES
ENTER COMPANY NAME AND YEAR OF DATA
XXXX 19XX
psco 79
PSCO 7900
THE INCLUSIVE TIME PERIOD OF INTEREST IS SPECIFIED BY TYPING THE
STARTING MONTH AND DAY AND THE ENDING MONTH AND DAY IN THE FORMAT
--/--/--/--. FOR EXAMPLE, TO SPECIFY JUNE 1 THROUGH OCTOBER 15 TYPE
06/01/10/15 THEN PRESS RETURN.
08/01/08/31
 8/ 1/ 8/31
DO YOU WISH TO SPECIFY THE DAYS OF THE WEEK FOR WHICH
THE CALCULATIONS ARE TO BE MADE?
no
NO
DO YOU WISH TO SPECIFY THE HOURS OF THE DAY FOR WHICH
THE CALCULATIONS ARE TO BE MADE?
no
NO
DO YOU WISH TO SPECIFY A RANGE OF HOURS DURING THE DAY
WHICH ARE NOT USED IN THE CALCULATION?
no
NO
DO YOU WISH TO SEE THE SELECTED DATA?
no
NO
DO YOU WISH TO SEE THE LOAD FREQUENCY PLOT?
no
NO
DO YOU WISH TO SEE THE LOAD DURATION CURVE?
no
NO
DO YOU WISH TO SEE THE LOAD PROBABILITY CURVE?
no
NO
DO YOU WISH TO HAVE AN AVERAGE AND PEAK DAY CALCULATED
FOR EACH DAY OF THE WEEK?
yes
YES
OUTPUT FOR THE AVERAGE AND PEAK DAY
CALCULATION IS AVAILABLE IN
   1  SUMMARY TABLE OF THE AVERAGE LOAD PER HOUR
      PER DAY AND THE PEAK LOAD PER HOUR PER DAY.
   2  A DAY BY DAY PLOT OF THE SUMMARY DATA
   3  BOTH OF THE ABOVE

TYPE THE NUMBER OF THE OUTPUT OPTION
3
3
```

PEAK MW 2755.

MO/DA/HR 8/ 6/17

THE LOAD FACTOR IS 70.2%

THE TOTAL MEGAWATT-HOUR SALES ARE 1438667.

THE FOLLOWING ARE AVERAGE LOAD DAYS FOR THE PERIOD 8/ 1 TO 8/31.

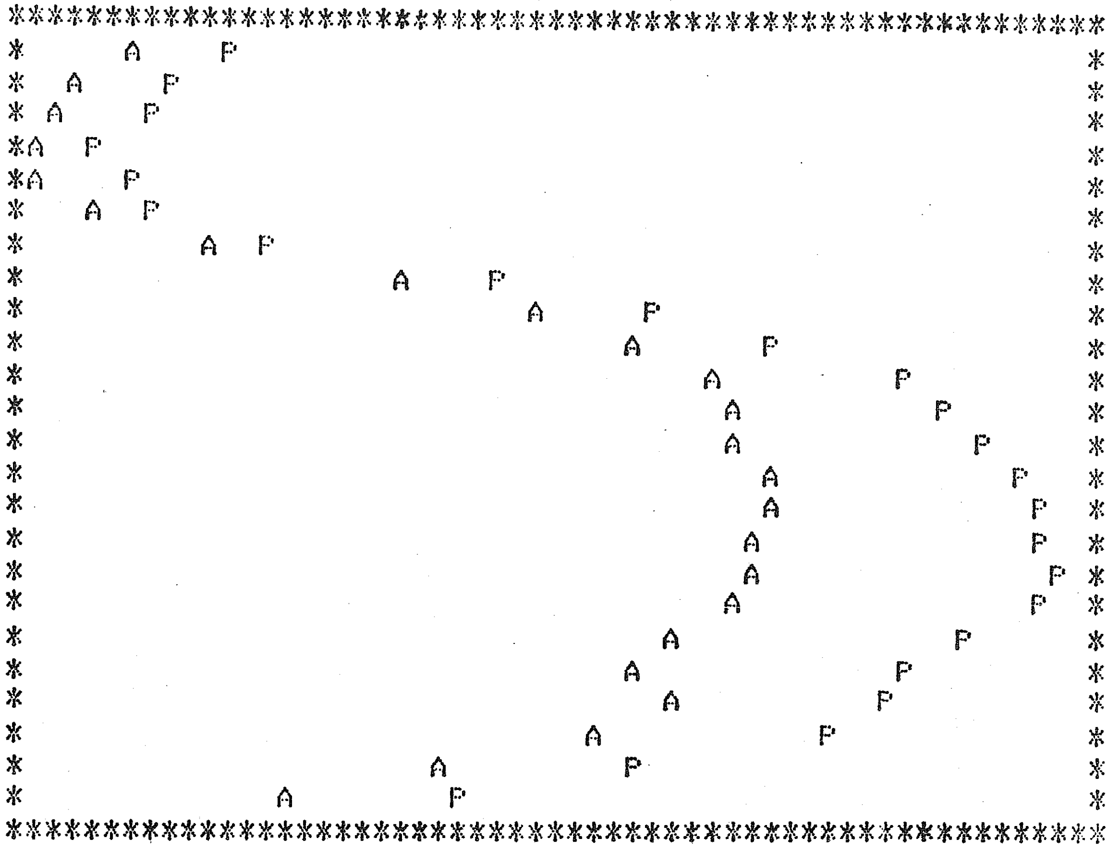
HR	MON	TUES	WED	THUR	FRI	WKDA	SAT	SUN	HOLI	WKED
1	1517.	1584.	1599.	1614.	1589.	1583.	1581.	1540.	0.	1561.
2	1453.	1530.	1542.	1548.	1517.	1520.	1505.	1446.	0.	1475.
3	1417.	1479.	1485.	1483.	1485.	1472.	1445.	1408.	0.	1426.
4	1402.	1469.	1457.	1467.	1473.	1455.	1435.	1380.	0.	1407.
5	1410.	1461.	1462.	1475.	1474.	1458.	1415.	1368.	0.	1391.
6	1488.	1523.	1545.	1541.	1538.	1529.	1409.	1369.	0.	1389.
7	1631.	1657.	1698.	1668.	1673.	1668.	1443.	1349.	0.	1396.
8	1884.	1880.	1907.	1911.	1898.	1897.	1553.	1412.	0.	1482.
9	2054.	2083.	2080.	2090.	2086.	2080.	1709.	1543.	0.	1626.
10	2193.	2209.	2234.	2218.	2209.	2214.	1864.	1655.	0.	1759.
11	2295.	2285.	2309.	2316.	2302.	2302.	1964.	1737.	0.	1850.
12	2322.	2333.	2358.	2355.	2354.	2346.	1997.	1811.	0.	1904.
13	2323.	2333.	2381.	2374.	2334.	2351.	1999.	1892.	0.	1946.
14	2376.	2374.	2409.	2413.	2363.	2388.	2014.	1888.	0.	1951.
15	2363.	2370.	2431.	2433.	2363.	2394.	1978.	1886.	0.	1932.
16	2345.	2377.	2426.	2410.	2330.	2379.	1968.	1894.	0.	1931.
17	2345.	2372.	2373.	2363.	2306.	2351.	1993.	1907.	0.	1950.
18	2324.	2329.	2340.	2335.	2253.	2315.	1996.	1934.	0.	1965.
19	2254.	2250.	2256.	2243.	2156.	2230.	1965.	1922.	0.	1943.
20	2202.	2187.	2175.	2175.	2107.	2167.	1924.	1912.	0.	1918.
21	2250.	2235.	2226.	2201.	2135.	2207.	1978.	1977.	0.	1977.
22	2149.	2139.	2158.	2141.	2060.	2128.	1934.	1933.	0.	1934.
23	1938.	1956.	1978.	1945.	1893.	1942.	1793.	1786.	0.	1790.
24	1728.	1749.	1748.	1729.	1701.	1730.	1653.	1600.	0.	1626.

THE FOLLOWING ARE PEAK LOAD DAYS FOR THE PERIOD 8/ 1 TO 8/31.

HR	MON	TUES	WED	THUR	FRI	WKDA	SAT	SUN	HOLI	WKED
1	1658.	1777.	1802.	1729.	1751.	1802.	1776.	1662.	0.	1776.
2	1592.	1715.	1745.	1643.	1648.	1745.	1645.	1581.	0.	1645.
3	1564.	1638.	1641.	1577.	1577.	1641.	1589.	1536.	0.	1589.
4	1483.	1621.	1624.	1583.	1564.	1624.	1550.	1486.	0.	1550.
5	1533.	1601.	1615.	1558.	1567.	1615.	1513.	1451.	0.	1513.
6	1543.	1682.	1692.	1652.	1624.	1692.	1529.	1466.	0.	1529.
7	1703.	1764.	1848.	1730.	1739.	1848.	1550.	1429.	0.	1550.
8	2003.	2029.	2079.	2012.	2011.	2079.	1667.	1500.	0.	1667.
9	2211.	2273.	2275.	2212.	2211.	2275.	1844.	1662.	0.	1844.
10	2373.	2412.	2479.	2331.	2378.	2479.	2028.	1798.	0.	2028.
11	2546.	2548.	2572.	2424.	2484.	2572.	2158.	1935.	0.	2158.
12	2612.	2630.	2648.	2507.	2546.	2648.	2276.	2028.	0.	2276.
13	2653.	2649.	2678.	2516.	2558.	2678.	2274.	2123.	0.	2274.
14	2709.	2721.	2702.	2533.	2603.	2721.	2308.	2129.	0.	2308.
15	2725.	2751.	2733.	2548.	2615.	2751.	2287.	2137.	0.	2287.
16	2741.	2752.	2744.	2529.	2602.	2752.	2261.	2160.	0.	2261.
17	2755.	2739.	2689.	2534.	2605.	2755.	2289.	2186.	0.	2289.
18	2723.	2696.	2554.	2515.	2568.	2723.	2272.	2203.	0.	2272.
19	2624.	2606.	2428.	2429.	2438.	2624.	2240.	2159.	0.	2240.
20	2543.	2497.	2308.	2336.	2356.	2543.	2189.	2149.	0.	2189.
21	2521.	2510.	2335.	2328.	2348.	2521.	2182.	2199.	0.	2199.
22	2441.	2418.	2277.	2327.	2313.	2441.	2174.	2189.	0.	2189.
23	2199.	2236.	2117.	2081.	2109.	2236.	2027.	2007.	0.	2027.
24	1956.	2053.	1869.	1875.	1923.	2053.	1822.	1806.	0.	1822.

AVERAGE AND PEAK LOADS FOR MONDAYS

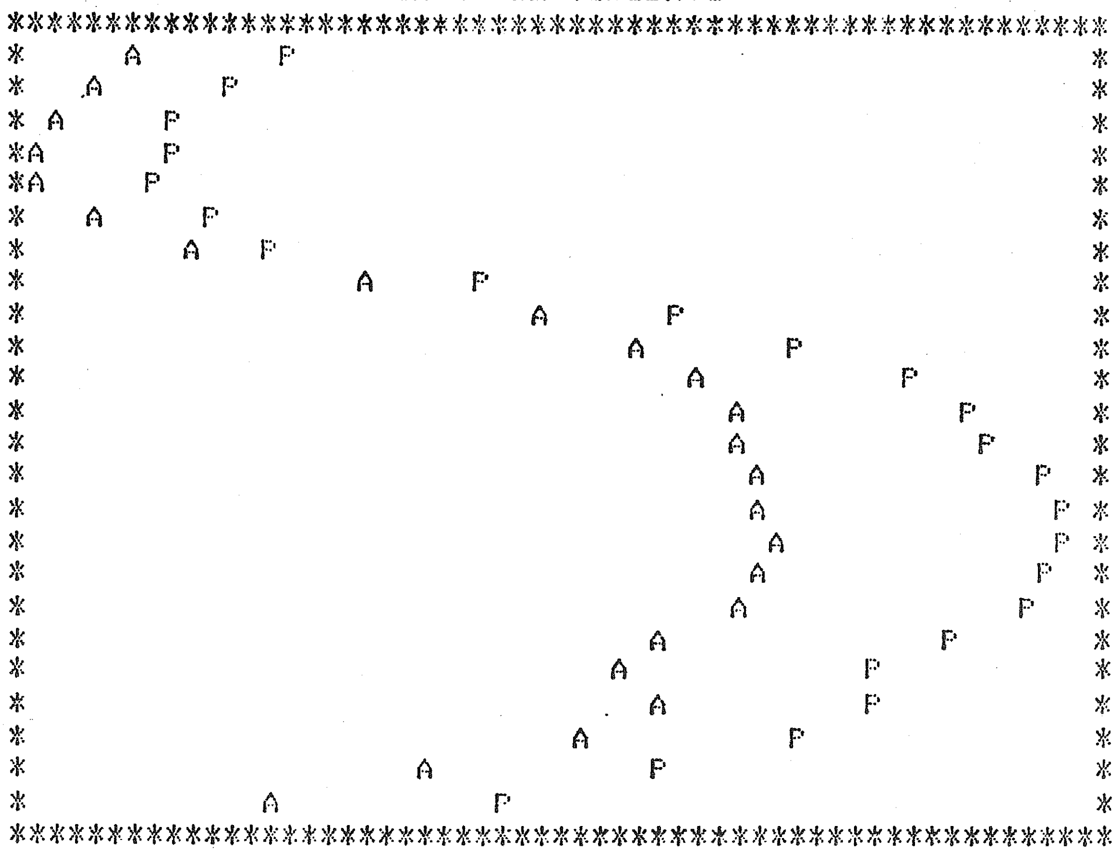
HR	AVE	PEAK
1	1517.	1658.
2	1453.	1592.
3	1417.	1564.
4	1402.	1483.
5	1410.	1533.
6	1488.	1543.
7	1631.	1703.
8	1884.	2003.
9	2054.	2211.
10	2193.	2373.
11	2295.	2546.
12	2322.	2612.
13	2323.	2653.
14	2376.	2709.
15	2363.	2725.
16	2345.	2741.
17	2345.	2755.
18	2324.	2723.
19	2254.	2624.
20	2202.	2543.
21	2250.	2521.
22	2149.	2441.
23	1938.	2199.
24	1728.	1956.



THERE ARE 4 MONDAYS
IN THE PERIOD 8/ 1/- 8/31/.

AVERAGE AND PEAK LOADS FOR TUESDAYS

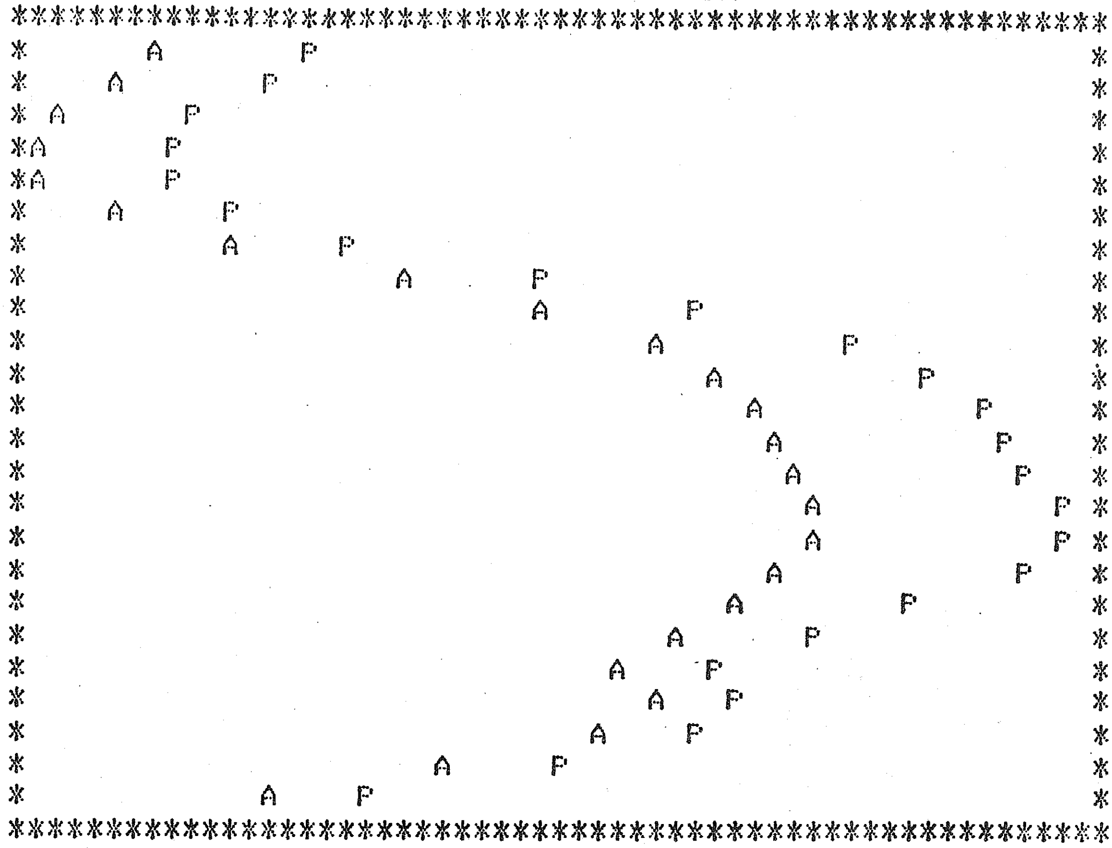
HR	AVE	PEAK
1	1584.	1777.
2	1530.	1715.
3	1479.	1638.
4	1469.	1621.
5	1461.	1601.
6	1523.	1682.
7	1657.	1764.
8	1880.	2029.
9	2083.	2273.
10	2209.	2412.
11	2285.	2548.
12	2333.	2630.
13	2333.	2649.
14	2374.	2721.
15	2370.	2751.
16	2377.	2752.
17	2372.	2739.
18	2329.	2696.
19	2250.	2606.
20	2187.	2497.
21	2235.	2510.
22	2139.	2418.
23	1956.	2236.
24	1749.	2053.



THERE ARE 4 TUESDAYS
IN THE PERIOD 8/ 1/- 8/31/.

AVERAGE AND PEAK LOADS FOR WEDNESDAYS

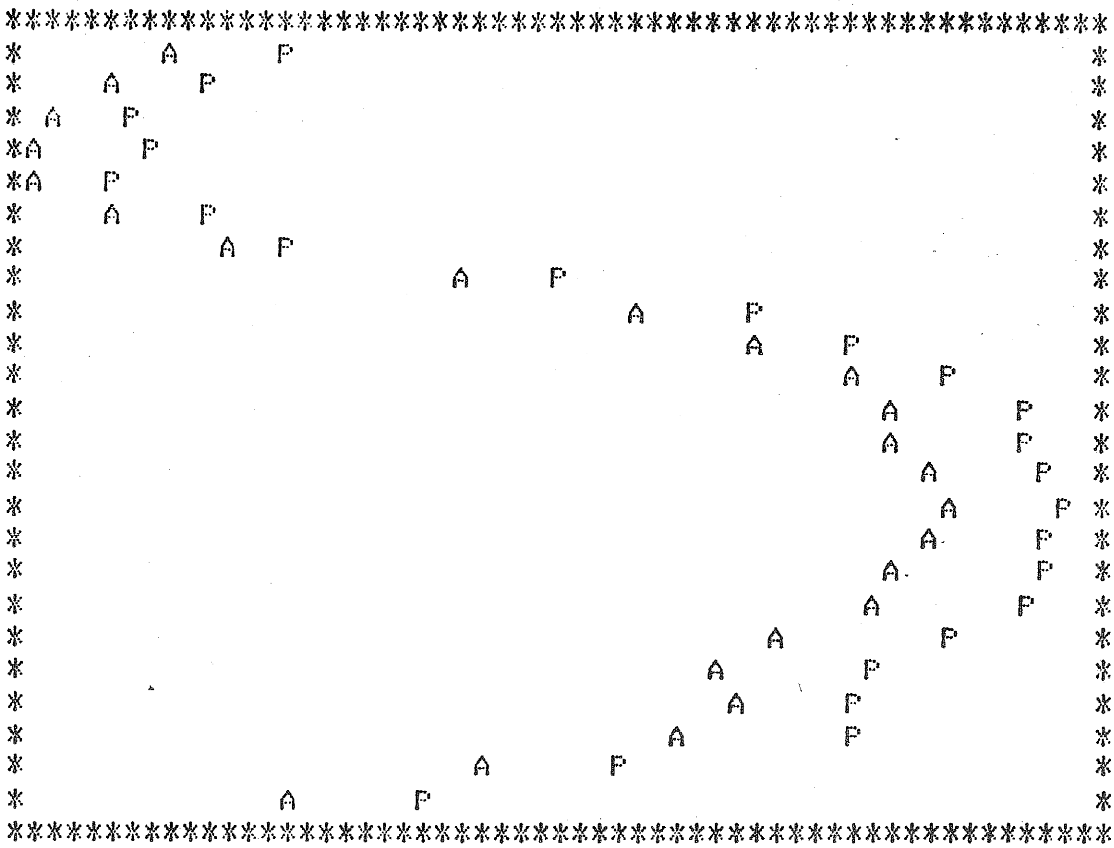
HR	AVE	PEAK
1	1599.	1802.
2	1542.	1745.
3	1485.	1641.
4	1457.	1624.
5	1462.	1615.
6	1545.	1692.
7	1698.	1848.
8	1907.	2079.
9	2080.	2275.
10	2234.	2479.
11	2309.	2572.
12	2358.	2648.
13	2381.	2678.
14	2409.	2702.
15	2431.	2733.
16	2426.	2744.
17	2373.	2689.
18	2340.	2554.
19	2256.	2428.
20	2175.	2308.
21	2226.	2335.
22	2158.	2277.
23	1978.	2117.
24	1748.	1869.



THERE ARE 5 WEDNESDAYS
IN THE PERIOD 8/ 1/- 8/31/.

AVERAGE AND PEAK LOADS FOR THURSDAYS

HR	AVE	PEAK
1	1614.	1729.
2	1548.	1643.
3	1483.	1577.
4	1467.	1583.
5	1475.	1558.
6	1541.	1652.
7	1668.	1730.
8	1911.	2012.
9	2090.	2212.
10	2218.	2331.
11	2316.	2424.
12	2355.	2507.
13	2374.	2516.
14	2413.	2533.
15	2433.	2548.
16	2410.	2529.
17	2363.	2534.
18	2335.	2515.
19	2243.	2429.
20	2175.	2336.
21	2201.	2328.
22	2141.	2327.
23	1945.	2081.
24	1729.	1875.



THERE ARE 5 THURSDAYS
IN THE PERIOD 8/ 1/- 8/31/.

AVERAGE AND PEAK LOADS FOR FRIDAYS

HR	AVE	PEAK
1	1589.	1751.
2	1517.	1648.
3	1485.	1577.
4	1473.	1564.
5	1474.	1567.
6	1538.	1624.
7	1673.	1739.
8	1898.	2011.
9	2086.	2211.
10	2209.	2378.
11	2302.	2484.
12	2354.	2546.
13	2334.	2558.
14	2363.	2603.
15	2363.	2615.
16	2330.	2602.
17	2306.	2605.
18	2253.	2568.
19	2156.	2438.
20	2107.	2356.
21	2135.	2348.
22	2060.	2313.
23	1893.	2109.
24	1701.	1923.

THERE ARE 5 FRIDAYS
IN THE PERIOD 8/ 1/- 8/31/.

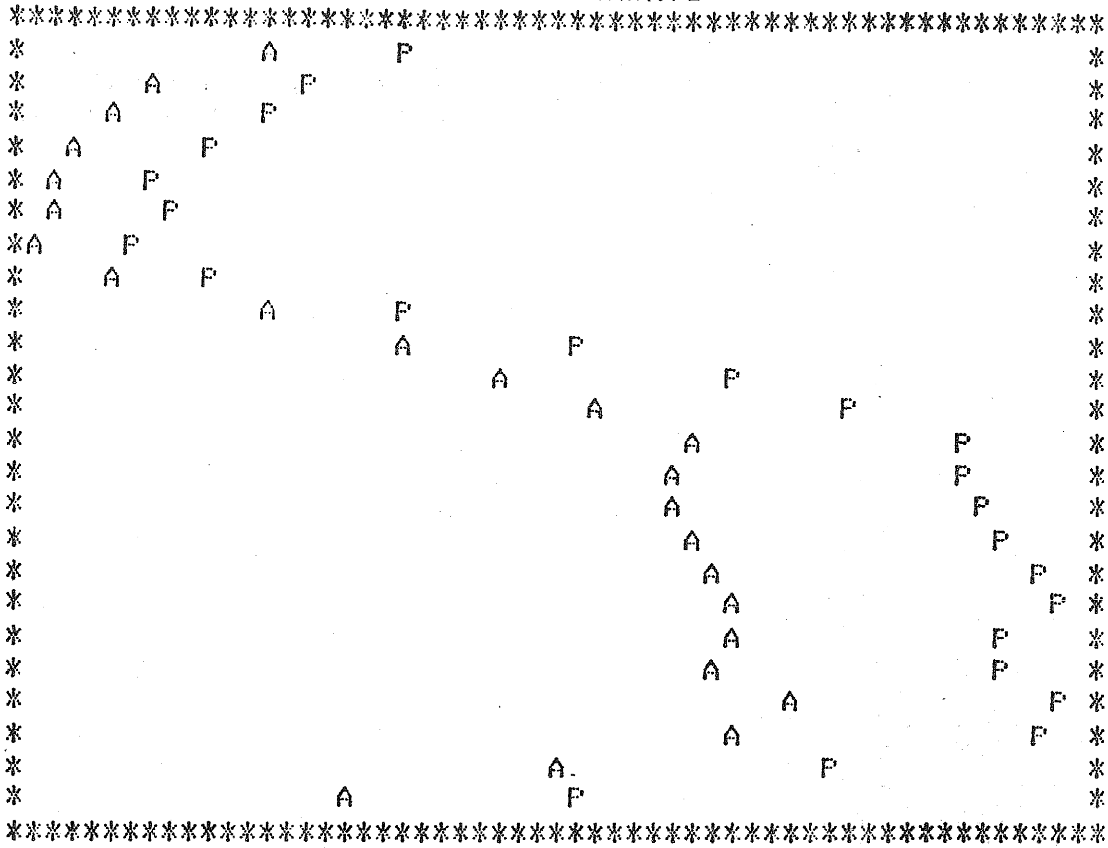
AVERAGE AND PEAK LOADS FOR SATURDAYS

HR	AVE	PEAK
1	1581.	1776.
2	1505.	1645.
3	1445.	1589.
4	1435.	1550.
5	1415.	1513.
6	1409.	1529.
7	1443.	1550.
8	1553.	1667.
9	1709.	1844.
10	1864.	2028.
11	1964.	2158.
12	1997.	2276.
13	1999.	2274.
14	2014.	2308.
15	1978.	2287.
16	1968.	2261.
17	1993.	2289.
18	1996.	2272.
19	1965.	2240.
20	1924.	2189.
21	1978.	2182.
22	1934.	2174.
23	1793.	2027.
24	1653.	1822.

THERE ARE 4 SATURDAYS
IN THE PERIOD 8/ 1/- 8/31/.

AVERAGE AND PEAK LOADS FOR SUNDAYS

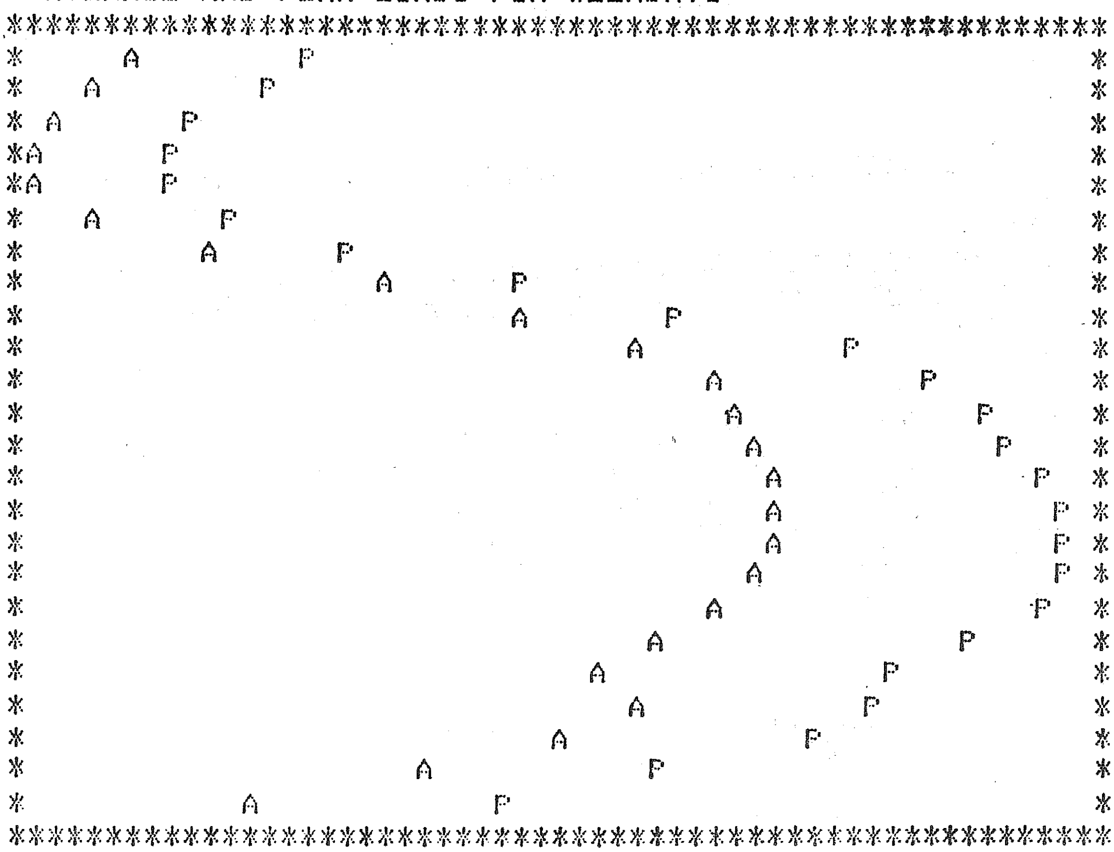
HR	AVE.	PEAK
1	1540.	1662.
2	1446.	1581.
3	1408.	1536.
4	1380.	1486.
5	1368.	1451.
6	1369.	1466.
7	1349.	1429.
8	1412.	1500.
9	1543.	1662.
10	1655.	1798.
11	1737.	1935.
12	1811.	2028.
13	1892.	2123.
14	1888.	2129.
15	1886.	2137.
16	1894.	2160.
17	1907.	2186.
18	1934.	2203.
19	1922.	2159.
20	1912.	2149.
21	1977.	2199.
22	1933.	2189.
23	1786.	2007.
24	1600.	1806.



THERE ARE 4 SUNDAYS
IN THE PERIOD 8/ 1/- 8/31/.

AVERAGE AND PEAK LOADS FOR WEEKDAYS

HR	AVE	PEAK
1	1583.	1802.
2	1520.	1745.
3	1472.	1641.
4	1455.	1624.
5	1458.	1615.
6	1529.	1692.
7	1668.	1848.
8	1897.	2079.
9	2080.	2275.
10	2214.	2479.
11	2302.	2572.
12	2346.	2648.
13	2351.	2678.
14	2388.	2721.
15	2394.	2751.
16	2379.	2752.
17	2351.	2755.
18	2315.	2723.
19	2230.	2624.
20	2167.	2543.
21	2207.	2521.
22	2128.	2441.
23	1942.	2236.
24	1730.	2053.



THERE ARE 23 WEEKDAYS
IN THE PERIOD 8/ 1/- 8/31/.

```
                 AVERAGE AND PEAK LOADS FOR WEEKEND DAYS
HR  AVE   PEAK *********************************************************
 1 1561. 1776. *          A           P                                *
 2 1475. 1645. *     A         P                                       *
 3 1426. 1589. *  A         P                                          *
 4 1407. 1550. * A       P                                             *
 5 1391. 1513. *A      P                                               *
 6 1389. 1529. *A       P                                              *
 7 1396. 1550. *A        P                                             *
 8 1482. 1667. *     A          P                                      *
 9 1626. 1844. *              A           P                            *
10 1759. 2028. *                     A               P                 *
11 1850. 2158. *                           A                P          *
12 1904. 2276. *                              A                    P   *
13 1946. 2274. *                                A                  P   *
14 1951. 2308. *                                A                    P *
15 1932. 2287. *                               A                    P  *
16 1931. 2261. *                               A                  P    *
17 1950. 2289. *                                A                   P  *
18 1965. 2272. *                                 A                 P   *
19 1943. 2240. *                                A                P     *
20 1918. 2189. *                               A              P        *
21 1977. 2199. *                                  A            P       *
22 1934. 2189. *                               A              P        *
23 1790. 2027. *                       A             P                 *
24 1626. 1822. *              A          P                             *
               *********************************************************

                  THERE ARE 8 WEEKEND DAYS
                  IN THE PERIOD  8/ 1/- 8/31/.


DO YOU WISH TO EXAMINE A DIFFERENT CASE WITHIN THE SAME YEAR?
yes
YES
DO YOU WISH TO ANALYZE THIS CASE FOR  THE SAME
DAYS, HOURS, AND OUTPUT OPTIONS AS IN THE LAST
CASE?
yes
YES
THE INCLUSIVE TIME PERIOD OF INTEREST IS SPECIFIED BY TYPING THE
STARTING MONTH AND DAY AND THE ENDING MONTH AND DAY IN THE FORMAT
--/--/--/--. FOR EXAMPLE, TO SPECIFY JUNE 1 THROUGH OCTOBER 15 TYPE
06/01/10/15 THEN PRESS RETURN.
01/01/01/31
 1/ 1/ 1/31


         PEAK MW          MO/DA/HR
          2675.             1/28/19

          THE LOAD FACTOR IS 75.6%

          THE TOTAL MEGAWATT-HOUR SALES ARE   1505251.
```

THE FOLLOWING ARE AVERAGE LOAD DAYS FOR THE PERIOD 1/ 1 TO 1/31.

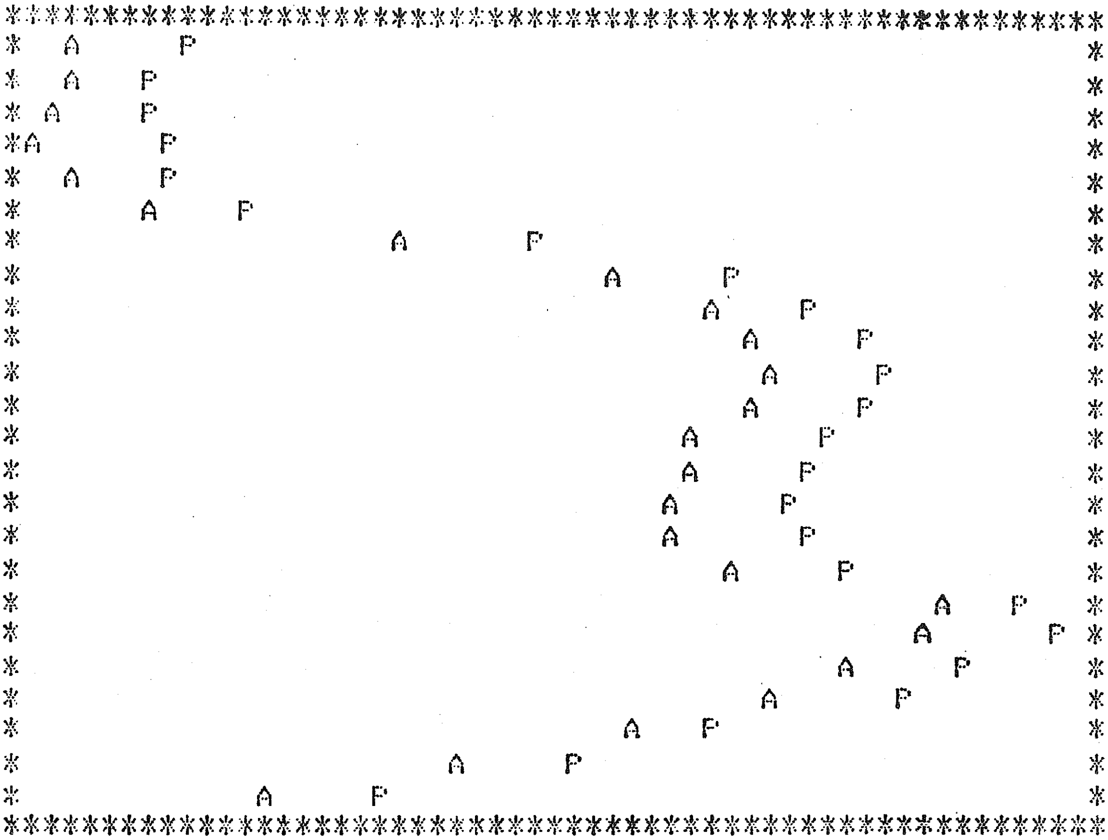
HR	MON	TUES	WED	THUR	FRI	WKDA	SAT	SUN	HOLI	WKED
1	1653.	1736.	1693.	1733.	1693.	1703.	1725.	1673.	1597.	1688.
2	1643.	1543.	1653.	1674.	1636.	1633.	1681.	1600.	1543.	1629.
3	1623.	1693.	1641.	1631.	1606.	1638.	1640.	1572.	1493.	1593.
4	1609.	1684.	1632.	1637.	1594.	1631.	1615.	1551.	1435.	1567.
5	1642.	1687.	1662.	1664.	1606.	1653.	1624.	1539.	1434.	1565.
6	1735.	1790.	1749.	1749.	1702.	1745.	1648.	1555.	1436.	1583.
7	1999.	2059.	1991.	1989.	1927.	1993.	1717.	1614.	1464.	1643.
8	2216.	2241.	2190.	2173.	2141.	2191.	1804.	1638.	1455.	1691.
9	2305.	2307.	2276.	2260.	2233.	2275.	1929.	1738.	1546.	1802.
10	2351.	2331.	2301.	2270.	2271.	2303.	2037.	1835.	1627.	1902.
11	2366.	2348.	2294.	2297.	2286.	2316.	2066.	1890.	1682.	1945.
12	2355.	2330.	2276.	2268.	2259.	2295.	2072.	1904.	1730.	1959.
13	2303.	2272.	2231.	2223.	2238.	2251.	2039.	1906.	1720.	1945.
14	2290.	2266.	2203.	2210.	2228.	2237.	1988.	1891.	1690.	1912.
15	2264.	2235.	2125.	2191.	2214.	2202.	1964.	1856.	1675.	1884.
16	2267.	2228.	2117.	2173.	2217.	2195.	1934.	1846.	1717.	1871.
17	2332.	2301.	2235.	2213.	2272.	2266.	2034.	1933.	1880.	1972.
18	2549.	2499.	2466.	2438.	2463.	2480.	2263.	2182.	2037.	2202.
19	2543.	2494.	2472.	2467.	2440.	2482.	2250.	2202.	2024.	2204.
20	2445.	2427.	2392.	2375.	2347.	2396.	2151.	2155.	2039.	2140.
21	2381.	2353.	2306.	2301.	2269.	2320.	2091.	2128.	1976.	2095.
22	2228.	2214.	2200.	2190.	2161.	2198.	2004.	2039.	1858.	2003.
23	2051.	2055.	2017.	1989.	2000.	2021.	1897.	1903.	1743.	1882.
24	1847.	1864.	1818.	1796.	1840.	1830.	1745.	1748.	1617.	1732.

THE FOLLOWING ARE PEAK LOAD DAYS FOR THE PERIOD 1/ 1 TO 1/31.

HR	MON	TUES	WED	THUR	FRI	WKDA	SAT	SUN	HOLI	WKED
1	1762.	1853.	1827.	1896.	1743.	1896.	1778.	1829.	1597.	1829.
2	1739.	1820.	1770.	1787.	1663.	1820.	1775.	1775.	1543.	1775.
3	1725.	1798.	1787.	1751.	1622.	1798.	1728.	1726.	1493.	1728.
4	1748.	1787.	1781.	1762.	1635.	1787.	1696.	1683.	1435.	1696.
5	1741.	1800.	1781.	1815.	1670.	1815.	1708.	1719.	1434.	1719.
6	1835.	1909.	1900.	1890.	1737.	1909.	1731.	1732.	1436.	1732.
7	2136.	2149.	2120.	2117.	1988.	2149.	1787.	1756.	1464.	1787.
8	2324.	2327.	2340.	2324.	2185.	2340.	1910.	1797.	1455.	1910.
9	2419.	2384.	2413.	2392.	2258.	2419.	2040.	1912.	1546.	2040.
10	2478.	2440.	2417.	2393.	2297.	2478.	2133.	2010.	1627.	2133.
11	2485.	2456.	2373.	2359.	2324.	2485.	2200.	2054.	1682.	2200.
12	2466.	2443.	2346.	2313.	2309.	2466.	2214.	2066.	1730.	2214.
13	2439.	2371.	2302.	2277.	2279.	2439.	2175.	2058.	1720.	2175.
14	2422.	2353.	2267.	2268.	2293.	2422.	2152.	2055.	1690.	2152.
15	2396.	2332.	2247.	2251.	2282.	2396.	2135.	2031.	1675.	2135.
16	2422.	2305.	2211.	2233.	2289.	2422.	2096.	2027.	1717.	2096.
17	2458.	2406.	2280.	2292.	2339.	2458.	2196.	2127.	1880.	2196.
18	2630.	2581.	2516.	2534.	2485.	2630.	2398.	2362.	2037.	2398.
19	2675.	2610.	2548.	2533.	2489.	2675.	2422.	2357.	2024.	2422.
20	2570.	2517.	2473.	2459.	2369.	2570.	2319.	2330.	2039.	2330.
21	2515.	2432.	2407.	2377.	2331.	2515.	2264.	2266.	1976.	2266.
22	2312.	2298.	2305.	2281.	2199.	2312.	2168.	2148.	1858.	2168.
23	2164.	2163.	2122.	2068.	2051.	2164.	2063.	2034.	1743.	2063.
24	1965.	1958.	1942.	1851.	1902.	1965.	1932.	1860.	1617.	1932.

AVERAGE AND PEAK LOADS FOR MONDAYS

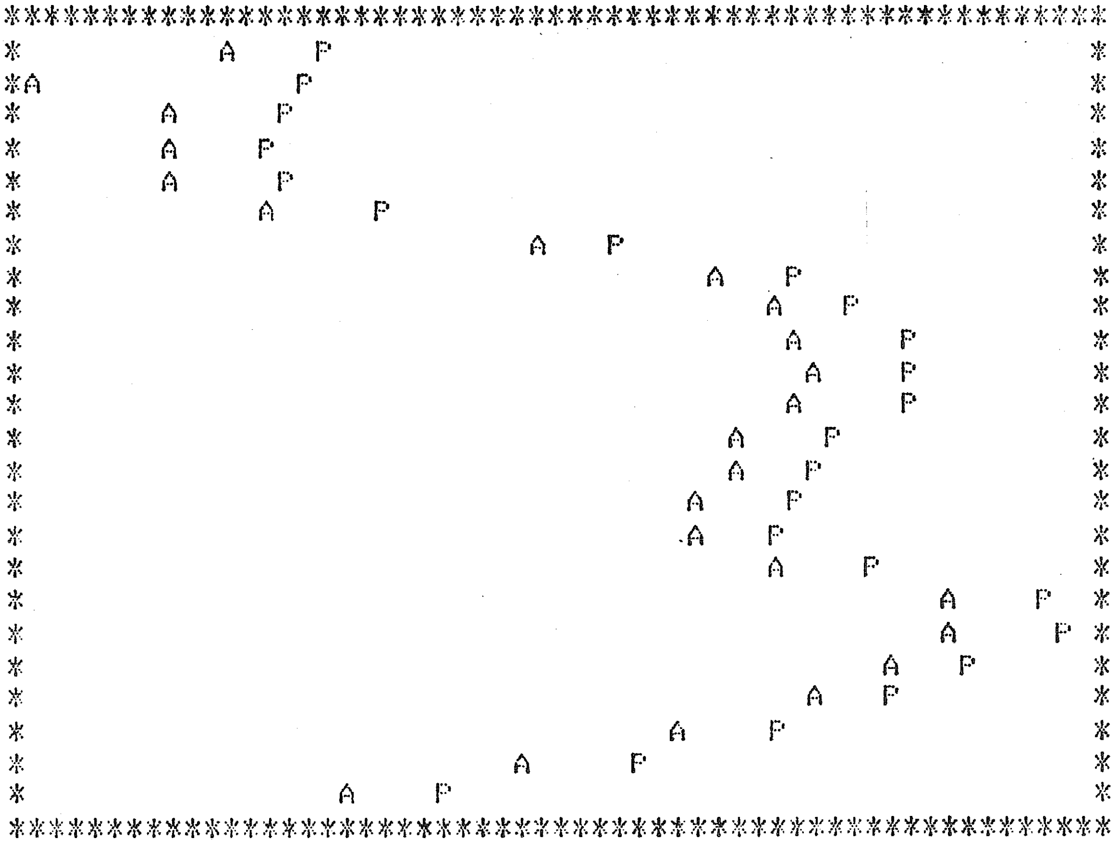
HR	AVE	PEAK
1	1653.	1762.
2	1643.	1739.
3	1623.	1725.
4	1609.	1748.
5	1642.	1741.
6	1735.	1835.
7	1999.	2136.
8	2216.	2324.
9	2305.	2419.
10	2351.	2478.
11	2366.	2485.
12	2355.	2466.
13	2303.	2439.
14	2290.	2422.
15	2264.	2396.
16	2267.	2422.
17	2332.	2458.
18	2549.	2630.
19	2543.	2675.
20	2445.	2570.
21	2381.	2515.
22	2228.	2312.
23	2051.	2164.
24	1847.	1965.



THERE ARE 4 MONDAYS
IN THE PERIOD 1/ 1/- 1/31/.

AVERAGE AND PEAK LOADS FOR TUESDAYS

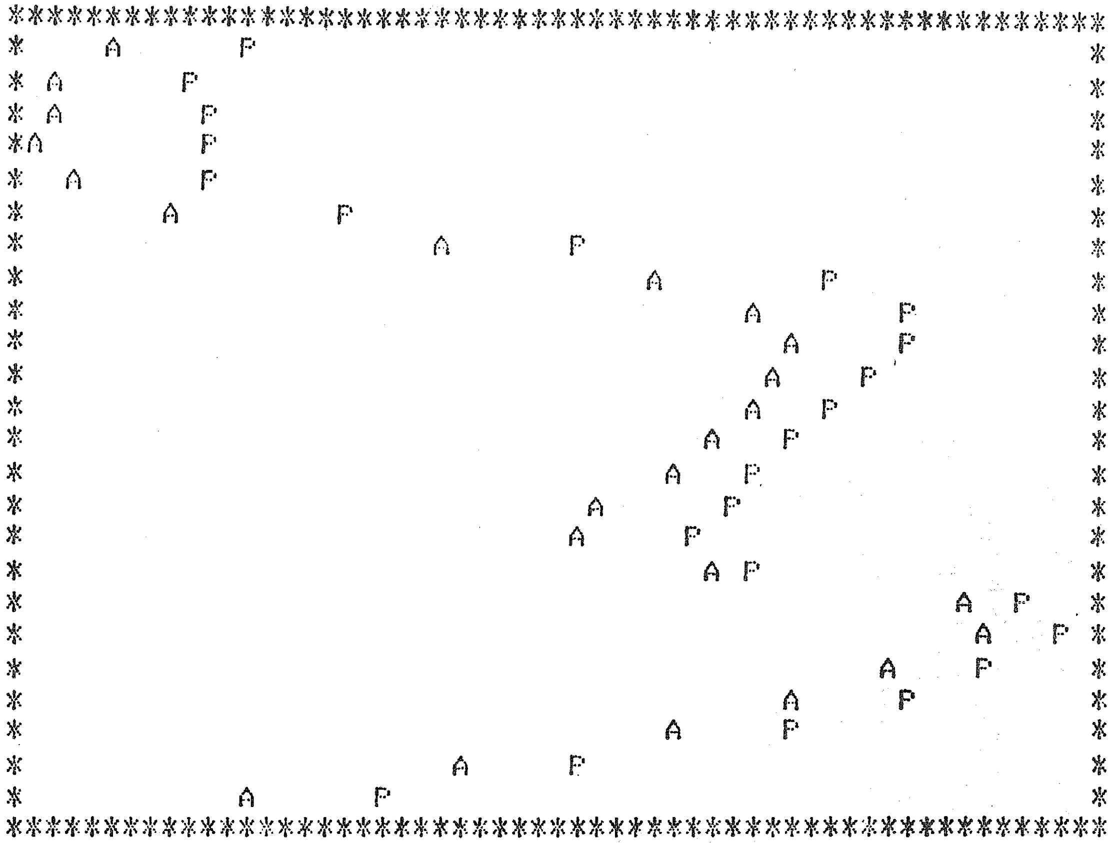
HR	AVE	PEAK
1	1736.	1853.
2	1543.	1820.
3	1693.	1798.
4	1684.	1787.
5	1687.	1800.
6	1790.	1909.
7	2059.	2149.
8	2241.	2327.
9	2307.	2384.
10	2331.	2440.
11	2348.	2456.
12	2330.	2443.
13	2272.	2371.
14	2266.	2353.
15	2235.	2332.
16	2228.	2305.
17	2301.	2406.
18	2499.	2581.
19	2494.	2610.
20	2427.	2517.
21	2353.	2432.
22	2214.	2298.
23	2055.	2163.
24	1864.	1958.



THERE ARE 4 TUESDAYS
IN THE PERIOD 1/ 1/- 1/31/.

AVERAGE AND PEAK LOADS FOR WEDNESDAYS

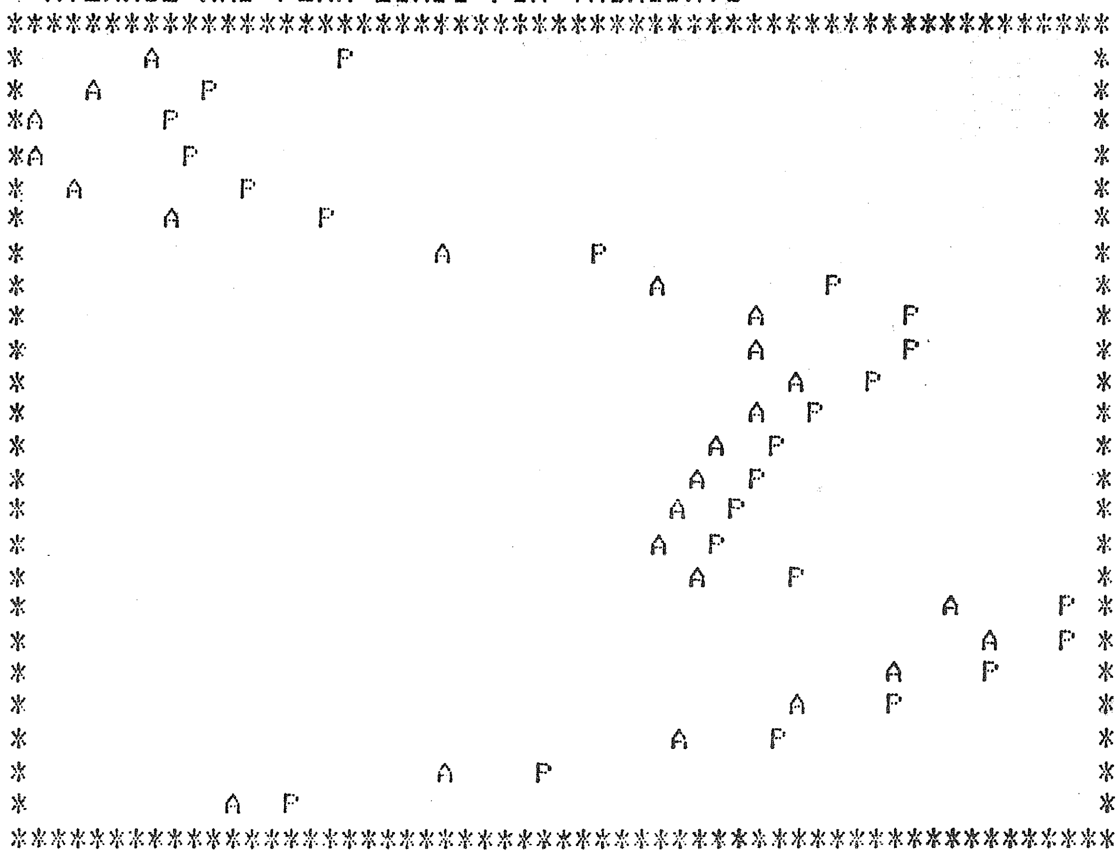
HR	AVE	PEAK
1	1693.	1827.
2	1653.	1770.
3	1641.	1787.
4	1632.	1781.
5	1662.	1781.
6	1749.	1900.
7	1991.	2120.
8	2190.	2340.
9	2276.	2413.
10	2301.	2417.
11	2294.	2373.
12	2276.	2346.
13	2231.	2302.
14	2203.	2267.
15	2125.	2247.
16	2117.	2211.
17	2235.	2280.
18	2466.	2516.
19	2472.	2548.
20	2392.	2473.
21	2306.	2407.
22	2200.	2305.
23	2017.	2122.
24	1818.	1942.



THERE ARE 5 WEDNESDAYS
IN THE PERIOD 1/ 1/- 1/31/.

AVERAGE AND PEAK LOADS FOR THURSDAYS

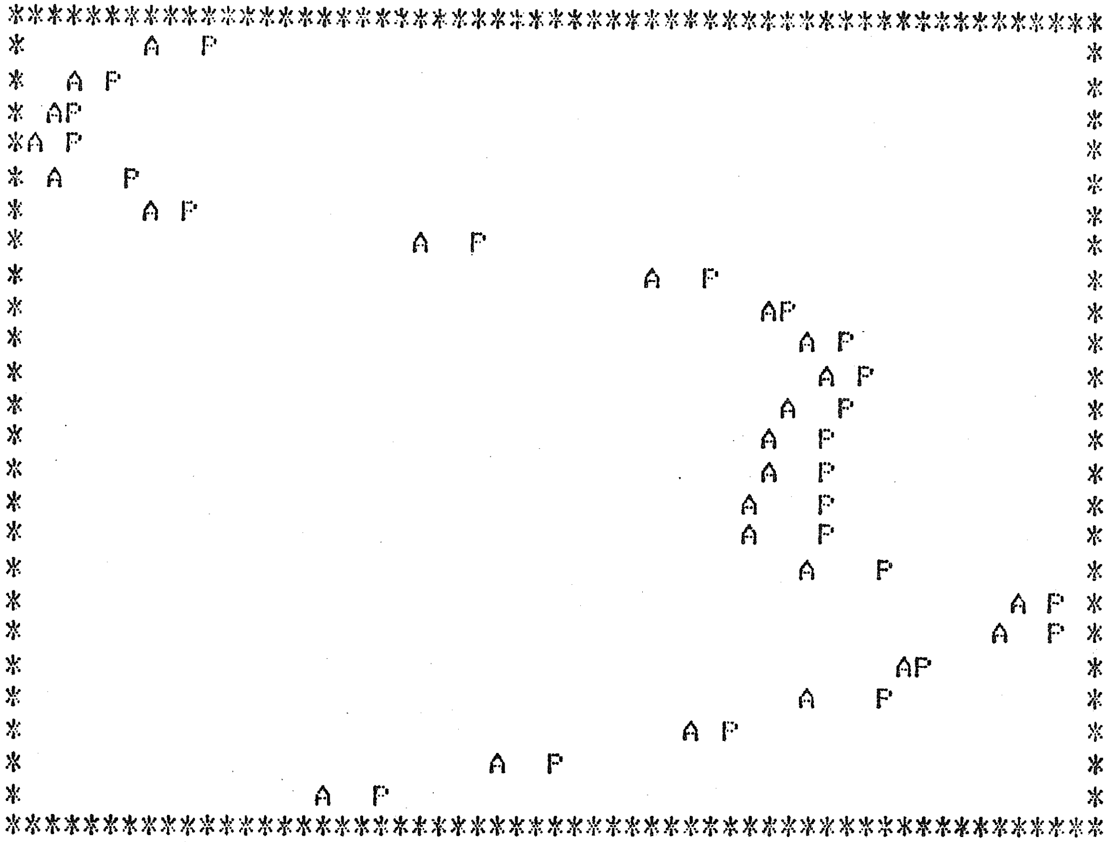
HR	AVE	PEAK
1	1733.	1896.
2	1674.	1787.
3	1631.	1751.
4	1637.	1762.
5	1664.	1815.
6	1749.	1890.
7	1989.	2117.
8	2173.	2324.
9	2260.	2392.
10	2270.	2393.
11	2297.	2359.
12	2268.	2313.
13	2223.	2277.
14	2210.	2268.
15	2191.	2251.
16	2173.	2233.
17	2213.	2292.
18	2438.	2534.
19	2467.	2533.
20	2375.	2459.
21	2301.	2377.
22	2190.	2281.
23	1989.	2068.
24	1796.	1851.



THERE ARE 5 THURSDAYS
IN THE PERIOD 1/ 1/- 1/31/.

AVERAGE AND PEAK LOADS FOR FRIDAYS

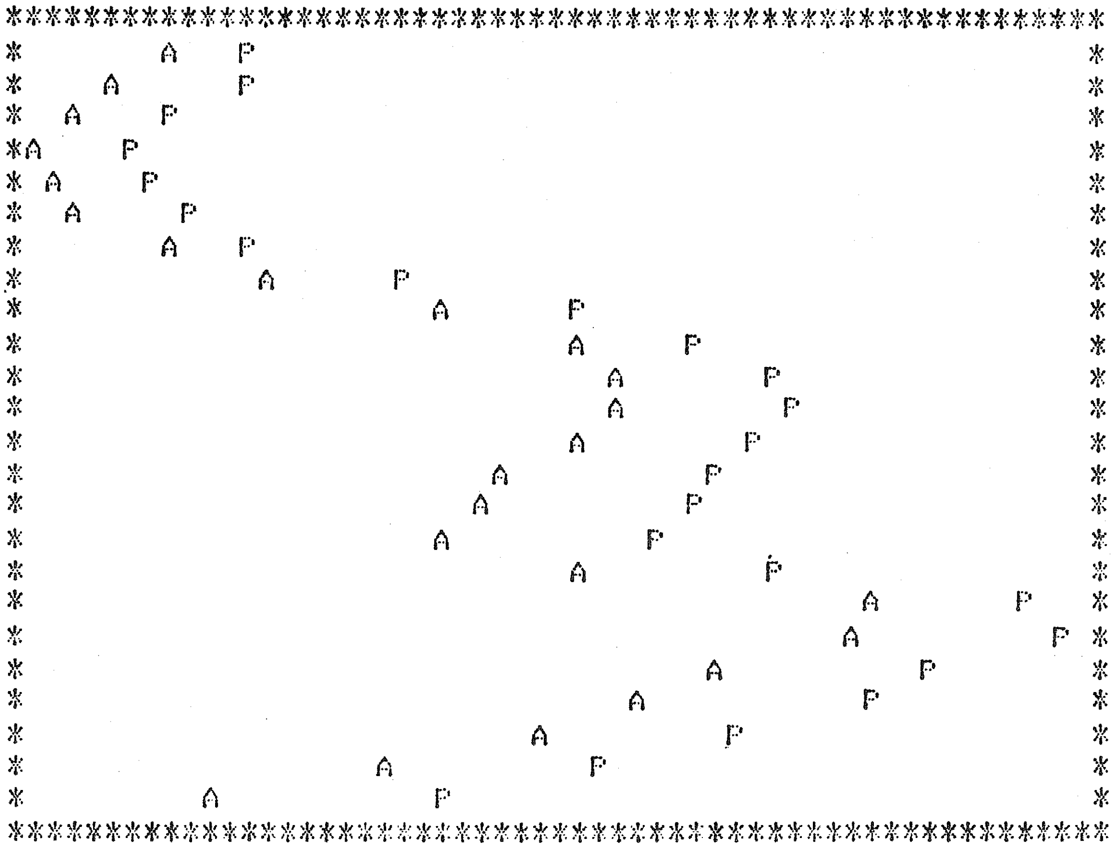
HR	AVE	PEAK
1	1693.	1743.
2	1636.	1663.
3	1606.	1622.
4	1594.	1635.
5	1606.	1670.
6	1702.	1737.
7	1927.	1988.
8	2141.	2185.
9	2233.	2258.
10	2271.	2297.
11	2286.	2324.
12	2259.	2309.
13	2238.	2279.
14	2228.	2293.
15	2214.	2282.
16	2217.	2289.
17	2272.	2339.
18	2463.	2485.
19	2440.	2489.
20	2347.	2369.
21	2269.	2331.
22	2161.	2199.
23	2000.	2051.
24	1840.	1902.



THERE ARE 4 FRIDAYS
IN THE PERIOD 1/ 1/- 1/31/.

AVERAGE AND PEAK LOADS FOR SATURDAYS

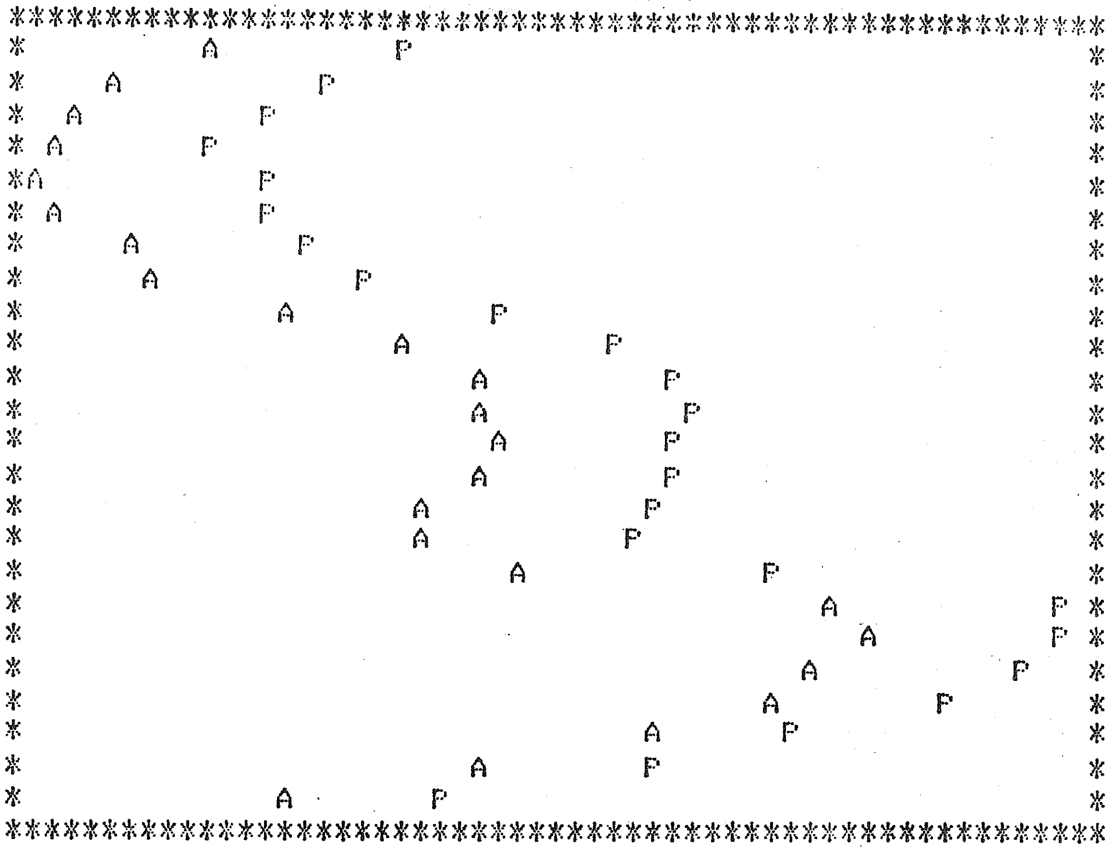
HR	AVE	PEAK
1	1725.	1778.
2	1681.	1775.
3	1640.	1728.
4	1615.	1696.
5	1624.	1708.
6	1648.	1731.
7	1717.	1787.
8	1804.	1910.
9	1929.	2040.
10	2037.	2133.
11	2066.	2200.
12	2072.	2214.
13	2039.	2175.
14	1988.	2152.
15	1964.	2135.
16	1934.	2096.
17	2034.	2196.
18	2263.	2398.
19	2250.	2422.
20	2151.	2319.
21	2091.	2264.
22	2004.	2168.
23	1897.	2063.
24	1745.	1932.



THERE ARE 4 SATURDAYS
IN THE PERIOD 1/ 1/- 1/31/.

AVERAGE AND PEAK LOADS FOR SUNDAYS

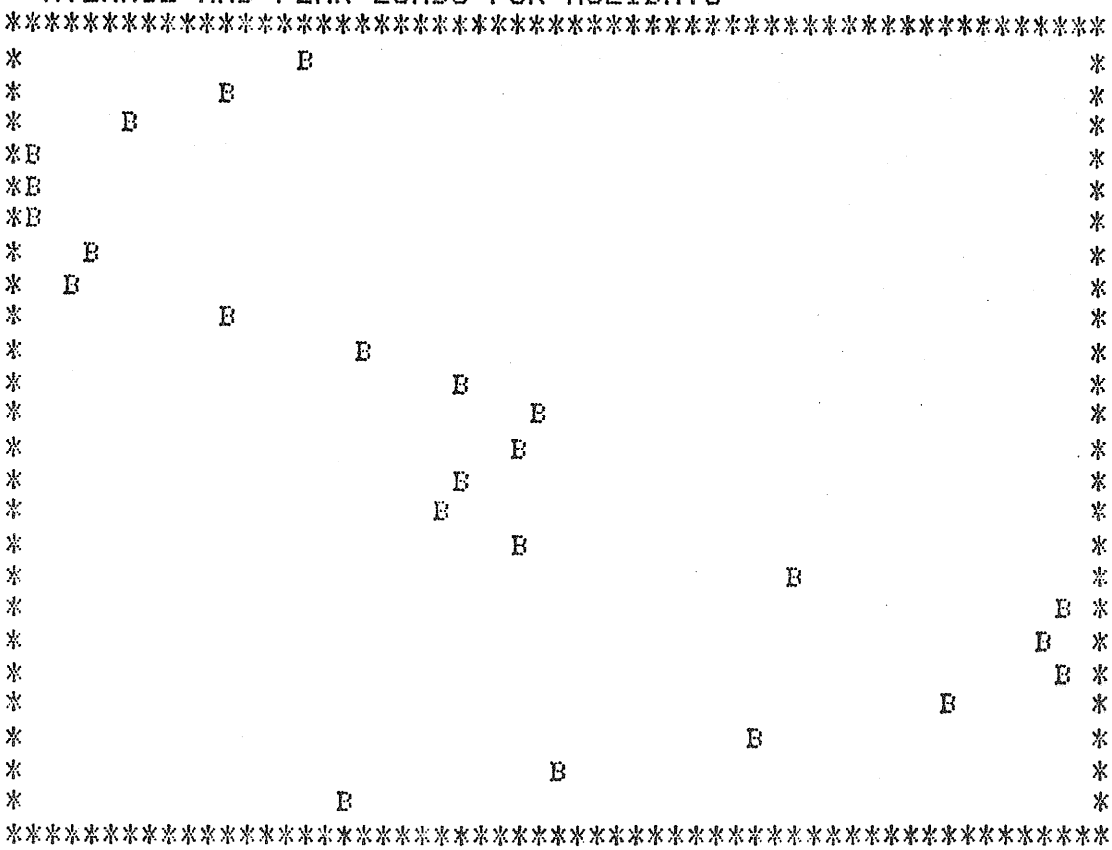
HR	AVE	PEAK
1	1673.	1829.
2	1600.	1775.
3	1572.	1726.
4	1551.	1683.
5	1539.	1719.
6	1555.	1732.
7	1614.	1756.
8	1638.	1797.
9	1738.	1912.
10	1835.	2010.
11	1890.	2054.
12	1904.	2066.
13	1906.	2058.
14	1891.	2055.
15	1856.	2031.
16	1846.	2027.
17	1933.	2127.
18	2182.	2362.
19	2202.	2357.
20	2155.	2330.
21	2128.	2266.
22	2039.	2148.
23	1903.	2034.
24	1748.	1860.



THERE ARE 4 SUNDAYS
IN THE PERIOD 1/ 1/- 1/31/.

AVERAGE AND PEAK LOADS FOR HOLIDAYS

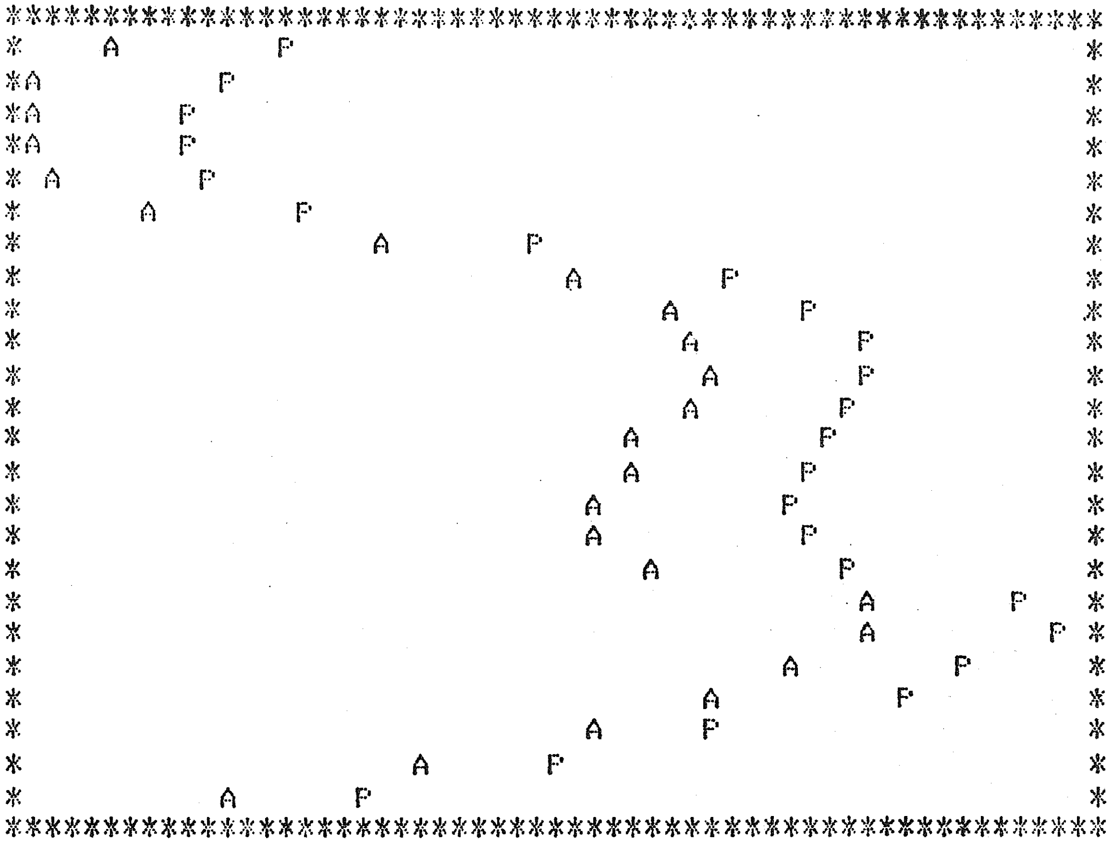
HR	AVE	PEAK
1	1597.	1597.
2	1543.	1543.
3	1493.	1493.
4	1435.	1435.
5	1434.	1434.
6	1436.	1436.
7	1464.	1464.
8	1455.	1455.
9	1546.	1546.
10	1627.	1627.
11	1682.	1682.
12	1730.	1730.
13	1720.	1720.
14	1690.	1690.
15	1675.	1675.
16	1717.	1717.
17	1880.	1880.
18	2037.	2037.
19	2024.	2024.
20	2039.	2039.
21	1976.	1976.
22	1858.	1858.
23	1743.	1743.
24	1617.	1617.



THERE ARE 1 HOLIDAYS
IN THE PERIOD 1/ 1/- 1/31/.

AVERAGE AND PEAK LOADS FOR WEEKDAYS

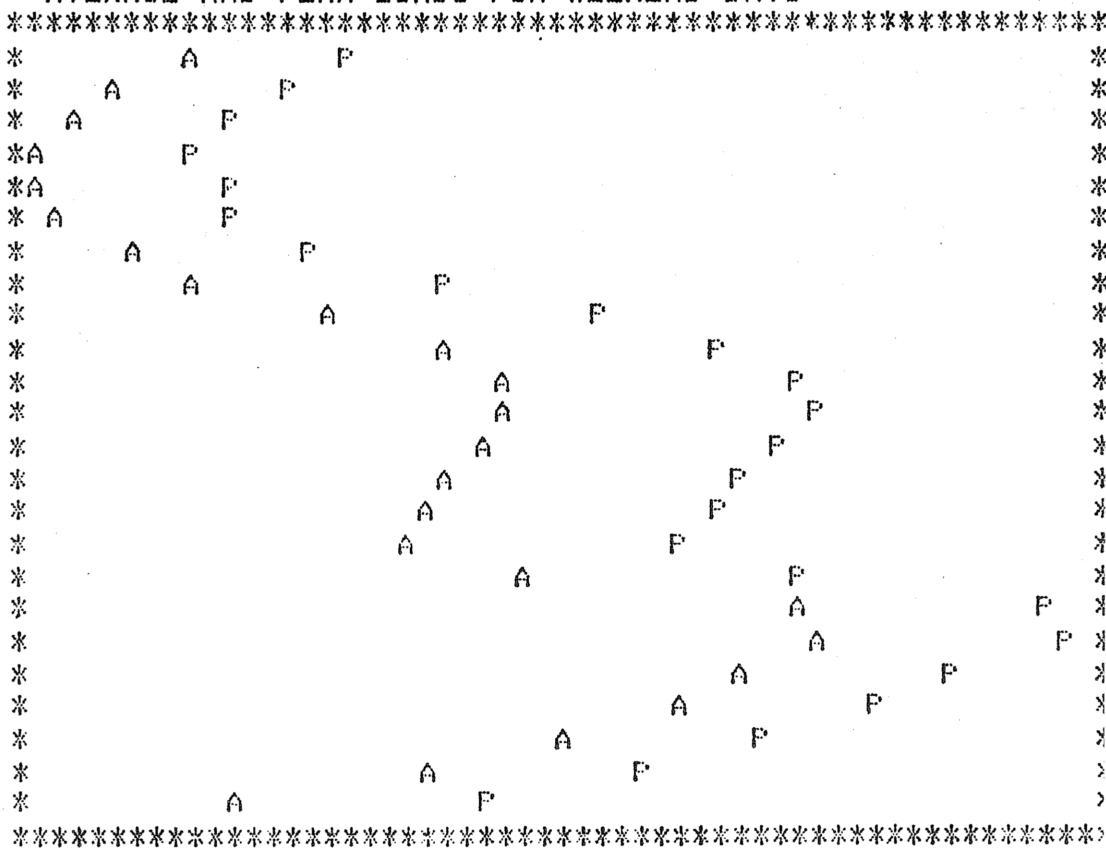
HR	AVE	PEAK
1	1703.	1896.
2	1633.	1820.
3	1638.	1798.
4	1631.	1787.
5	1653.	1815.
6	1745.	1909.
7	1993.	2149.
8	2191.	2340.
9	2275.	2419.
10	2303.	2478.
11	2316.	2485.
12	2295.	2466.
13	2251.	2439.
14	2237.	2422.
15	2202.	2396.
16	2195.	2422.
17	2266.	2458.
18	2480.	2630.
19	2482.	2675.
20	2396.	2570.
21	2320.	2515.
22	2198.	2312.
23	2021.	2164.
24	1830.	1965.



THERE ARE 22 WEEKDAYS
IN THE PERIOD 1/ 1/- 1/31/.

AVERAGE AND PEAK LOADS FOR WEEKEND DAYS

HR	AVE	PEAK
1	1688.	1829.
2	1629.	1775.
3	1593.	1728.
4	1567.	1696.
5	1565.	1719.
6	1583.	1732.
7	1643.	1787.
8	1691.	1910.
9	1802.	2040.
10	1902.	2133.
11	1945.	2200.
12	1959.	2214.
13	1945.	2175.
14	1912.	2152.
15	1884.	2135.
16	1871.	2096.
17	1972.	2196.
18	2202.	2398.
19	2204.	2422.
20	2140.	2330.
21	2095.	2266.
22	2003.	2168.
23	1882.	2063.
24	1732.	1932.



THERE ARE 9 WEEKEND DAYS
IN THE PERIOD 1/ 1/- 1/31/.

THE LOAD FREQUENCY AND DURATION (FRED)
DATA ANALYSIS PROGRAM
USER'S MANUAL

prepared by

THE NATIONAL REGULATORY RESEARCH INSTITUTE
2130 Neil Avenue
Columbus, Ohio 43210

for the

Colorado Public Utilities Commission
in partial fulfillment of
Contract No. 900342

May 1981

This report was prepared by The National Regulatory Research Institute under a contract with the Colorado Public Utilities Commission. The views and opinions of the authors do not necessarily state or reflect the views, opinions, or policies of the Colorado Public Utilities Commission or The National Regulatory Research Institute.

Reference to trade names or specific commercial products, commodities, or services in this report does not represent or constitute an endorsement, recommendation, or favoring by The National Regulatory Research Institute of the specific commercial product, commodity, or service.

TABLE OF CONTENTS

LIST OF FIGURES

PREFACE

The Load Frequency and Duration (FRED) Data Analysis Program was developed at The National Regulatory Research Institute (NRRI) at The Ohio State University to facilitate analyses of electric utility hourly system load data upon which to establish costing periods for time-of-use electric rates. The output of FRED may also be used as input data to other NRRI computer programs if further analysis of electric utility load characteristics and time-of-use pricing policies is required.

This user's manual provides information necessary to operate the FRED program including input data and program control data for operation of FRED in the interactive, batch, or remote batch mode, and sample output data from the FRED program.

INTRODUCTION

FRED is an interactive and/or batch-operated program that is used to analyze the load demand characteristics of electric utilities. The time period analyzed is one year. Any subperiod one day to one year can be analyzed independently. For each user specified time period, FRED has the capability to print and/or plot the electric utility peakload demand, the average load, or the load demand pattern. The latter is provided in terms of the period load duration, load probability, or load frequency curves.

CHAPTER 1

DESCRIPTION OF THE FRED PROGRAM

The FRED program was developed at The Ohio State University (OSU) to calculate and plot the load frequency, load duration, and load probability curves of an electric utility for specified periods of operation. FRED also calculates and plots the hourly average load curves and hourly peak-load curves of the utility for specific periods of time. The hourly load demand data for the system in the Edison Electric Institute (EEI) format is the basic source of input. FRED provides the means for analyzing the characteristics of the electric load and also provides inputs to a variety of programs available at NRRI that are used to analyze various aspects of electric utility operations.[1] This program is placed on disk storage at The Ohio State University for remote access through time-sharing terminals or may be installed on other computers for on-site use.

The hourly load demand data, used as input to FRED, are stored on disks and can optionally be printed during the execution of the program. The user of the code has the option of analyzing data from any one day to one full year. The load frequency, load duration, and load probability curves are calculated by arranging the data in order of load magnitude. In other words, the data are ordered from the lowest hourly usage to the peak hourly usage regardless of the time of day in which the usage occurred.

The load frequency curve shows load in megawatts on the horizontal (x-axis), ranging from just below the minimum hourly load to just above the peak hourly usage. On the vertical (y-axis), the number of hours for which

---

[1]These are the PCS, WASP, CERES, and LOAD CONTROL Programs. See S. Nakamura, et al., Electric Utility Analysis Package: A Set of Computer Programs Designed to Assist in the Analysis of Electric Operations, (Columbus, Ohio: The National Regulatory Research Institute, October 1977).

the system load was greater than or equal to the x-axis load value but less than the next x-axis load value are given. The load duration curve shows on the x-axis the number of hours for which the system load exceeded the load value on the y-axis. The load probability curve shows the probability that system load will exceed a given value.

The FRED code can be used to calculate and display the following:

1. For the given period, determine the peak system demand and the month, day, and hour it occurred, the load factor for the period, and the megawatt-hours generated.

2. List the hourly load data for a given period.

3. Calculate and plot the load frequency curve for a given period.

4. Calculate and plot the load duration curve for a given period.

5. Calculate and plot the load probability curve for a given period.

6. Calculate, list, and plot the average hourly load for each day of the week for a given period.

7. Calculate, list, and plot the peak hourly load for each day of the week for a given period.

The user has the option of selecting any combinations of outputs 2 through 7, while output 1 is always given.

In specifying the period of interest, the user has many options. These include the following:

1. Specifying the starting month and day of the period of interest and the ending month and day. (These are inclusive days.)

2. Within that period defined in item 1, specifying the individual days of the week to be used in the calculations.

3. Specifying the range of hours within each day to be used in the calculations. (These are inclusive hours.)

4. Specifying a range of hours, within those hours specified in item 3, not to be used in the calculation. (These are exclusive hours.)

Using these four options the user could, for example, analyze the hourly load data for the period May 15 through August 10, for weekdays only (excluding holidays), for the hours starting at 10:00 a.m. and ending at 7:00 p.m., excluding the hours of 12 noon and 1:00 p.m.

In summary, the outputs options and the options in specifying the period of interest are many. This gives FRED much versatility.

CHAPTER 2

INPUT DATA

Two types of input data are necessary, hourly load demand data, and program control data.

Load Demand Data

Hourly load data should be provided for the time period under consideration in Edison Electric Institute format. Figure 2-1 shows the EEI format specifications. The information in columns 8-15 contain the electric utility's code number and are not currently used by FRED and may be omitted. Nonexisting dates, for example, April 31, must be set to zero. Hourly load data in EEI format are usually provided for a 12-month period. The time period considered by FRED must be greater than one day and less then or equal to one year.

Control Data

Program control data can either be provided by responding to the program operations in the interactive mode[2] or by preparing an input file (deck of cards) for the batch execution mode. This file contains the responses to the questions that FRED asks in the interactive mode. In other words, FRED's interactive operation is preempted by a priori responding to FRED's questions. A sample interactive dialogue is given in figure 2-2. The corresponding file for batch execution is listed in figure 2-3. Note the following differences between the listing of control data in

---

[2]The FRED operating modes are discussed in chapter 3.

ORGANIZATION OF EEI LOAD CARDS

CARD 1 Column Number(s)	Description of Parameter	Reading Format
1-2	Month	I2
3-4	Day	I2
5-6	Year	I2
7	#1 for a.m.	I1
8-15	EEI code number for utility	I8
16	Day of week: 0=Dummy Day; 1=Monday; 7=Sunday; 8=Holiday	I9
17	Time zone 1=EST; 2-EDT	I1
18-20	Blank	3X
21-80	Hourly load in terms in MWh/hr. for the hours ending at 1:00 a.m. through 12 noon. Each load is given five columns and is right justified.	12I5 or 12F5.0
CARD 2		
1-6	Same as in card 1	3I2
7	#2 for p.m.	I1
8-10	First three digits of EEI utility ID number	I3
11-13	Average temperature for the day	I3
14-16	Departure from normal average for that day	I3
17-20	Blank	4X
21-90	Same as in card 1 but for the hours ending 1:00 p.m. through 12 midnight.	12I5 or 12F5.0

Figure 2-1 Edison Electric Institute format specifications for hourly system load data.

figures 2-2 and 2-3. First, there are no questions asked and no blank lines in the batch control data (figure 2-3). Second, the user responses (small case letters) in figure 2-2 are echo printed by the program. In the case of figure 2-3, only the user responses appear. Last, the response to the first question asked by FRED in figure 2-2 may be either YES or NO in interactive mode. However, in the batch input file the first line must always be YES.

```
                    **** FRED ****

     LOAD FREQUENCY, LOAD DURATION, LOAD PROBABILITY
     PEAK DAY, AND AVERAGE DAY CODE, SEPT., 1976
            THE OHIO STATE UNIVERSITY
            NUCLEAR ENGINEERING DEPARTMENT
            COLUMBUS, OHIO 43210

            REVISED BY THE NATIONAL REGULATORY
            RESEARCH INSTITUTE.     4/81

            FOR INFORMATION CONTACT :
            JEFFREY SHIH
            THE NATIONAL REGULATORY RESEARCH INSTITUTE
            THE OHIO STATE UNIVERSITY
            2130 NEIL AVENUE
            COLUMBUS, OHIO 43210
            (614) 422-9404


IF YOU WISH TO EXECUTE FRED VIA TERMINAL,
ENTER YES;
OTHERWISE ENTER NO TO CREATE AN INPUT FILE
FOR BATCH EXECUTION.
no
NO
ENTER COMPANY NAME AND YEAR OF DATA
XXXX 19XX
psco 1980
PSCO 1980
THE INCLUSIVE TIME PERIOD OF INTEREST IS SPECIFIED BY TYPING THE
STARTING MONTH AND DAY AND THE ENDING MONTH AND DAY IN THE FORMAT
--/--/--/--. FOR EXAMPLE, TO SPECIFY JUNE 1 THROUGH OCTOBER 15 TYPE
06/01/10/15 THEN PRESS RETURN.
01/01/01/31
 1/ 1/ 1/31
```

Figure 2-2 Sample control data entered via the interactive dialogue mode

```
DO YOU WISH TO SPECIFY THE DAYS OF THE WEEK FOR WHICH
THE CALCULATIONS ARE TO BE MADE?
no
NO
DO YOU WISH TO SPECIFY THE HOURS OF THE DAY FOR WHICH
THE CALCULATIONS ARE TO BE MADE?
no
NO
DO YOU WISH TO SPECIFY A RANGE OF HOURS DURING THE DAY
WHICH ARE NOT USED IN THE CALCULATION?
no
NO
DO YOU WISH TO SEE THE SELECTED DATA?
no
NO
DO YOU WISH TO SEE THE LOAD FREQUENCY PLOT?
yes
YES
DO YOU WISH TO SEE THE LOAD DURATION CURVE?
yes
YES
DO YOU WISH TO SEE THE LOAD PROBABILITY CURVE?
yes
YES
DO YOU WISH TO HAVE AN AVERAGE AND PEAK DAY CALCULATED
FOR EACH DAY OF THE WEEK?
no
NO


DO YOU WISH TO EXAMINE A DIFFERENT CASE WITHIN THE SAME YEAR?
no
NO
NORMAL EXIT FROM INPUT PREPARATION MODE OF FRED CODE
EXECUTE FRED ON BATCH

READY
```

Figure 2-2 (continued)

```
YES
PSCO 1980
 1  1  1 31
NO
NO
NO
NO
YES
YES
YES
NO
NO
```

Figure 2-3 Sample control data for batch execution

CHAPTER 3
OPERATION

FRED can be used in one of four operating modes:

a. Interactive mode through access at The Ohio State University computer.
b. Interactive mode at the local user's computer facility.
c. Batch mode at the local user's computer facility.
d. Remote batch mode at the local user's computer facility.

All four operating modes use the same input data, but the means through which these data are provided are different. Appendix A provides detailed procedures for accessing FRED interactively at The Ohio State University computer facility. These procedures are specifically adapted for The Ohio State University computer operating system and cannot be duplicated unless the local user's computer supports an identical operating system. However, the remaining modes of operation are not operating-system specific and can be easily adapted to the user's local computer environment.

The examples that are shown in this chapter have been tested at The Ohio State University AMDAHL 460V6 computer with the IBM OS/VS2 operating system.

Interactive Operating Mode

The fortran source code of FRED must be stored on disk file. Let the file name be

FRED.FORT

The hourly load data must also be on disk file. Its name may indicate the electric utility company and year of data: for example

PSCO80.DATA

The load data file must be allocated to logical unit 10. In the IBM environment, this can be accomplished through the time-sharing (TSO) command ALLOCATE:

```
ALLOCATE DA(FRED.NAME.LOAD.DATA) F(FT1ØFØØ1)
```

Now the user is ready to run the program through this TSO command RUN:

```
RUN FRED.FORT
```

The program will respond with the control data dialogue. In the above, it is assumed that logical units 5 and 6 are allocated by default to terminal READ and WRITE operations respectively.

A sample FRED execution is shown in figure 3-1. Note that the first part of figure 3-1 contains the control data input dialogue and is identical to figure 2-2 except for the response to the first question. This is YES in figure 3-1 because FRED execution is desired. The second part of the figure starts after the input dialogue and contains the following.

a. The peak load in megawatts (MW) and the month, day, and hour it occurred.
b. The load factor for the period.
c. List of the hourly load data by month, day, and hour. (The hour is expressed in military notation.)
d. The load frequency curve for the period.
e. The load duration curve for the period.
f. The load probability curve for the period.

```
**** FRED ****


        LOAD FREQUENCY, LOAD DURATION, LOAD PROBABILITY
        PEAK DAY, AND AVERAGE DAY CODE, SEPT., 1976
                 THE OHIO STATE UNIVERSITY
                 NUCLEAR ENGINEERING DEPARTMENT
                 COLUMBUS, OHIO 43210

                 REVISED BY THE NATIONAL REGULATORY
                 RESEARCH INSTITUTE.       4/81

                 FOR INFORMATION CONTACT :
                 JEFFREY SHIH
                 THE NATIONAL REGULATORY RESEARCH INSTITUTE
                 THE OHIO STATE UNIVERSITY
                 2130 NEIL AVENUE
                 COLUMBUS, OHIO 43210
                 (614) 422-9404


IF YOU WISH TO EXECUTE FRED VIA TERMINAL,
ENTER YES;
OTHERWISE ENTER NO TO CREATE AN INPUT FILE
FOR BATCH EXECUTION.
yes
YES
ENTER COMPANY NAME AND YEAR OF DATA
XXXX 19XX
psco 1980
PSCO 1980
THE INCLUSIVE TIME PERIOD OF INTEREST IS SPECIFIED BY TYPING THE
STARTING MONTH AND DAY AND THE ENDING MONTH AND DAY IN THE FORMAT
--/--/--/--. FOR EXAMPLE, TO SPECIFY JUNE 1 THROUGH OCTOBER 15 TYPE
06/01/10/15 THEN PRESS RETURN.
01/01/01/31
 1/ 1/ 1/31
DO YOU WISH TO SPECIFY THE DAYS OF THE WEEK FOR WHICH
THE CALCULATIONS ARE TO BE MADE?
```

Figure 3-1 Sample input/output list for interactive mode

```
no
NO
DO YOU WISH TO SPECIFY THE HOURS OF THE DAY FOR WHICH
THE CALCULATIONS ARE TO BE MADE?
no
NO
DO YOU WISH TO SPECIFY A RANGE OF HOURS DURING THE DAY
WHICH ARE NOT USED IN THE CALCULATION?
no
NO
DO YOU WISH TO SEE THE SELECTED DATA?
yes
YES
DO YOU WISH TO SEE THE LOAD FREQUENCY PLOT?
yes
YES
DO YOU WISH TO SEE THE LOAD DURATION CURVE?
yes
YES
DO YOU WISH TO SEE THE LOAD PROBABILITY CURVE?
yes
YES
DO YOU WISH TO HAVE AN AVERAGE AND PEAK DAY CALCULATED
FOR EACH DAY OF THE WEEK?
no
NO
```

Figure 3-1 (continued)

PEAK MW   MO/DA/HR
2675.   1/28/19

THE LOAD FACTOR IS 75.6%

THE TOTAL MEGAWATT-HOUR SALES ARE 1505251.

MO/DA		D	AM/PM 01	02	03	04	05	06	07	08	09	10	11	12
			13	14	15	16	17	18	19	20	21	22	23	24
1	1	8	1597	1543	1493	1435	1434	1436	1464	1455	1546	1627	1682	1730
			1720	1690	1675	1717	1880	2037	2024	2039	1976	1858	1743	1617
1	2	3	1533	1508	1482	1499	1516	1589	1824	2044	2186	2234	2265	2259
			2232	2189	2194	2211	2280	2505	2473	2381	2275	2185	2012	1793
1	3	4	1733	1692	1618	1620	1636	1778	1989	2137	2270	2252	2342	2313
			2277	2268	2251	2233	2292	2534	2489	2386	2289	2197	1992	1790
1	4	5	1699	1647	1582	1601	1603	1712	1916	2095	2172	2215	2218	2199
			2179	2164	2145	2147	2228	2433	2371	2304	2205	2119	1945	1789
1	5	6	1668	1623	1591	1600	1572	1603	1710	1770	1841	1985	2008	2006
			1973	1919	1863	1833	1930	2204	2139	2039	1971	1897	1823	1664
1	6	7	1574	1521	1496	1461	1434	1456	1517	1590	1691	1806	1894	1919
			1944	1937	1861	1855	1999	2221	2248	2207	2146	2054	1959	1783
1	7	1	1676	1688	1654	1651	1681	1779	2054	2247	2311	2361	2385	2368
			2330	2303	2237	2222	2363	2590	2588	2467	2388	2274	2110	1903
1	8	2	1774	1730	1727	1718	1716	1824	2058	2255	2328	2303	2351	2344
			2297	2289	2299	2299	2406	2581	2534	2442	2357	2226	2080	1874
1	9	3	1749	1713	1689	1694	1739	1814	2065	2242	2329	2314	2317	2292
			2243	2211	2161	2173	2270	2516	2482	2394	2321	2193	1996	1771
1	10	4	1688	1613	1566	1625	1623	1677	1932	2147	2198	2209	2218	2239
			2184	2159	2164	2161	2269	2476	2479	2377	2323	2194	1979	1805
1	11	5	1743	1663	1619	1635	1670	1737	1988	2185	2257	2297	2306	2275
			2241	2225	2186	2175	2242	2475	2453	2351	2261	2169	1996	1825
1	12	6	1715	1651	1612	1580	1564	1622	1682	1754	1916	2032	2031	2012
			1993	1906	1879	1873	1983	2190	2160	2060	2013	1913	1771	1608
1	13	7	1595	1503	1457	1472	1441	1436	1526	1504	1586	1657	1744	1757
			1754	1758	1718	1691	1759	2036	2048	2001	1991	1907	1750	1585
1	14	1	1528	1506	1472	1459	1513	1592	1844	2100	2193	2217	2241	2239
			2163	2178	2167	2166	2175	2435	2415	2305	2251	2129	1894	1688
1	15	2	1610	1543	1553	1546	1536	1616	1973	2118	2198	2253	2238	2223
			2171	2188	2118	2130	2175	2394	2361	2320	2261	2109	1951	1726
1	16	3	1623	1595	1563	1535	1570	1654	1911	2131	2186	2230	2234	2223
			2166	2165	1866	1895	2219	2446	2421	2336	2257	2152	1954	1803
1	17	4	1670	1629	1615	1591	1625	1704	1964	2166	2259	2272	2289	2245
			2207	2204	2150	2131	2184	2398	2433	2334	2273	2156	2000	1778
1	18	5	1672	1626	1622	1569	1585	1687	1898	2117	2244	2288	2324	2309
			2279	2293	2282	2289	2278	2485	2447	2369	2277	2155	2008	1843
1	19	6	1739	1675	1630	1584	1650	1635	1688	1781	1918	1997	2024	2056
			2016	1975	1978	1933	2026	2259	2280	2184	2117	2037	1929	1777

Figure 3-1 (continued)

```
1 20 7 1693 1599 1607 1589 1561 1596 1658 1659 1764 1868 1867 1872
       1868 1813 1814 1812 1846 2108 2156 2080 2108 2047 1870 1762
1 21 1 1644 1637 1639 1577 1631 1732 1962 2193 2296 2349 2352 2346
       2278 2255 2257 2259 2330 2541 2494 2437 2371 2197 2035 1831
1 22 2 1706 1079 1695 1683 1694 1810 2057 2265 2316 2327 2346 2310
       2247 2235 2190 2177 2240 2449 2469 2429 2361 2223 2025 1897
1 23 3 1733 1679 1685 1651 1706 1788 2035 2194 2264 2309 2282 2262
       2210 2185 2158 2119 2153 2404 2437 2375 2270 2166 2003 1780
1 24 4 1677 1647 1603 1588 1619 1697 1941 2092 2179 2222 2277 2237
       2180 2173 2146 2126 2106 2315 2403 2318 2245 2122 1904 1756
1 25 5 1659 1606 1601 1571 1566 1673 1905 2165 2258 2282 2295 2252
       2253 2231 2241 2258 2339 2460 2489 2363 2331 2199 2051 1902
1 26 6 1778 1775 1728 1696 1708 1731 1787 1910 2040 2133 2200 2214
       2175 2152 2135 2096 2196 2398 2422 2319 2264 2168 2063 1932
1 27 7 1829 1775 1726 1683 1719 1732 1756 1797 1912 2010 2054 2066
       2058 2055 2031 2027 2127 2362 2357 2330 2266 2148 2034 1860
1 28 1 1762 1739 1725 1748 1741 1835 2136 2324 2419 2478 2485 2466
       2439 2422 2396 2422 2458 2630 2675 2570 2515 2312 2164 1965
1 29 2 1853 1820 1798 1787 1800 1909 2149 2327 2384 2440 2456 2443
       2371 2353 2332 2305 2383 2570 2610 2517 2432 2298 2163 1958
1 30 3 1827 1770 1787 1781 1781 1900 2120 2340 2413 2417 2373 2346
       2302 2267 2247 2188 2254 2459 2548 2473 2407 2305 2122 1942
1 31 4 1896 1787 1751 1762 1815 1890 2117 2324 2392 2393 2359 2306
       2265 2246 2246 2212 2216 2467 2533 2459 2377 2281 2068 1851
 LOAD FREQUENCY CURVE FOR THE PERIOD  1/ 1/ 1- 1/31/24.

 LOAD     FREQ
  MW       HR   *******************************************************
1079.0     1.0 +                                                      *
1134.0     0.0 +                                                      *
1189.1     0.0 +                                                      *
1244.1     0.0 +                                                      *
1299.1     0.0 +                                                      *
1354.2     0.0 +                                                      *
1409.2     5.1 +--+                                                   *
1464.2    10.0 +------+                                               *
1519.3    20.0 +-------------+                                        *
1574.3    33.2 +-----------------------+                              *
1629.3    41.9 +------------------------------+                       *
1684.4    45.0 +--------------------------------+                     *
1739.4    44.0 +-------------------------------+                      *
1794.4    37.9 +---------------------------+                          *
1849.5    28.0 +-------------------+                                  *
1904.5    31.0 +----------------------+                               *
1959.6    22.0 +---------------+                                      *
2014.6    37.0 +--------------------------+                           *
2069.6    21.9 +---------------+                                      *
2124.7    37.1 +--------------------------+                           *
2179.7    69.0 +---------------------------------------------------+  *
2234.7    70.1 +---------------------------------------------------+  *
2289.8    63.0 +----------------------------------------------+       *
2344.8    45.0 +--------------------------------+                     *
2399.8    29.0 +--------------------+                                 *
2454.9    31.0 +---------------------+                                *
2509.9    12.0 +-------+                                              *
2564.9     7.0 +----+                                                 *
2620.0     2.0 ++                                                     *
2675.0     1.0 +                                                      *
                *******************************************************
```

Figure 3-1 (continued)

```
LOAD DURATION CURVE FOR THE PERIOD  1/ 1/ 1- 1/31/24.

TIME     LOAD
 HRS      MW   *BASE LOAD**********************************************
  1.0  2675.0 *--/  /---------------------------------------------+  *
 26.6  2482.2 *--/  /----------------------------------------+       *
 52.2  2434.6 *--/  /---------------------------------------+        *
 77.9  2388.3 *--/  /--------------------------------------+         *
103.5  2353.3 *--/  /-------------------------------------+          *
129.1  2323.1 *--/  /------------------------------------+           *
154.7  2300.3 *--/  /------------------------------------+           *
180.3  2277.3 *--/  /-----------------------------------+            *
206.0  2260.1 *--/  /-----------------------------------+            *
231.6  2244.2 *--/  /----------------------------------+             *
257.2  2218.7 *--/  /---------------------------------+              *
282.8  2197.3 *--/  /---------------------------------+              *
308.4  2174.8 *--/  /--------------------------------+               *
334.1  2155.0 *--/  /--------------------------------+               *
359.7  2118.7 *--/  /-------------------------------+                *
385.3  2055.5 *--/  /-----------------------------+                  *
410.9  2017.9 *--/  /----------------------------+                   *
436.6  1971.4 *--/  /---------------------------+                    *
462.2  1915.0 *--/  /-------------------------+                      *
487.8  1869.3 *--/  /------------------------+                       *
513.4  1815.9 *--/  /-----------------------+                        *
539.0  1778.2 *--/  /----------------------+                         *
564.7  1747.7 *--/  /---------------------+                          *
590.3  1713.5 *--/  /--------------------+                           *
615.9  1688.0 *--/  /--------------------+                           *
641.5  1648.3 *--/  /------------------+                             *
667.1  1619.4 *--/  /------------------+                             *
692.8  1591.0 *--/  /-----------------+                              *
718.4  1525.9 *--/  /---------------+                                *
744.0  1079.0 *--/  /---+                                            *
              *BASE LOAD**********************************************
```

Figure 3-1 (continued)

```
LOAD PROBABILITY CURVE FOR THE PERIOD  1/ 1/ 1- 1/31/24.

 LOAD     PROB
  MW                *******************************************************
1079.0 1.00000 *------------------------------------------------------+
1134.0 0.99866 *-----------------------------------------------------+
1189.1 0.99866 *-----------------------------------------------------+
1244.1 0.99866 *-----------------------------------------------------+
1299.1 0.99866 *-----------------------------------------------------+
1354.2 0.99866 *-----------------------------------------------------+
1409.2 0.99866 *-----------------------------------------------------+
1464.2 0.99181 *-----------------------------------------------------+
1519.3 0.97840 *----------------------------------------------------+
1574.3 0.95150 *---------------------------------------------------+
1629.3 0.90693 *-------------------------------------------------+
1684.4 0.85057 *----------------------------------------------+
1739.4 0.79013 *-------------------------------------------+
1794.4 0.73106 *----------------------------------------+
1849.5 0.68012 *------------------------------------+
1904.5 0.64250 *----------------------------------+
1959.6 0.60079 *--------------------------------+
2014.6 0.57120 *------------------------------+
2069.6 0.52145 *----------------------------+
2124.7 0.49198 *-------------------------+
2179.7 0.44216 *----------------------+
2234.7 0.34944 *------------------+
2289.8 0.25522 *-------------+
2344.8 0.17060 *--------+
2399.8 0.11016 *----+
2454.9 0.07122 *--+
2509.9 0.02957 *+
2564.9 0.01346 *+
2620.0 0.00403 *+
2675.0 0.00134 *+
               *******************************************************


DO YOU WISH TO EXAMINE A DIFFERENT CASE WITHIN THE SAME YEAR?
no
NO
NORMAL EXIT FROM INTERACTIVE EXECUTION OF FRED CODE
SESSION ENDED

READY
```

Figure 3-1 (continued)

Batch Operating Mode

It is obvious from figure 3-1 that FRED's output can be very lengthy; therefore, it is often desirable to run the program on a batch mode.

The load data must again be stored on disk file, as in the interactive mode described in the previous section. Let the load data name be

"FRED.NAME.LOAD.DATA"

The set of Job Control Language cards (JCL) that will execute FRED at the OSU computer is listed below:

```
// EXEC PGM=FORTRUN
//CMP DD *

     Fortran source program

/*
//SYSIN DD *

     Control data deck

/*
//GO.FT1ØFØØ1 DD DSN=FRED.NAME.LOAD.DATA,DISP=SHR
/*
//
```

The control data deck is prepared as described in chapter 2 and listed in figure 2.2.

Remote Batch Operating Mode

FRED is used first to create the control data file and then to execute it in batch mode. In this manner, long printouts can be retrieved from the high speed printer instead of from the terminal, thus saving considerable user's time. There are two steps in this process:

Step 1: Execute FRED interactively as explained in the previous section and listed in table 3-1, but with the following changes. Allocate a new disk file to logical unit 11 using the FREE, ALLOCATE, and ATTRIBUTE commands, for example, if the new file name is

FRED.NAME.CONTRL.DATA

and the hourly load data file name is

FRED.NAME.LOAD.DATA

```
FREE F(FT10F001,FT11F001)
FREE ATTRLIST (AT11)
ATTRIB AT11 RECFM(F,B) BLKSIZE(3120) LRECL(80)
ALLOC DA(FRED.NAME.LOAD.DATA) F(FT10F001)
ALLOC DA(FRED.NAME.CONTRL.DATA) F(FT11F001) NEW -
  USING(AT11) SPACE(1,1) TRACKS RELEASE
RUN FRED.FORT FORTLIB
```

The ATTRIBUTE command specifies that the new file should have a fixed record length of 80 characters (card images).

Respond to the "execution question" with NO.

Step 2: Submit FRED for execution through the TSO command procedure. Logical unit 10 should be allocated to the hourly load data and unit 5 to the newly created control data file. The following set of JCL is used at OSU:

```
// TIME=1
// EXEC PGM=FORTRUN
//SYSIN DD DSN=FRED.FORT,DISP=SHR
```

```
//GO.FT1ØFØØ1 DD DSN=FRED.NAME.LOAD.DATA, DISP=SHR
//GO.FTØ5F001 DD DSN=FRED.NAME.CONTRL.DATA, DISP=SHR
//
```

A sample run of FRED's remote batch-operating mode is shown in appendix B.

CHAPTER 4
GENERAL GUIDELINES

The user should become familiar with FRED's interactive mode before any attempt is made to use the batch mode. Not only is the interactive mode simpler to use, but it also provides the opportunity to interrupt the program's execution through the ATTENTION or BREAK terminal keys when an error is discovered. Remote batch mode should be used for runs that produce extensive printouts.

The experienced user may want to use a locally available EDITOR (for example, TSO EDIT, WYLBUR, ect.) to change and/or create the control data input file, instead of using step 1 in the remote batch execution mode. However, this is not recommended for the inexperienced user since it increases the chances for error without saving considerable computer time.

FRED is a modular, versatile, and easy to use and modify program. The fortran source code is listed in appendix C for further user references.

APPENDIX A

INTERACTIVE OPERATION OF FRED AT THE OHIO STATE UNIVERSITY COMPUTER

FRED is stored on disks at the OSU IRCC Computer Center and is accessible from a TSO terminal through the normal "logon" procedure. This procedure is shown in figure A-1 with the allocation and run commands for FRED. Once the user has established contact with the computer by using the data phone, he enters "logon." The computer will then ask a series of questions by which the computer identifies the user and the type of programming the user is going to use. As shown in figure A-1, the questions include the following:

1. USER ID? This is a six-character number assigned to the user by the OSU Customer Service Group.
2. PASSWORD? This is a six-character work assigned when the USER ID is assigned.
3. TERMINAL ID? This is a number on the terminal being used.
4. UNIVERSITY ID? This is a nine-character number that is generally the user's social security number.
5. PROCEDURE NAME? For all the programs in this report, the response is "fortuser." This identifies the user to the computer as a FORTRAN language user.

The computer will check this information against its account data files, if it is correct, the computer will respond with the word READY. Before the user runs this program, he should check the listing of data sets available. This is accomplished using the command

```
listds 'puco.data' mem
```

As shown in figure A-1, the computer will respond with a list of the member names of the partitioned data set PUCO.DATA. This data set contains hourly load data for electric utilities.

Once a current listing of data sets has been checked, the user, as shown in figure A-1, enters the following statements:

```
alloc da('puco.data') f(ft10f001)
```

The computer responds with READY. The user enters the following:

```
run 'puco.fredl.fort'
```

The program will compile and operate.

An example of the input dialogue is given in figure A-2. The output that results from this input data is similar to that listed in appendix B.

The procedure described above requires storage of large amounts of data on computer disks. Since disk storage is expensive, the data have been moved to tape storage. Therefore, the above procedure is not currently "active" at the OSU computer facility. It can easily be reactivated, however, by the NRRI computer specialist.

```
OW+43929P US¢UW  YQAQS
IKJ53020A ENTER  LOGON
logon
USERID? ts0207
PASSWORD? [redacted]
TERMINAL ID? r124
UNIVERSITY ID? [redacted]
PROCEDURE NAME? fortuser
TS0287 LOGON IN PROGRESS AT 14:10:44 ON JANUARY 10, 1977
READY
listds 'puco.data' mem
PUCO.DATA
--RECFM-LRECL-BLKSIZE-DSORG
  FB    80    3120    PO
--VOLUMES--
  IRCC71
--MEMBERS--
  CC073L
  CC074L
  CE173L
  CE174L
  CGE73L
  CGE74L
  CGE75L
  CS074L
  CS075L
  DPL73L
  DPL74L
  DPL75L
  DPL76L
  DUQ73L
  DUQ74L
  OED73L
  OED74L
  OED75L
  TED73L
  TED74L
  TED75L
READY
alloc da('puco.data') f(ft10f001)
READY
run 'puco.fredl.fort'
```

Figure A-1 Logon procedure, request for data set names, and the alloc and run commands

```
                LOAD FREQUENCY, LOAD DURATION, LOAD PROBABILITY
                PEAK DAY, AND AVERAGE DAY CODE, SEPT. 1976
                          THE OHIO STATE UNIVERSITY
                          NUCLEAR ENGINEERING DEPARTMENT
                          COLUMBUS, OHIO  43210


IMPORTANT--TO ELIMINATE DATA ENTRY ERRORS DATA ENTERED
BY YOU WILL BE ECHOED FOR ACCURACY.  IF THE ENTRY IS CORRECT
PRESS THE RETURN KEY.  IF NOT TYPE NO THEN RETURN THEN ENTER
THE CORRECT INPUT.
TO SELECT DATA TYPE THE SIX CHARACTER DATA SET NAME.
dpl761
DPL76L

IEC225I 00,TS0287,LOGON1,FT10F001,431,IRCC71,PUCO.DATA
THE INCLUSIVE TIME PERIOD OF INTEREST IS SPECIFIED BY TYPING THE
STARTING MONTH AND DAY AND THE ENDING MONTH AND DAY IN THE FORMAT
--/--/--/--.FOR EXAMPLE, TO SPECIFY JUNE 1 THROUGH OCTOBER 15 TYPE
06/01/10/15 THEN PRESS RETURN.
05/15/08/10
 5/15  8/10

DO YOU WISH TO SPECIFY THE DAYS OF THE WEEK FOR WHICH
THE CALCULATIONS ARE TO BE MADE?
yes
IN SPECIFYING THE DAYS OF THE WEEK THE FOLLOWING
OPTIONS ARE AVAILABLE:
         1.  WEEKDAYS WITHOUT HOLIDAYS
         2.  WEEKENDS WITH HOLIDAYS
         3.  INDIVIDUAL DAYS OF THE WEEK

TO SPECIFY THE DESIRED OPTION, TYPE THAT NUMBER, THEN RETURN
3
TO SPECIFY INDIVIDUAL DAYS, TYPE THE STANDARD ABBREVIATION
FOR A GIVEN DAY THEN PRESS RETURN. REPEAT THIS FOR EACH DAY
OF INTEREST. WHEN ALL DAY OF INTEREST HAVE BEEN SPECIFIED
TYPE THE WORD END THEN PRESS RETURN.  HOLIDAYS ARE INCLUDED IN THE
CALCULATION BY TYPING HOLI THEN PRESS RETURN
mon
tues
wed
thur
fri
end
```

Figure A-2 Operations of FRED with option 1 output

```
DO YOU WISH TO SPECIFY THE HOURS OF THE DAY FOR WHICH
THE CALCUALTIONS ARE TO BE MADE?
yes
TO SPECIFY THE PERIOD OF THE DAY YOU ARE INTERESTED IN TYPE
THE STARTING HOUR AND THE ENDING HOUR USING MILITARY
NOTATION IN THE FORMAT
--/--  FOR EXAMPLE, TO SPECIFY 11AM THROUGH 4PM TYPE
11/16 THEN PRESS RETURN
10/19
10/19

DO YOU WICH TO SPCIFY A RANGE OF HOURS DURING THE DAY
WHICH ARE NOT USED IN THE CALCULATION
yes
TYPE THE RANGE OF HOURS NOT TO BE USED IN THE
CALCULATION IN THE FORMAT
--/--    THEN PRESS RETURN
12/13
12/13

DO YOU WISH TO SEE THE SELECTED DATA?
yes
DO YOU WISH TO SEE THE LOAD FREQUENCY PLOT?
yes
DO YOU WISH TO SEE THE LOAD DURATION CURVE?
yes
DO YOU WISH TO SEE THE LOAD PROBABILITY CURVE?
yes
DO YOU WISH TO HAVE AN AVERAGE AND PEAK DAY CALCULATED
FOR EACH DAY OF THE WEEK?
yes
OUTPUT FOR THE AVERAGE AND PEAK DAY
CALCULATION IS AVAILABLE IN
  1. SUMMARY TABLE OF THE AVERAGE LOAD PER HOUR
     PER DAY AND THE PEAK LOAD PER HOUR PER DAY.
  2. A DAY BY DAY PLOT OF THE SUMMARY DATA
  3. BOTH OF THE ABOVE
TYPE THE NUMBER OF THE OUTPUT OPTION
3
```

Figure A-2 (continued)

APPENDIX B

REMOTE BATCH-OPERATING MODE

The control data input preparation procedure is listed in section B.1, and the control data file is listed in section B.2 of this appendix. The third section (section B.3) contains the sample output from the high-speed printer that resulted from the control data shown in section B.2.

B.1 Control Data Input Preparation Procedure

The Fred dialogue that prepares the control data for the remote batch execution mode is listed below.

```
LOAD FREQUENCY, LOAD DURATION, LOAD PROBABILITY
PEAK DAY, AND AVERAGE DAY CODE, SEPT., 1976
         THE OHIO STATE UNIVERSITY
         NUCLEAR ENGINEERING DEPARTMENT
         COLUMBUS, OHIO 43210

         REVISED BY THE NATIONAL REGULATORY
         RESEARCH INSTITUTE.     4/81

         FOR INFORMATION CONTACT :
         JEFFREY SHIH
         THE NATIONAL REGULATORY RESEARCH INSTITUTE
         THE OHIO STATE UNIVERSITY
         2130 NEIL AVENUE
         COLUMBUS, OHIO 43210
         (614) 422-9404


IF YOU WISH TO EXECUTE FRED VIA TERMINAL,
ENTER YES;
OTHERWISE ENTER NO TO CREATE AN INPUT FILE
FOR BATCH EXECUTION.
no
NO
ENTER COMPANY NAME AND YEAR OF DATA
XXXX 19XX
psco 1979
PSCO 1979
THE INCLUSIVE TIME PERIOD OF INTEREST IS SPECIFIED BY TYPING THE
STARTING MONTH AND DAY AND THE ENDING MONTH AND DAY IN THE FORMAT
--/--/--/--. FOR EXAMPLE, TO SPECIFY JUNE 1 THROUGH OCTOBER 15 TYPE
06/01/10/15 THEN PRESS RETURN.
06/01/10/15
 6/ 1/10/15
DO YOU WISH TO SPECIFY THE DAYS OF THE WEEK FOR WHICH
THE CALCULATIONS ARE TO BE MADE?
yes
YES
```

```
IN SPECIFYING THE DAYS OF THE WEEK THE FOLLOWING
OPTIONS ARE AVAILABLE:
          1.  WEEKDAYS WITHOUT HOLIDAYS
          2.  WEEKENDS WITH HOLIDAYS
          3.  INDIVIDUAL DAYS OF THE WEEK


TO SPECIFY THE DESIRED OPTION, TYPE THAT NUMBER, THEN RETURN
3
3
TO SPECIFY INDIVIDUAL DAYS, USE THESE ABBREVIATIONS
(MO,TU,WE,TH,FR,SA,SU) FOR A GIVEN DAY
AND PRESS RETURN. REPEAT FOR EACH DAY OF INTEREST.
HOLIDAYS ARE INCLUDED BY USING ABBREVIATION (HO).
WHEN ALL DAYS ARE SPECFIED, TYPE (EN) END.
mo
::
tu
::
we
::
th
::
fr
::
sa
::
su
::
ho
::
en
::
DO YOU WISH TO SPECIFY THE HOURS OF THE DAY FOR WHICH
THE CALCULATIONS ARE TO BE MADE?
no
NO
DO YOU WISH TO SPECIFY A RANGE OF HOURS DURING THE DAY
WHICH ARE NOT USED IN THE CALCULATION?
no
NO
DO YOU WISH TO SEE THE SELECTED DATA?
no
NO
DO YOU WISH TO SEE THE LOAD FREQUENCY PLOT?
yes
YES
DO YOU WISH TO SEE THE LOAD DURATION CURVE?
yes
YES
DO YOU WISH TO SEE THE LOAD PROBABILITY CURVE?
yes
YES
```

```
DO YOU WISH TO HAVE AN AVERAGE AND PEAK DAY CALCULATED
FOR EACH DAY OF THE WEEK?
yes
YES
OUTPUT FOR THE AVERAGE AND PEAK DAY
CALCULATION IS AVAILABLE IN
   1  SUMMARY TABLE OF THE AVERAGE LOAD PER HOUR
      PER DAY AND THE PEAK LOAD PER HOUR PER DAY.
   2  A DAY BY DAY PLOT OF THE SUMMARY DATA
   3  BOTH OF THE ABOVE

TYPE THE NUMBER OF THE OUTPUT OPTION
3
3



DO YOU WISH TO EXAMINE A DIFFERENT CASE WITHIN THE SAME YEAR?
yes
YES
DO YOU WISH TO ANALYZE THIS CASE FOR  THE SAME
DAYS, HOURS, AND OUTPUT OPTIONS AS IN THE LAST
CASE?
no
NO
THE INCLUSIVE TIME PERIOD OF INTEREST IS SPECIFIED BY TYPING THE
STARTING MONTH AND DAY AND THE ENDING MONTH AND DAY IN THE FORMAT
--/--/--/--. FOR EXAMPLE, TO SPECIFY JUNE 1 THROUGH OCTOBER 15 TYPE
06/01/10/15 THEN PRESS RETURN.
05/01/05/31
 5/ 1/ 5/31
DO YOU WISH TO SPECIFY THE DAYS OF THE WEEK FOR WHICH
THE CALCULATIONS ARE TO BE MADE?
no
NO
DO YOU WISH TO SPECIFY THE HOURS OF THE DAY FOR WHICH
THE CALCULATIONS ARE TO BE MADE?
yes
YES
TO SPECIFY THE PERIOD OF THE DAY YOU ARE INTERESTED IN TYPE
THE STARTING HOUR AND THE ENDING HOUR USING MILITARY
NOTATION IN THE FORMAT
--/--. FOR EXAMPLE, TO SPECIFY 11AM THROUGH 4PM TYPE
11/16 THEN PRESS RETURN
09/21
 9/21
DO YOU WISH TO SPECIFY A RANGE OF HOURS DURING THE DAY
WHICH ARE NOT USED IN THE CALCULATION?
no
NO
```

```
DO YOU WISH TO SEE THE SELECTED DATA?
yes
YES
DO YOU WISH TO SEE THE LOAD FREQUENCY PLOT?
yes
YES
DO YOU WISH TO SEE THE LOAD DURATION CURVE?
yes
YES
DO YOU WISH TO SEE THE LOAD PROBABILITY CURVE?
yes
YES
DO YOU WISH TO HAVE AN AVERAGE AND PEAK DAY CALCULATED
FOR EACH DAY OF THE WEEK?
yes
YES
OUTPUT FOR THE AVERAGE AND PEAK DAY
CALCULATION IS AVAILABLE IN
   1  SUMMARY TABLE OF THE AVERAGE LOAD PER HOUR
      PER DAY AND THE PEAK LOAD PER HOUR PER DAY.
   2  A DAY BY DAY PLOT OF THE SUMMARY DATA
   3  BOTH OF THE ABOVE

TYPE THE NUMBER OF THE OUTPUT OPTION
2
2


DO YOU WISH TO EXAMINE A DIFFERENT CASE WITHIN THE SAME YEAR?
no
NO
NORMAL EXIT FROM INPUT PREPARATION MODE OF FRED CODE
EXECUTE.FRED ON BATCH

READY
```

B.2 Control Data File

The control data for remote batch execution are listed below.

```
YES
PSCO 1979
 6  1 10 15
YES
3
MO
TU
WE
TH
FR
SA
SU
HO
EN
NO
NO
NO
YES
YES
YES
YES
3
YES
NO
 5   1   5 31
NO
YES
 9 21
NO
YES
YES
YES
YES
YES
2
NO
```

B.3 Sample Output

The FRED output that resulted from the input control data listed in section B.2 is listed below.

```
                LOAD FREQUENCY, LOAD DURATION, LOAD PROBABILITY
                PEAK DAY, AND AVERAGE DAY CODE, SEPT., 1976
                        THE OHIO STATE UNIVERSITY
                        NUCLEAR ENGINEERING DEPARTMENT
                        COLUMBUS, OHIO 43210

                        REVISED BY THE NATIONAL REGULATORY
                        RESEARCH INSTITUTE.      4781

                        FOR INFORMATION CONTACT :
                        JEFFREY SHIH
                        THE NATIONAL REGULATORY RESEARCH INSTITUTE
                        THE OHIO STATE UNIVERSITY
                        2130 NEIL AVENUE
                        COLUMBUS, OHIO 43210
                        (614) 422-9404


IF YOU WISH TO EXECUTE FRED VIA TERMINAL,
ENTER YES;
OTHERWISE ENTER NO TO CREATE AN INPUT FILE
FOR BATCH EXECUTION.
YES
ENTER COMPANY NAME AND YEAR OF DATA
XXXX 19XX
PSCO 1979
THE INCLUSIVE TIME PERIOD OF INTEREST IS SPECIFIED BY TYPING THE
STARTING MONTH AND DAY AND THE ENDING MONTH AND DAY IN THE FORMAT
--/--/--/--. FOR EXAMPLE, TO SPECIFY JUNE 1 THROUGH OCTOBER 15 TYPE
06/01/10/15 THEN PRESS RETURN.
 6/ 1/10/15
DO YOU WISH TO SPECIFY THE DAYS OF THE WEEK FOR WHICH
THE CALCULATIONS ARE TO BE MADE?
YES
IN SPECIFYING THE DAYS OF THE WEEK THE FOLLOWING
OPTIONS ARE AVAILABLE:
                1.   WEEKDAYS WITHOUT HOLIDAYS
                2.   WEEKENDS WITH HOLIDAYS
                3.   INDIVIDUAL DAYS OF THE WEEK

TO SPECIFY THE DESIRED OPTION, TYPE THAT NUMBER, THEN RETURN
3
TO SPECIFY INDIVIDUAL DAYS, USE THESE ABBREVIATIONS
(MO,TU,WE,TH,FR,SA,SU) FOR A GIVEN DAY
AND PRESS RETURN. REPEAT FOR EACH DAY OF INTEREST.
HOLIDAYS ARE INCLUDED BY USING ABBREVIATION (HO).
WHEN ALL DAYS ARE SPECFIED, TYPE (EN) END.
```

```
DO YOU WISH TO SPECIFY THE HOURS OF THE DAY FOR WHICH
THE CALCULATIONS ARE TO BE MADE?
NO
DO YOU WISH TO SPECIFY A RANGE OF HOURS DURING THE DAY
WHICH ARE NOT USED IN THE CALCULATION?
NO
DO YOU WISH TO SEE THE SELECTED DATA?
NO
DO YOU WISH TO SEE THE LOAD FREQUENCY PLOT?
YES
DO YOU WISH TO SEE THE LOAD DURATION CURVE?
YES
DO YOU WISH TO SEE THE LOAD PROBABILITY CURVE?
YES
DO YOU WISH TO HAVE AN AVERAGE AND PEAK DAY CALCULATED
FOR EACH DAY OF THE WEEK?
YES
OUTPUT FOR THE AVERAGE AND PEAK DAY
CALCULATION IS AVAILABLE IN
   1  SUMMARY TABLE OF THE AVERAGE LOAD PER HOUR
      PER DAY AND THE PEAK LOAD PER HOUR PER DAY.
   2  A DAY BY DAY PLOT OF THE SUMMARY DATA
   3  BOTH OF THE ABOVE

TYPE THE NUMBER OF THE OUTPUT OPTION
3
```

PEAK MW — 2755.

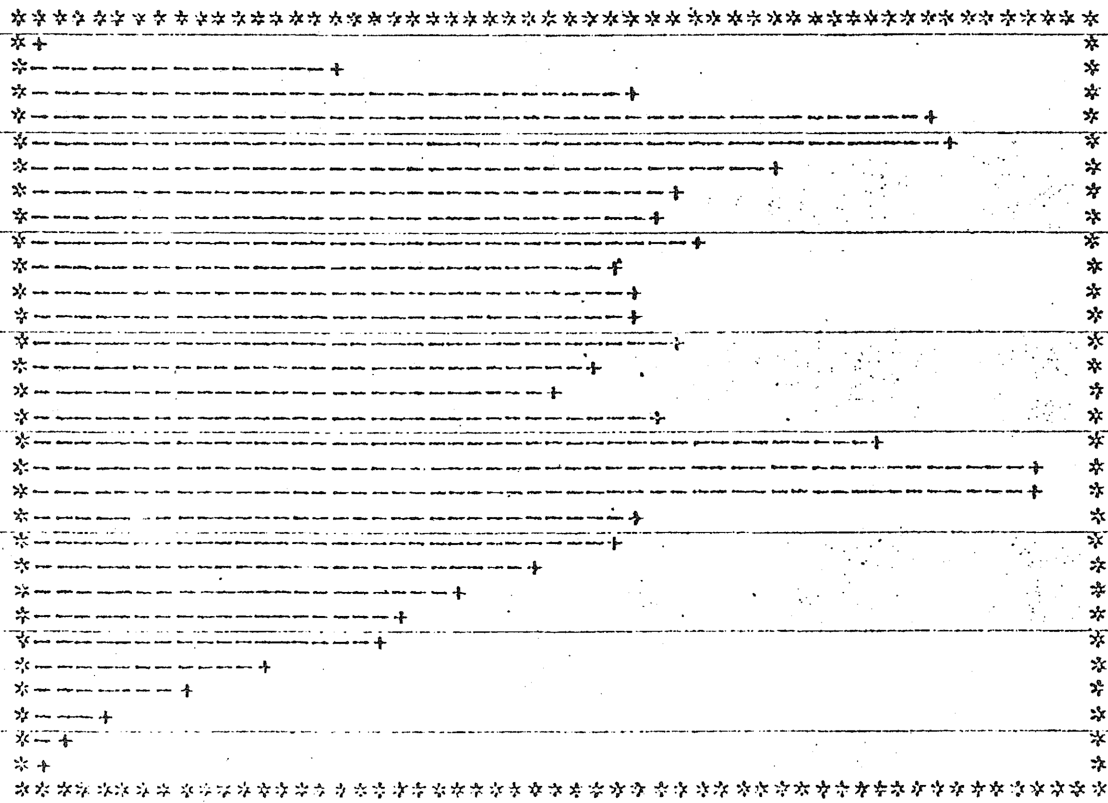
MO/DA/HR — 8/ 6/17

THE LOAD FACTOR IS 68.52

THE TOTAL MEGAWATT-HOUR SALES ARE 6208876.

LOAD FREQUENCY CURVE FOR THE PERIOD 6/ 1/ 1-10/15/24.

LOAD MW	FREQ HR
1235.0	7.1
1287.4	65.3
1339.8	126.2
1392.2	187.0
1444.7	190.8
1497.1	154.6
1549.5	134.8
1601.9	130.8
1654.3	137.9
1706.7	123.1
1759.1	125.0
1811.5	124.1
1864.0	132.0
1916.4	117.9
1968.8	111.0
2021.2	130.9
2073.6	175.1
2126.0	207.1
2178.4	202.8
2230.9	126.9
2283.3	121.9
2335.7	105.0
2388.1	88.0
2440.5	76.0
2492.9	72.1
2545.3	49.0
2597.8	32.0
2650.2	16.0
2702.6	9.0
2755.0	7.0

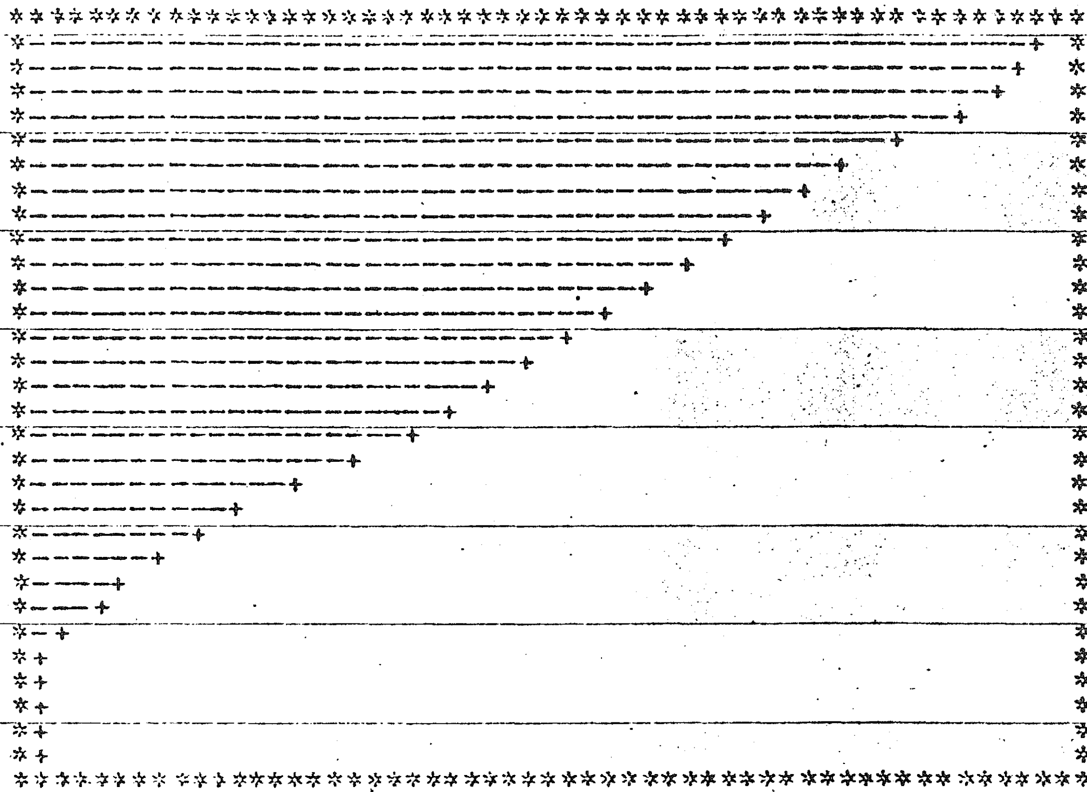


LOAD DURATION CURVE FOR THE PERIOD 6/ 1/ 1-10/15/24.

TIME HRS	LOAD MW
3.0	2755.0
116.3	2522.7
229.5	2445.6
342.8	2371.3
456.1	2313.4
569.4	2269.0
682.7	2219.7
795.9	2185.0
909.2	2160.3
1022.5	2132.3
1135.8	2101.6
1249.0	2069.0
1362.3	2024.8
1475.6	1976.9
1588.9	1919.8
1702.1	1876.0
1815.4	1833.5
1928.7	1782.7
2042.0	1735.7
2155.2	1687.6
2268.5	1643.3
2381.8	1596.5
2495.1	1551.9
2608.3	1504.9
2721.6	1476.2
2834.9	1443.7
2948.2	1412.8
3061.4	1383.2
3174.7	1339.2
3288.0	1235.0

LOAD PROBABILITY CURVE FOR THE PERIOD 6/ 1/ 1-10/15/24.

LOAD MW	PROB
1235.0	1.00000
1237.4	0.99785
1339.8	0.97798
1392.2	0.93960
1444.7	0.88272
1497.1	0.82468
1549.5	0.77765
1601.9	0.73665
1654.3	0.69636
1706.7	0.65492
1759.1	0.61746
1811.5	0.57943
1864.0	0.54168
1916.4	0.50154
1968.8	0.46563
2021.2	0.43191
2073.6	0.39208
2126.0	0.33882
2178.4	0.27580
2230.9	0.21380
2283.3	0.17520
2335.7	0.13811
2388.1	0.10617
2440.5	0.07941
2492.9	0.05628
2545.3	0.03436
2597.8	0.01945
2650.2	0.00972
2702.6	0.00436
2755.0	0.00212



THE FOLLOWING ARE AVERAGE LOAD DAYS FOR THE PERIOD 6/ 1 TO 10/15.

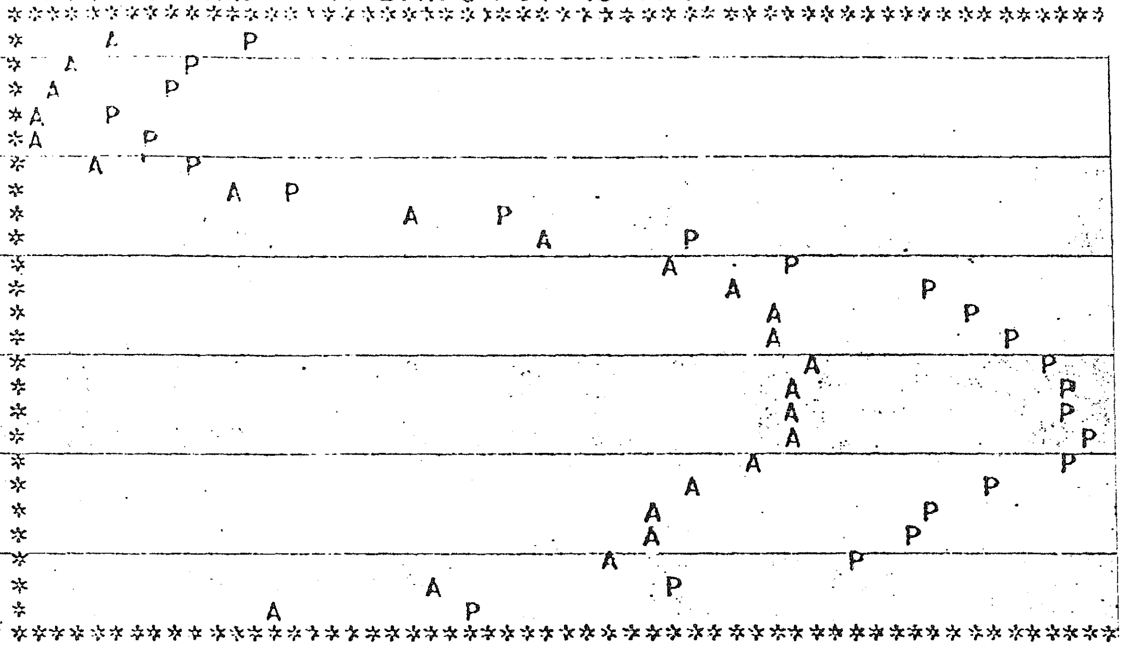
HR	MON	TUES	WED	THUR	FRI	WKDA	SAT	SUN	HOLI	WK
1	1480.	1543.	1567.	1573.	1573.	1548.	1479.	1429.	1443.	145
2	1424.	1463.	1506.	1508.	1506.	1436.	1412.	1361.	1333.	135
3	1399.	1437.	1457.	1458.	1462.	1443.	1359.	1310.	1332.	133
4	1384.	1425.	1428.	1439.	1449.	1426.	1342.	1287.	1301.	131
5	1394.	1419.	1443.	1443.	1457.	1432.	1326.	1278.	1307.	130
6	1458.	1480.	1515.	1511.	1510.	1495.	1331.	1268.	1327.	130
7	1634.	1649.	1682.	1676.	1679.	1665.	1362.	1260.	1407.	131
8	1872.	1873.	1907.	1907.	1902.	1892.	1466.	1314.	1503.	139
9	2064.	2061.	2082.	2077.	2077.	2072.	1626.	1427.	1632.	153
10	2201.	2178.	2200.	2197.	2184.	2192.	1757.	1533.	1780.	165
11	2291.	2253.	2273.	2281.	2258.	2271.	1839.	1613.	1863.	173
12	2337.	2298.	2314.	2303.	2302.	2310.	1974.	1682.	1893.	178
13	2336.	2301.	2324.	2331.	2301.	2318.	1877.	1728.	1905.	180
14	2381.	2336.	2356.	2366.	2326.	2352.	1869.	1735.	1935.	181
15	2379.	2333.	2363.	2375.	2322.	2354.	1847.	1731.	1912.	179
16	2364.	2339.	2361.	2359.	2296.	2343.	1835.	1734.	1920.	179
17	2358.	2334.	2335.	2340.	2270.	2326.	1839.	1753.	1924.	180
18	2314.	2296.	2298.	2310.	2214.	2285.	1852.	1772.	1917.	181
19	2249.	2218.	2233.	2234.	2138.	2213.	1820.	1768.	1905.	180
20	2197.	2181.	2199.	2193.	2110.	2175.	1807.	1781.	1915.	180
21	2197.	2185.	2204.	2185.	2098.	2172.	1817.	1812.	1916.	182
22	2126.	2109.	2135.	2122.	2038.	2105.	1791.	1802.	1849.	180
23	1914.	1924.	1945.	1931.	1873.	1917.	1676.	1663.	1706.	167
24	1691.	1707.	1714.	1716.	1682.	1702.	1535.	1497.	1541.	151

THE FOLLOWING ARE PEAK LOAD DAYS FOR THE PERIOD 6/ 1 TO 10/15.

HR	MON	TUES	WED	THUR	FRI	WKDA	SAT	SUN	HOLI	WKE
1	1658.	1777.	1802.	1779.	1783.	1802.	1812.	1749.	1530.	1812
2	1592.	1715.	1745.	1727.	1688.	1745.	1718.	1622.	1439.	1718
3	1564.	1638.	1641.	1646.	1605.	1646.	1634.	1536.	1394.	1634
4	1496.	1621.	1624.	1597.	1609.	1624.	1561.	1499.	1340.	1561
5	1533.	1601.	1615.	1609.	1622.	1622.	1572.	1497.	1322.	1572
6	1592.	1682.	1692.	1652.	1630.	1692.	1563.	1466.	1370.	1563
7	1718.	1764.	1848.	1797.	1761.	1848.	1599.	1429.	1551.	1599
8	2003.	2029.	2079.	2026.	2032.	2079.	1714.	1500.	1770.	1770
9	2232.	2273.	2275.	2275.	2245.	2275.	1905.	1662.	1903.	1903
10	2373.	2412.	2479.	2451.	2468.	2479.	2105.	1798.	2039.	2106
11	2546.	2548.	2572.	2557.	2545.	2572.	2212.	1935.	2066.	2212
12	2612.	2630.	2648.	2612.	2593.	2648.	2275.	2028.	2053.	2276
13	2653.	2649.	2678.	2638.	2612.	2678.	2296.	2123.	2078.	2296
14	2709.	2721.	2702.	2662.	2648.	2721.	2308.	2129.	2144.	2308
15	2725.	2751.	2733.	2666.	2671.	2751.	2294.	2137.	2135.	2294
16	2741.	2752.	2744.	2669.	2678.	2752.	2261.	2160.	2082.	2261
17	2755.	2739.	2689.	2623.	2635.	2755.	2291.	2186.	2050.	2291
18	2723.	2696.	2603.	2550.	2568.	2723.	2299.	2203.	2012.	2299
19	2624.	2606.	2528.	2460.	2458.	2624.	2240.	2159.	2045.	2240
20	2543.	2497.	2442.	2361.	2412.	2543.	2159.	2149.	2115.	2189
21	2521.	2510.	2390.	2352.	2370.	2521.	2182.	2199.	2021.	2199
22	2441.	2418.	2385.	2357.	2330.	2441.	2206.	2189.	1902.	2206
23	2199.	2236.	2186.	2171.	2156.	2235.	2071.	2007.	1717.	2071
24	1956.	2053.	1940.	1956.	1950.	2053.	1896.	1806.	1591.	1896

AVERAGE AND PEAK LOADS FOR MONDAYS

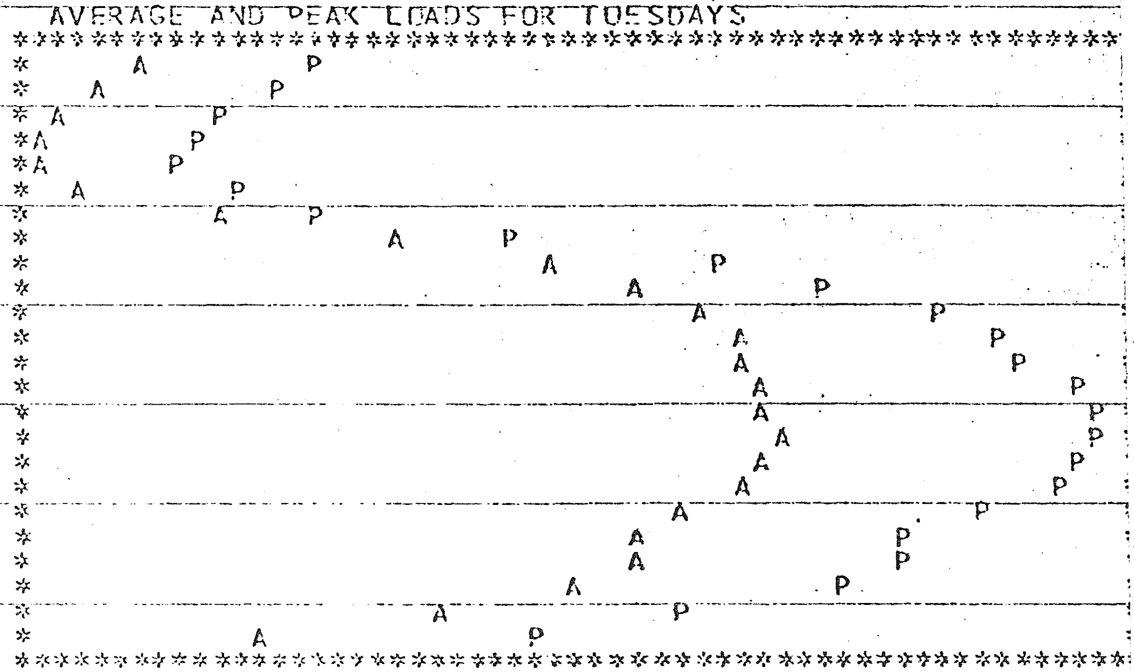
HR	AVE	PEAK
1	1480.	1658.
2	1424.	1592.
3	1398.	1564.
4	1384.	1496.
5	1394.	1533.
6	1456.	1592.
7	1634.	1718.
8	1872.	2003.
9	2064.	2232.
10	2201.	2373.
11	2291.	2546.
12	2337.	2612.
13	2336.	2653.
14	2381.	2709.
15	2379.	2725.
16	2364.	2741.
17	2358.	2755.
18	2314.	2723.
19	2249.	2624.
20	2197.	2543.
21	2197.	2521.
22	2126.	2441.
23	1914.	2199.
24	1691.	1956.



THERE ARE 18 MONDAYS
IN THE PERIOD 6/ 1/-10/15/.

AVERAGE AND PEAK LOADS FOR TUESDAYS

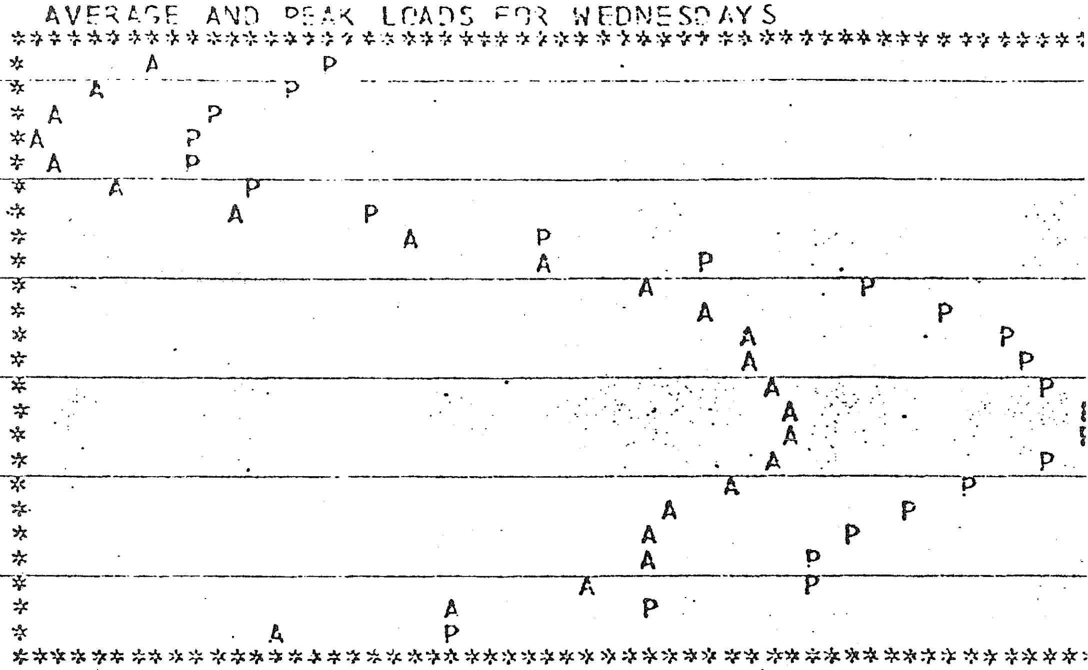
HR	AVE	PEAK
1	1543.	1777.
2	1483.	1715.
3	1437.	1638.
4	1425.	1621.
5	1419.	1601.
6	1480.	1632.
7	1649.	1764.
8	1873.	2029.
9	2061.	2273.
10	2178.	2412.
11	2253.	2548.
12	2298.	2630.
13	2301.	2649.
14	2336.	2721.
15	2333.	2751.
16	2339.	2752.
17	2334.	2739.
18	2296.	2696.
19	2218.	2606.
20	2181.	2497.
21	2185.	2510.
22	2109.	2413.
23	1924.	2236.
24	1707.	2053.



THERE ARE 19 TUESDAYS
IN THE PERIOD 6/ 1/-10/15/

AVERAGE AND PEAK LOADS FOR WEDNESDAYS

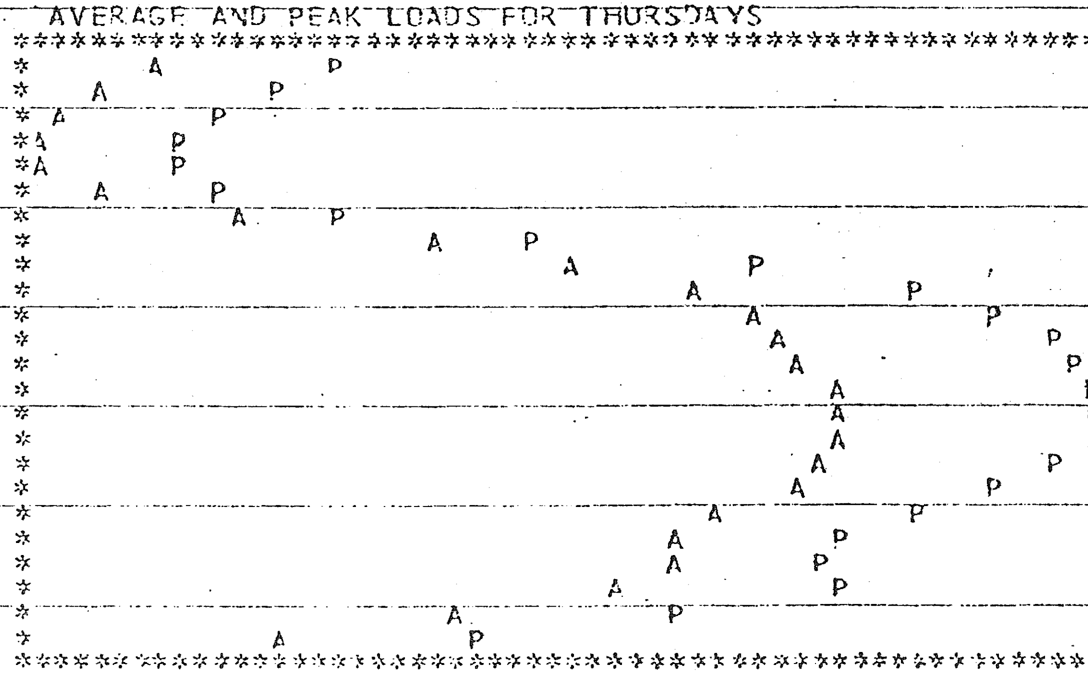
HR	AVE	PEAK
1	1567.	1802.
2	1506.	1745.
3	1457.	1641.
4	1428.	1624.
5	1443.	1615.
6	1515.	1692.
7	1682.	1848.
8	1907.	2079.
9	2082.	2275.
10	2200.	2479.
11	2273.	2572.
12	2314.	2648.
13	2324.	2678.
14	2356.	2702.
15	2363.	2733.
16	2361.	2744.
17	2335.	2689.
18	2298.	2603.
19	2233.	2528.
20	2199.	2442.
21	2204.	2390.
22	2135.	2385.
23	1945.	2186.
24	1714.	1940.



THERE ARE 15 WEDNESDAYS
IN THE PERIOD 6/ 1/-10/15/.

AVERAGE AND PEAK LOADS FOR THURSDAYS

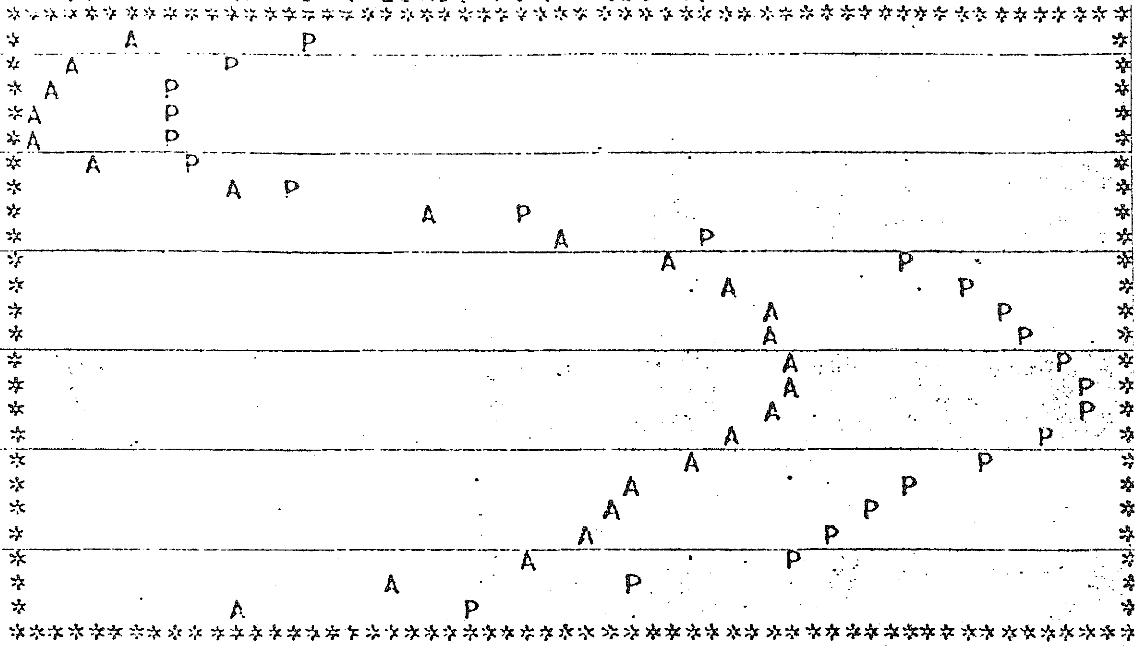
HR	AVE	PEAK
1	1573.	1779.
2	1508.	1727.
3	1458.	1646.
4	1439.	1597.
5	1443.	1609.
6	1511.	1652.
7	1676.	1797.
8	1907.	2026.
9	2077.	2275.
10	2197.	2451.
11	2281.	2557.
12	2303.	2612.
13	2331.	2638.
14	2366.	2662.
15	2375.	2666.
16	2359.	2669.
17	2340.	2623.
18	2310.	2550.
19	2234.	2460.
20	2193.	2361.
21	2185.	2352.
22	2122.	2357.
23	1931.	2171.
24	1716.	1956.



THERE ARE 19 THURSDAYS
IN THE PERIOD 6/ 1/-10/15/

AVERAGE AND PEAK LOADS FOR FRIDAYS

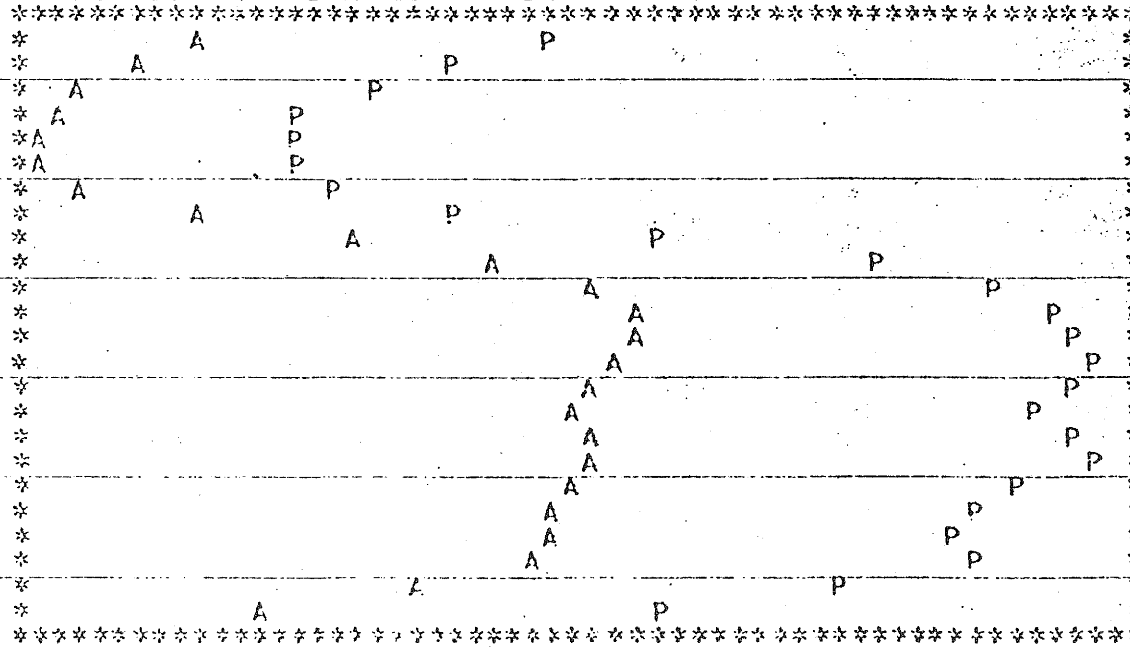
HR	AVE	PEAK
1	1573.	1783.
2	1506.	1623.
3	1462.	1605.
4	1449.	1609.
5	1457.	1622.
6	1510.	1630.
7	1679.	1761.
8	1902.	2032.
9	2077.	2245.
10	2184.	2468.
11	2258.	2545.
12	2302.	2593.
13	2301.	2612.
14	2326.	2648.
15	2322.	2671.
16	2296.	2678.
17	2270.	2635.
18	2214.	2563.
19	2138.	2458.
20	2110.	2412.
21	2098.	2370.
22	2038.	2330.
23	1973.	2156.
24	1682.	1950.



THERE ARE 20 FRIDAYS
IN THE PERIOD 6/ 1/-10/15/

AVERAGE AND PEAK LOADS FOR SATURDAYS

HR	AVE	PEAK
1	1479.	1812.
2	1412.	1718.
3	1359.	1634.
4	1342.	1561.
5	1326.	1572.
6	1331.	1563.
7	1362.	1599.
8	1466.	1714.
9	1626.	1905.
10	1757.	2106.
11	1839.	2212.
12	1874.	2276.
13	1877.	2296.
14	1869.	2303.
15	1847.	2294.
16	1835.	2261.
17	1839.	2291.
18	1852.	2299.
19	1820.	2240.
20	1807.	2189.
21	1917.	2182.
22	1791.	2206.
23	1676.	2071.
24	1535.	1896.

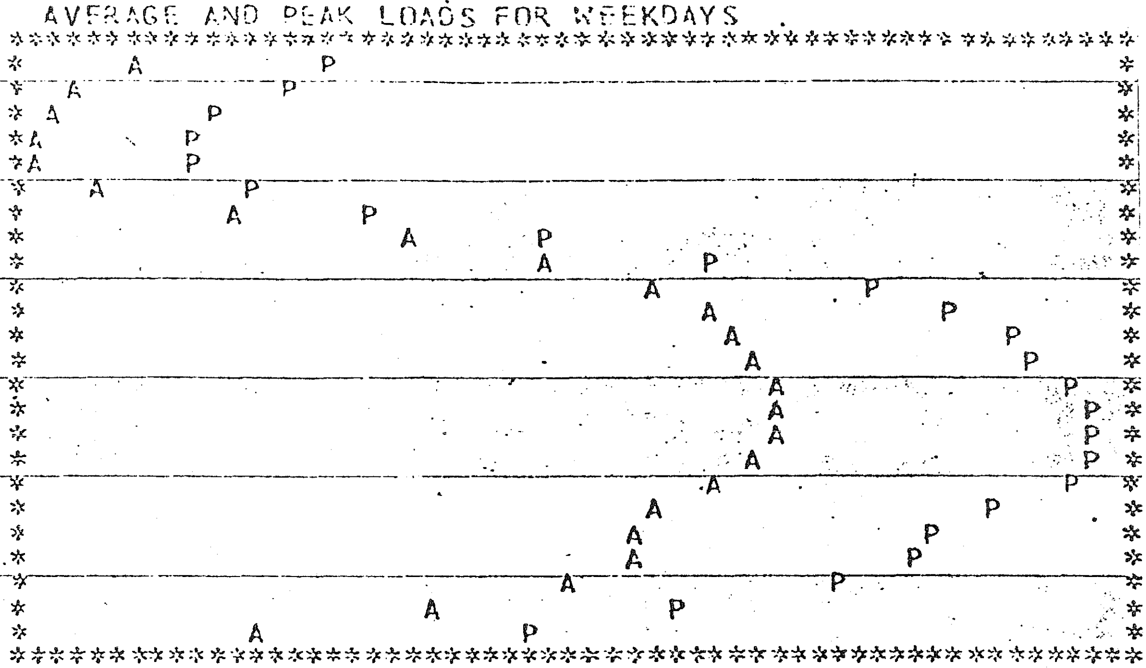


THERE ARE 21 SATURDAYS
IN THE PERIOD 6/ 1/-10/15/

```
                    AVERAGE AND PEAK LOADS FOR SUNDAYS
HR   AVE.   PEAK  ************************************************
 1  1429.  1749.  *        A              P
 2  1361.  1622.  *     A           P
 3  1310.  1536.  *   A         P
 4  1287.  1499.  *  A        P
 5  1278.  1497.  * A         P
 6  1268.  1466.  *A         P
 7  1260.  1429.  *A       P
 8  1314.  1500.  *   A       P
 9  1427.  1662.  *        A           P
10  1533.  1798.  *             A            P
11  1613.  1935.  *                 A               P
12  1682.  2028.  *                     A               P
13  1728.  2123.  *                      A                    P
14  1735.  2129.  *                       A                   P
15  1731.  2137.  *                      A                    P
16  1734.  2160.  *                       A                     P
17  1753.  2186.  *                        A                     P
18  1772.  2203.  *                         A                     P
19  1768.  2159.  *                         A                   P
20  1781.  2149.  *                         A                  P
21  1812.  2199.  *                           A                   P
22  1802.  2189.  *                          A                   P
23  1668.  2007.  *                    A                P
24  1497.  1806.  *           A               P
                  ************************************************

                    THERE ARE 21 SUNDAYS
                    IN THE PERIOD  6/ 1/-10/15/.

                    AVERAGE AND PEAK LOADS FOR HOLIDAYS
HR   AVE.   PEAK  ************************************************
 1  1443.  1530.  *        A   P
 2  1383.  1439.  *    A   P
 3  1332.  1394.  *  A  P
 4  1301.  1340.  *A P
 5  1307.  1322.  *AP
 6  1337.  1370.  *  A P
 7  1407.  1551.  *      A       P
 8  1503.  1770.  *           A             P
 9  1632.  1903.  *                  A              P
10  1780.  2039.  *                          A             P
11  1863.  2066.  *                               A          P
12  1893.  2083.  *                                 A         P
13  1905.  2078.  *                                 A         P
14  1935.  2144.  *                                   A           P
15  1912.  2135.  *                                  A           P
16  1920.  2082.  *                                  A        P
17  1924.  2050.  *                                  A      P
18  1917.  2012.  *                                  A     P
19  1905.  2045.  *                                 A       P
20  1915.  2115.  *                                  A          P
21  1916.  2021.  *                                  A     P
22  1849.  1902.  *                              A   P
23  1706.  1717.  *                      AP
24  1541.  1591.  *             A  P
                  ************************************************

                    THERE ARE 3 HOLIDAYS
                    IN THE PERIOD  6/ 1/-10/15/.
```

AVERAGE AND PEAK LOADS FOR WEEKDAYS

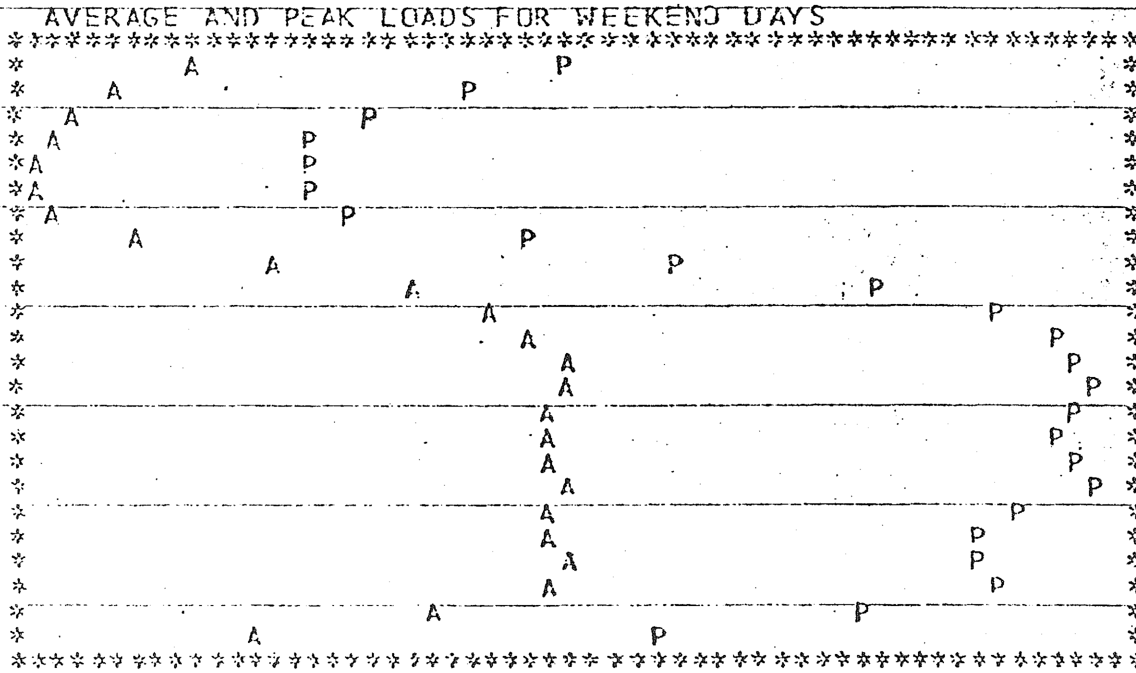
HR	AVE	PEAK
1	1546.	1802.
2	1486.	1745.
3	1443.	1646.
4	1426.	1624.
5	1432.	1622.
6	1495.	1692.
7	1665.	1848.
8	1892.	2079.
9	2072.	2275.
10	2192.	2479.
11	2271.	2572.
12	2310.	2648.
13	2318.	2678.
14	2352.	2721.
15	2354.	2751.
16	2343.	2752.
17	2326.	2755.
18	2285.	2723.
19	2213.	2624.
20	2175.	2543.
21	2172.	2521.
22	2105.	2441.
23	1917.	2236.
24	1702.	2053.



THERE ARE 94 WEEKDAYS
IN THE PERIOD 6/ 1/-10/15/.

AVERAGE AND PEAK LOADS FOR WEEKEND DAYS

HR	AVE	PEAK
1	1453.	1812.
2	1386.	1718.
3	1334.	1634.
4	1314.	1561.
5	1302.	1572.
6	1302.	1563.
7	1317.	1599.
8	1398.	1770.
9	1534.	1905.
10	1654.	2106.
11	1735.	2212.
12	1786.	2276.
13	1809.	2296.
14	1811.	2308.
15	1797.	2294.
16	1794.	2261.
17	1805.	2293.
18	1819.	2299.
19	1801.	2240.
20	1802.	2189.
21	1821.	2199.
22	1800.	2206.
23	1674.	2071.
24	1518.	1896.



THERE ARE 45 WEEKEND DAYS
IN THE PERIOD 6/ 1/-10/15/.

```
DO YOU WISH TO EXAMINE A DIFFERENT CASE WITHIN THE SAME YEAR?
YES
DO YOU WISH TO ANALYZE THIS CASE FOR THE SAME
DAYS, HOURS, AND OUTPUT OPTIONS AS IN THE LAST
CASE?
NO
THE INCLUSIVE TIME PERIOD OF INTEREST IS SPECIFIED BY TYPING THE
STARTING MONTH AND DAY AND THE ENDING MONTH AND DAY IN THE FORMAT
--/--/--/--. FOR EXAMPLE, TO SPECIFY JUNE 1 THROUGH OCTOBER 15 TYPE
06/01/10/15 THEN PRESS RETURN.
 5/ 1/ 5/31
DO YOU WISH TO SPECIFY THE DAYS OF THE WEEK FOR WHICH
THE CALCULATIONS ARE TO BE MADE?
NO
DO YOU WISH TO SPECIFY THE HOURS OF THE DAY FOR WHICH
THE CALCULATIONS ARE TO BE MADE?
YES
TO SPECIFY THE PERIOD OF THE DAY YOU ARE INTERESTED IN TYPE
THE STARTING HOUR AND THE ENDING HOUR USING MILITARY
NOTATION IN THE FORMAT
--/--. FOR EXAMPLE, TO SPECIFY 11AM THROUGH 4PM TYPE
11/16 THEN PRESS RETURN
 9/21
DO YOU WISH TO SPECIFY A RANGE OF HOURS DURING THE DAY
WHICH ARE NOT USED IN THE CALCULATION?
NO
DO YOU WISH TO SEE THE SELECTED DATA?
YES
DO YOU WISH TO SEE THE LOAD FREQUENCY PLOT?
YES
DO YOU WISH TO SEE THE LOAD DURATION CURVE?
YES
DO YOU WISH TO SEE THE LOAD PROBABILITY CURVE?
YES
DO YOU WISH TO HAVE AN AVERAGE AND PEAK DAY CALCULATED
FOR EACH DAY OF THE WEEK?
YES
OUTPUT FOR THE AVERAGE AND PEAK DAY
CALCULATION IS AVAILABLE IN
   1  SUMMARY TABLE OF THE AVERAGE LOAD PER HOUR
      PER DAY AND THE PEAK LOAD PER HOUR PER DAY.
   2  A DAY BY DAY PLOT OF THE SUMMARY DATA
   3  BOTH OF THE ABOVE

TYPE THE NUMBER OF THE OUTPUT OPTION
2
```

PEAK MW	MO/DA/HR
2244.	5/22/15

THE LOAD FACTOR IS 86.2%

THE TOTAL MEGAWATT-HOUR SALES ARE 779190.

MO/DA	D	AM/PM 09	10	11	12	13	14	15	16	17	18	19	20	21
5 1	4	2172	1700	2151	2140	2114	1697	2034	1610	2090	1680	1997	1652	2036
5 2	5	1998	2049	2067	2062	2034	2043	2009	1998	1962	1911	1845	1872	1957
5 3	6	1605	1716	1748	1770	1717	1693	1691	1646	1691	1723	1679	1710	1782
5 4	7	1451	1521	1573	1612	1594	1587	1568	1540	1581	1608	1636	1703	1758
5 5	1	1999	2056	2117	2122	2072	2101	2060	2086	2011	2038	1989	1921	2024
5 6	2	2009	2059	2086	2124	2037	2073	2076	2084	2030	1994	1965	1987	2044
5 7	3	1996	2078	2121	2099	2056	2095	2084	2064	2087	2106	2036	1992	2024
5 8	4	2011	2095	2128	2112	2088	2084	2117	2055	2072	2035	1990	1930	1989
5 9	5	1961	2042	2060	2066	2034	2034	2017	1985	1923	1940	1853	1839	1892
5 10	6	1617	1748	1815	1819	1797	1774	1744	1701	1737	1763	1716	1717	1761
5 11	7	1459	1551	1664	1702	1722	1718	1661	1652	1710	1726	1720	1749	1810
5 12	1	2079	2127	2159	2155	2101	2104	2088	2050	2004	2022	2007	1980	2027
5 13	2	2005	2073	2111	2083	2052	2089	1998	2022	2006	1984	1923	1929	2008
5 14	3	2020	2044	2103	2064	2034	2093	2057	2039	2096	2106	2075	2023	2023
5 15	4	2055	2124	2137	2119	2114	2133	2082	2095	2092	2103	2095	2050	2059
5 16	5	2030	2095	2094	2100	2043	2040	2005	1993	2002	1980	1952	1954	1958
5 17	6	1634	1846	1935	1907	1923	1884	1821	1782	1821	1819	1783	1793	1815
5 18	7	1445	1517	1553	1573	1585	1545	1518	1502	1523	1547	1528	1552	1699
5 19	1	1987	2066	2090	2114	2083	2084	2082	2064	2037	2001	1953	1895	1972
5 20	2	1961	2035	2081	2115	2078	2096	2072	2085	2081	2008	1932	1903	1996
5 21	3	1993	2066	2098	2156	2132	2156	2165	2156	2123	2091	2018	1938	2017
5 22	4	2023	2088	2146	2178	2168	2216	2244	2210	2184	2145	2062	1951	2039
5 23	5	2016	2120	2156	2168	2197	2199	2184	2177	2114	2051	2000	1889	1927
5 24	6	1527	1651	1721	1731	1716	1684	1659	1625	1639	1682	1650	1628	1660
5 25	7	1445	1503	1537	1582	1599	1578	1546	1554	1589	1570	1561	1563	1646
5 26	8	1498	1610	1672	1697	1677	1645	1634	1615	1678	1681	1661	1639	1775
5 27	2	1968	2057	2136	2149	2153	2166	2157	2168	2162	2101	2015	1982	2006
5 28	3	1985	2084	2187	2212	2163	2219	2223	2191	2202	2156	2050	1999	2086
5 29	4	2021	2158	2215	2214	2197	2161	2154	2149	2100	2058	2003	1942	1985
5 30	5	2000	2126	2122	2136	2182	2197	2184	2177	2111	2055	1962	1925	1971
5 31	6	1651	1790	1854	1869	1826	1835	1804	1749	1794	1829	1752	1735	1788

LOAD FREQUENCY CURVE FOR THE PERIOD 5/ 1/ 9- 5/31/21.

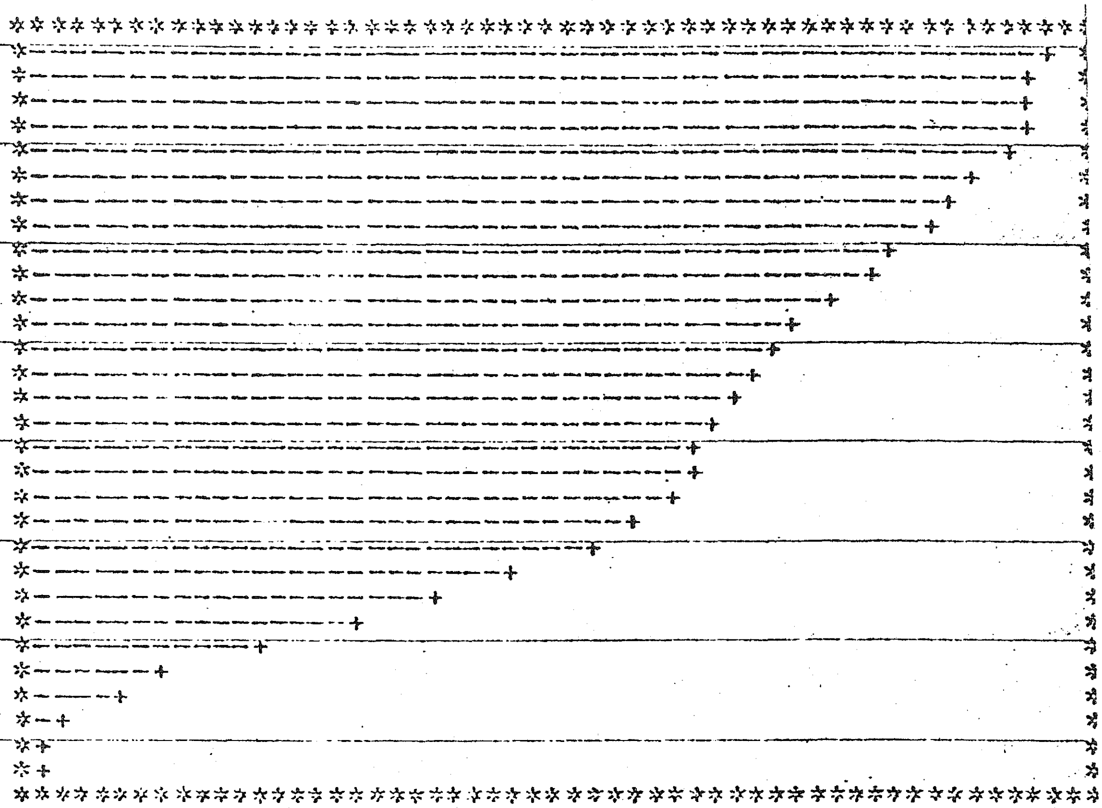
LOAD MW	FREQ HR
1445.0	3.0
1472.6	1.0
1500.1	3.0
1527.7	8.0
1555.2	10.0
1582.8	10.0
1610.3	8.0
1637.9	12.0
1665.4	11.0
1693.0	15.0
1720.5	14.0
1748.1	10.0
1775.6	9.0
1803.2	7.0
1830.7	8.0
1858.3	6.0
1885.8	4.0
1913.4	8.0
1940.9	12.0
1968.5	13.0
1996.0	36.0
2023.6	27.0
2051.1	32.0
2078.7	42.1
2106.2	32.0
2133.8	16.0
2161.3	23.0
2188.9	15.0
2216.4	7.0
2244.0	1.0

LOAD DURATION CURVE FOR THE PERIOD 5/ 1/ 9- 5/31/21.

```
  TIME      LOAD
  HRS        MW     *BASE LOAD**************************************************
    1.0    2244.0  *--/  /---------------------------------------------+
   14.9    2195.3  *--/  /-------------------------------------------+
   28.7    2168.3  *--/  /------------------------------------------+
   42.6    2155.6  *--/  /-----------------------------------------+
   56.4    2128.3  *--/  /---------------------------------------+
   70.3    2118.6  *--/  /---------------------------------------+
   84.2    2098.5  *--/  /--------------------------------------+
   98.0    2095.1  *--/  /--------------------------------------+
  111.9    2087.6  *--/  /-------------------------------------+
  125.8    2080.4  *--/  /-------------------------------------+
  139.6    2065.8  *--/  /------------------------------------+
  153.5    2057.6  *--/  /------------------------------------+
  167.3    2041.9  *--/  /-----------------------------------+
  181.2    2025.8  *--/  /----------------------------------+
  195.1    2016.1  *--/  /----------------------------------+
  208.9    2006.2  *--/  /---------------------------------+
  222.8    1994.0  *--/  /--------------------------------+
  236.7    1970.2  *--/  /-------------------------------+
  250.5    1938.9  *--/  /-----------------------------+
  264.4    1902.0  *--/  /----------------------------+
  278.2    1829.1  *--/  /-----------------------+
  292.1    1786.4  *--/  /--------------------+
  306.0    1743.5  *--/  /------------------+
  319.8    1720.0  *--/  /-----------------+
  333.7    1687.5  *--/  /---------------+
  347.6    1659.6  *--/  /--------------+
  361.4    1615.3  *--/  /-----------+
  375.3    1578.6  *--/  /----------+
  389.1    1540.5  *--/  /-------+
  403.0    1445.0  *--/  /---+
                    *BASE LOAD**************************************************
```

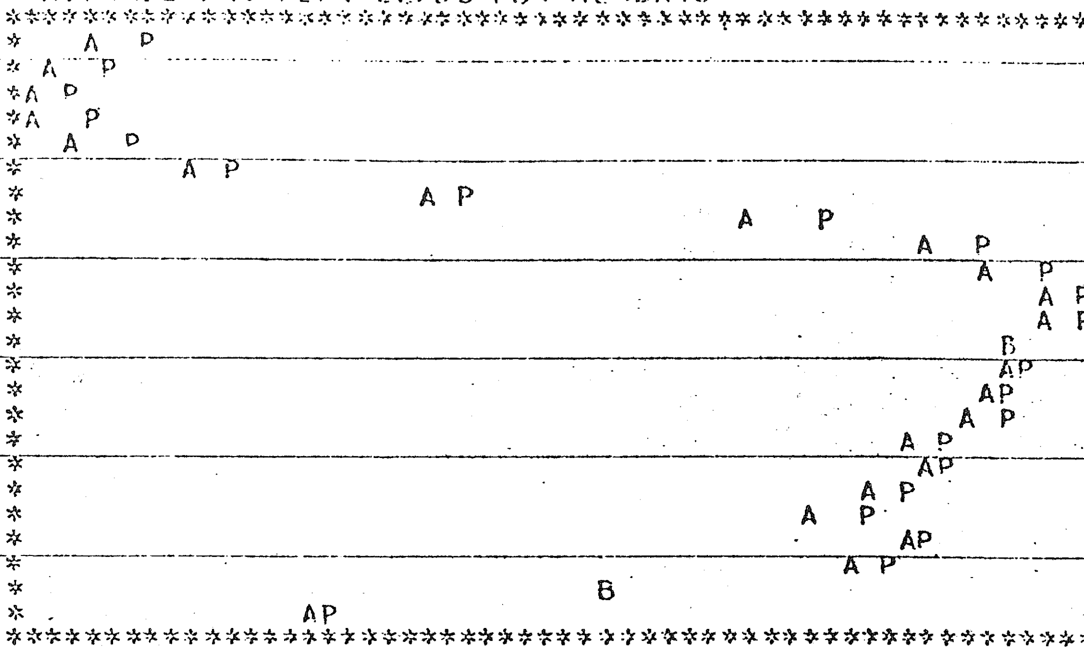
LOAD PROBABILITY CURVE FOR THE PERIOD 5/ 1/ 9- 5/31/21.

LOAD MW	PROB
1445.0	1.00000
1472.6	0.99255
1500.1	0.99009
1527.7	0.98264
1555.2	0.96281
1582.8	0.93600
1610.3	0.91321
1637.9	0.89337
1655.4	0.86354
1693.0	0.83625
1720.5	0.79905
1748.1	0.76435
1775.6	0.73953
1803.2	0.71718
1830.7	0.69980
1858.3	0.68000
1885.8	0.66513
1913.4	0.65518
1940.9	0.63529
1968.5	0.60553
1996.0	0.57328
2023.6	0.48389
2051.1	0.41685
2078.7	0.32740
2106.2	0.23304
2133.8	0.15369
2161.3	0.11406
2188.9	0.05705
2216.4	0.01984
2244.0	0.00248



AVERAGE AND PEAK LOADS FOR MONDAYS

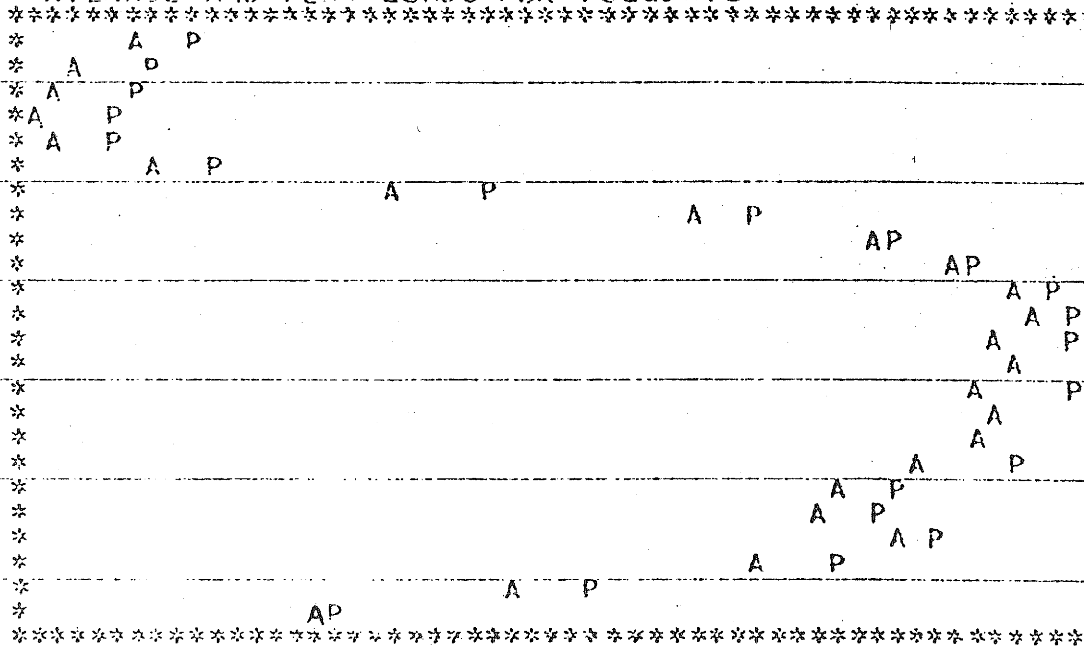
HR	AVE	PEAK
1	1340.	1389.
2	1310.	1356.
3	1290.	1327.
4	1295.	1345.
5	1317.	1367.
6	1414.	1455.
7	1614.	1652.
8	1878.	1943.
9	2022.	2079.
10	2083.	2127.
11	2122.	2159.
12	2130.	2155.
13	2087.	2101.
14	2096.	2104.
15	2077.	2088.
16	2067.	2086.
17	2017.	2037.
18	2020.	2035.
19	1986.	2007.
20	1932.	1980.
21	2008.	2027.
22	1958.	1988.
23	1760.	1773.
24	1519.	1528.



THERE ARE 3 MONDAYS
IN THE PERIOD 5/ 1/- 5/31/.

AVERAGE AND PEAK LOADS FOR TUESDAYS

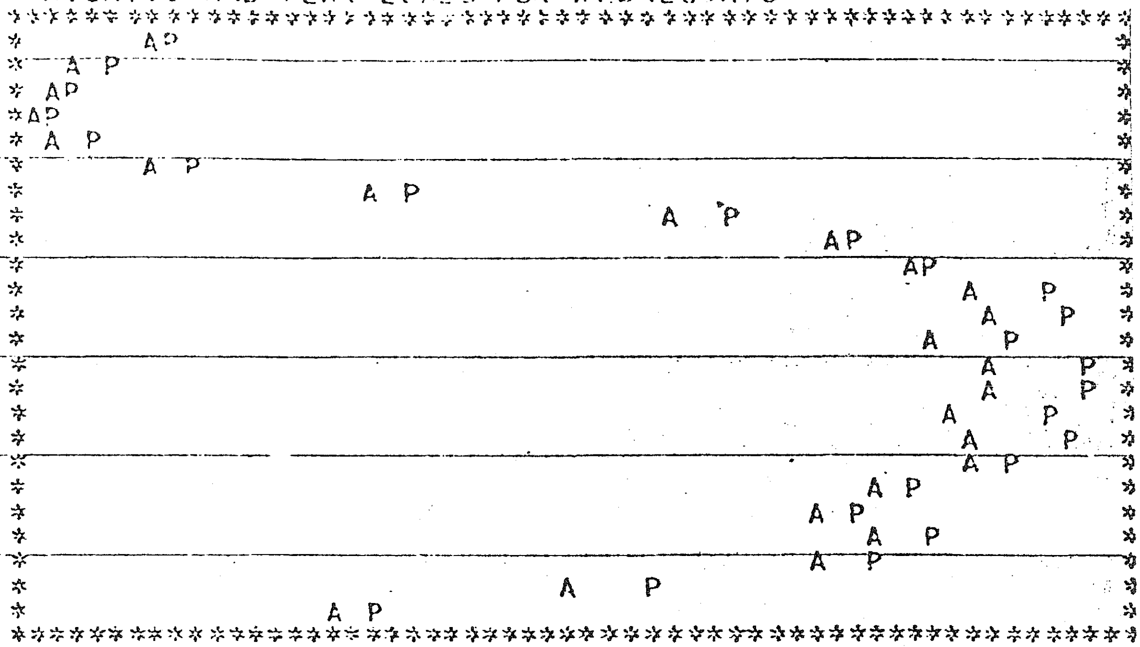
HR	AVE	PEAK
1	1405.	1450.
2	1364.	1425.
3	1345.	1410.
4	1327.	1386.
5	1343.	1387.
6	1419.	1469.
7	1607.	1687.
8	1847.	1899.
9	1986.	2009.
10	2056.	2073.
11	2104.	2136.
12	2118.	2149.
13	2093.	2153.
14	2106.	2166.
15	2076.	2157.
16	2090.	2168.
17	2070.	2162.
18	2022.	2101.
19	1959.	2015.
20	1950.	1987.
21	2014.	2044.
22	1895.	1954.
23	1714.	1773.
24	1544.	1570.



THERE ARE 4 TUESDAYS
IN THE PERIOD 5/ 1/- 5/31/.

AVERAGE AND PEAK LOADS FOR WEDNESDAYS

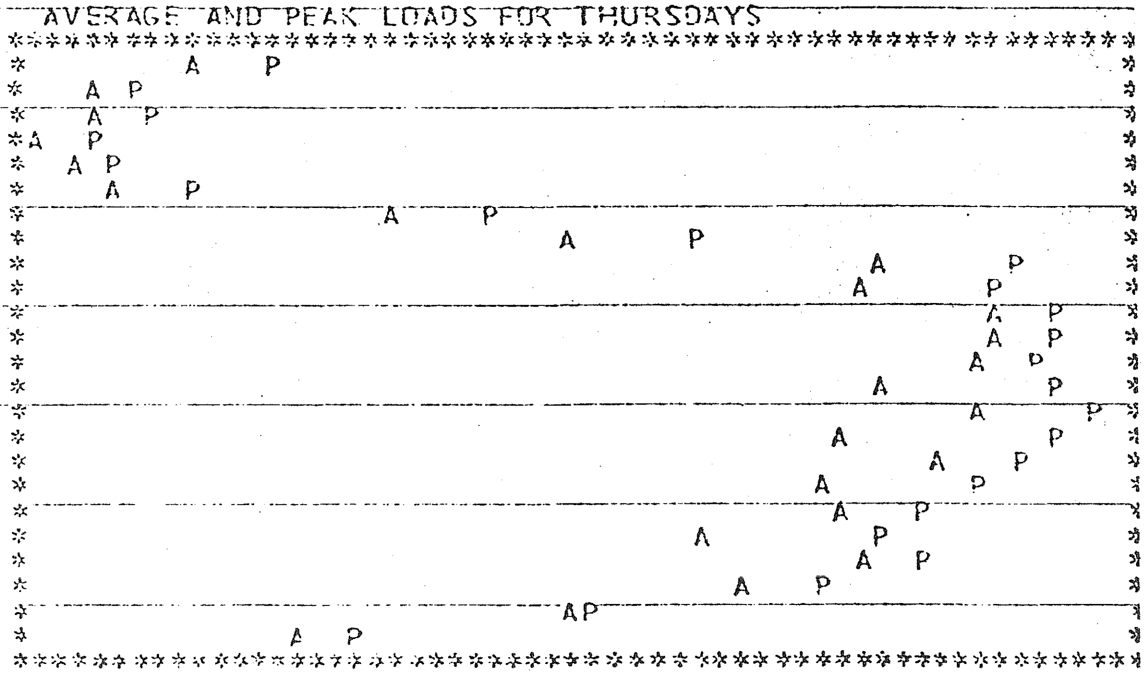
HR	AVE	PEAK
1	1425.	1448.
2	1372.	1393.
3	1343.	1364.
4	1332.	1351.
5	1357.	1388.
6	1428.	1473.
7	1612.	1648.
8	1865.	1921.
9	1999.	2020.
10	2068.	2084.
11	2127.	2187.
12	2133.	2212.
13	2096.	2163.
14	2141.	2219.
15	2132.	2223.
16	2113.	2191.
17	2127.	2202.
18	2115.	2156.
19	2045.	2075.
20	1988.	2023.
21	2038.	2086.
22	1985.	2035.
23	1786.	1848.
24	1582.	1614.



THERE ARE 4 WEDNESDAYS
IN THE PERIOD 5/ 1/- 5/31/.

AVERAGE AND PEAK LOADS FOR THURSDAYS

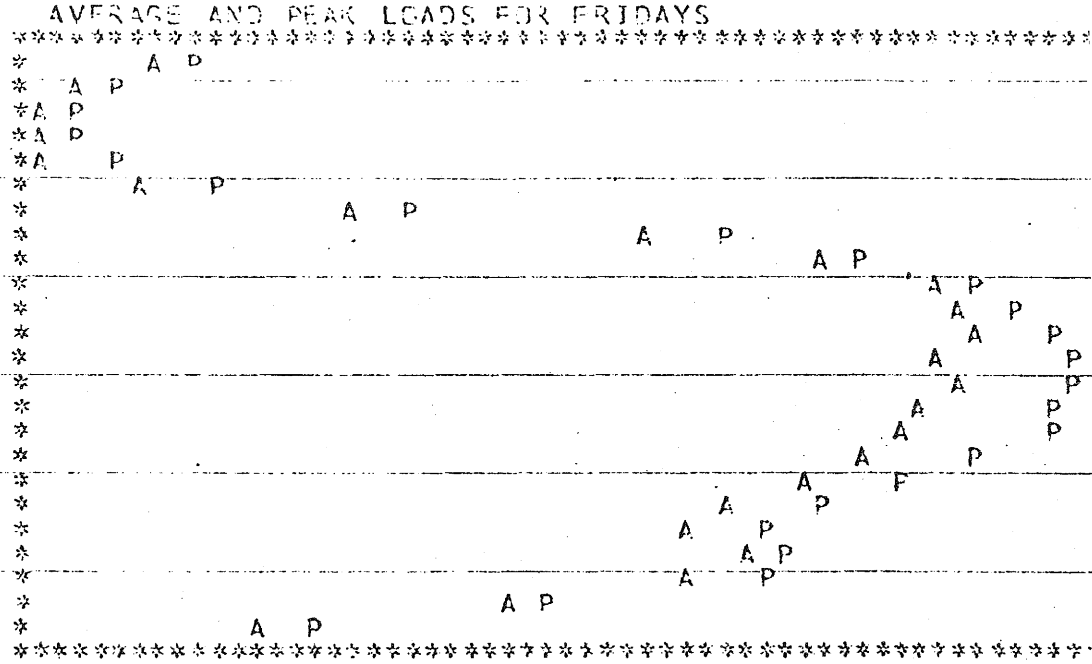
HR	AVE	PEAK
1	1473.	1541.
2	1391.	1418.
3	1389.	1449.
4	1338.	1382.
5	1365.	1401.
6	1412.	1475.
7	1652.	1725.
8	1799.	1907.
9	2056.	2172.
10	2033.	2158.
11	2155.	2215.
12	2153.	2214.
13	2136.	2197.
14	2058.	2216.
15	2136.	2244.
16	2024.	2210.
17	2108.	2184.
18	2004.	2145.
19	2029.	2095.
20	1905.	2050.
21	2032.	2086.
22	1939.	2009.
23	1799.	1815.
24	1559.	1610.



THERE ARE 5 THURSDAYS
IN THE PERIOD 5/ 1/- 5/31/.

AVERAGE AND PEAK LOADS FOR FRIDAYS

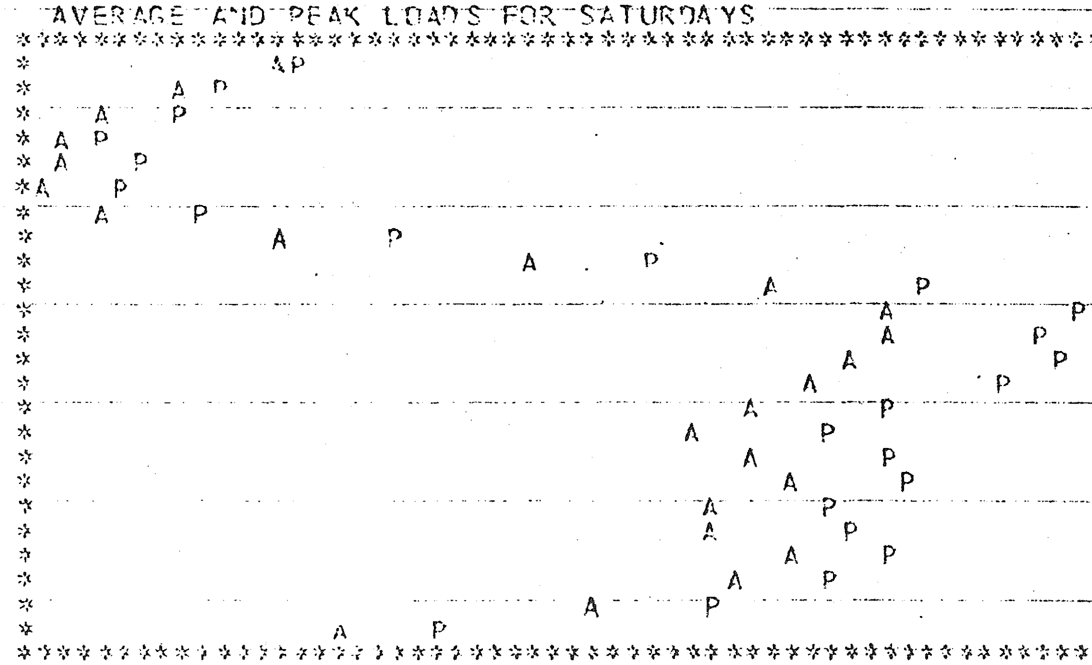
HR	AVE	PEAK
1	1465.	1496.
2	1407.	1432.
3	1383.	1407.
4	1377.	1411.
5	1381.	1439.
6	1454.	1510.
7	1628.	1679.
8	1859.	1918.
9	2001.	2030.
10	2086.	2126.
11	2100.	2156.
12	2116.	2186.
13	2098.	2197.
14	2103.	2199.
15	2080.	2184.
16	2066.	2177.
17	2022.	2114.
18	1987.	2055.
19	1922.	2000.
20	1896.	1954.
21	1940.	1971.
22	1892.	1949.
23	1749.	1788.
24	1555.	1587.



THERE ARE 5 FRIDAYS
IN THE PERIOD 5/ 1/- 5/31/.

AVERAGE AND PEAK LOADS FOR SATURDAYS

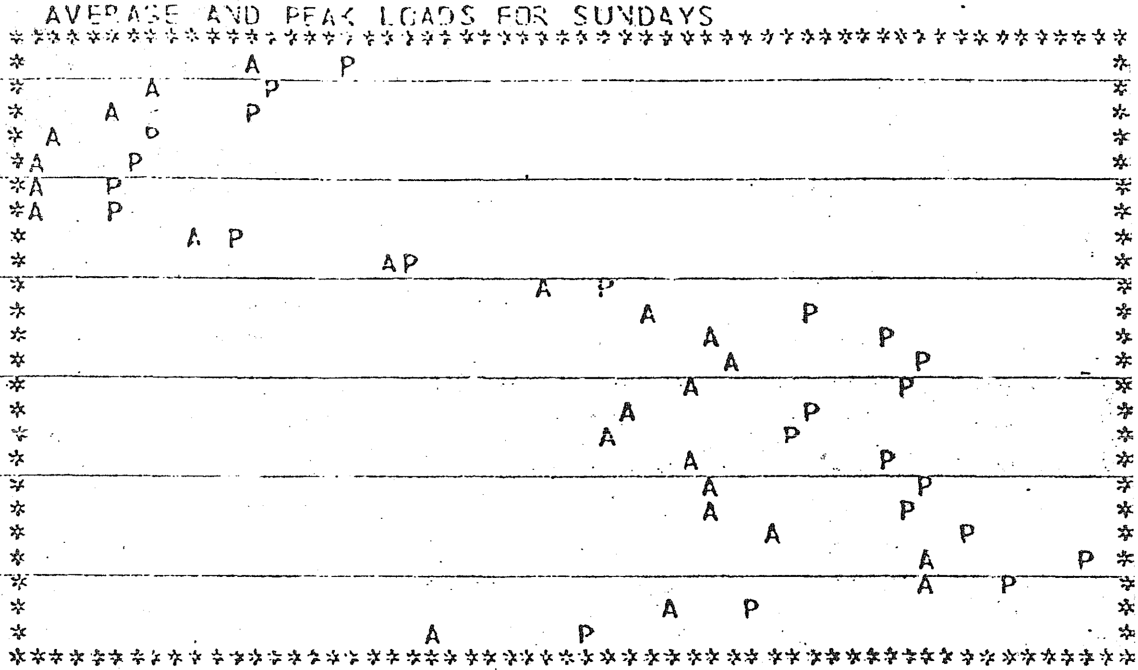
HR	AVE	PEAK
1	1461.	1470.
2	1400.	1428.
3	1355.	1402.
4	1331.	1360.
5	1332.	1376.
6	1323.	1367.
7	1355.	1411.
8	1462.	1533.
9	1617.	1654.
10	1745.	1846.
11	1815.	1935.
12	1819.	1907.
13	1797.	1924.
14	1774.	1884.
15	1744.	1821.
16	1701.	1782.
17	1736.	1821.
18	1763.	1829.
19	1716.	1783.
20	1717.	1793.
21	1761.	1815.
22	1726.	1799.
23	1649.	1719.
24	1502.	1550.



THERE ARE 5 SATURDAYS
IN THE PERIOD 5/ 1/- 5/31/.

AVERAGE AND PEAK LOADS FOR SUNDAYS

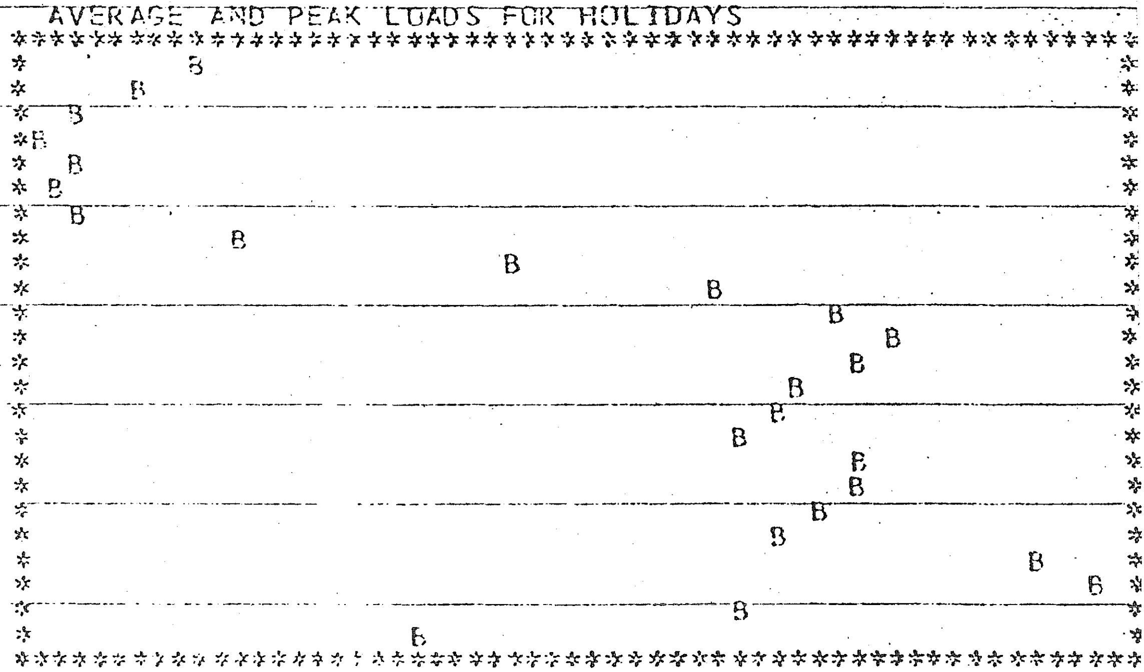
HR	AVE	PEAK
1	1377.	1425.
2	1323.	1384.
3	1299.	1372.
4	1267.	1321.
5	1264.	1309.
6	1265.	1306.
7	1260.	1302.
8	1341.	1366.
9	1450.	1459.
10	1526.	1561.
11	1582.	1654.
12	1617.	1702.
13	1625.	1722.
14	1607.	1718.
15	1573.	1661.
16	1562.	1652.
17	1601.	1710.
18	1613.	1726.
19	1611.	1720.
20	1642.	1749.
21	1728.	1810.
22	1731.	1764.
23	1594.	1635.
24	1462.	1546.



THERE ARE 4 SUNDAYS
IN THE PERIOD 5/ 1/- 5/31/.

AVERAGE AND PEAK LOADS FOR HOLIDAYS

HR	AVE	PEAK
1	1331.	1331.
2	1297.	1297.
3	1269.	1269.
4	1244.	1244.
5	1261.	1261.
6	1259.	1259.
7	1264.	1264.
8	1347.	1347.
9	1498.	1498.
10	1610.	1610.
11	1672.	1672.
12	1697.	1697.
13	1677.	1677.
14	1645.	1645.
15	1634.	1634.
16	1615.	1615.
17	1678.	1678.
18	1681.	1681.
19	1661.	1661.
20	1639.	1639.
21	1775.	1775.
22	1807.	1807.
23	1613.	1613.
24	1444.	1444.



THERE ARE 1 HOLIDAYS
IN THE PERIOD 5/ 1/- 5/31/.

AVERAGE AND PEAK LOADS FOR WEEKDAYS

HR	AVE	PEAK
1	1430.	1541.
2	1374.	1432.
3	1356.	1449.
4	1338.	1411.
5	1356.	1439.
6	1426.	1510.
7	1625.	1725.
8	1846.	1943.
9	2014.	2172.
10	2054.	2158.
11	2122.	2215.
12	2130.	2214.
13	2104.	2197.
14	2099.	2219.
15	2102.	2244.
16	2069.	2210.
17	2071.	2202.
18	2027.	2156.
19	1987.	2095.
20	1931.	2050.
21	2004.	2086.
22	1931.	2035.
23	1763.	1848.
24	1554.	1614.

THERE ARE 21 WEEKDAYS
IN THE PERIOD 5/ 1/- 5/31/.

AVERAGE AND PEAK LOADS FOR WEEKEND DAYS

HR	AVE	PEAK
1	1414.	1470.
2	1359.	1428.
3	1324.	1403.
4	1297.	1360.
5	1298.	1376.
6	1293.	1367.
7	1308.	1411.
8	1402.	1533.
9	1538.	1684.
10	1645.	1846.
11	1707.	1935.
12	1726.	1907.
13	1716.	1928.
14	1694.	1884.
15	1665.	1821.
16	1637.	1782.
17	1676.	1821.
18	1695.	1829.
19	1659.	1783.
20	1679.	1793.
21	1749.	1815.
22	1736.	1807.
23	1623.	1719.
24	1480.	1550.

THERE ARE 10 WEEKEND DAYS
IN THE PERIOD 5/ 1/- 5/31/.

```
DO YOU WISH TO EXAMINE A DIFFERENT CASE WITHIN THE SAME YEAR?
NO
```

APPENDIX C
FORTRAN LISTING

This appendix contains the FRED program fortran source listing.

DSN=TS1780.FRED.FORT,VOL=IRCC71

```
C     THE ELECTRIC UTILITY LOAD DATA INFORMATION CODE
C                 THE OHIO STATE UNIVERSITY
C                 DEPARTMENT OF MECHANICAL ENGINEERING
C                 COLUMBUS, OHIO 43210
C
C     PURPOSE
C        THE FUNCTION OF THIS CODE IS TO CALCULATE AND PLOT FROM
C        REAL TIME LOAD DATA THE LOAD FREQUENCY INFORMATION, THE
C        LOAD DURATION INFORMATION, THE LOAD PROBABILITY INFORMATION,
C        THE AVERAGE HOURLY LOAD FOR EACH DAY OF THE WEEK AND HOLIDAYS,
C        THE AVERAGE HOURLY LOAD FOR THE WEEKDAYS COMBINED AND FOR THE
C        WEEKENDS INCLUDING HOLIDAYS COMBINED, THE PEAK HOURLY LOAD
C        FOR EACH DAY OF THE WEEK AND HOLIDAYS, THE PEAK HOURLY LOAD
C        FOR THE WEEKDAYS COMBINED AND FOR THE WEEKENDS INCLUDING
C        HOLIDAYS.
C
C     DISCRIPTION OF PARAMETERS NEEDED TO BE SUPPLIED BY THE USER
C
C        LODA(12,31,24) -IS THE HOURLY LOAD DATA STORED BY MONTH,
C                        DAY AND HOUR OF THE DAY. DAYS WHICH DO
C                        NOT EXIST SUCH AS SEPTEMBER 31 HAVE THEIR
C                        HOURLY LOADS SET TO ZERO, THE INPUT FORMAT
C                        FOLLOWS THE EEI LOAD REPORTING FORMAT
C        DAY(12,31)     -IS A NUMBER FROM 0 TO 8 STORED BY MONTH
C                        AND DAY WHICH TELLS THE DAY OF THE WEEK.
C                        FOR EXAMPLE 1=MONDAYS,7=SUNDAYS, 8=HOLIDAYS,
C                        AND 0=DUMMY OR ZERO LOAD DAY.
C        ISM/ISD        -IS THE STARTING MONTH AND DAY OF THE TIME
C                        PERIOD OVER WHICH THE CALCULATIONS ARE TO
C                        BE MADE, E.G. 06/07 IS JUNE 7TH.
C        IEM/IED        -IS THE ENDING MONTH AND DAY OF THE TIME
C                        PERIOD OF INTEREST  E.G. 07/24 IS JULY 24TH
C        ISH/IEH        -IS THE INCLUSIVE TIME PERIOD DURING EACH DAY
C                        OVER WHICH THE CALCULATIONS ARE MADE. E.G.
C                        SPECIFING 10/16 TELLS THE PROGRAM TO USE ONLY
C                        LOAD DATA FROM THE TIME PERIOD OF 10AM THROUGH
C                        4PM. (IEH>ISH)
C        IHES/IHEE      -IS AN INCLUSIVE TIME PERIOD WITHIN THE TIME
C                        PERIOD ISH/IEH FOR WHICH THE LOADS OCURRING
C                        DURING THAT PERIOD ARE NOT USE. EG BY SPECIFING
C                        12/13 THE LOAD DATA AT NOON AND 1PM IS NOT
C                        USED IN THE CALCULATIONS. IF IHES>IHE OR
C                        IHEE<IHS NO EXCLUSION PERIOD WILL OCURR.
C
C     INDIVIDUAL DAYS OF THE WEEK AND HOLIDAYS CAN BE SPECIFIED FOR
C     USE IN THE CALCULATION OR NOT. IF THE DAY IS TO BE USED
C     ASSIGN THE NUMBER 1 TO 8 TO THAT DAY WHERE
C        MON=1 TUES=2 WED=3 THURS=4 FRI=5 SAT=6 SUN=7 HOLI=8
C     IF THE DAY IS NOT TO BE USED GIVE IT A VALUE OF 0.
C
C     DISCRIPTION OF OUTPUT PARAMETERS
C        LOD100 -IS AN ARRAY OF 100 UNIFORMILY SPACED LOAD POINTS
C                WHERE LOD100(1)=BASE LOAD AND LOD100(100)=PEAK LOAD
C        FRQ100 -IS AN ARRAY OF 100 CORRESPONDING LOAD FREQUENCY
C                VALUES
C        LODVAL -IS AN ARRAY OF NOPT UNIFORMILY SPACED LOAD POINTS
C                WHERE LODVAL(1)=BASE LOAD AND LODVAL(NOPT)=PEAK LOAD
C        FREQ   -IS AN ARRAY OF NOPT CORRESPONDING LOAD FREQUENCY
C                VALUES
C        PBIL   -IS AN ARRAY OF NOPT LOAD PROBABILITY VALUES WHICH
C                CORRESPOND TO LODVAL
C        HOURS  -IS AN ARRAY OF NOPT UNIFORMILY DISTRIBUTED TOTAL
C                HOUR VALUES IN THE PERIOD OF INTEREST WHERE
C                HOURS(1) IS THE NUMBER OF HOURS THE SYSTEM PEAK
```

```
C               IN SUBROUTINE LODFRQ.
C         NOPT   -IS THE NUMBER OF DATA POINTS CALCULATED AND
C               PLOTTED NOPT< 100
      DIMENSION FRQ100(100), FREQ(100), HOURS(100), PBIL(100)
      INTEGER DAY(12,31)
      REAL LODA(12,31,24),LOD100(100),LODVAL(100),LOAD(100)
      INTEGER TUES,WED,THURS,FRI,SAT,SUN,HOLI
      REAL*8 COMPNA
      REAL NO/'NO  '/,YES/'YES '/
      REAL END/'EN  '/,MO/'MO  '/,TU/'TU  '/,WE/'WE  '/,TH/'TH  '/,FR/'F
     1R  '/,SA/'SA  '/,SU/'SU  '/,HO/'HO  '/
      INFILE=5
      WRITE(6,96)
      WRITE (6,90)
      ISTORE=11
      WRITE(6,400)
      READ(5,100) FEXEC
      WRITE(6,101) FEXEC
      IF(FEXEC.EQ.NO) WRITE(ISTORE,100)YES
      NOPT=30
C     ASK FOR AND READ THE COMPANY NAME AND YEAR
C
C
      REP=NO
   10 WRITE (6,255)
   15 READ (INFILE,260) COMPNA,IYEAR
      WRITE (6,265) COMPNA,IYEAR
      IF(FEXEC.EQ.NO) WRITE(ISTORE,260) COMPNA,IYEAR
C
C     INITIALIZATION OF LOAD ARRAY
C
      DO 19 I=1,12
      DO 19 J=1,31
      DO 19 K=1,24
   19 LODA(I,J,K)=0.0
C     READ THE HOURLY LOAD DATA FROM LOGICAL UNIT 10
   20 READ (10,270,END=25) I,J,DAY(I,J),(LODA(I,J,K),K=1,24)
      GO TO 20
C     ASK FOR AND READ THE STARTING AND ENDING MONTHS AND YEAR
C
C
   25 WRITE (6,275)
   30 READ (INFILE,280) ISM,ISD,IEM,IED
      WRITE (6,285) ISM,ISD,IEM,IED
      IF(FEXEC.EQ.NO) WRITE(ISTORE,280) ISM,ISD,IEM,IED
C
C
      IF(REP.EQ.YES) GO TO 86
C
C
      MON=0
      TUES=0
      WED=0
      THURS=0
      FRI=0
      SAT=0
      SUN=0
      HOLI=0
      WRITE (6,290)
      READ (INFILE,100) YND
      WRITE (6,101) YND
      IF(FEXEC.EQ.NO) WRITE(ISTORE,100) YND
      IOP=0
      IF(YND.EQ.NO) GO TO 35
      WRITE (6,295)
      READ (INFILE,300) IOP
      WRITE (6,301) IOP
```

```
      IF(FEXEC.EQ.NO) WRITE(ISTORE,300) IOP
      GO TO (40,35,45), IOP
 35   SUN=7
      SAT=6
      HOLI=8
      IF(IOP.EQ.2) GO TO 55
 40   MON=1
      TUES=2
      WED=3
      THURS=4
      FRI=5
      GO TO 55
C     ASK FOR AND READ ALL THE WEEKDAYS TO BE INCLUDED IN THE LOAD CURVE
 45   WRITE (6,305)
 50   READ (INFILE,310) DANAME
      IF(FEXEC.EQ.NO) WRITE(ISTORE,310) DANAME
      WRITE (6,311) DNAME
      IF(DANAME.EQ.END) GO TO 55
      IF(DANAME.EQ.MO) MON=1
      IF(DANAME.EQ.TU) TUES=2
      IF(DANAME.EQ.WE) WED=3
      IF(DANAME.EQ.TH) THURS=4
      IF(DANAME.EQ.FR) FRI=5
      IF(DANAME.EQ.SA) SAT=6
      IF(DANAME.EQ.SU) SUN=7
      IF(DANAME.EQ.HO) HOLI=8
      GO TO 50
 55   WRITE (6,315)
      READ (INFILE,100) YN
      IF(FEXEC.EQ.NO) WRITE(ISTORE,100) YN
      WRITE (6,101) YN
      IF(YN.EQ.NO) GO TO 65
C     ASK FOR AND READ THE STARTING AND ENDING HOURS TO BE INCLUDED IN
C     THE LOAD CURVE
      WRITE (6,320)
 60   READ (INFILE,325) ISH,IEH
      IF(FEXEC.EQ.NO) WRITE(ISTORE,325) ISH,IEH
      WRITE (6,330) ISH,IEH
      GO TO 70
 65   ISH=1
      IEH=24
 70   WRITE (6,335)
      READ (INFILE,100) YERHR
      IF(FEXEC.EQ.NO) WRITE(ISTORE,100) YERHR
      WRITE (6,101) YERHR
      IF(YERHR.EQ.NO) GO TO 80
      WRITE (6,340)
 75   READ (INFILE,325) IHES,IHEE
      IF(FEXEC.EQ.NO) WRITE(ISTORE,325) IHES,IHEE
      WRITE (6,330) IHES,IHEE
      GO TO 85
 80   IHES=25
      IHEE=0
 85   WRITE (6,345)
      READ (INFILE,100) YDATA
      IF(FEXEC.EQ.NO) WRITE(ISTORE,100) YDATA
      WRITE (6,101) YDATA
      WRITE (6,350)
      READ (INFILE,100) YLFC
      IF(FEXEC.EQ.NO) WRITE(ISTORE,100) YLFC
      WRITE (6,101) YLFC
      WRITE (6,355)
      READ (INFILE,100) YLDC
      IF(FEXEC.EQ.NO) WRITE(ISTORE,100) YLDC
      WRITE (6,101) YLDC
      WRITE (6,360)
```

```
      WRITE (6,365)
      READ (INFILE,100) YPKAVD
      IF(FEXEC.EQ.NO) WRITE(ISTORE,100) YPKAVD
      WRITE (6,101) YPKAVD
      IF(YPKAVD.EQ.NO) GO TO 86
      WRITE(6,366)
      READ(INFILE,300) IOUTPT
      WRITE (6,301) IOUTPT
      IF(FEXEC.EQ.NO) WRITE(ISTORE,300) IOUTPT
   86 CONTINUE
   87 CONTINUE
      IF(FEXEC.EQ.YES) GO TO 88
      GO TO 92
   88 CONTINUE
C     CALL SUBROUTINE LODFRQ TO FORM THE LOAD FREQUENCY CURVE
      CALL LODFRQ (LODA,DAY,ISM,ISD,ISH,IHES,IEM,IED,IEH,IHEE,MON,TUES,W
     1ED,THURS,FRI,SAT,SUN,HOLI,LOD100,LODVAL,FRQ100,FREQ,NOPT,HRSIP)
C     CALL SUBROUTINE WRITE, IF DESIRED, TO PRINT THE SELECTED DATA
      IF(YDATA.EQ.YES) CALL WRITE (LODA,DAY,ISM,ISD,ISH,IEM,IED,IEH)
C     CALL SUBROUTINE LFPLOT, IF DESIRED, TO PLOT THE LOAD FREQUENCY
C     CURVE
      IF(YLFC.EQ.YES) CALL LFPLOT (LODVAL,FREQ,NOPT,ISM,ISD,ISH,IEM,IED,
     1IEH)
C     CALL SUBROUTINE LDCP TO FORM THE LOAD DURATION CURVE
      IF(YLDC.EQ.YES) CALL LDCP (LOD100,FRQ100,LOAD,HOURS,HRSIP,NOPT)
C     CALL SUBROUTINE LDPLOT, IF DESIRED, TO PLOT THE LOAD DURATION
C     CURVE
      IF(YLDC.EQ.YES) CALL LDPLOT (HOURS,LOAD,NOPT,ISM,ISD,ISH,IEM,IED,I
     1EH)
C     CALL SUBROUTINE LDPB TO FORM THE LOAD PROBABILITY CURVE
      IF(YLPC.EQ.YES) CALL LDPB (FREQ,PBIL,NOPT)
C     CALL SUBROUTINE LPPLOT, IF DESIRED, TO PLOT THE LOAD PROBABILITY
C     CURVE
      IF(YLPC.EQ.YES) CALL LPPLOT (LODVAL,PBIL,NOPT,ISM,ISD,ISH,IEM,IED,
     1IEH)
C     CALL SUBROUTINE PKAVDA, IF DESIRED, TO HAVE AN AVERAGE AND PEAK
C     DAY CALCULATED FOR EACH DAY OF THE WEEK
      IF(YPKAVD.EQ.YES) CALL PKAVDA(LODA,DAY,ISM,ISD,IEM,IED,IOUTPT)
C     SEE IF THERE IS ANOTHER CASE TO BE CALCULATED
   92 WRITE (6,375)
      READ (INFILE,100) YGO
      IF(FEXEC.EQ.NO) WRITE(ISTORE,100) YGO
      WRITE(6,101) YGO
      IF(YGO.NE.YES) GO TO 89
      WRITE(6,390)
      READ(5,100) REP
      IF(FEXEC.EQ.NO) WRITE(ISTORE,100) REP
      WRITE(6,101) REP
      GO TO 25
   89 CONTINUE
      IF(FEXEC.NE.YES) GO TO 1000
      WRITE(6,440)
      GO TO 1100
 1000 WRITE(6,430)
 1100 STOP
C
   96 FORMAT('1'////27X,'**** FRED ****'/)
   90 FORMAT (///11X,'LOAD FREQUENCY, LOAD DURATION, LOAD PROBABILITY'/
     1     11X,'PEAK DAY, AND AVERAGE DAY CODE, SEPT., 1976'/20X,'THE OHI
     2O STATE UNIVERSITY'/20X,'NUCLEAR ENGINEERING DEPARTMENT'/20X,'COLU
     3MBUS, OHIO 43210'//
     +20X,'REVISED BY THE NATIONAL REGULATORY'/
     +20X,'RESEARCH INSTITUTE.      4/81'//
     +20X,'FOR INFORMATION CONTACT :'/
     +20X,'JEFFREY SHIH'/
     +20X,'THE NATIONAL REGULATORY RESEARCH INSTITUTE'/
     +20X,'THE OHIO STATE UNIVERSITY'/
```

```
     +20X,'2130 NEIL AVENUE'/
     +20X,'COLUMBUS, OHIO 43210'/
     +20X,'(614) 422-9404'///)
 100  FORMAT(A3)
 101  FORMAT(1X,A3)
 255  FORMAT (' ENTER COMPANY NAME AND YEAR OF DATA'/' XXXX 19XX')
 260  FORMAT (A4,1X,I4)
 265  FORMAT (1X,A4,1X,I4)
 270  FORMAT (2I2,11X,I1,4X,12F5.0/20X,12F5.0)
 275  FORMAT (1X,'THE INCLUSIVE TIME PERIOD OF INTEREST IS SPECIFIED BY
     1TYPING THE'/1X,'STARTING MONTH AND DAY AND THE ENDING MONTH AND DA
     2Y IN THE FORMAT'/1X,'--/--/--/--. FOR EXAMPLE, TO SPECIFY JUNE 1 T
     3HROUGH OCTOBER 15 TYPE'/1X,'06/01/10/15 THEN PRESS RETURN.')
 280  FORMAT (I2,3(1X,I2))
 285  FORMAT (1X,I2,'/',I2,'/',I2,'/',I2)
 290  FORMAT (1X,'DO YOU WISH TO SPECIFY THE DAYS OF THE WEEK FOR WHICH'
     1/1X,'THE CALCULATIONS ARE TO BE MADE?')
 295  FORMAT (1X,'IN SPECIFYING THE DAYS OF THE WEEK THE FOLLOWING'/1X,'
     1OPTIONS ARE AVAILABLE:'/10X,'1.  WEEKDAYS WITHOUT HOLIDAYS'/10X,'2
     2.  WEEKENDS WITH HOLIDAYS'/10X,'3.  INDIVIDUAL DAYS OF THE WEEK'//
     3/1X,'TO SPECIFY THE DESIRED OPTION, TYPE THAT NUMBER, THEN RETURN'
     4)
 300  FORMAT (I1)
 301  FORMAT(1X,I1)
 305  FORMAT (' TO SPECIFY INDIVIDUAL DAYS, USE THESE ABBREVIATIONS'/' (
     1MO,TU,WE,TH,FR,SA,SU) FOR A GIVEN DAY'/' AND PRESS RETURN. REPEAT 
     2FOR EACH DAY OF INTEREST.'/' HOLIDAYS ARE INCLUDED BY USING ABBREV
     3IATION (HO).'/' WHEN ALL DAYS ARE SPECFIED, TYPE (EN) END.')
 310  FORMAT (A2)
 311  FORMAT(1X,A2)
 315  FORMAT (1X,'DO YOU WISH TO SPECIFY THE HOURS OF THE DAY FOR WHICH'
     1/1X,'THE CALCULATIONS ARE TO BE MADE?')
 320  FORMAT (1X,'TO SPECIFY THE PERIOD OF THE DAY YOU ARE INTERESTED IN
     1 TYPE'/1X,'THE STARTING HOUR AND THE ENDING HOUR USING MILITARY'/1
     2X,'NOTATION IN THE FORMAT'/1X,'--/--. FOR EXAMPLE, TO SPECIFY 11AM
     3 THROUGH 4PM TYPE'/1X,'11/16 THEN PRESS RETURN')
 325  FORMAT (I2,1X,I2)
 330  FORMAT (1X,I2,'/',I2)
 335  FORMAT (1X,'DO YOU WISH TO SPECIFY A RANGE OF HOURS DURING THE DAY
     1'/1X,'WHICH ARE NOT USED IN THE CALCULATION?')
 340  FORMAT (1X,'TYPE THE RANGE OF HOURS NOT TO BE USED IN THE'/1X,'CAL
     1CULATION IN THE FORMAT'/1X,'--/--. THEN PRESS RETURN')
 345  FORMAT (' ','DO YOU WISH TO SEE THE SELECTED DATA?')
 350  FORMAT (' ','DO YOU WISH TO SEE THE LOAD FREQUENCY PLOT?')
 355  FORMAT (' ','DO YOU WISH TO SEE THE LOAD DURATION CURVE?')
 360  FORMAT (1X,'DO YOU WISH TO SEE THE LOAD PROBABILITY CURVE?')
 365  FORMAT (1X,'DO YOU WISH TO HAVE AN AVERAGE AND PEAK DAY CALCULATED
     1'/1X,'FOR EACH DAY OF THE WEEK?')
 366  FORMAT(1X,'OUTPUT FOR THE AVERAGE AND PEAK DAY'/
     11X,'CALCULATION IS AVAILABLE IN'/
     23X,'1  SUMMARY TABLE OF THE AVERAGE LOAD PER HOUR'/
     33X,'   PER DAY AND THE PEAK LOAD PER HOUR PER DAY.'/
     43X,'2  A DAY BY DAY PLOT OF THE SUMMARY DATA'/
     53X,'3  BOTH OF THE ABOVE'//
     61X,'TYPE THE NUMBER OF THE OUTPUT OPTION')
 390  FORMAT(1X,'DO YOU WISH TO ANALYZE THIS CASE FOR  THE SAME'/
     +' DAYS, HOURS, AND OUTPUT OPTIONS AS IN THE LAST'/
     +' CASE?')
 375  FORMAT (///' ','DO YOU WISH TO EXAMINE A DIFFERENT CASE WITHIN THE
     1 SAME YEAR?')
 400  FORMAT(1X,'IF YOU WISH TO EXECUTE FRED VIA TERMINAL,'/
     +' ENTER YES;'/
     +' OTHERWISE ENTER NO TO CREATE AN INPUT FILE'/
     +' FOR BATCH EXECUTION.')
 430  FORMAT(1X,'NORMAL EXIT FROM INPUT PREPARATION MODE OF FRED CODE'/
     +' EXECUTE FRED ON BATCH '/)
```

```
      END
C     SUBROUTINE WRITE
C
C     PURPOSE
C        TO WRITE THE LOAD DATA FOR THE TIME PERIOD OF INTEREST
C
C     USAGE
C        CALL WRITE(LODA,DAY,ISM,ISD,ISH,IEM,IED,IEH)
C
C     DISCRIPTION OF INPUT PARAMETERS
C        LODA    -THE HOURLY LOAD DATA
C        DAY     -A NUMBER FROM 1-8 INDICATING THE DAY OF THE WEEK
C                  1=MONDAY, 7=SUNDAY, 8=HOLIDAY
C        ISM     -STARTING MONTH OF THE PERIOD OF INTEREST
C        ISD     -STARTING DAY OF THE PERIOD OF INTEREST
C        ISH     -STARTING HOUR OF THE PERIOD OF INTEREST
C        IED     -ENDING DAY OF THE PERIOD OF INTEREST
C        IEM     -ENDING MONTH OF THE PERIOD OF INTEREST
C        IEH     -ENDING HOUR OF THE PERIOD OF INTEREST
C
C     SUBROUTINE REQUIRED
C        NONE
C
      SUBROUTINE WRITE (LODA,DAY,ISM,ISD,ISH,IEM,IED,IEH)
      DIMENSION ILODA(24)
      REAL LODA(12,31,24)
      INTEGER DAY(12,31)
      REAL HEAD(24)/'  01',' 02',' 03',' 04',' 05',' 06',' 07','
     108',' 09',' 10',' 11',' 12',' 13',' 14',' 15',' 16',' 17'
     2,' 18',' 19',' 20',' 21',' 22',' 23',' 24'/
C     INDEX THROUGH ALL THE DAYS OF THE MONTH TO BE INCLUDED IN THE
C     LOAD FREQUENCY CURVE
      KKID=-1
      IF(ISM.GT.IEM) KKID=1
      LLND=IEM-ISM+1
      IF(KKID.GT.0) LLND=LLND+12
      DO 40 ISTAR=1,LLND
      IF(KKID.LT.0) GO TO 45
      I=ISM+(ISTAR-IEM)-1
      IF(ISTAR.LE.IEM) I=ISTAR
      GO TO 50
 45   I=ISTAR+ISM-1
 50   WRITE(6,15)
      WRITE (6,20) (HEAD(J),J=ISH,IEH)
      IS=1
      IE=31
      IF(I.EQ.ISM) IS=ISD
      IF(I.EQ.IEM) IE=IED
      DO 10 J=IS,IE
      IF(LODA(I,J,1).EQ.0.) GO TO 10
      DO 5 K=1,24
 5    ILODA(K)=LODA(I,J,K)
C     WRITE: THE MONTH, DAY, DAY OF THE WEEK, AND HOURLY LOAD LEVELS
C     FOR THAT DAY
      WRITE (6,25) I,J,DAY(I,J),(ILODA(K),K=ISH,IEH)
 10   CONTINUE
 40   CONTINUE
      RETURN
C
 15   FORMAT ('1')
 20   FORMAT (12X,'AM/PM'/2X,'MO/DA D',12(1X,A4)/9X,12(1X,A4))
 25   FORMAT (2X,I2,1X,I2,1X,I1,12I5/9X,12I5)
      END
C     SUBROUTINE  PKAVDA
C
C     PURPOSE
C        THIS SUBROUTINE CALCULATES THE AVERAGE LOAD BY HOUR
C        FOR EACH DAY OF THE WEEK AND HOLIDAYS; THE AVERAGE
```

```
C          LOAD BY HOUR FOR WEEKDAYS AND WEEKENDS INCLUDING
C          HOLIDAYS; THE PEAK LOAD VALUE FOR EACH HOUR FOR EACH
C          DAY OF THE WEEK AND HOLIDAYS; THE PEAK LOAD BY HOUR
C          FOR WEEKS AND WEEKENDS INCLUDING HOLIDAYS. THE OUTPUTS
C          ARE LISTED AND, IF DESIRED, PLOTTED.
C
C       USAGE
C       CALL PKAVDA(LODA,DAY,ISM,ISD,IEM,IED,IOUTPT)
C
C       DISCRIPTION OF INPUT PARAMETERS
C          LODA    -THE HOURLY LOAD DATA READ IN BY MAIN
C          DAY     -VALUE FROM 0-8 WHERE 0=DUMMY DAY; 1-7=MONDAY-SUNDAY;
C                   8=HOLIDAY
C          ISM     -THE STARTING MONTH OF THE PERIOD OF INTEREST
C          ISD     -THE STARTING DAY OF THE PERIOD OF INTERST
C          IEM     -THE ENDING MONTH OF THE PERIOD OF INTERST
C          IED     -THE ENDING DAY OF THE PERIOD OF INTEREST
C          IOUPUT -OUTPUT OPTION
C
C       DISCRIPTION OF PROGRAM PARAMETERS
C          AVE     -AVERAGE LOAD VALUES
C          PKD     -PEAK LOAD VALUES
C          COUNT   -NUMBER OF DAYS OF EACH TYPE
C
C
C       SUBROUTINES REQUIRED
C          NONE
        SUBROUTINE PKAVDA(LODA,DAY,ISM,ISD,IEM,IED,IOUTPT)
        DIMENSION AVE(10,24), PKD(10,24), COUNT(10), H(57), TITLE(10,3)
        DIMENSION LODA(12,31,24), DAY(12,31)
        REAL LODA
        INTEGER DAY,COUNT
        DATA BLANK,P,A,B,STAR/' ','P','A','B','*'/
        DATA TITLE(1,1),TITLE(1,2),TITLE(1,3)/'MOND','AYS ','    '/
        DATA TITLE(2,1),TITLE(2,2),TITLE(2,3)/'TUES','DAYS','    '/
        DATA TITLE(3,1),TITLE(3,2),TITLE(3,3)/'WEDN','ESDA','YS  '/
        DATA TITLE(4,1),TITLE(4,2),TITLE(4,3)/'THUR','SDAY','S   '/
        DATA TITLE(5,1),TITLE(5,2),TITLE(5,3)/'FRID','AYS ','    '/
        DATA TITLE(6,1),TITLE(6,2),TITLE(6,3)/'SATU','RDAY','S   '/
        DATA TITLE(7,1),TITLE(7,2),TITLE(7,3)/'SUND','AYS ','    '/
        DATA TITLE(8,1),TITLE(8,2),TITLE(8,3)/'HOLI','DAYS','    '/
        DATA TITLE(9,1),TITLE(9,2),TITLE(9,3)/'WEEK','DAYS','    '/
        DATA TITLE(10,1),TITLE(10,2),TITLE(10,3)/'WEEK','END ','DAYS'/
        IPC = 0
        ISH=1
        IEH=24
        DO 5 I=1,10
        COUNT(I)=0
        DO 5 K=1,24
        PKD(I,K)=0.
   5    AVE(I,K)=0.
        H(1)=STAR
        H(57)=STAR
C       THIS SECTION ORDERS THE LOAD DATA BY DAY AND HOUR INTO THE PEAK
C       AND TOTAL AMOUNT OF GENERATION ALSO THE TOTAL NUMBERS OF EACH DAY
C       ARE COUNTED
        KKID=-1
        IF(ISM.GT.IEM) KKID=1
        LLND=IEM-ISM+1
        IF(KKID.GT.0) LLND=LLND+12
        DO 200 ISTAR=1,LLND
        IF(KKID.LT.0) GO TO 210
        I=ISM+(ISTAR-IEM)-1
        IF(ISTAR.LE.IEM) I=ISTAR
        GO TO 220
 210    I=ISTAR+ISM-1
```

```
      IF(I.EQ.IEM) I2=IED
      DO 15 J=I1,I2
      IF(DAY(I,J).LT.1.OR.DAY(I,J).GT.8) GO TO 15
      M=DAY(I,J)
      COUNT(M)=COUNT(M)+1
      DO 10 K=1,24
      IF(LODA(I,J,K).GT.PKD(M,K)) PKD(M,K)=LODA(I,J,K)
   10 AVE(M,K)=AVE(M,K)+LODA(I,J,K)
   15 CONTINUE
  200 CONTINUE
C     THIS SECTION CALCULATES THE PEAK LOAD BY HOUR AND THE AVERAGE LOAD
C     BY HOUR FOR WEEKDAYS AND WEEKENDS AND THE AVERAGE DAILY LOAD BY
C     HOUR
      DO 30 K=1,24
      COUNT(10)=0
      COUNT(9)=0
      DO 20 M=1,5
      COUNT(9)=COUNT(9)+COUNT(M)
      AVE(9,K)=AVE(9,K)+AVE(M,K)
      IF(COUNT(M).NE.0) AVE(M,K)=AVE(M,K)/COUNT(M)
   20 IF(PKD(9,K).LT.PKD(M,K)) PKD(9,K)=PKD(M,K)
      IF(COUNT(9).NE.0) AVE(9,K)=AVE(9,K)/COUNT(9)
      DO 25 M=6,8
      AVE(10,K)=AVE(10,K)+AVE(M,K)
      COUNT(10)=COUNT(10)+COUNT(M)
      IF(COUNT(M).NE.0) AVE(M,K)=AVE(M,K)/COUNT(M)
   25 IF(PKD(10,K).LT.PKD(M,K)) PKD(10,K)=PKD(M,K)
   30 IF(COUNT(10).NE.0) AVE(10,K)=AVE(10,K)/COUNT(10)
      IF(IOUTPT.EQ.2) GO TO 41
      WRITE (6,65) ISM,ISD,IEM,IED
      WRITE (6,70)
      DO 35 K=1,24
   35 WRITE (6,85) K,(AVE(M,K),M=1,5),AVE(9,K),(AVE(M,K),M=6,8),AVE(10,K
     1)
      WRITE (6,75)
      WRITE (6,80) ISM,ISD,IEM,IED
      WRITE (6,70)
      DO 40 K=1,24
   40 WRITE (6,85) K,(PKD(M,K),M=1,5),PKD(9,K),(PKD(M,K),M=6,8),PKD(10,K
     1)
   41 IPL=0
      IF(IOUTPT.EQ.1) RETURN
      DO 60 I=1,10
      IF(COUNT(I).EQ.0) GO TO 60
      IF(IPC.EQ.0) WRITE (6,90)
      IPC=IPC+1
      IF(IPC.EQ.2) IPC=0
      WRITE (6,95) (TITLE(I,J),J=1,3)
      WRITE (6,100) (STAR,J=1,57)
      YMAX=PKD(I,1)
      YMIN=AVE(I,1)
      DO 45 K=1,24
      IF(PKD(I,K).GT.YMAX) YMAX=PKD(I,K)
   45 IF(AVE(I,K).LT.YMIN) YMIN=AVE(I,K)
      YDIF=YMAX-YMIN
      DO 55 K=1,24
      IP=(PKD(I,K)-YMIN)*53/YDIF+2.5
      IA=(AVE(I,K)-YMIN)*53/YDIF+2.5
      DO 50 J=2,56
   50 H(J)=BLANK
      H(IA)=A
      H(IP)=P
      IF(IP.EQ.IA) H(IA)=B
   55 WRITE (6,105) K,AVE(I,K),PKD(I,K),(H(J),J=1,57)
      WRITE (6,110) (STAR,J=1,57)
      IF(COUNT(I).LT.10) WRITE (6,115) COUNT(I),(TITLE(I,J),J=1,3),ISM,I
     1SD,IEM,IED
```

```
      IF(COUNT(I).GE.10.AND.COUNT(I).LT.100) WRITE (6,120) COUNT(I),(TIT
     1LE(I,J),J=1,3),ISM,ISD,IEM,IED
      IF(COUNT(I).GE.100) WRITE (6,125) COUNT(I),(TITLE(I,J),J=1,3),ISM,
     1ISD,IEM,IED
   60 CONTINUE
      RETURN
C
   65 FORMAT ('1','THE FOLLOWING ARE AVERAGE LOAD DAYS FOR THE PERIOD',1
     1X,I2,'/',I2,1X,'TO',1X,I2,'/',I2,'.'/)
   70 FORMAT (1X,'HR',3X,'MON',4X,'TUES',3X,'WED',4X,'THUR',3X,'FRI',4X,
     1'WKDA',3X,'SAT',4X,'SUN',4X,'HOLI',3X,'WKED')
   75 FORMAT (1X//)
   80 FORMAT (' ','THE FOLLOWING ARE PEAK LOAD DAYS FOR THE PERIOD',1X,I
     12,'/',I2,1X,'TO',1X,I2,'/',I2,'.'/)
   85 FORMAT (1X,I2,10F7.0)
   90 FORMAT ('1')
   95 FORMAT (18X,'AVERAGE AND PEAK LOADS FOR ',3A4)
  100 FORMAT (1X,'HR',2X,'AVE',3X,'PEAK',1X,57A1)
  105 FORMAT (1X,I2,1X,F5.0,1X,F5.0,1X,57A1)
  110 FORMAT (16X,57A1/)
  115 FORMAT (18X,'THERE ARE ',I1,1X,3A4/18X,'IN THE PERIOD ',2(I2,'/'),
     1'-',2(I2,'/'),'.'/)
  120 FORMAT (18X,'THERE ARE ',I2,1X,3A4/18X,'IN THE PERIOD ',2(I2,'/'),
     1'-',2(I2,'/'),'.'/)
  125 FORMAT (18X,'THERE ARE ',I3,1X,3A4/18X,'IN THE PERIOD ',2(I2,'/'),
     1'-',2(I2,'/'),'.'/)
      END
C     SUBROUTINE LODFRQ
C
C     PURPOSE
C     A 100 POINT LOAD FREQUENCY CURVE AND A NOPT POINT LOAD
C     FREQUENCY CURVE IS CALCULATED. THE PEAK AND BASE LOADS ARE
C     FOUND. THE SYSTEM LOAD FACTOR AND THE TOTLE MEGAWATT
C     HOURS GENERATED ARE GIVEN.
C
C     USAGE
C        CALL LODFRQ(LODA,DAY,ISM,ISD,ISH,IHES,IEM,IED,IEH,IHEE,
C               MON,TUES,WED,THURS,FRI,SAT,SUN,HOLI,LOD100,LODVAL,
C               FRQ100,FREQ,NOPT,HRSIP)
C
C     DISCRIPTION OF PARAMETERS
C        LODA   -HOURLY SYSTEM LOAD VALUES
C        DAY    -VALUE FROM 0-8 WHERE 0=DUMMY DAY, 1-7=MONDAY-SUNDAY,
C                8=HOLIDAY
C        ISM    -THE STARTING MONTH OF THE CALCULATION
C        ISD    -THE STARTING DAY OF THE CALCULATION
C        ISH    -THE STARTING HOUR OF THE CALCULATION
C        IHES   -THE FIRST HOUR OF THE DAY WHICH IS NOT USED
C        IEM    -THE ENDING MONTH OF THE CALCULATION
C        IED    -THE ENDING DAY OF THE CALCULATION
C        IEH    -THE ENDING HOUR OF THE CALCULATION
C        IHEE   -THE LAST HOUR OF THE DAY WHICH IS NOT USED
C        MON    -1 IF MONDAYS ARE TO BE USED IN THE CALCULATION
C        TUES   -2 IF TUESDAYS ARE TO BE USED IN THE CALCULATION
C        WED    -3 IF WEDNESDAYS ARE TO BE USED IN THE CALCULATION
C        THURS  -4 IF THURSDAYS ARE TO BE USED IN THE CALCULATION
C        FRI    -5 IF FRIDAYS ARE TO BE USED IN THE CALCULATION
C        SAT    -6 IF SATURDAYS ARE TO BE USED IN THE CALCULATION
C        SUN    -7 IF SUNDAYS ARE TO BE USED IN THE CALCULATION
C        HOLI   -8 IF HOLIDAYS ARE TO BE USED IN THE CALCULATION
C        LOD100 -100 UNIFORMILY DISTRIBUTED LOAD VALUES BETWEEN
C                THE BASE AND PEAK VALUES
C        LODVAL -NPOT UNIFORMILY DISTRIBUTED LOAD VALUES BETWEEN
C                THE BASE AND PEAK VALUES
C        FRQ100 -100 LOAD FREQUENCY VALUES FOR LOD100
C        FREQ   -NPOT LOAD FREQUENCY VALUES FOR LODVAL
```

```
C        REMARKS
C           THIS SUBROUTINE USES THE INPUT DATA SUPPLIED TO THE
C           MAIN PROGRAM TO GENERATE THE LOAD FREQUENCY CURVE
C           USED BY SUBROUTINE LDCP AND SUBROUTINE LDPB. THE INFORMATION
C           SUPPLIED BY COMMON STORAGE IS REQUIRE FOR TO SUBROUTINE TO
C           OPERATE
C
C        SUBROUTINES REQUIRED
C           NONE
C
C        METHOD
C           THE DIFFERENCE BETWEEN THE PEAK AND BASE VALUES ARE
C           DIVIDED INTO 100 AND NPOT UNIFORMIALY DISTRIBUTED VALUES.
C           THE REAL TIME LOAD DATA (LODA(12,31,24) IS COMPARED TO
C           THE CALCULATED LOAD INTERVALS (LOD100 AND LODVAL) AND THE
C           ENERGY ASSOCIATED WITH THE REAL TIME LEVEL IS ASSIGNED TO
C           THE CALCULATED LEVEL NEAREST IT. AFTER ALL THE REAL TIME
C           DATA HAS BEEN ANALYZED, THE HOURS AT EACH CALCULATED LOAD
C           LEVEL IS OBTAINED BY DIVIDING THE ENERGY ASSIGNED TO THAT
C           LEVEL BY THE LEVEL. THIS IS DONE TO MAINTAIN THE TOTAL
C           ENERGY GENERATION FOR THE PERIOD OF INTEREST AT A CONSTANT.
C
         SUBROUTINE LODFRQ (LODA,DAY,ISM,ISD,ISH,IHES,IEM,IED,IEH,IHEE,MON,
        1TUES,WED,THURS,FRI,SAT,SUN,HOLI,LOD100,LODVAL,FRQ100,FREQ,NOPT,HRS
        2IP)
         DIMENSION LODA(12,31,24), DAY(12,31)
         DIMENSION FRQ100(1), FREQ(1), LODVAL(1), LOD100(1)
         DIMENSION IPM(10), IPD(10), IPH(10)
         REAL LODA,LODVAL,LOD100
         REAL MWHRS,LODFAC
         INTEGER DAY,TUES,WED,THURS,FRI,SAT,SUN,HOLI
C        IN THIS SECTION THE PEAK AND BASE LOAD; THE MONTH, DAY, AND HOURS
C        AT WHICH THE PEAK LOAD OCCURRS; THE LOAD FACTOR; AND THE TOTAL
C        MEGAWATTS GENERATED ARE FOUND
         MWHRS=0.
         HRSIP=0.
         PEAK=0.
         BASE=100000.
         NPC=1
C        INDEX FROM STARTING MONTH TO ENDING MONTH
         KKID=-1
         IF(ISM.GT.IEM) KKID=1
         LLND=IEM-ISM+1
         IF(KKID.GT.0) LLND=LLND+12
         DO 70 ISTAR=1,LLND
         IF(KKID.LT.0) GO TO 75
         I=ISM+(ISTAR-IEM)-1
         IF(ISTAR.LE.IEM) I=ISTAR
         GO TO 80
  75     I=ISTAR+ISM-1
  80     ID=1
         JD=31
         IF(I.EQ.ISM) ID=ISD
         IF(I.EQ.IEM) JD=IED
C        INDEX FROM THE STARTING DAY TO THE ENDING DAY
         DO 10 J=ID,JD
         IF(LODA(I,J,1).EQ.0.) GO TO 10
         J2=0
         IF(DAY(I,J).EQ.MON) J2=1
         IF(DAY(I,J).EQ.TUES) J2=1
         IF(DAY(I,J).EQ.WED) J2=1
         IF(DAY(I,J).EQ.THURS) J2=1
         IF(DAY(I,J).EQ.FRI) J2=1
         IF(DAY(I,J).EQ.SAT) J2=1
         IF(DAY(I,J).EQ.SUN) J2=1
         IF(DAY(I,J).EQ.HOLI) J2=1
         IF(J2.EQ.0) GO TO 10
```

```
C     FIND THE PEAK AND BASE LOAD VALUES AND THE LOAD FACTOR FOR ALL
C     THE DAYS TO BE INCLUDED IN THE LOAD CURVE
      DO 5 K=ISH,IEH
      IF(K.GE.IHES.AND.K.LE.IHEE) GO TO 5
      IF(LODA(I,J,K).EQ.0.) GO TO 5
      IF(LODA(I,J,K).LT.BASE) BASE=LODA(I,J,K)
      HRSIP=HRSIP+1
      MWHRS=MWHRS+LODA(I,J,K)
      IF(LODA(I,J,K).LT.PEAK) GO TO 5
      IF(LODA(I,J,K).EQ.PEAK) NPC=NPC+1
      IPH(NPC)=K
      IPD(NPC)=J
      IPM(NPC)=I
      PEAK=LODA(I,J,K)
      IF(NPC.EQ.1) GO TO 5
      NPC1=NPC-1
      I1=IPM(NPC1)
      I2=IPD(NPC1)
      I3=IPH(NPC1)
      IF(LODA(I1,I2,I3).GE.PEAK) GO TO 5
      IPH(1)=IPH(NPC)
      IPD(1)=IPD(NPC)
      IPM(1)=IPM(NPC)
      NPC=1
  5   CONTINUE
 10   CONTINUE
 70   CONTINUE
      WRITE (6,50)
      DO 15 I=1,NPC
 15   WRITE (6,55) PEAK,IPM(I),IPD(I),IPH(I)
      LODFAC=(MWHRS*100.)/(HRSIP*PEAK)
      WRITE (6,60) LODFAC
      WRITE (6,65) MWHRS
      DEL100=(PEAK-BASE)/99.
      DELTA=(PEAK-BASE)/(NOPT-1)
      FREQ(1)=0.
      LODVAL(1)=BASE
      LOD100(1)=BASE
      FRQ100(1)=0.
C     FORM THE TABLE OF LOAD VALUES FOR THE 100 POINT LOAD CURVE
      DO 20 N=1,99
      NP1=N+1
      LOD100(NP1)=LOD100(N)+DEL100
 20   FRQ100(NP1)=0.
      NOPTM1=NOPT-1
C     FORM THE TABLE OF LOAD VALUES FOR THE NOPT POINT LOAD CURVE
      DO 25 N=1,NOPTM1
      NP1=N+1
      LODVAL(NP1)=LODVAL(N)+DELTA
 25   FREQ(NP1)=0.
      DO 90 ISTR=1,LLND
      IF(KKID.LT.0) GO TO 95
      I=ISM+(ISTR-IEM)-1
      IF(ISTR.LE.IEM) I=ISTR
      GO TO 100
 95   I=ISTR+ISM-1
 100  II=1
      JJ=31
      IF(I.EQ.ISM) II=ISD
      IF(I.EQ.IEM) JJ=IED
      DO 35 J=II,JJ
      IF(LODA(I,J,1).EQ.0.) GO TO 35
      J2=0
      IF(DAY(I,J).EQ.MON) J2=1
      IF(DAY(I,J).EQ.TUES) J2=1
      IF(DAY(I,J).EQ.WED) J2=1
```

```
      IF(DAY(I,J).EQ.SUN) J2=1
      IF(DAY(I,J).EQ.HOLI) J2=1
      IF(J2.EQ.0) GO TO 35
      DO 30 K=ISH,IEH
      IF(K.GE.IHES.AND.K.LE.IHEE) GO TO 30
      IF(LODA(I,J,K) .LE. 0.0) GO TO 30
      I1=(LODA(I,J,K)-BASE)/DEL100+1.5
      FRQ100(I1)=FRQ100(I1)+LODA(I,J,K)
      I1=(LODA(I,J,K)-BASE)/DELTA+1.5
      FREQ(I1)=FREQ(I1)+LODA(I,J,K)
   30 CONTINUE
   35 CONTINUE
   90 CONTINUE
C     FORM THE CORRESPONDING TABLE OF LOAD FREQUENCY VALUES FOR THE
C     100 POINT LOAD CURVE
      DO 40 I=1,100
   40 FRQ100(I)=FRQ100(I)/LOD100(I)
C     FIND THE CORRESPONDING TABLE OF LOAD FREQUENCY VALUES FOR THE
C     NOPT POINT LOAD CURVE
      DO 45 I=1,NOPT
   45 FREQ(I)=FREQ(I)/LODVAL(I)
      RETURN
C
   50 FORMAT ('1'///10X,'PEAK MW',10X,'MO/DA/HR')
   55 FORMAT (11X,F6.0,10X,I2,'/',I2,'/',I2)
   60 FORMAT (/11X,'THE LOAD FACTOR IS ',F4.1,'%'/)
   65 FORMAT (11X,'THE TOTAL MEGAWATT-HOUR SALES ARE ',F10.0///)
      END
C     SUBROUTINE LFPLOT
C
C     PURPOSE
C        TO PLOT NOPT LOAD FREQUENCY DATA POINTS
C        CALCULATED BY  LODFRQ
C
C     USAGE
C        CALL LFPLOT(LODVAL,FREQ,NOPT,ISM,ISD,ISH,IEM,IED,IEH)
C
C     DISCRIPTION OF PARAMETERS
C        LODVAL -X-AXIS LOAD VALUES
C        FREQ   -Y-AXIS FREQUENCY VALUES
C        NOPT   -NUMBER OF POINTS TO BE PLOTTED
C        ISM    -THE STARTING MONTH OF THE CALCULATION
C        ISD    -THE STARTING DAY OF THE CALCULATION
C        ISH    -THE STARTING HOUR OF THE CALCULATION
C        IEM    -THE ENDING MONTH OF THE CALCULATION
C        IED    -THE ENDING DAY OF THE CALCULATION
C        IEH    -THE ENDING HOUR OF THE CALCULATION
C
C     REMARKS
C        THIS IS A SPECIALIZED PLOTTING SUBROUTINE TO BE
C        USED WITH SUBROUTINE LODFRQ
C
C     SUBROUTINES REQUIRED
C        NONE
C
      SUBROUTINE LFPLOT (LODVAL,FREQ,NOPT,ISM,ISD,ISH,IEM,IED,IEH)
      DIMENSION LODVAL(1), FREQ(1), H(57)
      REAL LODVAL
      DATA PLUS,STAR,DASH,BLANK/'+','*','-',' '/
      WRITE (6,25) ISM,ISD,ISH,IEM,IED,IEH
      H(1)=STAR
      H(55)=STAR
      H(54)=BLANK
      YMAX=FREQ(1)
C     FIND THE MINIMUM AND MAXIMUM LOAD VALUES SO THAT THE PLOT
C     MAY BE SCALED
      DO 5 I=1,NOPT
```

```
    5     IF(FREQ(I).GT.YMAX) YMAX=FREQ(I)
          WRITE (6,30) (H(1),I=1,55)
          DO 20 I=1,NOPT
C         FIND THE PRINTER COLUMN THAT CORRESPONDS TO THIS POINT ON
C         THE LOAD CURVE
          IN=FREQ(I)*52/YMAX
C         DEFINE THE PLOTTING ARRAY TO BE DASHES FOR ALL VALUES UP
C         TO THE CURRENT LOAD POINT, A PLUS FOR THE POINT, AND BLANKS
C         FOR ALL VALUES ABOVE THE LOAD POINT
          DO 10 J=2,IN
   10     H(J)=DASH
          H(IN+1)=PLUS
          IN=IN+2
          IF(IN.GE.54) GO TO 20
          DO 15 J=IN,53
   15     H(J)=BLANK
C         WRITE THE LOAD VALUE, THE LOAD FREQUENCY, AND THE PLOTTING
C         ARRAY
   20     WRITE (6,35) LODVAL(I),FREQ(I),(H(J),J=1,55)
          WRITE (6,40) (H(55),J=1,55)
          RETURN
C
   25     FORMAT ('1',3X,'LOAD FREQUENCY CURVE FOR THE PERIOD ',2(I2,'/'),I2
         1,'-',2(I2,'/'),I2,'.'/)
   30     FORMAT (4X,'LOAD',4X,'FREQ'/4X,' MW ',4X,' HR ',2X,55A1)
   35     FORMAT (2X,F7.1,1X,F7.1,1X,55A1)
   40     FORMAT (18X,55A1)
          END
C         SUBROUTINE LDPB
C
C         PURPOSE
C            THE LOAD PROBABILITY CURVE FOR NOPT POINTS IS CALCULATED
C            AND PLOTTED FOR UP TO 100 POINTS
C
C         USAGE
C            CALL LDPB(FREQ,PBIL,NOPT)
C
C         DISCRIPTION OF PARAMETERS
C            NPOT    -THE NUMBER OF POINTS IN THE LOAD PROBABILITY CURVE
C            FREQ    -NOPT LOAD FREQUENCY VALUES
C            PBIL    -NOPT LOAD PROBABILITY VALUES
C
C         SUBROUTINES REQUIRED
C            NONE
C
          SUBROUTINE LDPB (FREQ,PBIL,NOPT)
          DIMENSION FREQ(1), PBIL(1)
          DO 5 I=1,NOPT
    5     PBIL(I)=0.
C         FORM A TABLE OF FREQUENCY VALUES WHICH REPRESENTS THE NUMBER
C         OF HOURS A GIVEN LOAD HAS BEEN EQUALED OR EXCEEDED
          DO 10 I=1,NOPT
          DO 10 J=I,NOPT
   10     PBIL(I)=PBIL(I)+FREQ(J)
C         NORMALIZE THE RESULTING CURVE SO THAT THE HIGHEST TOTAL
C         FREQUENCY HAS A VALUE OF 1.0
          DO 15 I=2,NOPT
   15     PBIL(I)=PBIL(I)/PBIL(1)
          PBIL(1)=1.
          RETURN
          END
C         SUBROUTINE LPPLOT
C
C         PURPOSE
C            TO PLOT NOPT LOAD PROBABILITY DATA POINTS CALCULATED
C            BY LDPB
```

```
C
C      DISCRIPTION OF PARAMETERS
C         LODVAL -X-AXIS LOAD VALUES
C         PBIL   -Y-AXIS PROBABILITY VALUES
C         NOPT   -NUMBER OF POINT TO BE PLOTTED MAX 100
C         ISM    -THE STARTING MONTH OF THE CALCULATION
C         ISD    -THE STARTING DAY OF THE CALCULATION
C         ISH    -THE STARTING HOUR OF THE CALCULATION
C         IEM    -THE ENDING MONTH OF THE CALCULATION
C         IED    -THE ENDING DAY OF THE CALCULATION
C         IEH    -THE ENDING HOUR OF THE CALCULATION
C
C      REMARKS
C         THIS IS A SPECIALIZED PLOTTING SUBROUTINE TO BE USED WITH
C         SUBROUTINE LDPB
C
C      SUBROUTINES REQUIRED
C         NONE
C
       SUBROUTINE LPPLOT (LODVAL,PBIL,NOPT,ISM,ISD,ISH,IEM,IED,IEH)
       DIMENSION LODVAL(1), PBIL(1), H(55)
       REAL LODVAL
       DATA PLUS,STAR,DASH,BLANK/'+','*','-',' '/
       H(1)=STAR
       H(55)=STAR
       H(54)=BLANK
       WRITE (6,30) ISM,ISD,ISH,IEM,IED,IEH
       WRITE (6,35) (H(55),I=1,55)
       DO 25 I=1,NOPT
C      FIND THE PRINTER COLUMN THAT CORRESPONDS TO THIS POINT ON
C      THE LOAD CURVE
       IN=PBIL(I)*52
       IF(IN.GE.2) GO TO 5
       IN=1
       GO TO 15
C      DEFINE THE PLOTTING ARRAY
 5     DO 10 J=2,IN
 10    H(J)=DASH
 15    H(IN+1)=PLUS
       IN=IN+2
       IF(IN.GE.54) GO TO 25
       DO 20 J=IN,53
 20    H(J)=BLANK
C      WRITE THE LOAD VALUE, THE LOAD PROBABILITY VALUE, AND THE
C      PLOTTING ARRAY
 25    WRITE (6,40) LODVAL(I),PBIL(I),(H(J),J=1,55)
       WRITE (6,45) (H(55),J=1,55)
       RETURN
C
 30    FORMAT ('1',3X,'LOAD PROBABILITY CURVE FOR THE PERIOD ',2(I2,'/'),
      1I2,'-',2(I2,'/'),I2,'.'/)
 35    FORMAT (4X,'LOAD',4X,'PROB'/4X,' MW ',10X,55A1)
 40    FORMAT (2X,F7.1,1X,F7.5,1X,55A1)
 45    FORMAT (18X,55A1)
       END
C      SUBROUTINE LDCP
C
C      PURPOSE
C         A 100 POINT LOAD DURATION CURVE WITH EQUALLY SPACE LOAD VALUES
C         IS CALCULATED FROM LOD100 AND FRQ100. FROM THIS CURVE
C         LOAD VALUES ARE INTERPOLATED FOR EQUALLY SPACED HOUR
C         VALUES
C      USAGE
C         CALL LDCP(LOD100,FRQ100,LOAD,HOURS,HRSIP,NOPT)
C
C      DISCRIPTION OF PARAMETERS
C         NPOT   -NUMBER OF POINTS TO BE CALCULATED AND PLOTTED
```

```
C        LOD100 -100 LOAD VALUES
C        FRQ100 -100 LOAD FREQUENCY VALUES CORRESPONDING TO LOD100
C        HOURS  -NPOT EQUALLY SPACED LOAD DURATION HOUR LEVELS
C        LOAD   -NPOT RESUTTANT LOAD VALES FOR HOURS.
C
C     SUBROUTINES REQUIRED
C        ATSM
C        ALI
C
      SUBROUTINE LDCP (LOD100,FRQ100,LOAD,HOURS,HRSIP,NOPT)
C
      DIMENSION FRQ100(1), HOURS(1)
      DIMENSION WOKARY(100), HOUSW(20), WOKAR2(100)
      DIMENSION LOD100(1), LOAD(1)
      REAL LOD100,LOAD
      REAL LOADW(20)
      LOAD(1)=LOD100(100)
      LOAD(NOPT)=LOD100(1)
      WOKARY(1)=FRQ100(100)
      DO 5 I=1,99
      I2=100-I
 5    WOKARY(I+1)=WOKARY(I)+FRQ100(I2)
      I2=NOPT-1
      HOURS(1)=WOKARY(1)
      DETHR=(HRSIP-HOURS(1))/(NOPT-1)
C     DEFINE A TABLE OF EQUALLY SPACED HOUR VALUES HOURS(I) STARTING
C     WITH THE LOAD FREQUENCY VALUE OF THE PEAK LOAD
      DO 10 I=1,I2
 10   HOURS(I+1)=HOURS(I)+DETHR
      HOURS(NOPT)=HRSIP
C     INVERT THE TABLE OF LOAD VALUES TO FORM A WORKING ARRAY WOKAR2
C     TO BE USED IN THE SUBROUTINES BELOW
      DO 15 I=1,100
      I3=101-I
 15   WOKAR2(I)=LOD100(I3)
      DO 20 I=2,I2
C     CALL ATSM TO REORDER THE POINTS OF THE LOAD FREQUENCY CURVE SO
C     THAT THE FREQUENCY VALUES FORM A MONOTONICALLY INCREASING TABLE
C     USED FOR THE INTERPOLATION PROCEDURE IN SUBROUTINE ALI
      CALL ATSM (HOURS(I),WOKARY,WOKAR2,100,1,HOUSW,LOADW,20)
C     CALL ALI TO INTERPOLATE THE LOAD VALUES OF THE TABLE FORMED IN
C     ATSM SO THAT THE LOAD VALUES CORRESPOND TO THE TABLE OF EQUALLY
      CALL ALI (HOURS(I),HOUSW,LOADW,LOAD(I),20,.5,IER)
 20   CONTINUE
      RETURN
      END
C     SUBROUTINE ALI
C
C     PURPOSE
C        TO INTERPOLATE FUNTION VALUE Y FOR A GIVEN ARGUMENT VALUE
C        X USING A GIVEN TABLE (ARG,VAL) OF ARGUMENT AND FUNCTION
C        VALUES.
C     SPACED HOUR VALUES HOURS(I)
C
C     USAGE
C        CALL ALI(X,ARG,VAL,Y,NDIM,EPS,IER)
C
C     DESCRIPTION OF PARAMETERS
C        X      -THE ARGUMENT VALUE SPECIFIED BY INPUT
C        ARG    -THE INPUT VECTOR (DIMENSION NDIM) OF ARGUMENT
C                VALUES OF THE TABLE (NOT DESTROYED).
C        VAL    -THE INPUT VECTOR (DIMENSION NDIM) OF FUNCTION
C                VALUES OF THE TABLE (DESTROYED).
C        Y      -THE RESULTING INTERPOLATED FUNCTION
C        NDIM   -AN INPUT VALUE WHICH SPECIFIES THE NUMBER OF
C                POINTS IN TABLE (ARG,VAL).
```

```
C
C        REMARKS
C           (1)  TABLE (ARG,VAL) SHOULD REPRESENT A SINGLE-VALUED
C                FUNCTION AND SHOULD BE STORED IN SUCH A WAY, THAT THE
C                DISTANCES ABS(ARG(I)-X) INCREASE WITH INCREASING
C                SUBSCRIPT J. TO GENERATE THIS ORDER IN TABLE (ARG,VAL)
C                SUBROUTINE ATSM IS USED
C           (2)  INTERPOLATION IS TERMINATED EITHER IF THE DIFFERENCE
C                BETWEEN TWO SUCCESSIVE INTERPOLATED VALUES IS
C                ABSOLUTELY LESS THAN TOLERANCE EPS, OR IF THE ABSOLUTE
C                VALUE OF THIS DIFFERENCE STOPS DIMINISHING, OR AFTER
C                (NDIM-1) STEPS. FURTHER IT IS TERMINATED IF THE
C                PROCEDURE DISCOVERS TWO ARGUMENT VALUES IN VECTOR ARG
C                WHICH ARE IDENTICAL. DEPENDENT ON THESE FOUR CASES,
C                ERROR PARAMETER IER IS CODED IN THE FOLLOWING FORM
C                 IER=0 - NO ERROR
C                 IER=1 - BECAUSE OF ROUNDING ERRORS THE REQUIRED
C                         ACCURACY WAS NOT REACHED
C                 IER=2 - ACCURACY NOT CHECKED BECAUSE NDIM IS LESS
C                         THAN 3
C                 IER=3 - TWO VALUES IN ARG ARE THE SAME
C
C        SUBROUTINES REQUIRED
C           NONE
C
C        METHOD
C           INTERPOLATION IS DONE BY MEANS OF AITKENS SCHEME OF
C           LAGRANGE INTERPOLATION. ON RETURN Y CONTAINS AN
C           INTERPOLATED FUNCTION VALUE AT POINT X, WHICH IS IN THE
C           SENSE OF REMARK (3) OPTIMAL WITH RESPECT TO GIVEN TABLE.
C
C
      SUBROUTINE ALI (X,ARG,VAL,Y,NDIM,EPS,IER)
C
      DIMENSION ARG(1), VAL(1)
      IER=2
      DELT2=0.
      IF(NDIM-1) 45,35,5
C
C     START OF AITKEN-LOOP
    5 DO 30 J=2,NDIM
      DELT1=DELT2
      IEND=J-1
      DO 10 I=1,IEND
      H=ARG(I)-ARG(J)
      IF(H) 10,65,10
   10 VAL(J)=(VAL(I)*(X-ARG(J))-VAL(J)*(X-ARG(I)))/H
      DELT2=ABS(VAL(J)-VAL(IEND))
      IF(J-2) 30,30,15
   15 IF(DELT2-EPS) 50,50,20
   20 IF(J-5) 30,25,25
   25 IF(DELT2-DELT1) 30,55,55
   30 CONTINUE
C     END OF AITKEN LOOP
C
   35 J=NDIM
   40 Y=VAL(J)
   45 RETURN
C
C     THERE IS SUFFICIENT ACCURACY WITHIN NDIM-1 ITERATION STEPS
   50 IER=0
      GO TO 40
C
C     TEST VALUE DELT2 STARTS OSCILLATING
   55 IER=1
   60 J=IEND
      GO TO 40
```

```
C
C        THERE ARE TWO IDENTICAL ARGUMENT VALUES IN VECTOR ARG
   65 IER=3
      GO TO 60
      END
C     SUBROUTINE ATSM
C
C     PURPOSE
C        NDIM POINTS OF A GIVEN TABLE WITH MONOTONIC ARGUMENTS ARE
C        SELECTED AND ORDERED SUCH THAT
C        ABS(ARG(I)-X).GE.ABS(ARG(J)-X)  IF I.GT.J
C
C     USAGE
C        CALL ATSM(X,Z,F,IROW,ICOL,ARG,VAL,NDIM)
C
C     DESCRIPTION OF PARAMETERS
C        X      - THE SEARCH ARGUMENT
C        Z      - THE VECTOR OF ARGUMENT VALUES (DIMENSION IROW)
C                 THE ARGUMENT VALUES MUST BE STORED IN INCREASING
C                 OR DECREASING SEQUENCE
C        F      - IF ICOL=1, F IS THE ARRAY OF FUNCTION VALUES
C                 (DIMENSION IROW)
C                 IF ICOL=2, F IS AN IROW BY 2 ARRAY. THE FIRST
C                 COLUMN SPECIFIES THE VECTOR OF FUNCTION VALUES
C                 AND THE SECOND THE DERIVATIVE VALUES
C        IROW   - THE DIMENSION OF VECTOR Z AND OF EACH COLUMN
C                 IN MATRIX F.
C        ICOL   - THE NUMBER OF COLUMNS IN F (I.E.  1)
C        ARG    - THE RESULTING VECTOR OF SELECTED AND ORDERED
C                 ARGUMENT VALUES (DIMENSION NDIM)
C        VAL    - THE RESULTING VECTOR OF SELECTED FUNCTION VALUES
C                 (DIMENSION NDIM) IF ICOL=1. IF ICOL=2, VAL IS
C                 THE VECTOR OF FUNCTION AND DERIVATIVE VALUES
C                 (DIMENSION 2*NDIM) WHICH ARE STORED IN PAIRS
C                 (I.E. EACH FUNCTION VALUE IS FOLLOWED BY ITS
C                 DERIVATIVE VALUE)
C        NDIM   - THE NUMBER OF POINTS WHICH MUST BE SELECTED
C                 OUT OF THE GIVEN TABLE (Z,F)
C
C     REMARKS
C        NO ACTION IF IROW.LT.1
C        IF INPUT VALUE NDIM IS GREATER THAN IROW, THE PROGRAM
C        SELECTS ONLY A MAXIMUM TABLE OF IROW POINTS. THEREFORE,
C        CHECK CORRESPONDENCE BETWEEN TABLE (ARG,VAL) AND ITS
C        DIMENSION BY COMPARISON OF NDIM AND IROW.
C        SUBROUTINE ATSM IS USED FOR GENERATING THE TABLE
C        (ARG,VAL) USED IN SUBROUTINE ALI.
C
C     SUBROUTINES REQUIRED
C        NONE
C
C     METHOD
C        SELECTION IS DONE BY SEARCHING THE SUBSCRIPT J OF THAT
C        ARGUMENT, WHICH IS NEXT TO X (BINARY SEARCH).
C        AFTERWARDS NEIGHBOURING ARGUMENT VALUES ARE TESTED
C        AND SELECTED IN THE ABOVE SENSE.
C
      SUBROUTINE ATSM (X,Z,F,IROW,ICOL,ARG,VAL,NDIM)
C
      DIMENSION Z(1), F(1), ARG(1), VAL(1)
C
C     CASE IROW=1 IS CHECKED OUT
      IF(IROW-1) 115,105,5
    5 N=NDIM
C
C     IF N IS GREATER THAN IROW, N IS SET EQUAL TO IROW
```

```
C       CASE IROW,GE,2
C       SEARCHING FOR SUBSCRIPT J SUCH THAT Z(J) IS NEXT TO X
 15     IF(Z(IROW)-Z(1)) 25,20,20
 20     J=IROW
        I=1
        GO TO 30
 25     I=IROW
        J=1
 30     K=(J+I)/2
        IF(X-Z(K)) 35,35,40
 35     J=K
        GO TO 45
 40     I=K
 45     IF(IABS(J-I)-1) 50,50,30
 50     IF(ABS(Z(J)-X)-ABS(Z(I)-X)) 60,60,55
 55     J=I
C
C       TABLE SELECTION
 60     K=J
        JL=0
        JR=0
C       SEARCH THE TABLE FOR A SUBSCRIPT J SUCH THAT Z(J) IS NEXT
C       TO ARG(I)
        DO 100 I=1,N
        ARG(I)=Z(K)
        IF(ICOL-1) 70,70,65
 65     VAL(2*I-1)=F(K)
        KK=K+IROW
        VAL(2*I)=F(KK)
        GO TO 75
 70     VAL(I)=F(K)
 75     JJR=J+JR
        IF(JJR-IROW) 80,90,90
 80     JJL=J-JL
        IF(JJL-1) 95,95,85
 85     IF(ABS(Z(JJR+1)-X)-ABS(Z(JJL-1)-X)) 95,95,90
 90     JL=JL+1
        K=J-JL
        GO TO 100
 95     JR=JR+1
        K=J+JR
 100    CONTINUE
        RETURN
C
C       CASE IROW=1
 105    ARG(1)=Z(1)
        VAL(1)=F(1)
        IF(ICOL-2) 115,110,115
 110    VAL(2)=F(2)
 115    RETURN
        END
C       SUBROUTINE LDPLOT
C
C       PURPOSE
C          TO PLOT NOPT LOAD DURATION DATA POINTS
C          CALCULATED BY SUBROUTINE LDCP
C
C       USAGE
C          CALL LDPLOT(HOURS,LOAD,NOPT,ISM,ISD,ISH,IEM,IED,IEH)
C
C       DISCRIPTION OF PARAMETERS
C          HOURS  -X-AXIS HOUR VALUES
C          LOAD   -Y-AXIS LOAD VALUES
C          NOPT   -NUMBER OF POINTS TO BE PLOTTED MAX 100
C          ISM    -THE STARTING MONTH OF THE CALCULATION
C          ISD    -THE STARTING DAY OF THE CALCULATION
C          ISH    -THE STARTING HOUR OF THE CALCULATION
```

```
C         IEM    -THE ENDING MONTH OF THE CALCULATION
C         IED    -THE ENDING DAY OF THE CALCULATION
C         IEH    -THE ENDING HOUR OF THE CALCULATION
C
C      REMARKS
C         THIS IS A SPECIALIZED PLOTTING SUBROUTINE TO BE
C         USED WITH SUBROUTINE  LDCP
C
C      SUBROUTINES REQUIRED
C         NONE
C
       SUBROUTINE LDPLOT (HOURS,LOAD,NOPT,ISM,ISD,ISH,IEM,IED,IEH)
       DIMENSION HOURS(1), LOAD(1), H(55)
       REAL LOAD
       DATA PLUS,STAR,DASH,BLANK/'+','*','-',' '/
       DATA SLASH/'/'/
       H(1)=STAR
       H(2)=DASH
       H(3)=DASH
       H(4)=SLASH
       H(5)=BLANK
       H(6)=BLANK
       H(7)=SLASH
       H(8)=DASH
       H(9)=DASH
       H(55)=STAR
       H(54)=BLANK
       YMAX=LOAD(1)
       YMIN=LOAD(NOPT)
       WRITE (6,20) ISM,ISD,ISH,IEM,IED,IEH
       WRITE (6,25)
       DO 15 I=1,NOPT
C      FIND THE PRINTER COLUMN THAT CORRESPONDS TO THIS POINT ON
C      THE LOAD CURVE
       IN=(LOAD(I)-YMIN)*42/(YMAX-YMIN)+10
C      DEFINE THE PLOTTING ARRAY
       DO 5 J=10,IN
  5    H(J)=DASH
       H(IN+1)=PLUS
       IN=IN+2
       IF(IN.GE.54) GO TO 15
       DO 10 J=IN,53
 10    H(J)=BLANK
C      WRITE THE HOUR VALUE, THE LOAD DURATION VALUE, AND THE
C      PLOTTING ARRAY
 15    WRITE (6,30) HOURS(I),LOAD(I),(H(J),J=1,55)
       WRITE (6,35)
       RETURN
C
 20    FORMAT ('1',3X,'LOAD DURATION CURVE FOR THE PERIOD ',2(I2,'/'),I2,
      1'-',2(I2,'/'),I2,'.'/)
 25    FORMAT (4X,'TIME',4X,'LOAD'/4X,' HRS',4X,' MW ',2X,'*BASE LOAD****
      1******************************************')
 30    FORMAT (2X,F7.1,1X,F7.1,1X,55A1)
 35    FORMAT (18X,'*BASE LOAD*******************************************
      1**')
       END
```

Final Report on

A METHOD FOR COMPUTING THE MAIN BENEFITS AND COSTS OF TIME-OF-USE RATES FOR COLORADO ELECTRIC UTILITIES

Daniel Z. Czamanski
Institute Fellow in Economics

G. Timothy Biggs
Graduate Research Associate

THE NATIONAL REGULATORY RESEARCH INSTITUTE
2130 Neil Avenue
Columbus, OH 43210

prepared for the

Colorado Public Utilities Commission
in partial fulfillment of

Contract No. 900342

July 1981

EXECUTIVE SUMMARY

This report describes a method of calculating the main benefits and costs associated with time-of-use (TOU) electricity rates for Colorado electric utilities. Specifically, the report considers capacity and energy costs savings in light of metering costs. No attention is paid to other economic efficiency considerations. The method is based on estimated changes in consumption patterns following the introduction of TOU rates. Capital and energy costs per kilowatt-hour (kWh) are estimated with the help of the Cicchetti, Gillen and Smolenski computer program. Data requirements for, and sample output of the computer programs are also presented.

TABLE OF CONTENTS

CHAPTER 1
INTRODUCTION

The purpose of this report is to present a method of estimating the major costs and benefits associated with time-of-use (TOU) rates for Colorado electric utilities. The main direct benefits occasioned through the use of TOU rates are a reduction in capacity costs and in energy costs resulting from possible cancellation or deferment of planned expansion of the utility's generating facilities. Energy cost savings may also result from a change in the dispatch order of existing generating plants on the utility's system. These savings would result from increased utilization of existing generating equipment caused by a shift in customer usage from peak to off-peak times. As customers shift their usage to take advantage of low off-peak rates, it is likely that the more fuel efficient generating facilities already on the utility's system can be more fully utilized than is currently the case. The result is a reduction in energy costs below current levels.

The main cost of TOU rates is the necessary additions to customer metering equipment used to measure consumption during the various costing periods. Since large volume users usually have the necessary metering equipment in place, the cost of implementing TOU rates for these customers is likely to be minimal.

The costs and benefits mentioned above are the reduction in capacity and energy costs (the benefit) and increase in metering costs (the cost) resulting from changes in the utility's load curve as a result of implementing TOU rates. The method presented in this report may be used to determine whether the benefits (as described herein) exceed the costs (as described herein).

This method does not consider other costs and benefits that might be termed "social" costs and benefits or what are frequently referred to in the economic literature as "producers' surplus" and "consumers' surplus". These costs and benefits are much more difficult to measure. They may be thought of as an attempt to measure the value of service to the various members of society, producers and consumers.

The Occasion

The Colorado Public Utilities Commission has held a generic regulatory proceeding concerning the rate structure of all electric utilities operating within its jurisdiction (Case No. 5693). At the conclusion of that proceeding, the commission issued a decision (Decision No. C79-1111) in which, among other things, it stated its position regarding time-of-use pricing.[1]

The commission stated that the record of the generic proceeding indicates that costs of service vary by time of use, and that benefits will accrue to electric customers if rates are based upon those cost variations. The commission also stated that TOU rates will place the cost burden of supplying electric service on those responsible for the costs, and will encourage, over time, consumers to shift some portion of their consumption to off-peak periods, thereby contributing to capital and energy conservation. Even if TOU rates do not induce consumers to shift a portion of their consumption to off-peak periods, the commission continued, rates based on variations in costs will adequately reflect the cost of service so that those consuming electricity on peak will pay an appropriate higher price. (That is, customers may choose to consume on peak if the value of the service is greater than its price).

Following its generic proceeding, and Decision No. C79-1111, the Colorado commission has contracted with The National Regulatory Research

---

[1]Decision No. C79-1111, Colorado Public Utilities Commission, Case No., 5693, July 1977, p. 183.

Institute (NRRI) to perform an analysis of various electric utility ratemaking issues. A part of that analysis requires the development of a method to assess the costs and benefits of time-of-use rates. This report is presented in fulfillment of that requirement.

An Overview of the Proposed Method

The most frequently cited reason for introducing time differentiated rates for electricity is the expectation that the resulting changes in consumption patterns will reduce capacity requirements. In addition, it is generally expected that the new consumption patterns will lead to improved load factors and create cost savings. Such savings are achievable at a cost associated with the implementation of time-differentiated, or time-of-use rates. The implementation cost consists of costs of the meters and associated metering costs, such as reading the meters and billing.

TOU rates are characterized by the fact that the electricity price charged to customers is determined according to the time during which consumption takes place. Thus, TOU rates include as special instances seasonal rates and time-of-day (TOD) rates. In other words, TOU rates vary according to the season of the year and the time of day.

There are several means for constructing such rates. The selection of a particular ratemaking method typically reflects the underlying objectives associated with the ratemaking process. Since the purpose of this report is to describe one simple method for computing the net benefits (that is, benefits minus costs) of TOU rates, it is important to specify the underlying objectives of TOU rates because the evaluation of the proposed rates is performed in terms of these objectives.

In this report, it is assumed that the purpose of introducing TOU rates is to realize capacity and energy costs savings. It is assumed that the feasibility of such rates is judged in terms of the extent to which the potential savings can cover the inevitable meter and metering costs. Thus, in this report

$$\text{Net Benefits} = \text{Capacity Costs Savings} + \text{Energy Costs Savings} - \text{Metering Costs.} \qquad (1\text{-}1)$$

This approach abstracts from the potential of the new rates to influence the well-being of individual consumers. It does not consider the desirability of the resulting changes in the basket of goods and services that society produces and consumes. It is a "narrow" approach that relates the cost of metering, or implementation costs, to savings associated with changes in the operations of utilities.

In addition to being selective about the inclusion of types of benefits, the proposed method consists of simplified calculations of the included benefits. This simplification was introduced into the proposed method in order to reduce the burden of acquiring computer skills and data. It is important to note that the resulting calculations make it possible to compare the desirability of various proposed TOU rates, despite the conservative estimate of costs and benefits.

The proposed method is based on a sequence of calculations that yield a net benefit figure for a typical year of the period during which the rates would be in effect, expressed in constant dollars. A zero or negative figure would indicate that the necessary implementation costs do not justify the realizable benefits. A positive figure would indicate that implementation costs are more than covered by the potential benefits of the proposed TOU rates.

The sequence of calculations is as follows:

Calculate changes in consumption associated with TOU rates.
Calculate capacity cost savings.
Calculate energy costs savings.
Calculate metering costs.

Finally, it is noteworthy that the proposed method lends itself to a variety of experimental calculations that may be useful in rate-making. For example, a partial introduction of TOU rates may yield more desirable net benefits than a complete implementation covering all customers. Sequential application of the proposed method may help in the decision about which customers should be under TOU rates. The method can handle these questions as well as the basic question of whether the proposed TOU rates are justified--do they lead to sufficient capacity and energy costs savings in general to make adoption worth while?

CHAPTER 2

CAPACITY AND ENERGY COSTS SAVINGS

Capacity and energy costs are a function of consumption patterns that the utility must meet. Although off-peak consumption contributes to capacity additions and energy use, it is primarily consumption growth during a narrow peak period that causes major costs to be incurred. This is because capacity added to serve peak period consumption may be idle during the off-peak period. Furthermore, growth of peak period consumption contributes to an inferior load factor, the use of more expensive fuels, and inefficient operation of plants. Thus, the extent to which consumption during the peak period can be reduced is an important determinant of potential capacity and energy costs savings.

Calculation of Changes in Consumption

The expectation that consumption patterns will change after the introduction of TOU rates is based on the assumption that TOU rates will result in an increased peak period price as compared to current rates and a reduced off-peak period price. It is assumed that people respond to changed prices by adjusting their consumption. The calculation of changes in consumption is based on a specific number, the customers' response coefficient, or price elasticity, (N), that expresses the percentage change in consumption as a percentage change in price.

There is little long-term experience with TOU rates in the United States. Nevertheless, a number of studies report a variety of estimated customers' response coefficients based on actual experience from experiments in the United States and elsewhere. Table 2-1 presents these estimates. Even if these estimates are accurate for typical customer

TABLE 2-1

ESTIMATED CUSTOMERS' RESPONSE COEFFICIENTS

Commission or Utility	Rate Description	Study Length	Short-run Coefficient	Long-run Coefficient
Arizona PSC[a]	3 part kWh rate during three time periods - residential customers	6 months	Group 1[1] -0.2721 - -0.6240[2] Group 2 -0.6237 - -0.7897[2] Group 3 -0.2923 - -0.7148[2]	- - -
			Group 1[1] -0.2308 - -0.6404[2] Group 2 -0.5748 - -0.7864[2] Group 3 -0.3534 - -0.6940[2]	- - - -
CH_2M Hill estimates on Arizona PSC and Conn. L & P.[b]	3 part kWh rate during three time periods for Arizona's 6 part kWh rate; seasonal for Conn.-Residential	6 and 12 months respectively	-0.3 - -0.7[3]	-
VEPCO[c]	All marginal cost energy prices, all marginal cost demand prices - residential, commercial, industrial	June through September for the period 1960-73	-0.31 -0.06	-0.44 -0.08
Various States[d,4] Based on L.D. Taylor summarization	Residential Commercial Industrial	Various	- 0.13 - -0.90 -0.17 -0.22	-1.02 - 2.00 -1.36 -1.25 - -1.94

Sources: a - Scott E. Atkinson, "Responsiveness to time-of-day electricity pricing," Journal of Econometrics 9 (1979): 92.
b - CH_2M Hill, "A Method to Assess the Economic Feasibility of Time-of-Day Pricing for Residential Customers (Columbus, Ohio: The National Regulatory Research Institute, 1979): 27.
c - Robert M. Spann and Edward C. Beauvais, "Econometric Estimation of Peak Electricity Demands; "Journal of Econometrics 9 (1979): 128.
d - Lester D. Taylor, "The Demand for Electricity: a Survey," Bell Journal of Economics 6 (Spring 1975): 101.

[1]Group 1 experiences a peak period from 2-5 p.m.; a mid-peak from 9 a.m.-2 p.m.; and an off peak from 10 a.m.-9a.m.
Group 2 experiences a peak period from 2-7 p.m.; a mid-peak from 9 a.m.- 2 p.m. and 7 p.m. - 10 a.m.; and on off-peak from 10 p.m. - 9 a.m.
Group 3 experiences a peak period from 2-10 p.m.; a mid-peak from 9 a.m. - 2 p.m.; and an off peak from 10 p.m. - 9 a.m.

[2]Significance at the 0.05 level.

[3]CH_2M Hill made the following assumptions to derive a single estimate of the peak-period elasticity from the results of the Arizona and Connecticut studies:
- Own-price elasticity is constant and invariant with economic factors; and
- the cross-price elasticity is equal to zero.

[4]The Taylor article presents a survey and critique of the econometric literature on the demand for electricity. The elasticity ranges presented in this table represent the lowest and highest figures derived from all the studies Taylor cites.

classes of a U.S. utility, there is no assurance that Colorado consumers are precisely like the average consumer described in the published studies. To increase the precision of the calculations employed in this method, estimates of N specific to Colorado may need to be obtained.

Given an accurate estimate of such a coefficient, the obtained number reflects the ratio

$$N = \frac{\text{Percentage change of consumption on peak}}{\text{Percentage change in peak price}} \tag{2-1}$$

From equation (2-1) it is possible to obtain a percentage change in consumption on peak as

$$\text{(Percentage change in consumption on peak)} = (N) \times \text{(Percentage change in peak price)}. \tag{2-2}$$

The figure for percentage change in peak price is obtainable either directly from the utility or as

$$\text{(Percentage change in peak price)} = \frac{\text{(Peak price)} - \text{(Average company price)}\times(100)}{\text{(Average company price)}} \tag{2-3}$$

Equation (2-3) is based on the assumption that under TOU rates there exists a single price during the peak period. Such a price would be invariant with the quantity of electricity consumed by an individual customer. Should such an assumption be invalid for the proposed TOU rates in Colorado, average peak period prices under TOU and current rates would need to be calculated.

The resulting estimate of change in consumption during the peak period due to TOU rates is obtained as in equation (2-4) below.

$$\text{(Customer response on peak)} = \text{(Percentage change in consumption on peak)} \times \text{(Consumption on peak under company rates)}. \quad (2\text{-}4)$$

Customer response on peak is calculated separately for each customer class and is expressed in kilowatt-hours. It is assumed in the energy savings calculation that the drop in consumption during the peak period is compensated for exactly by increased consumption during the off-peak period. This unrealistic assumption is justified by lack of precise estimates of appropriate customers' response coefficients and the conservative approach of underestimating benefits. That is, this assumption, while doing no harm to the analysis, produces a conservative estimate of the benefits resulting from TOU rates. Other assumptions, such as assuming that the reduction in consumption during the peak period is not shifted to the off-peak period but simply represents a decline in total kWh consumption, can also be made.

This conservative approach to estimating energy savings also assumes that there is no reduction in rates during the off-peak period. In practice, a utility may reduce the prices it charges for service during off-peak hours when it increases the prices for service during peak hours. This would especially be true if current off-peak rates reflect some component of fixed (capacity) costs, and the new TOU rates change all capacity costs to the peak period.

Under this condition, customers can be expected to increase their consumption during off-peak hours above current levels in order to take advantage of the new, lower off-peak rates. This change in consumption patterns would need to be taken into consideration in the calculation of net benefits derived from the introduction of TOU rates. The increase in consumption during off-peak hours would not affect capacity cost savings, unless a new system peak was created during this time period. The likelihood of this event occurring depends on the relative price differential between peak and off-peak periods and the customers' response coefficient during these times. (It is assumed that the cross-price elasticity between these two periods is zero.) Also, the likelihood of such an event occurring can be substantially reduced, or effectively eliminated, by properly designing the peak and off-peak periods in the first place.

The change in energy costs during the off-peak period resulting from the increase in consumption can be calculated by multiplying the change in consumption off-peak, in kilowatt-hours by the energy cost per kWh, off-peak. If this change in consumption results in an increase in energy costs during this period, this increase would need to be deducted from the energy cost savings occurring during the peak period in order to determine the net energy cost savings resulting from the introduction of TOU rates.

To sum the data requirements so far, the analysis of consumption pattern changes requires:

a. Estimates of customers' response coefficients (price elasticities).
b. Definition of peak and off-peak periods.
c. Average company rates during the peak and off-peak periods.
d. Consumption by customer class and by period under company rates.
e. TOU rates for each customer class and each period.

Should the proposed TOU rates not be flat unit prices, estimates of such prices would also be needed.

Calculation of Capacity and Energy Cost Savings

Because several technologies are used simultaneously, the most complicated part of an electric utility is the generation system. As we know, these technologies can include internal combustion engines, gas turbines, coal-fired steam plants, nuclear plants and, hydroelectric installations. The optimum mix of plants depends on the time-varying nature of demand, summarized as the utility's load duration curve (LDC). Base load plants are capital intensive but are relatively inexpensive to run. As demand grows during a day, the system dispatcher will always use base load plants first, if they are available and are not down for maintenance. As demand increases, intermediate load plants are brought on line. These have somewhat higher running costs than the base load units.

If demand approaches the system's expected peak, the dispatcher will serve these requirements with peaking units that are expensive to run but have low capital costs.

The mix of these technologies depends upon the LDC. If a utility has a pronounced peak, it will use relatively more peaker units and avoid the capital expense of a base unit. If demand is high all year so that the LDC is relatively flat, base load units become economical since they can be run all year and the resulting fuel cost savings more than offsets the higher initial capital cost.

Changes in consumption patterns lead to capacity costs savings because each consumption pattern has an associated least cost configuration of generators. As peak period consumption shrinks and off-peak period consumption grows it is presumed that the expected load can be met by a configuration of plants that is less expensive, while the level of system reliability is maintained. Ideally, in order to calculate the expected capacity costs savings it is necessary to predict the optimal configuration of plants before and after the introduction of TOU rates. No such calculations are required for the proposed method.

A fundamental assumption of the proposed method is that the changes in consumption patterns due to the introduction of TOU rates is such that the least-cost configuration of plants is not affected. That is, it is assumed that the order in which plants are constructed remains unchanged. The only change that is caused by the new consumption pattern is a change in dates of constuction. This assumption greatly simplifies the data requirements and calculations needed in the analysis and produces results that adequately reflect the true costs and savings of implementing TOU rates. This is the same approach taken in the Cicchetti, Gillen and, Smolenski computer model (see below) which has been applied in determining the costs and benefits of TOU rates in several jurisdictions.

More specifically, Cicchetti, Gillen, and Smolenski (CGS)[1] developed a computer program that yields a capacity cost per kilowatt-hour (kWh) useful in the following calculation

(Capacity costs savings) =

(Capacity cost per kWh)x(Customer response on peak) (2-5)

The CGS program determines both a capacity and an energy cost component of generation. Based on the work of Ralph Turvey, it assumes that system planners usually respond to changes in customer demand by adjusting a future plant's date of operation either forward or backward. The assertion is that the costs associated with the resulting change in the utility's capital expansion plan can be used as a good estimate of the additional capacity cost incurred or saved because of a change in output.

The cost associated with this change in system plans is obtained by calculating the present value of the difference between the stream of costs from two plans, one normal and one with a one-year advancement. There are two types of costs resulting from an alteration in the construction schedule. First, there is the cost associated with making the capital expenditure one year earlier at the time of initial installation and each time the plant is replaced in the future. Disregarding the existence of inflation or technical progress, this difference in costs is equivalent to the annualized cost in an amortization schedule.

The other component of costs is the change in operating costs that results from having the newer, presumably more efficient, plant operating one year sooner or one year later. In the case of savings, these result from the reduction in fuel costs as the newer plant displaces less efficient plants in the dispatch schedule. The amount of fuel savings is calculated by simulating the future dispatch of the system under both scenarios and determining the present value of the difference in fuel costs. Since a new baseload plant may require several years of operation before it can be operated at rated capacity, this simulation should span a long enough period of time to include all differential effects.

---

[1]See appendix A for data required to run this program. Hypothetical results are presented in appendix B.

The fuel savings are deducted from the capital cost of advancing the plant to determine the net cost of the schedule adjustment. This value is then divided by the capacity of the plant to yield the cost per kilowatt (kW) of the additional output. Next, this cost of capacity is multiplied by an adjustment factor to include the required reserve margin in order to compute the cost that would actually be incurred to meet an additional kW of demand at the busbar. Finally, line losses multipliers that are calculated at peak are applied to this value to determine the appropriate capacity costs for each voltage level of service.

This discussion has considered only the situation in which a single plant is adjusted. If, in fact, the change in demand would be met by altering the scheduling of more than one plant, changes in the cost of capacity would then be calculated as a weighted average of the costs associated with rescheduling each plant.

The computer program provided by CGS does not include the dispatching algorithm that is needed to calculate the fuel savings. Such dispatching programs are quite common and are usually available from the particular utility. If not, the NRRI has one available.

It is important to understand that the reasoning behind this so-called forward-backward method is based on the utility's expansion plan being optimal. In these circumstances, it makes no difference whether the plant being analyzed is a base-load or peaker unit. If the expansion plan was previously the least cost method of meeting future demand, it is quite likely that the mix of plants corresponds closely to the requirements of the load duration curve.

If the utility's expansion plan is not optimal, the accuracy of the CGS method of calculating the cost of new capacity is reduced, although it still provides a good estimate.

Given the above calculations, energy cost savings are obtained as:

(Energy costs savings) = (Difference in energy costs per kWh on-peak and off-peak) x (Customer response on peak) (2-6)

This provides a conservative estimate of energy cost savings. A less conservative estimate would be obtained by assuming that the reduction in on-peak consumption results in no increase in off-peak consumption. In this case, the energy savings would be the product of the on-peak energy cost and the on-peak customer response. Equation 2-6 calculates the minimum energy cost savings.

New generating capacity may require providing extra transmission and distribution (T & D) capacity that increases costs and raises operation and maintenance expenditures for the various types of physical facilities used for transmission and distribution to each voltage level of service. Such facilities may include, for example, additional high voltage transmission wires and the additional power capacity of transmission and transmission and distribution substations and line transformers.

Transmission and distribution facilities serving each voltage level depend on the types of customers being served. High voltage users are served by high voltage transmission lines and transmission substations. Primary voltage users are served in addition by distribution lines and distribution substations, as well as line capacitors. Facilities for serving low voltage users must include additional lines and transformers.

CGS assume that the number and type of such facilities at a given voltage level of service varies directly with the customer kilowatt demand at that voltage level. Two ways are suggested to find this relationship. One approach uses the future expansion plan to find the planned number of additional facilities per additional kW of peak demand. The second approach is to gather historical data on the physical quantities of T & D facilities at each voltage level and the kW demand that these facilities reveal. A simple linear regression analysis provides an estimate of the kinds of each facility required to serve each kW of demand.

After finding the relation between physical facilities and kW demand (essentially the ratio of inputs to output), this is multiplied by the annualized cost of each type of facility, to yield a cost per kW. This is adjusted for line losses, as before. The cost for each voltage level is obtained by adding the costs of those facilities that serve that particular voltage level and all voltage levels that are higher. Implicitly, it is assumed that the distribution network has a hierarchical form, so that an expansion of demand at 220 volts (low voltage) also implies that demand must increase at 69.5 kilovolts (high voltage). This model of the network system is not strictly correct. For instance, portions of the high or primary voltage network that are quite expensive, but cannot be attributed to any single customer, are not in the network between the residential customer and the generating plants. Despite this, the hierarchical model seems reasonable, until more detailed T & D network analysis is conducted.

CGS attribute the entire capacity cost of the T & D network to the peak period. Again, this seems to be a reasonable approximation; however, it is clear that portions of the distribution network may have local peak demands at times that do not coincide with the generation peak. The proper way to account for different time patterns of demand between generation and local distribution facilities is to calculate separately the time varying costs for each and then add the costs in the same rating periods. Such an analysis would require a separate cost study for each portion of the distribution network and would be impractical and costly to conduct. In practice, the usual suggestion is to broaden the definition of the peak rating period so that residential customers, for example, do not create a severe load on local distribution facilities at the close of the business day when demand for generation lessens.

Total benefits are defined as the sum of capacity costs savings obtained in equation (2-5) and energy costs savings obtained in equation (2-6).

It should be noted that the benefits derived from the introduction of TOU rates are partially determined by the length of the peak and off-peak periods selected. A short peak period is likely to result in a greater shift of consumption to off-peak periods than is a relatively long peak period. In the latter case, an absolute reduction in consumption (rather than a shift) may occur. The actual result will depend on the length of the selected peak and off-peak periods, the price differential between these periods, and the customer response coefficient.

In any case, the selected costing periods should adequately reflect the actual costs of service and load characteristics of a given utility. A broadly defined peak period, based on these costs and load characteristics, is likely to result in a smaller price differential between peak and off-peak periods than is a narrowly defined peak. The customer response, therefore, is also likely to be smaller.

As noted above, the assumption made for the current analysis is that all reduction in consumption during the peak period is shifted to the off-peak period. This assumption is made due to the lack of specific information on customer response coefficients for Colorado utilities, and in order to produce a conservative estimate of the benefits of TOU rates for Colorado. As more specific information becomes available, improved estimates of customer response coefficients may be used.

The peak and off-peak periods used in the example of the method presented in chapter 4 are those selected by a Colorado electric utility as presented in its Public Utility Regulatory Policies Act of 1978 (PURPA) Section 133 filing requirement. The peak and off-peak period prices used in the example were also based on those prices submitted by the company.

CHAPTER 3
METERING COSTS

Types of Meters

Conventional kilowatt-hour meters are designed to record total kWh consumption at that service point. When price incentives are introduced to stimulate shifts in energy consumptions from on-peak to off-peak hours, more advanced metering devices are required to measure consumption by time-of-day and maximum demand. These advanced metering devices require a time clock, an activating device, and at least one other dial in order for the system to operate efficiently and effectively.

This section identifies types of meters that can measure consumption under TOD pricing policies. The five types of meters described below are (1) a two-dial kWh meter, (2) a three-dial kWh meter, (3) a two-dial kWh meter and peak-period kW dial, (4) an electronic multi-function meter, and (5) an automatic meter reader.

Before proceeding, the reader is reminded that TOD metering is a relatively recent innovation in the electric utility industry. Cost-benefit studies pertaining to these types of equipment are still rather sketchy. Although purchase and installation costs for TOD meters have been adequately ascertained, administrative costs and equipment reliability are not certain because little data exist on this topic.[1] A good summary of

---

[1]Barney L. Capehart and Michael O. Storin, "Part III Metering For Innovative Electric Rates." (University of Florida: Public Utility Research Center, 1981), pp. 7-3 - 7-5; additional information for General Electric meters presented in the following subsections of this report came from manufacturer's publications.

the types of meters generally available for electric utility TOU pricing has been prepared by the Electric Utility Rate Design Study.[2]

Two-Dial kWh Meter

The two-dial kWh meter measures kWh consumption during two periods, usually throughout the day and during the peak period. Sangamo's MTR-20 meter provides a good description of this meter type. The switchable register dials are controlled by an electronic clock calendar. Preprogrammed non-volatile magnetic cards are available for specific time periods, holidays and weekends. This device has eight set points and a 35 day battery carryover (in order to avoid the costs of resetting every time power outages occur) with battery replacement every six years. Optional features are the customer alert (a flashing signal that indicates which rate applies and the rate of consumption), a load control (that activates control of customer loads, such as air conditioners) and a byback access port. Manual reading in required.

Three-Dial kWh Meter

This meter type measures peak kWh, total kWh and intermediate (shoulder) kWh. Three separate sets of dials register consumption. One register of four dials measures peak usage, another four-dial register measures a second (or mid) peak and a middle register of five dials records total electric usage. The General Electric Model IR 70 fits into this category. Reprogrammable non-volatile circuit cards allow for numerous combinations of three rating periods. The seven day battery carry-over has a life expectancy of five years. This model is capable of alerting the consumer that he is consuming during a peak period and it has an optional

---

[2]Task Force No. 7, Metering: Topic 7, prepared for the Electric Utility Rate Design Study, Electric Power Research Institute (Palo Alto, CA 12 January 1977).

load control. A sealable access port provides quick access to the programming receptacle. This permits time setting, programming and reprogramming of the meter.

Two-Dial kWh with kW Demand

This meter type allows for the measurement of total kWh, peak kWh and maximum kW consumption. Sangamo's MTR 21 is designed with these measurement specifications. The MTR 21 is very similar to the MTR 20. It has a 35 day battery carry-over, optional customer alert and load control, an annual calendar, eight set points, a keylock access port and reprogrammable non-volabile circuit cards. The MTR 21 registers with a basic watt-hour meter.

Electronic Multi-function Meter

This is an advanced TOD metering system. The General Electric TM-80 is representative of this meter type. The TM-80 allows for five full years of programming, which includes four seasons and ten holidays a year. It has a 40 day battery carry-over, optional customers alert (up to three alerts) and load control, six set points (on quarter hour intervals) and a separable access port. The 9000 TM-80s are presently in operation.

Automatic Meter-reader (AMR)

The AMR system is varied and flexible. Its main purpose is to be able to shed a part of the total system demand at the time of system peak demand. This is achieved by connecting switches to various customers appliances that are remotely controlled from the utility's main station.

The AMR system is part of a two-way communications system that allows for information and directive flows between the central control unit (CCU), which serves as a data accumulation center, and a meter located on the customer's site. Major components of such a system are load management, automated distribution, meter reading, and recognition of multi-periods for TOD metering.

The four communication systems receiving the most attention are telephone systems, radio systems, low frequency ripple systems using power lines, and high frequency power line carrier systems.

American Science and Engineering (AS & E) has designed an AMR system. The AS & E system is a two-way system which retrives remotely all metering data automatically over the power lines. The key components of the AS & E system include a data dispatch controller that monitors and controls system operations, and a substation communication unit (SCU) that receives data dispatch control signals that have been sent through telephone lines and retransmitted over the utility distribution lines to transponders and load control receivers. The substation retransmits signals received from the transponders back to the central control unit. The transponders serve as transmitters and receivers at each two-way point. They also accept control signals, read and store metering data, and transmit status data back to the central control unit. Within the transponder is a multistate metering module containing three separate non-volatile, 24-bit memories.

The AMR system is the only one of the TOD metering systems mentioned in this report that does not require manual meter reading.[3]

Metering Costs

When considering the implementation of a TOD pricing policy it is, of course, crucial that benefits of implementation exceed the costs. These costs include the total cost of purchasing, installing and maintaining the meters. Since most large industrial users already have the necessary meters, net benefits of such a pricing policy would most probably exceed the costs. Therefore, it is important to focus on the metering costs associated with residential, small industrial and commercial users.

---

[3] CH_2M Hill, A Method to Assess the Economic Feasibility of Time-of-Day Pricing for Residential Customers. (Columbus, Ohio: The National Regulatory Research Institute, 1979), pp. 13-21.

The most recent cost of the meters discussed in the previous section are presented in table 3-1. The first four metering types require the installation of a new meter on each customer site. The AMR requires only the installation of an encoder on the existing meter. The costs of the AMR system uses the AS & E type as representative. Included is the prorated cost of the CCU and the SCU.

The annualized costs of all metering types is based upon the best available information. Costs per meter may decrease as more units are produced allowing for fixed costs to be spread out over a larger number of units.

The annualized cost of meters is based on a 20 year equipment life. The annual charge for the meters is based on the following data. [4]

1) Cost of money (latest U.S. Treasury Bill figures)	-	12.50%
2) Depreciation	-	5.00%
3) Insurance	-	.10%
4) Annual charge	-	17.60%

The annualized metering costs were computed as follows:

$$\text{annualized meter cost} = A \left(\frac{i(1+i)^n}{(1+i)^n - 1} \right)$$

where: i = annual charge (expressed as a decimal),
n = 20 year life of meter,
A = total cost of each metering type.

---

[4] CH_2M Hill, op. cit., p. 9.

TABLE 3-1

COMPARISON OF ANNUALIZED COSTS FOR
TIME OF DAY METERING (1980 $/METER)

Type	Purchase	Installation	O&M/Year	Annualized Cost
2-Dial kWh meter	$100 - 210	$ 5 - 10	$ 2 - 4	$19.58 - 40.99
3-Dial kWh meter	$165 - 235	$ 5 - 15	$ 5 - 12	$32.03 - 47.95
2-Dial kWh meter and peak period dial	$165 - 305	$ 5 - 15	$ 5 - 15	$32.03 - 60.76
Electronic multi-function meter	$210 - 350	$10 - 25	$10 - 15	$42.09 - 71.37
AMR	$160 - 240	$20	N.A.	$32.94 - 47.58 (excluding O&M)

Source: "Part III for innovative electric rates"; A Method to Assess the Economic Feasibility Time of Day Pricing for Residential Customers.

CHAPTER 4
AN EXAMPLE

This chapter presents an example set of calculations based on actual data supplied by a Colorado utility. The presentation is for illustrative purposes only. It provides another basis for understanding the method described in chapter 2.

Each attempt to execute the analysis is based on several alternate scenarios, or cases, among which comparisons are to be made. From these comparisons the most preferred course of action is chosen. All together the cases defined in table 4-1 constitute one of many possible alternatives. The table defines a situation under which all customers would be subject to time-of-use rates, with a specific definition of peak period supplied. Another set of cases could be defined based on a different peak period. Or, the alternatives could be defined in terms of different customer groups facing time-of-use rates.

Table 4-2 corresponds to equation 2-3. The end product is contained in column (5). It is the percentage change in peak period price. Both the "old" average company price and the proposed peak period price should be supplied by the company. The resulting numbers in column (5) are positive because the proposed price is higher than the old price.

The expected benefits associated with time-of-use prices are the result of customers' response to the increased prices during the peak period recorded in table 4-2. The next step in the analysis is to make calculations according to equation 2-4. These calculations yield an estimate of the drop in peak period consumption.

TABLE 4-1

DEFINITION OF CASES

Case Number (1)	Customer Group (2)	Definition of Peak Period (3)	
1	Residential	"Summer" -	June, July, August, September 8:00a.m. to 11:00 p.m. Monday through Friday
2	Residential	"Winter" -	November, December, January, February 8:00 a.m. to 11:00 p.m. Monday through Friday
3	Residential	"Transition -	March, April, May, October 8:00 a.m. to 11:00 p.m. Monday through Friday
4	GLP	"Summer"	
5	GLP	"Winter"	
6	GLP	"Transition"	
7	LLP	"Summer"	
8	LLP	"Winter"	
9	LLP	"Transition"	

GLP - general light and power
LLP - large light and power

Source: PURPA Section 133 cost-of-service information

TABLE 4-2

PRICE CHANGES DUE TO TIME-OF-USE RATES

Case Number (1)	Peak Price ¢/kwh (2)	Average "Old" Company Price ¢/kwh (3)	Difference In Prices (2) - (3) (4)	Percentage Change in Price (5)
1	6.13	4.37	1.76	40.27
2	5.64	4.37	1.27	29.06
3	5.59	4.37	1.22	27.91
4	6.13	3.86	2.27	58.80
5	5.64	3.86	1.78	46.11
6	5.59	3.86	1.73	44.81
7	5.60	3.50	2.10	60.00
8	3.82	3.50	0.32	9.14
9	5.17	3.50	1.67	47.71

Source: PURPA Section 133 cost-of-service information and author's calculations

The calculations are divided into two steps. Table 4-3 contains the calculation of percentage change in peak period consumption, while in table 4-4 these percentages are applied to obtain an estimate of customers' response. Three sets of calculations are presented in these tables. Each set of calculations corresponds to a different assumption about the customer response coefficient. As experience with time of use rates is accumulated in Colorado, these calculations will not be necessary. Precise estimates of customer response coefficient in Colorado will then be available.

Table 4-5 contains calculations that correspond to equations 2-5, 2-6, and 1-1. The previous calculations provide inputs to table 4-5. It is important to note that for the purpose of these calculations a medium coefficient of customers' response was assumed. A much more important assumption is embedded in column (2). This column represents the capacity cost per kwh used in equation 2-5. In the example the incremental capacity cost figure is used. An alternative for it might be past average capacity cost or the average cost of the most recently added capacity.

It is important to note that according to this method the estimated drop in peak period consumption used to calculate capacity cost savings is assumed not to result in an equivalent increase in the off-peak period consumption. This is not assumed in the case of energy cost saving calculations. In the case of some companies, especially those with relatively flat load curves, this assumption may lead to the undesirable result of peak period shifting, that is, the off-peak period may become the peak period. This property of the method suggests that care be exercised in the definition of periods and the selection of customer response coefficients. It is recommended that the analyst always examine the resulting load curves for unrealistic characterics.

The bottom row of table 4-5 corresponds to equation 1-1. It yields the amount of net benefits associated with implementation of time-of-use rates for all the customers.

TABLE 4-3

PERCENTAGE CHANGE IN CONSUMPTION DUE TO TIME-OF-USE RATES

Case Number	Percentage Change in Price	Assumed Customer-Response Coefficient			Percentage Change in Consumption On Peak		
		Low	Medium	High	Low	Medium	High
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	40.27	-0.44	-1.02	-1.36	-17.71	-41.07	-54.76
2	29.06	-0.44	-1.02	-1.36	-12.78	-29.64	-39.52
3	27.91	-0.44	-1.02	-1.36	-12.28	-28.46	-37.96
4	58.80	-0.44	-1.02	-1.36	-25.87	-59.98	-79.97
5	46.11	-0.44	-1.02	-1.36	-20.29	-47.03	-62.71
6	44.81	-0.44	-1.02	-1.36	-19.71	-45.70	-60.94
7	60.00	-0.44	-1.02	-1.36	-26.40	-61.20	-81.60
8	9.14	-0.44	-1.02	-1.36	-4.02	-9.32	-12.43
9	47.71	-0.44	-1.02	-1.36	-20.99	-48.66	-64.88

Source: Data from tables 4-1 and 4-2 and calculations based on equation 2-4.

TABLE 4-4

CUSTOMER RESPONSE ON PEAK

Case Number	Consumption on Peak Under Company (MWH)	Percentage Change in Consumption Under Various Assumptions			Customer Response on Peak (MWH)		
		Low Response	Medium Response	High Response	Low Response	Medium Response	High Response
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	397,652.76	-17.71	-41.07	-54.76	-70,424.30	-163,315.98	-217,754.65
2	461,094.78	-12.78	-29.64	-39.52	-58,927.91	-136,668.49	-175,031.57
3	399,616.77	-12.28	-28.46	-37.96	-44,072.94	-113,730.93	-151,694.52
4	772,358.75	-25.87	-59.98	-79.97	-199,809.20	-463,260.77	-617,655.29
5	658,326.53	-20.29	-47.03	-62.71	-133,574.45	-309,609.57	-412,836.56
6	682,365.28	-19.71	-45.70	-60.94	-135,244.79	-313,546.84	-418,085.20
7	472,457.63	-26.40	-61.20	-81.60	-124,728.81	-289,144.06	-385,525.42
8	438,262.64	-4.02	-9.32	-12.43	-17,618.16	-40,846.08	-54,476.05
9	450,450.16	-20.99	-48.66	-64.88	-94,549.49	-219,189.04	-292,252.06

Source: Data from previous tables and PURPA Section 133 cost-of-service information.

TABLE 4-5

BENEFITS AND COSTS OF TIME-OF-USE RATES

Case Number	Incremental Capacity Costs (¢/kwh)	Medium On-Peak Customer Response (MWH)	Capacity Benefits ($)	On/Off Peak Period Energy Cost Difference (¢/kwh)	Energy Savings ($)	Metering Costs ($)	Net Benefits (4) + (6)-(7) ($)
(1)	(2)	(3)	(4)	(5)	(6)	(7)[1]	(8)[1]
1	3.28	163,315.98	5,052,861.90	1.01	1,649,491.30		
2	2.61	136,668.49	3,567,047.50	0.43	587,674.51		
3	2.86	113,730.93	3,252,704.50	0.67	761,997.23		
4	3.28	463,260.77	15,194,053.00	1.01	4,678,933.70		
5	2.61	309,609.57	8,080,809.70	0.43	1,331,321.10		
6	2.86	313,546.84	8,967,439.60	0.67	2,100,763.80		
7	2.85	289,144.06	8,240,605.70	0.96	2,775,782.90		
8	0.91	40,846.08	371,699.32	0.39	159,299.71		
9	2.54	219,189.04	5,567,401.60	0.62	1,358,972.20		
TOTAL			58,294,622.82		15,404,236.45	20,128,950.00	53,569,909.27

Source: PURPA Section 133 cost-of-service information and calculations based on equations 1-1, 2-5, and 2-6.

[1]Metering costs and net benefits are provided only on a system wide basis rather than for each customer class.

APPENDIX A
DATA REQUIREMENT

The company should submit all basic data used in its PURPA Section 133 filing, including the calculations of its embedded class cost-of-service study and in its marginal class cost-of-service study, and also a description of the methods for converting the basic data into calculated class costs of service.

The company should also submit the following data listed as items 1 through 26, if not included in the basic data for the Company's studies.

PURPA requires the calculation of costs by voltage level of service. For the purpose of supplying information in this Appendix, the company should choose between three and five voltage levels that are representative of voltage levels servicing large blocks of customers. For example, three voltages levels may be reported as follows: 69 kilovolts (kV) representing high voltage service, 12.5 kV representing primary voltage service, and 0.120 kV representing low voltage service. When certain information pertaining to a voltage level is requested, for example, annual low voltage sales, all sales at 120 V, 240 V and so on, are to be reported, up to a cut-off point of (say) 1000 volts, beyond which sales would be classified as primary voltage service. Hence, the sum of the sales at each voltage level equals total system retail sales.

As used herein, a loss/load ratio at a particular voltage level is the ratio of power (in kW) lost in the voltage transformation from the next higher voltage level to the particular voltage level divided by the power (in kW) at the particular voltage level.

The utility should supply the following information:

1. The number of voltage levels (between 3 and 5) and the voltage at each level.
2. The annual kilowatt-hour sales and revenues at each particular voltage level, and the annual (estimated) kilowatt-hour line losses associated with each level. The total system load on and off peak.
3. The loss/load ratios for each voltage level.
4. If available, the average loss/load ratio at system peak for each voltage level.
5. If available, the marginal loss/load ratio at system peak for each voltage level.
6. If available, the marginal loss/load ratio during off-peak periods for each voltage level.
7. The number of plants of the company's expansion plan, for the next ten years.
8. The interest rate for annualizing the capital costs of plants in the expansion plan.
9. The proposed reserve margin of capacity for the company, expressed as a percentage.
10. The year each individual plant in the company's ten year expansion plan is expected to come on line.
11. The capacity each plant in the company's ten year expansion plan is expected to provide to the system.
12. The company's share of the plant capital costs for each plant in the company's ten year expansion, in dollars.
13. The number of years over which each plant's capital costs are to be annualized for each plant in the company's ten year expansion plan.
14. The annual fixed operation and maintenance cost of each plant in the company's ten year expansion plan.
15. The number of years over which there is a fuel savings for each plant in the company's ten year expansion plan, that is, the

number of years over which the utility forecasts a savings in its annual fuel expense due to the plant's new position in the loading order for dispatch.

16. The fuel savings, for each year in which there is a fuel savings, for each plant in the company's ten year expansion plan, that is, the estimated annual saving in fuel expense associated with each new plant when brought on line.
17. The number of types of transmission and distribution facilities for each voltage level of service.
18. The capital costs per unit of facility capacity (for example, line mile of cable or kilovolt-ampere of substation capacity) for each type or transmission and distribution facility for each voltage level of service.
19. The annual fixed operation and maintenance cost per unit of facility capacity for each type of transmission and distribution facility for each voltage level of service.
20. The total annual capacity of each T & D facility for each voltage level for each of the last ten years, expressed in line miles, kilovolt-amperes, or kilowatts.
21. The annual peak customer load expressed in kilowatts for each voltage level for each of the last ten years.
22. The anticipated increase in T & D capacity, expressed in line miles, kilovolt-amperes, or kilowatts for each transmission and distribution facility at each voltage level for a specified future date.
23. The anticipated additional customer load at each voltage level that requires the addition of T & D capacity reported in request 22.
24. A specification of no more than six on-peak and off-peak periods during the test year, naming each period according to calendar dates, days of the week, holidays and hours of the day, and stating whether each period is a peak period or an off-peak period.
25. The incremental fuel costs for each peak period and off-peak period in cents per kilowatt-hour, that is, a weighted average.
26. Hourly loads for the test year.

APPENDIX B

INCREMENTAL COSTS FOR A HYPOTHETICAL COMPANY

The purpose of presenting the attached computer print-out is to illustrate the type of data diversity obtainable from the CGS program for a hypothetical utility. Of major significance for the purposes of this report are the capacity and energy costs as listed on page 2 of the print-out. It is noteworthy that the results of other calculations are given as a by-product.

LOSS MULTIPLIERS

VOLTAGE STAGE	FOR DEMAND ON PEAK SIMPLE	FOR DEMAND ON PEAK CUMULATIVE	FOR ENERGY ON PEAK SIMPLE	FOR ENERGY ON PEAK CUMUL.	FOR ENERGY OFF PEAK SIMPLE	FOR ENERGY OFF PEAK CUMUL.
FROM GENERATION TO HIGH VOLTAGE CUSTOMERS AND HIGH SIDE OF STAGE 1 TRANSFORMERS	1.0350	1.0350	1.0250	1.0250	1.0190	1.0190
FROM HIGH SIDE OF STAGE 1 TRANSFORMERS TO STAGE 2 CUSTOMERS AND HIGH SIDE OF STAGE 2 TRANSFORMERS	1.0240	1.0598	1.0170	1.0424	1.0150	1.0343
FROM HIGH SIDE OF STAGE 2 TRANSFORMERS TO STAGE 3 CUSTOMERS AND HIGH SIDE OF STAGE 3 TRANSFORMERS	1.0700	1.1339	1.0410	1.0852	1.0350	1.0704

MARGINAL COST OF GENERATING CAPACITY ($/KW)

VOLTAGE LEVEL (1=HI VOLTAGE)	MARGINAL COST
1	101.011
2	103.431
3	110.669

MARGINAL COST OF TRANSMISSION AND DISTRIBUTION CAPACITY ($/KW)

VOLTAGE LEVEL (1=HI VOLTAGE)	MARGINAL COST TRANS. + DIST.	MARGINAL COST GEN. + TRANS. + DIST.
1	3.476	104.487
2	4.500	107.931
3	41.289	151.958

LENGTH OF PERIODS (HOURS)

DAY AND EVENING	NIGHT	WEEKEND
3132	3132	2520

MARGINAL COST OF ENERGY (CENTS/KWH)

VOLTAGE STAGE (1= HI)	PERIOD DAY AND EVENING	NIGHT	WEEKEND

1	1.661	1.477	1.477
2	1.689	1.500	1.500
3	1.758	1.552	1.552

TOTAL MARGINAL COST (CENTS/KWH)

ON-PEAK PERIODS-- TOTAL MARGINAL COST (= GEN. + TRANS. + DIST. + ENERGY COSTS)

VOLT. LEVEL	PERIOD	GENER.	TRANS. + DIST.	ENERGY	TOTAL
1	DAY AND EVENING	4.838	0.166	1.661	6.665
2	DAY AND EVENING	4.954	0.216	1.689	6.858
3	DAY AND EVENING	5.300	1.977	1.758	9.036

OFF-PEAK PERIODS-- TOTAL MARGINAL COST (= ENERGY COST)

VOLTAGE LEVEL	NIGHT	WEEKEND
1	1.477	1.477
2	1.500	1.500
3	1.552	1.552

ARE THERE ANY CHANGES YOU WISH TO MAKE IN THE DATA? NO

AU REVOIR

SELECTED BIBLIOGRAPHY

1. Atkinson, Scott E., "Responsiveness to Time-of-Day Electricity Pricing." Journal of Econometrics 9 (1979): 79-95.

2. Berg, Sanford V., Benefit Cost Analysis for Load Management. Part I: Policy Issues Background Paper. University of Florida, 1980.

3. Capehart, Barney L., and Storim, Michael O., "Metering for Innovative Electric Rates." University of Florida, 1981.

4. CH_2M Hill, A Method to Assess the Economic Feasibility of Time-of-Day Pricing for Residential Customers. Columbus, Ohio: National Regulatory Research Institute, 1979.

5. Gordian Associates, Measuring the Peak Cost Advantages of Peak-Load Pricing: Topic 6 (Phase B). Prepared for Electric Utility Rate Design Study, Electric Power Research Institute: Palo Alto, California, 1977.

6. Hoffman, Abram E., and Czamanski, Daniel, A Computerized Analysis of Time-of-Use Rates for Massachusetts. Columbus, Ohio: National Regulatory Research Institute, 1979.

7. Houthakker, Hendrik S., Electricity Demand Revisited. Discussion Paper No. 711. Cambridge, Massachusetts: Harvard Institute of Economic Research, 1979.

8. ICF, Inc., Benefits and Costs of Selecting Load Management Options for Gulf State Utilities. Washington, D.C., 1980.

9. Lawrence A., and Aigner D., eds. "Modelling and Forecasting Time-of-Day and Seasonal Electricity Demands." Journal of Econometrics 9 (1979).

10. National Economic Research Associates, Inc., Considerations of the Price Elasticity of Demand for Electricity: Topic 2. Prepared for Electric Utility Rate Design Study, Electric Power Research Institute: Palo Alto, California, 1977.

11. Resource Planning Associates, Inc., Approach to Cost-Based Electric Rates in Nevada. Columbus, Ohio: National Regulatory Research Institute, 1978.

12. Spann, Robert M., and Beauvais, Edward C., "Econometric Estimation of Peak Electricity Demands", Journal of Econometrics 9 (1979): 119-136.

13. Storch, Stephen N., A Users Manual for Marginal Cost: A Computer Program Developed by Charles J. Cicchetti. Columbus, Ohio: National Regulatory Research Institute, 1979.

14. Task Force No. 7, Metering: Topic 7. Prepared for Electric Utility Rate Design Study, Electric Power Research Institute: Palo Alto, California, 1977.

15. Taylor, Lester D., "The Demand for Electricity: A Survey." Bell Journal of Economics 6 (Spring 1975): 74-110.

16. U.S., Federal Energy Administration, Office of Conservation, National Energy Conservation Programs, Evaluation and Classification of Load Management Equipment. Washington, D.C., 1977.

17. Wilson, J.W., and Associates, Inc., Costing and Rate Design Methodologies for Electric Utilities. Columbus, Ohio: National Regulatory Research Institute, 1978.

18. ________. Elasticity of Demand: Topic 2. Prepared for Electric Utility Rate Design Study, Electric Power Research Institute: Palo Alto, California, 1977.

Final Report on

ASSESSING THE REASONABLENESS OF INTERRUPTIBLE RATES FOR COLORADO ELECTRIC UTILITIES

Russell J. Profozich
Senior Institute Economist

Roger K. McElroy
Senior Research Associate

Timothy Pryor
Graduate Research Associate
in Economics

THE NATIONAL REGULATORY RESEARCH INSTITUTE
2130 Neil Avenue
Columbus, Ohio 43210

prepared for the

Colorado Public Utilities Commission

in partial fulfillment of

Contract No. 900342

June 1981

EXECUTIVE SUMMARY

The purpose of this report is to present a method for assessing the reasonableness of rates for interruptible service proposed by Colorado electric utilities. The Colorado commission determined in its Decision No. C79-1111 concluding the generic electric utility rate investigation that significant benefits may be derived from implementation of interruptible rates by jurisdictional electric utilities.

Interruptible rates are a form of load management designed to control or alter the timing and magnitude of an electric utility's system load. Benefits derived from interruptible rates may include a reduction in capital expenditures by the utility resulting in lower costs of service to customers, reduction in fuel cost resulting from less intensive use of peaking capacity, improved load factor resulting in increased usage of existing capacity, and improved environmental quality resulting from reduced capacity expansion and reduced fuel consumption.

It is generally accepted that electric utility rates (and therefore interruptible rate) should be based on costs of service. This practice aids in the elimination of cross-subsidies between customers and customer classes, promotes economic efficiency, and promotes revenue stability for the utility.

It is also generally accepted that the cost, and therefore the price, of interruptible service is below that of regular or firm service due to the reduced reliability of this service. However, value-of-service considerations also arise in that the reduction in the value of this service to customers may be greater than the cost reduction to the utility. Interruptible rate should therefore be offered on a voluntary basis. State public utility commissions usually require that actual service interruptions be in line with those called for within the tariff. This helps assure that the rates charged are commensurate with the level of service reliability provided.

If interruptible rates are based on costs avoided by the utility, a condition identified herein as the "threshold" problem may develop. This situation results when a minimum amount of interruptible load is necessary for a utility to cancel or postpone capacity expansion. The cost of plant not built is the utility's avoided cost. If an insufficient number of customers subscribe to interruptible service, no capacity cost savings may accrue to the utility. If more than enough customers subscribe, the utility may have to decide which of these receive the service and which do not. Also, future cost savings may not be identified if interruptible service is closed to new customers.

A survey of interruptible rates offered to industrial customers and summarized within this report found that most utilities specify a minimum customer load (in kilowatts) to be interrupted or a minimum customer curtailable load (total of customer interruptible and firm service). These restrictions are at least partially determined by cost-effectiveness considerations.

The survey also found that utilities often limit interruptible load to an amount deemed appropriate for the system and close the rate to additional customers once this level is reached. Other qualifications for this service include a requirement that interruptible service be separately metered and taken at one delivery point, requirement of customer notification and impending curtailment, and penalty provisions for customer noncompliance.

The types of industrial customers most often subscribing to interruptible service were reported as arc and alloy furnaces; steel mills; mineral extraction, processing, and crushing; rolling mills; induction heating applications; paper products production; and some chemical processes including production of chlorine, caustic soda, abrasives, carbide, graphite, and industrial gases. Testing facilities such as wind tunnels, and government and military research labs were also identified as potential interruptible customers.

Several methods of estimating cost upon which to base interruptible rates are presented in the report. One method estimates the avoided cost of generating equipment, net of any necessary investment in load control or metering equipment, and reduces rates for interruptible service below those for firm service based on this cost savings and the interruptible load (in kilowatts) of each customer in combination with the length of the customer's service interruption.

A second method estimates avoided cost by determining the type of plant and its cost that would otherwise be used to provide service. For example, if a peaking plant normally operates during 1000 hours of a utility's peak period and has a capacity cost of $31 per kilowatt, an interruptible customer group allowing its service to be curtailed up to 1000 peak hours would receive a capacity credit of $31 per kilowatt.

A third, "cost plus margin," approach to pricing interruptible service assumes that the peak period load of interruptible customers is provided for entirely from the idle reserve capacity of regular service customers.

With this approach, interruptible service customers are charged for the fuel and operating and maintenance costs that they impose on the system. They are also charged for fixed transmission and distribution costs, as well as for customer costs, including any special metering or control device costs associated with interruptible service. In addition, the interruptible customer pays a portion of the cost of the capacity shared with regular service customers. This negotiated charge is called the margin, and it reflects the benefit received by regular service customers.

The "peak responsibility" method determines the capacity charge for interruptible service based upon the contribution of this customer class to the system peak demand. Use of this method requires the selection of a peak period during which service to interruptible customers can be expected to be curtailed. Capacity cost may be measured using either a marginal cost or embedded cost methodology.

PREFACE

This report was completed under a National Regulatory Research Institute (NRRI) contract with the Colorado Public Utilities Commission (Contract No. 900342). The Colorado commission requested as one part of the contract an analysis of a method for assessing the reasonableness of rates for interruptible service proposed by Colorado electric utilities. This report summarizes the various issues involved in pricing interruptible electric services and presents a method for assessing the reasonableness of electric utility interruptible rates. This report was prepared by Russell J. Profozich, Senior Institute Economist, Roger K. McElroy, Senior Research Associate, and Timothy Pryor, Graduate Research Associate, under the direction of Dr. Kevin A. Kelly, Associate Director. This report was typed by Gayle Swinger, NRRI staff secretary.

TABLE OF CONTENTS

LIST OF TABLES

CHAPTER 1
INTRODUCTION

The purpose of this report is to present a method for assessing the reasonableness of rates for interruptible service proposed by Colorado electric utilities. Interruptible rates may be considered as one type of load management activity. Load management is any method or activity designed to control or alter the timing and magnitude of an electric utility's customer load. Customer load (or demand) is the amount of electric power (measured in kilowatts) delivered or required at a specified point or points on a utility system. System load is the total amount of these individual customer requirements.

The purpose of load management--and therefore of interruptible rates--is to reduce a utility's system peak demand. This reduction allows the utility to reduce its capital expenditures for generation and transmission equipment as well as to achieve a reduction in fuel costs below the level achievable if all customers were noninterruptible (that is, if all customers were "firm" customers). Interruptible rates allow an electric utility to diversify service offerings to its customers in that those customers that do not require a high degree of service reliability do not pay for more reliability than they need.[1] Interruptible rates also allow a utility the opportunity to meet the total demand on its system at a lower overall cost than might otherwise be achievable. This is so because

---

[1]Service reliability refers to the percentage of time over a given period that electric service is available to the customer on demand. A 100 percent service reliability means that service is available 100 percent of the time (for example, no service interruptions). Utilities usually design their systems to achieve a given level of reliability, which historically has been established at 1 day of service interruption in 10 years. While no system is 100 percent reliable, the degree of reliability designed within the system for interruptible customers is less than that for firm customers.

investment in load management equipment is often less expensive than investment in generation and transmission equipment that it, in a sense, replaces on the system.

Costing and pricing of interruptible service presents many difficulties to the regulator. It is generally accepted that the cost, and therefore the price, of interruptible service is less than that for firm service, due to the reduction in service reliability. The correlation between cost of service and service reliability is far from certain, however, due to the joint nature of most costs of service. A problem for the regulator is to determine the degree of cost responsibility associated with a particular level of reliability. The regulator is concerned that a reduction in service reliability to the interruptible customer actually takes place and that it is commensurate with the reduction in rates.

Value-of-service issues also become involved in interruptible service ratemaking. Interruptible service may be a convenient mechanism for a utility to lower the price of its electric service to a group of customers who value the service less than firm customers. Even if properly priced, interruptible service may have few customers if the reduction in the value of the service to the interruptible customer is greater than the reduction in the price.

These issues will be taken up in this report. Examples of interruptible rates and the results of a survey indicating the number of electric utilities offering this service and the type of customers subscribing to the service are also presented. The art of ratemaking is an inexact exercise in determining the causal relationship between cost of electric service and demand for that service. As a result, electric ratemaking can be accomplished by several costing methods, and several methods of assessing the reasonableness of rates for interruptible service are presented here. The presentation is intended for application to the Colorado circumstance. However, due to the lack of specific information on interruptible service of Colorado electric utilities (it appears that only) one electric utility in Colorado currently has an interruptible tariff for one of its industrial customers), the discussion applies to interruptible electric rates in general rather than to interruptible rates of Colorado electric utilities in particular.

The Occasion

In its Decision No. C79-1111, issued on July 27, 1979, at the end of its generic hearings concerning rate structures of all jurisdictional electric utilities, the Colorado Public Utilities Commission (PUC) determined that there are significant utility benefits to be derived from the implementation of load management in general and interruptible rates in particular. The commission also determined that it is appropriate to implement both load management techniques and interruptible rates and that interruptible rates will likely be the most cost-effective of the various load management techniques.[2]

In discussing its decision with regard to load management and interruptible rates, the commission noted that a utility can control the entire load of any particular customer, or any particular energy consuming device of that customer, through the use of several devices such as: radio signals, high-frequency impulses carried over power lines, or low-frequency ripple signals transmitted by means of an independent communication channel. The commission stated that if determined to be cost-effective, the cost of installation of such load management devices should be borne by service accrued to the utility system as a whole rather than merely to the customers that select such service.

The commission also noted that load management controls may be a more effective means of controlling demand on a utility's system than time-of-use rates. This is so, according to the commission, for the following reasons: load management controls can be more flexibly used to match the

---

[2]Decision No. C79-1111, Colorado Public Utilities Commission, Case No. 5693, July 27, 1979, p. 75.

demands of consumers with system needs than inflexible, established time-of-use rates; load management has relative certainty as to the magnitude of shift from peak to off-peak demand, as contrasted with time-of-use rates that are uncertain; load management provides the opportunity for an absolute reduction in peak demand without any significant shift of such demand to other time periods, whereas time-of-use rates appear to shift peak demand to other periods; the affected utility is aware of its inventory of interruptible customers, and such inventory is available at any given time.

Finally, the commission states that the record in its generic hearings demonstrates that there are several prime areas with regard to interruptible rates that it believes should be examined by jurisdictional electric utilities. These include the following:

1. Industrial customers that typically have very large loads that have grown rapidly in recent years and contribute significantly to the yearly and daily peaks of several Colorado utilities.
2. Commercial air conditioning loads that also contribute significantly to the peak of several summer peaking Colorado electric utilities.
3. Irrigation customers that have become an increasing proportion of the summertime peak of several utilities.
4. Residential and commercial space-heating and water-heating customers that contribute significantly to the peak of winter-peaking electric utilities in Colorado.

Appendix C of Decision No. C79-1111 contains the Colorado PUC's views on rate design criteria for interruptible rates. The commission states that the cost of interruptible power varies with its availability.[3] If no guarantee is given to the customer that power will be available, the commission states that the electric power can be sold at a "dump" or commodity rate that includes only the variable costs associated with its production. On the other hand, if the utility provides specified amounts of energy

---

[3]Ibid., appendix C, p. 178.

within stated time periods, or can interrupt service only after giving advance notice or under otherwise limited conditions, the commission believes that some portion of the fixed costs of production should be recovered from the customer. Under such "limited" interruptible service, however, the utility should not recover the fully allocated fixed costs that would be recovered from a customer receiving firm service.

The commission took no position on the amount of demand charge discount (rate reduction) that might be attributable to interruptible service, leaving this provision for the utilities to work out, subject to commission approval. The commission did establish the following criteria to be met by jurisdictional electric utilities seeking approval of proposed interruptible rates.[4]

1. On an hourly basis, the interruptible service should be curtailed whenever a utility's incremental cost of energy exceeds the revenue the utility would receive from the customer for service rendered at 100 percent load factor.

2. All interruptible service must be terminable at the discretion of the utility rendering service without a requirement for giving advance notice to the customer.

3. The commission does not intend to encourage profiteering through interruptible service. For example, interrupting customers in favor of a sale-for-resale simply because the sale-for-resale will yield more revenue than the sale to an interruptible customer will not be permitted.

4. The commission encourages establishment of a resale rate to be applicable when interruption, voltage reductions, or voltage blackouts are undertaken by one utility at the behest of another utility and paid for by the utility causing the curtailment of service.

5. Demand charges applicable to interruptible service shall not be recovered through the energy component of the rate. The allocation of demand costs to interruptible service shall be grounded upon a rational basis that shall relate to the savings in capacity costs realized by rendering the interruptible service.

---

[4] Ibid. pp. 179-80.

CHAPTER 2

COSTING CONSIDERATIONS FOR INTERRUPTIBLE SERVICE

Before considering the various issues involved in costing interruptible service, a definition of interruptible service, as used within this report, needs to be presented. Some utilities distinguish between "interruptible" service and "curtailable" service, with the former meaning shutoff of all of a customer's load and the latter meaning shutoff of only a portion of a customer's load, the remaining load being firm or noncurtailable. In this report, interruptible service is defined as that service offered by an electric utility that allows all or any portion of a customer's load to be shutoff or interrupted at the discretion of the utility, whether or not an advance notice is required to be given by the utility. This definition, thus, includes both "interruptible" and "curtailable" service.

The current trend in electric utility regulation is to have prices more accurately reflect the actual costs of providing service to each customer and customer class than may have been the case in the past. This process aids in eliminating cross-subsidies among customers and helps assure that each customer pays a price for his electric service that accurately reflects the costs of providing that service. That is, this process contributes to the achievement of economic efficiency.

Basing prices for electric service accurately upon the costs of providing that service is a difficult endeavor due to the joint-cost nature of many of the costs incurred in providing service. A large generating unit, for example, may cost hundreds of millions of dollars to build and generate hundreds of millions of kilowatt-hours of electricity over a single year. This generating unit would likely provide electricity to various types of customers (industrial, commercial, residential, farm, street lighting), and for various types of service (high voltage, low voltage, firm, interruptible, irrigation). Any method for determining which portion of the total costs of service are caused by which type of customer and which type of service is a difficult undertaking, necessarily involving some degree of judgment. This is especially true in costing and pricing interruptible service.

It is generally agreed that prices for interruptible service (for any service) should accurately reflect the costs of that service. It is also generally agreed that the costs, and therefore the prices, of that service should be less than those for firm service. This is due to the fact that an interruptible customer has a lower degree of service reliability than does a firm customer. That is, a firm customer receives electricity on demand during all hours of the day and year, both peak and off-peak. An interruptible customer receives the same service except that his demand may be interrupted (either totally or partially) by the utility at its discretion, usually when the utility's system demand approaches a peak condition.

Since the utility builds its system to meet the peak demand, many facilities on that system are used primarily to serve the peak demand. If an interruptible customer's load is reduced (either partially or totally) during peak conditions, then that customer has less responsibility for the costs incurred by the utility in supplying electricity to meet peak demands. By reducing peak demand through service interruptions below what it would otherwise be, the utility is likely to achieve cost reductions through reduced expenditure on plant and equipment and fuel cost savings, since peaking plants are less fuel efficient than other types of generating plants. These costs savings should be reflected in the rates (prices) charged for interruptible service. The problem here is to determine what level of cost responsibility is associated with interruptible service. One way of aproaching this problem is to determine the cost savings accruing to the utility as a result of offering interruptible service. Rates for this service then, would be reduced below those for firm service based upon those cost savings.

Value-of-Service Implications

Although rates for interruptible service should be based on the costs of that service, value-of-service implications arise within the costing procedure. Any product or service supplied to a customer has both a cost of production to the company and a value to the customer. This value is the maximum amount that the customer is willing to pay based upon the usefulness of the product. The actual price charged will be somewhere between the product's cost and its value.

Since interruptible service is at a lower level of reliability than is firm service, it is of a lower value to the customer. Economic efficiency requires that this value of service be considered when establishing interruptible rates; otherwise, the customer may be worse off than if he were to receive firm service. That is, the reduction in value of interruptible service as compared to firm service may be greater than the cost reduction to the utility. Rates based on these costs may be higher than the customer is willing to pay. A customer required to take service on an interruptible rate may suffer a loss if the price he pays is greater than the value of that service to him. A way of avoiding this situation is to make customer acceptance of interruptible service voluntary. Then only those customers that can achieve <u>real</u> cost savings will subscribe to the service.[1] A complication here is that few, if any, customers may subscribe to the service on a voluntary basis. In this case, the utility would realize little or no cost savings because customers are willing to pay the cost of firm electric service.

Value-of-service issues arise in another context with regard to interruptible service. A utility may offer this service to large

---

[1]For a discussion of the relation between value and cost of service for load management techniques, see, for example, Sanford V. Berg, Gainesville, Fla.: <u>Benefit Cost Analysis for Load Management</u>, Public Utility Research Center, University of Florida, September 9, 1980).

industrial customers with a rate discount based on value rather than cost of service. This situation may result in subsidization of large interruptible customer by other, firm service customers if interruptible rates are below the cost of this service. The regulatory commission wanting to assure that interruptible rates are based on costs of service would check that the proposed interruptions actually take place. Otherwise, interruptible customers may receive greater service reliability than they are paying for with the difference made up through charges to other customers.

The Threshold Problem

As already noted, one method of determining the cost of interruptible service is to provide a discount on firm service rates equal to the cost savings accruing to the utility as a consequence of providing the service. These cost savings are equal to the avoided cost of that plant and equipment (including fuel costs) that would otherwise need to be built to serve the total demand on the system (total demand equals firm demand plus interruptible demand). Indeed, this is the approach usually taken by utility companies and commissions as indicated by the results of a survey presented in the following chapter.

For example, an electric utility may be able to interrupt 200 megawatts (MW) of system demand during peakhours and thus avoid the costs of constructing one or more plants and their associated fuel costs that would otherwise be needed to supply this demand. The costs avoided, then, would be used as a basis for computing the reduction in rates to interruptible service below that of firm service. However, if 200 MW is the minimum amount of generating capacity required to be interrupted before a utility realizes any significant cost savings, the service may not be offered at all if the utility cannot find customers with at least that amount of load capable of being interrupted. If, for example, customers with a total of only 150 MW of interruptible load are willing to subscribe to the service, the utility may not offer the service. On the other hand, if customers totaling 300 MW of load are willing to subscribe to the service but capacity savings accrue in 200 MW intervals, how is the utility to decide which of those customers receive the service and which do not? If the company offers the service on a first-come-first-served basis and closes the rate after the 200 MW threshold is reached, it may forgo additional capacity savings in the future when the need to expand capacity to meet growth in demand again arises.

In practice, a smaller interruptible load, of 50 MW for example, may be insufficient to allow cancellation of a planned plant, but it may be sufficient to allow delay in bringing the plant on-line. This may result in cost savings, or "avoidable" costs to the utility. Nevertheless, some threshold interruptible load is needed to allow such savings.

This problem is a difficult one for utilities and commissions to deal with. One answer may be to base the cost per kilowatt of interruptible capacity on some type of peak responsibility method. Since interruptible customers are less responsible for system peak demand than firm customers, due to the fact that they are interrupted during peakhours, a peak responsibility method could allocate a lower portion of demand-related costs to those customers experiencing demand interruption. This method will be taken up in chapter 4 of this report.

CHAPTER 3

CURRENT APPLICATIONS OF INTERRUPTIBLE RATES

Interruptible rates are currently in force in various jurisdictions throughout the United States. A study of the benefits and costs of load management options, including interruptible service, for Gulf States Utilities was performed by ICF Incorporated.[1] This study also includes the results of a survey of utilities offering interruptible electric service for industrial and large power customers.

With regard to interruptible rates, the analysis presented credits for interruptible service (that is, reductions in rates below those charged for firm service) based upon capacity savings resulting from eliminating rather than meeting load during peak loss of load probability (LOLP) hours. Estimated credits for Gulf States Utilities for 1980 range from $13.43 per kilowatt (kW) for interruptions of 5 hours duration and totaling 500 hours per year, to $27 per kW for longer service interruptions.[2] The study found that essentially all savings are obtained from interruptions of up to 8 to 10 hours duration during peak hours, although some additional savings occur from more frequent interruptions, that is, more total hours per year.

In summarizing its findings, ICF reported that interruptible rates could be offered on a voluntary basis to any customer willing to subscribe and that actual interruptions should occur up to scheduled limits whenever advantageous to the utility, either when needed to avoid emergency energy purchases or because marginal-running costs are greater than recovered revenues at that time. ICF found that essentially all the benefits of load

---

[1]ICF Incorporated, Benefits and Costs of Selected Load Management Options for Gulf States Utilities, (Washington, D.C.: September 3, 1980).

[2]Ibid., p. 43 and table 5.

management, including interruptible service, stem from savings in bulk power supply costs acheived through shifts in the system load pattern. Offsetting these savings are the costs incurred in implementation, including metering and control equipment costs, and costs incurred by customers such as larger hot water tanks, timers, interlocks, and insulation, and reduction in the value of service to customers.[3] For some load management options, such as cycling of air conditioners or space heaters, the study found that the loss in the value of service was proportional to the intensity of cycling (length of interruption). This loss in value of service is illustrated by the magnitude of the price differential required to induce customers to subscribe to the service.

The study found that generation and transmission capacity savings resulting from load management are of two types. Immediate savings result from dispatching existing units to meet an altered load curve. These are principally energy cost savings resulting from lessened use of peaking units and are net of any increased generation during off-peak periods. Long-run savings are possible if load management eliminates or defers generating units or transmission lines that would otherwise be added to the system. Since various levels of costs or savings can be realized under conditions of changing system reliability, ICF states that it is important that unit deferrals be calculated on the basis of constant system reliability.[4]

Results of a Survey of Interruptible Rates

ICF performed a survey of utilities offering interruptible electric service for industrial and large power uses. The survey focuses on industrial customers, as ICF found that only four of the companies surveyed offered interruptible service to commercial or public sector customers. The utilities were surveyed selectively, based upon a previous survey of

---

[3]Ibid., pp. 4-6.

[4]Ibid., p. 10.

load management rates conducted by ICF. Fifty-three utilities in 24 states were identified as having special tariffs or schedule riders for customers with interruptible loads.[5]

The survey found that most utilities specify a minimum kilowatt load to be interrupted and/or limit the number of customers eligible for the service. The minimum curtailable load (that is, customer interruptible and firm power combined) of utilities surveyed ranged from 100 kW to 50,000 kW. In most cases, the utility required at least 1 megawatt (MW) of curtailable load for each customer. The factors used to determine this minimum level are associated with cost-effectiveness and were reported to include the type of metering necessary to monitor performance, the investment and operation and maintenance cost of such metering, other service-related and equipment costs, and the effects of rate incentives on utility revenues. Interruptible service may not be cost-effective to the utility if the load available for interruption is below some minimum level. If, however, demand meters or other equipment are in place for billing purposes, interruptible service to relatively small customers may be cost-effective.

The survey results show that the high levels of minimum curtailable load (as defined above) required by some utilities result from the utilities desire to limit the sum of curtailable load to an amount deemed appropriate for the system. In these situations, it was reported that utilities may close the rate to new customers. One utility in the survey reported that it believed it had a sufficient amount of interruptible load, given present system load and capability conditions, and that it is not seeking additional interruptible customers. This is an indication of the "threshold" problem referred to earlier, in that capacity savings may occur in increments. Once the minimum increment is reached, no additional savings may be achieved until the next increment of avoided capacity is reached. Several utilities in the survey indicated that interruptible service is closed to new customers at the point where additions to

---

[5]Ibid., appendix B.

interruptible capacity may begin to affect the utilities resale contracts and load-drop ration adversely.

Of the 53 utilities included in the survey results, about 30 percent designate minimum interruptible customer loads of under 3,000 kW, about 20 percent designate minimum interruptible loads between 3,000 kW and 9,999 kW, and about 30 percent between 10,000 kW and 50,000 kW. Approximately 5 percent of the utilities do not specify a minimum interruptible customer load.

Other qualifications for interruptible service commonly specified in the survey include a minimum transmission voltage level at which service is taken, the requirement that service be separately metered and taken from one delivery point, and a requirement of notice of service interruption and penalty if the customer does not comply.

Generally, if the utility controls the service interruption, the length of time of advance notice is less than if the customer controls the interruption. Also, there is no penalty for noncompliance because the utility controls the load. All utilities included in the survey attempt to notify customers of a pending service interruption. In some cases, this is a requirement of the service, in others it is simply a courtesy. The amount of advance notification varies from 10 minutes to 24 hours. When the customer has control over the interruptible load, the tariff usually specifies a penalty for noncompliance. Examples of such penalties include a charge per kW for each kW of demand used over firm power, often including the elimination of accumulated credits from earlier interruptions; a reduction in the amount of contracted interruptible power to the least amount actually curtailed; and a discontinuance of interruptible service to the customer.

The survey results show that the number of customers receiving interruptible electric service is relatively small. Several utilities included in the survey have no customers on their interruptible rates, while others have as many as 180 customers subscribing to the service. Factors reported as affecting the acceptability of interruptible service include customers' unwillingness to identify the amount of their total load that could be curtailable, high daily load factors that inhibit load shifting, small potential financial benefits since electricity costs are a small part of total costs, customers with industrial processes that fluctuate with economic conditions and with reluctance to enter into long-term contracts for interruptible service, equipment or processes that are not adaptable to interruption, and concern that penalty provisions for noncompliance are too costly.

Manufacturing companies capable of interrupting steps in an industrial process and companies with high-energy costs relative to labor costs were reported as most frequent subscribers to interruptible service. The most common interruptible processes, according to the survey, are arc and alloy furnaces, steel mills, mineral extraction, processing, and crushing (including coal), rolling mills, induction heating applications, paper products production, and some chemical processes including production of chlorine, caustic soda, abrasives, carbide, graphite, and industrial gases. Testing facilities such as wind tunnels, product-testing facilities, and government and military research labs were also identified as potential customers for interruptible service.

Interruptible Rate Investigations

The NRRI has collected information on state public utility commission investigations of interruptilbe electric service. This information was acquired through the NRRI Regulatory Information Exchange Program.[6] Summaries of the results of several of these investigations are provided in the following paragraphs. Copies of representative interruptible rate tariffs are provided in the appendix to this report. The information supplied in the following sections is the most recently available to the

---

[6]The Regulatory Information Exchange Program is an ongoing program designed to disseminate information regarding state public utility commission regulatory activities. <u>See Regulatory Information Exchange Current Awareness Bulletin Number 4</u>, prepared by Myra B. Adelman (Columbus, Ohio: The National Regulatory Research Institute, October 1980).

NRRI. More detailed information may be obtained from staff members of the particular commissions.

Michigan Public Service Commission

The Michigan commission has approved interruptible electric service for several utilities within its jurisdiction. Consumers Power Company has introduced a Primary Interruptible Service Rate for retail customers with curtailable load of 5,000 kW or greater.[7] The purpose of the rate, according to the company, is to promote more efficient use of available energy supply.

The rate is based on 600 hours per year of service interruption, not to exceed 14 hours per day. The rate is identical to the utility's Primary Service Rate D, except that the capacity charge is approximately one-half that of Rate D. The 600 hours of interruption represent about one-half of the utility's total annual on-peak hours.

A customer applying for the rate is limited to 100,000 kW of capacity (demand), and the total capacity of all customers served under the rate is limited to 200,000 kW. The rate is not available for auxiliary or standby service, street lighting, or for resale purposes.

The utility stated its belief that conversion of the stated amount of firm service to interruptible status would increase its load-shedding ability, lessen purchases of emergency power due to outages, and improve the supply reliability of firm power service.[8] Benefits to other customers were reported to include increased system reliability, reduced environmental impact, and energy savings. The company expected that approximately 30 of its present primary service customers, with suitable revisions to their internal wiring, would qualify for the rate.

---

[7]Michigan Public Service Commission, Case No. U-5305, Approval of Application of Consumers Power Company to Establish a Primary Interruptible Service Rate, (Lansing, Mich.: March 7, 1977).

[8]Ibid., p. 2.

North Carolina Utilities Commission

The North Carolina Commission held a generic investigation of cost-based rates, load management, and conservation oriented end-use activities for jurisdictional electric utilities (Docket No. M-100 SUB 78). In its order concerning that investigation, the commission found that initial studies indicate that under certain carefully planned programs, the long-term savings in generation plant investment resulting from physical load management more than offset the cost of control equipment required to implement the programs.[9] These studies also indicate that with proper planning, physical load control will result in little or no adverse effect on individual customer's life-style or operations.

The commission also stated that there is little information currently available with which to precisely estimate customer acceptance rates, changes in consumption patterns, effects on utility system operations, and resulting net benefits. Consequently, the commission decided that gradual implementation of physical load management programs by electric utilities is a prudent method for gathering data on which to base future decisions.

The commission found that the ability of electric utilities to level daily and annual load curves and to reduce peak demands offers the potential for reducing reliance on generating units with high-fuel costs as well as lowering capital requirements. In this regard, reduced growth in peak demands allows a substitution of investment in load control devices for investment in new generating equipment.

Three different load control programs for industrial customers were offered under the proposed program. These are a rate offering a 4-hour per day service interruption with a maximum of 200 hours of curtailment per

---

[9]North Carolina Utilities Commission, Docket No. M-100 SUB 78, Commission Order, dated June 6, 1979.

year, an 8-hour per day interruption period with a maximum of 400 hours per year, and a 13-hour per day interruption with a 600-hour per year maximum interruption.

A second program of utility control of residential water heating was proposed. This program would allow the utility to use radio control signals to interrupt water-heating service for a maximum of four hours per day in exchange for a flat monthly discount on the customers' bill.

Evidence presented during the generic proceeding showed that residential customers with water heater storage capacities of 66 gallons or more would not experience an uncomfortable drop in water temperature under the proposed load management program. Evidence presented also indicated that a monthly credit of about $1.50 on each customer's bill would induce residential customers to accept this program.

A study of the cost-effectiveness of interruptible rates for two large North Carolina electric utilities indicated that possible cost savings to the utilities varied widely. The study was based on the present value of investment in load management equipment as opposed to investment in generating equipment. The estimated monthly savings for industrial customers per kW of interrupted demand, and for residential water-heating customers per month are shown in table 3-1. The estimated monthly savings for industrial customers range from $0.83 per kW to $11.59 per kW. For electric water heating, the estimated savings range from $0.26 per customer per month to $4.04 per customer per month.

From these estimates, a set of proposed discounts for interruptible service for industrial and residental water-heating customers was developed for both companies. These discounts are presented in table 3-2.

TABLE 3-1

ESTIMATED MONTHLY SAVINGS OF INDUSTRIAL CUSTOMERS
AND RESIDENTAL WATER-HEATING CUSTOMERS FOR
DUKE POWER COMPANY AND CAROLINA POWER & LIGHT

Industrial	Duke Power Company (kW/month)	Carolina Power & Light (kW/month)
4-hour interruption	$0.83 to $11.59	$2.08 to $4.22
8-hour interruption	$2.20 to $7.36	$2.73 to $7.76
13-hour interruption (12-hour for Carolina P&L)	$2.21 to $7.41	$3.74 to $9.24
Residential		
Electric water heating	$0.36 to $4.04/customer/month to $0.26 to $3.46/customer/month	

Source: North Carolina Utilities Commission, Docket No. M-100 SUB 78, Commission Order, June 1, 1979, p. 15

TABLE 3-2

PROPOSED DISCOUNTS FOR INTERRUPTIBLE SERVICE FOR
INDUSTRIAL AND RESIDENTIAL CUSTOMERS OF DUKE POWER COMPANY
AND CAROLINA POWER & LIGHT

Control Program	Monthly Discount
Industrial	
4-hour interruption	$1.75/kW
8-hour interruption	$2.50/kW
13-hour interruption	$3.00/kW
Residential	
Electric water heater control	$1.50/customer

Source: North Carolina Utilities Commission, Docket No. M-100 SUB 78, Commission Order, June 1, 1979, p. 16

Pennsylvania Public Utility Commission

The Pennsylvania commission held a generic rate structure investigation of alternative rate structures and rate design techniques (including interruptible electric service) for jurisdictional electric utilities. The Final Report issued by the commission contained the following conclusions with regard to interruptible service:[10]

1. Duquesne Light Company and West Penn Power Company offer interruptible rates for large industrial customers. These rate schedules require interruption of the total customer load. Experience has shown that this rate form has limited applicability and is best suited to an industry that is energy intensive. At the present time, West Penn Power has three customers on its interruptible rate and Duquesne Light has one.
2. The amount of reimbursement to customers resulting from curtailment of electric service may not offer sufficient economic incentive for customers to take advantage of the rate.
3. Ninety-two percent of all residential electric water heaters in the Philadelphia Electric Company's service territory utilize a controlled water-heating rate. Metropolitan Edison Company Pennsylvania Electric Company eliminated off-peak water-heating service during the 1940s and 1950s for the following reasons:

   a. During the period of declining unit costs of service, it did not seem justifiable to incur the expense of two meters and associated operating and maintenance expense.
   b. Difficulty in keeping time clocks accurate.
   c. Growth in other loads made water heating a less significant part of total load.
   d. Absence of sufficient off-peak hours due to increasing system load factor.

---

[10] The Pennsylvania Public Utility Commission, Final Report: Generic Rate Structure Investigation, (Harrisburg, Pa.: December 1977).

e. Increasing number of customer complaints of insufficient hot water due to increased saturation of the automatic washer.

4. Philadelphia Electric Company conducted a study to investigate the feasibility of offering interruptible service as a means of improving its load factor. The study considered the entire Pennsylvania-New Jersey-Maryland (PJM) Interchange system in 1978, of which Philadelphia Electric is a member. A system reserve requirement of 20 percent was assumed. It was also assumed that curtailment would be implemented whenever an impending capacity deficiency situation occurred (defined as when operating reserves would be less than 5 percent). The study concluded the following.

   a. If 10 percent of PJM annual peakload were interruptible, reserve margin could be reduced from 20 percent to 8 percent.
   b. Under these conditions, annual capacity factor would increase from 48 percent to 54 percent.
   c. Energy output from current capacity would also increase by 12 percent.
   d. These benefits would be realized if interruptible load were available for the entire summer season--mid-May to the end of September. If restricted to only the annual peak week, the reserve savings would be reduced by half.

Colorado Electric Utilities

As a part of its investigation into assessing the reasonablenss of interruptible rates, the NRRI sent a letter of inquiry to several Colorado electric utilities requesting information on interruptible rates. The electric utilities to which the inquiry was addressed are the Public Service Company of Colorado (PSCO), city of Colorado Springs, Department of Public Utilities (Colorado Springs), and Colorado-Ute Electric Association (Colorado-Ute). These utilities were selected, upon consultation with staff members of the Colorado PUC, because they represent a cross-section of the electric utility industry in Colorado. That is, they represent a mixture of types of ownership and service territory. PSCO represents a privately owned electric utility that serves most of the major metropolitan areas of Colorado as well as surrounding rural areas. Colorado Springs is a municipally owned utility serving primarily the city in which it is located. Colorado-Ute is a cooperatively owned utility selling electric power on a wholesale basis to its member (and other) companies. The service territory of Colorado-Ute is primarily rural in nature but includes various small cities and towns throughout the state and includes most of Colorado's ski resorts.

The letter of inquiry sent to each of these electric utilities asked the companies to supply the following information with regard to interruptible rates:

1. A copy of the interruptible rate tariffs or contracts currently in force.
2. Explain the rationale for charges contained in the interruptible rates:
    (a) Is the rate based on cost of service?
    (b) If so, how was the cost calculated (customer, energy, and demand components)?
    (c) If not, what is the basis for charges in the tariff or contract?
3. Occasions during the last five years during which customers load(s) was interrupted.
    (a) In what amount (kW) and for how long (hours) were these interruptions?
    (b) If no interruptions have been made, why not?
4. Provide results of customer surveys, if any, on customer interest in an interruptible service plan.
5. Provide estimates, if any exist, of magnitude of potential interruptible customer load for the current year and for each of the next 10 years by customer class.
6. Provide a list of industrial customers in your service area and the industrial customers' SIC code if available.

In replying to the inquiry, Colorado-Ute stated that it had no interruptible tariffs in effect and did not supply information on the remaining parts of the inquiry. Colorado Springs also stated that it had no interruptible tariffs in effect and that the other information requested was not available. PSCO replied that it had one interruptible tariff in force, that being a special contract between PSCO and CF&I Steel Corporation (CF&I). The contract requires PSCO to provide firm service and "controlled service" to CF&I, with deliveries of controlled service subject to curtailment by PSCO for emergency purposes. These emergency purposes include, but are not limited to, the following:[11]

> 1. As necessary to ensure stability on Service Company's [PSCO] electric system or any system directly or indirectly interconnected therewith.
>
> 2. As required because of the loss of major generating resources or transmission lines associated with the supply of power to Firm Service customers of Service Company, including curtailment for any of the causes contemplated in Article XV hereof.

With regard to the rationale for the various cost components charged within the interruptible tariff, PSCO provided information that stated the following:

> CF&I Steel Corporation's contract with the Company [PSCO] defines "controlled service" as "the power and energy supplied to the electrode circuits of the electric arc furnaces." The contract provides that "deliveries of controlled service may be subject to curtailment by service company for emergency purposes. . . ." The contract does not require CF&I Steel Corporation to cease receiving its "controlled service" on a regular and routine basis during times when the Company's electric system is experiencing a peakload. Consequently, the "controlled service" to CF&I Corporation is not an interruptible type of service in the context that it is subject to interruption on a regular daily basis at times of the Company's maximum system loads. . . . [The Company] would define

---

[11] Power Purchase Agreement, Document Department No. 50913, Public Service Company of Colorado (Denver, Colorado, May 1971).

"controlled service" as something between firm service and interruptible service.

The company also stated that the interruptible rate for CF&I was designed "on a fully cost tracking basis" but did not provide any details as to how that was accomplished.

With regard to the number and length of service interruptions occasioned through the interruptible rate with CF&I, PSCO stated that for the 12-month period ending March 1975, CF&I's controlled service was curtailed 2.9 percent of the time; for the 12-month period ending November 1976, CF&I was curtailed 0.32 percent of the time; for the 12 months ending December 1977, curtailment equaled 0.63 percent of the test year hours; for the 12-month period ending December 1978, CF&I was curtailed 4.67 percent of the total test year hours. For the years 1979 and 1980, the percentage of hours interrupted equaled 3.06 percent and 3.14 percent, respectively. The company provided a copy of its interruptible rate tariff with CF&I but, other than the information outlined above, did not specify how the interruptible service rate followed the costs of providing this service.

Finally, with respect to inquiries 4, 5, and 6, PSCO stated that no surveys of customer interest in interruptible service have been conducted, no estimates of the magnitude of potential interruptible customer load have been made, and although the company serves some 79,000 commercial and industrial customers, it does not have available a list of these customers' SIC codes.

The above information points out the apparent lack of interest of Colorado electric utilities in providing interruptible service to their customers. Perhaps this is why the Colorado PUC has requested the NRRI to analyze costing principles as they relate to interruptible service. The responses received from the three Colorado utilities are also a major reason for the generalized treatment of interruptible rate issues contained in this report, rather than a more Colorado specific analysis.

CHAPTER 4

ASSESSING INTERRUPTIBLE RATES

Given the assumptions that rates for electric utility service should be based on the costs of that service, and that the cost--and therefore the price--of interruptible service is below that of firm service due to the lower level of service reliability, a method for assessing the reasonableness of interruptible rates should determine whether or not those rates adequately reflect actual costs. Since the causal relationship between demand for interruptible service and the utility system costs occasioned by that demand are not well documented, several methods of assessing the reasonableness of interruptible rates are presented.

One such method is to determine those utility costs that are avoidable by offering certain customers interruptible rather than firm service. These costs are equal to the annualized present value of capacity cost savings in generating plant and possibly in transmission plant as well, net of any necessary additional investment in metering or other load management equipment. These costs can be estimated in several ways (see below). Once measured, these costs can be used to discount or reduce the price of interruptible service below that for firm service. This rate reduction would also be based on the amount of customer load actually interrupted and the length of service interruptions on both a daily and annual basis.

Most utilities employ a system expansion model to estimate the total amount and optimal mix of generating, transmission, and distribution facilities required to meet anticipated growth in system load. Based on current system capacity and estimated system load growth, these models determine the least cost method of capacity expansion required to meet forecasted load. The output of these models includes a schedule of plant additions and the annualized present value of total capital investment and operating costs for meeting load over the system expansion plan.

By assuming two load growth options, one without the inclusion of interruptible customers (that is, assuming all customers are firm customers), and one with the inclusion of interruptible customers, the utility can determine the cost savings (if any) resulting from interruptible service by determining the difference in the annualized present value costs of these two options. This is the "avoided" cost associated with interruptible service. Dividing the total avoided cost by the difference in capacity requirements (in kilowatts) will result in a dollar per kilowatt capacity credit that can be applied to the rate charged for interruptible service.

This method estimates the marginal cost of capacity "avoided" through the use of interruptible rates. If rate schedules are based on average costs, an estimate of avoidable costs based on average capacity costs may be more appropriate. In any case, rates for interruptible service should not be reduced below the utility's short-run variable (running) costs.

The method just outlined is a lengthy and costly procedure requiring the use of a computer program and large amount of data. Although this method produces accurate results, it may not be appropriate for use, especially if the anticipated number of interruptible customers on a utility's system is small.

A less complicated and less expensive, but also less accurate, method of estimating the avoided cost of interruptible service is the following.

1. Estimate the amount of generating capacity (in kilowatts) that can be either "avoided" or deferred within the utility's current expansion plan as a result of providing interruptible service. This amount can be derived from the utility's system expansion model, from a survey of current and anticipated interruptible

customer load on the system, or from the utility's estimate of the total amount of system load currently capable of being interrupted while still maintaining system reliability and appropriate loss-load relationships.

2. Estimate the annualized cost of building and operating the generating plants necessary to supply this load based on either marginal costs or average costs. This estimate can be provided from the utility's system expansion model, from a computer program such as the MARGINALCOST program that estimates the annualized cost of moving generating plant foreward or backward within a utility's current expansion plan,[1] from industry or utility data on the current cost of building and operating generating capacity, and from utility historical data on the actual cost of generating plant currently on the system.

If the cost of necessary metering equipment and other load management equipment is to be borne by all of the utility's customers, as suggested by the Colorado commission, the cost estimate referred to in (2) would be net of these costs.

Once the amount of interruptible load and its annualized cost in $/kW is estimated, a capacity credit or reduction in rates for interruptible service below that for firm service can be calculated in the following manner.

1. Define the peak period for the utility system on a daily and annual basis. This is the total number of hours when the system approaches a peak condition that would require curtailment of interruptible load. This period may be defined as those times when the revenue derived from supplying interruptible load is

---

[1]For a more detailed explanation of the method for determining the cost of capacity expansion using either the utility's system expansion model or the MARGINALCOST program see Roger K. McElroy, et al., Marginal Cost Ratemaking for Cogeneration, Interruptible, and Back-up Service, (Columbus, Ohio: The National Regulatory Research Institute, February 1981).

less than the cost of that service, when the system loss of load probability reaches some predetermined peak condition, when the utility is required to purchase power from other utilities to meet its peakload, when all incremental load on the system is being supplied by peaking capacity, when the net to last peaking unit is placed on-line, or some other appropriate measure.

2. Base the annual capacity credit for interruptible service on the customer's interruptible load and on the length of this service interruption expressed as a percentage of the total peak period. This method translates into the following relationship:

$$\text{Annual capacity credit} = \left(\frac{\text{customer interruptible load (kW)}}{\text{total interruptible load (kW)}}\right) \times \left(\frac{\text{length of customer interruption (hours)}}{\text{total length of peak period (hours)}}\right) \times \begin{array}{c}\text{annualized cost of} \\ \text{avoided capacity} \\ (\$/\text{kW})\end{array}$$

For example:

given,

Total interruptible load = 50,000 kW
total length of peak period = 400 hours
customer interruptible load = 5,000 kW
length of customer interruption = 200 hours
annualized cost of avoided capacity = \$50/kW

then,

$$\text{Annual capacity credit} = \frac{5{,}000\text{ kW}}{50{,}000\text{ kW}} \times \frac{200\text{ hours}}{400\text{ hours}} \times \$50/\text{kW} =$$

(10%) x (50%) x \$50/kW = \$2.50/kW

the monthly capacity credit is derived by dividing the annual capacity credit by 12.

For residential water-heating customers or other customers with small interruptible loads, the customer interruptible load and the length of customer interruption would be that for the entire class of interruptible customers rather than for an individual customer.

The Cost Savings and Cost Plus Margin Approaches to Interruptible Rates

This section presents two alternative methods of pricing interruptible service recommended by Task Force 4 of the Electric Utility Rate Design Study as acceptable methods for setting interruptible rates.[2] The "cost savings" and "cost plus margin" approaches are described and examined.

The Cost Savings Approach

This technique is similar to the avoided cost method just described and can be used to yield an estimate of the utility's ability to avoid building new generation capacity or avoid making peak period power purchases. These avoided costs are then remitted to interruptible service customers as a credit per kW of their interruptible load or as a reduction in the demand charge to interruptible customers.

To estimate these avoided generation capacity costs, the utility first calculates the average number of hours that a baseload, intermediate load, or peaker unit is in operation during the utility's peak period. The utility also would collect information on the total number of hours of power purchases it makes during the peak period. Table 4-1 summarizes the average peak period hours of service and annual cost per kW of the alternative means of providing for the peakload.

---

[2]Task Force 4, Critical Issues in Costing Approaches for Time-differentiated Rates, prepared for the Electric Utility Rate Design Study, Electric Power Research Institute (Palo Alto, Calif.: January 12, 1978), pp. 79-87.

TABLE 4-1

THE COST AND PEAK PERIOD USAGE OF GENERATION CAPACITY SOURCES

Generation Capacity Source	Average Annual Hours of Peak Period Use	Annual Marginal Cost ($/kW)
Baseload	4,300	62.57
Intermediate Load	3,000	53.86
Peaker Load	1,000	30.91
Peak Period Purchases	300	12

Source: Electric Utility Rate Design Study, op. cit., p. 81, with calculations based on a sample utility's expansion plan and NERA's VEPCO study, June 7, 1977

According to this avoided capacity cost approach, interruptible customers are allowed a credit per kW of their interruptible load based on the system's generating capacity savings. The size of this credit per kW of interruptible load depends upon the length of interruption that customers are willing to accept. If an interruptible customer is willing to permit 300 hours of interruption per year, then that customer is presumed to be allowing the utility to avoid peak period power purchases that would cost $12/kW of load. Hence, interruptible customers that are willing to risk 300 hours per year of interruption could receive a $12 credit per kW of interruptible load. An interruptible customer group willing to undergo up to 1,000 hours per year of interruption may allow the utility to avoid the construction of a peaker. This interruptible customer group would then receive a credit per kW of interruptible load of $30.91 based on the annual generation cost savings associated with not building a peaker. Extending this analysis implies that interruptible customers willing to risk 3,000 or 4,300 hours of interruption per year would receive credits of $53.86/kW and $62.57/kW respectively.

This avoided cost approach would also allow the customer charge to reflect the special metering and control device cost associated with interruptible service. In addition, an attempt may be made to measure energy and transmission savings, although savings in these areas are likely to be small and significantly more difficult to quantify than generating facilities saving.

There are several important problems associated with the avoided cost approach to pricing interruptible power. These include the influence that this rate design method has on minimum service reliability and thus on the acceptability of this service to potential industrial customers, and the shortcomings of this particular method's ability to measure avoided costs accurately.

In the example provided by the Task Force 4, just described, potential interruptible customers are offered credits of $12.00, $30.91, $53.86, or $62.57 per kW of interruptible load provided that they agree to risk interruptions of 300, 1,000, 3,000, or 4,300 hours per year, respectively. If, for example, the utility has many industrial customers that would be willing to risk 30 hours of interruption per year, this group is effectively foreclosed from participating in an interruptible service option. The point to note is that the minimum level of service reliability offered by a utility to its potential interruptible customers should reflect their particular reliability needs. A crucial problem with the avoided generation capacity cost savings method is that the reliability levels (that is, the maximum annual hours of interruption) are often chosen to simplify the avoided capacity cost calculations and not to provide a viable reliability option for customers (a clear example of the tail wagging the dog).

Requiring interruptible customers to agree to risk hundreds of hours of interruptions per year has several detrimental effects. Many prime industrial candidates for interruptible service may be discouraged from ever using interruptible service if the reliability of this service is extremely low. According to a recently published survey of industrial interruptible service, the Michigan utilities that offer interruptible service with 500 and 600 hours of maximum interruption per year have yet to attract a customer.[3]

Another problem with specifying many hundreds of hours as the maximum interruption per year is that it often leaves the actual reliability of this service as an unknown. Interruptible customers may expect that given the reserve margin of their utility the hours of interruption per year will be considerably less than the maximum allowed. This suggests that if and when the utility decides to avoid construction of generation facilities based on the available interruptible load, the reliability of this service is likely to deteriorate. Lower than normal, but relatively stable levels of reliability, seem more appropriate in meeting the needs of interruptible customers. One approach would be to specify a realistic maximum number of hours of interruption per year for interruptible service and have the utility treat this reliability level as a target in planning its expansion of generating capacity.

A second major criticism of the cost savings (that is, plant-not-built) approach to interruptible service is that it does not estimate the actual cost of providing interruptible service, but rather it estimates the reduced cost associated with not providing service at certain times. It is not clear why an industrial customer that closes down and ceases all electricity purchases could not claim an avoided cost payment from the utility with equal persuasiveness.

In addition, the procedure of basing the per kW credit for interruptible service customers on the marginal generation cost of plants-not-constructed implicitly treats regular service as if it were nonexistent. Generation faciliies acting as a reserve for regular service customers can at the same time be meeting the load of interruptible service customers. Thus, basing the capacity credit on the marginal cost of avoided capacity

---

[3]ICF Incorporated, op. cit., Industrial Interruptible Service Table.

may tend to overestimate the savings to the utility. Under no circumstances should the rates for interruptible service be priced below the utility's running costs (fuel and variable operation and maintenance costs).

The failure of the plant-not-constructed cost savings method to recognize the ability of generation reserves leads to a threshold problem, which is based on the assumption that the interrupted load of interruptible service must reach a certain magnitude before significant generation capacity savings occur. The interdependence of the generation capacity needs of both regular and interruptible service is not recognized by the cost savings technique.

Cost Plus Margin Approach

This approach assumes that the peak period load of interruptible service customers is provided for strictly from the idle reserve capacity needed to provide the reliability required for regular service. Hence, interruptible customers in a sense share responsibility with regular service customers for the cost of these generating facilities.

Interruptible service customers are then charged for fuel and operating and maintenance costs they impose on the system. They are also charged for the fixed transmission and distribution costs as well as for customer costs that include any special metering or control device costs associated with interruptible service.

In addition, the interruptible customer pays a portion of the cost of the capacity he shares with regular service customers. This negotiated charge is called the margin, and it reflects the benefit received by regular service customers able to share the cost of supporting their reserve margin with interruptible customers. The negotiated margin determines the extent to which interruptible service customers relieve regular service customers of their generating reserve capacity costs.

The cost plus margin method is not without its share of problems. The negotiation between the industrial interruptible customer and the utility to determine the share of the generating reserve costs to be paid by interruptible customers amounts to an essentially arbitrary allocation of generation costs among these customer classes.

Furthermore, the assertion that interruptible service customers utilize only idle generating capacity limits the expansion of interruptible service. If industrial interruptible service proves popular, then the utility must develop some means of rationing the available reserve generation capacity among interruptible customers. Often this is done by closing the availability of interruptible service to new customers. Another approach is to permit the number of interruptible service customers to expand and allow the reliability of interruptible service to fall as more and more interruptible service customers compete with each other for the use of reserve generating capacity. Instability in the reliability of service to interruptible customers is the chief drawback to this approach.

An attractive alternative to rationing interruptible service or allowing its reliability to deteriorate is to expand capacity to maintain interruptible service reliability at some target level.

The Peak Responsibility Method

Another method of acknowledging the capacity-related benefits of being able to interrupt customer load at times of system peak demand is to measure the relative contribution of the various customer classes (including interruptible customers as a separate class) to the creation of the utility's peak period. The method presented here is based on the marginal cost of capacity, although this method can also be applied using average cost. One can then determine the total annual demand-related generation charges for each customer class based on its uninterrupted load at the time of the system peak.[4] Use of this method requires that some

---

[4]This method for pricing interruptible service was developed in the NRRI report, Marginal Cost Ratemaking for Cogeneration, Interruptible, and Back-up Service, referred to earlier.

care be taken in identifying the peak period. The process involves more than simply identifying the high point on the utility's annual load curve. One must also determine that the peak period selected is a time when all possible interruptible load has been shed by the utility. Most of the time, this period will coincide with the high point on the utility's annual load curve. It can be the case, however, whether because of imprudent interruption practices, unanticipated seasonal consumption, or unexpected frequencies of forced outages, that the time of system annual peakload is not the time when all available interruptible load is being curtailed.

A convenient indicator to use for selecting the peak relevant for the calculation of the interruptible customer class capacity responsibility may be the observable pattern of actual interruptible customer class curtailment. The period of highest system demand with the highest amount of load being interrupted is most likely to be the time when the system's ability to provide power is under maximum stress. The relative contribution of interruptible customers to this maximum stress period is one measure of their relative contribution to the utility system's need to expand capacity and incur additional capacity costs.

The duration of this period for measurement of interruptible customer capacity responsibility should also be defined with care. Defining the period too narrowly could allow some momentary interruption error to provide a false indication of system stress. Defining the period too broadly, on the other hand, by the inclusion of hours with less intense demand pressure, can overestimate the relative contribution of interruptible customers to the utility's period of maximum reliability stress. Some judgment by the analyst will be required in determining the exact number of hours of this peak period. Methods for selecting the peak period, such as those outlined above, may be used for this analysis.

In order to illustrate how an interruptible capacity charge may be computed with this method, let us assume that this period of maximum stress on utility capacity has been identified and that the results of research into customer class consumption during the period are as illustrated in table 4-2. Note in column (1) that total regular service average demand during the period is 1,320,000 kilowatts, and the average noncurtailable demand of interruptible customers is 40,000 kilowatts. In this example, interruptible customers are all high-voltage, industrial users. Regular service is provided at three voltage levels: high (69 kilovolts), primary (12.5 kilovolts), and low (220/120 volts). Their respective demands during the peak are 120,000; 400,000; and 800,000 kilowatts. Let us also assume that the utility's annualized marginal cost of system generating capacity has been estimated at $63.96 per kilowatt in current dollars. Adjusting this estimate for transmission and distribution line loss by customer voltage level in column (2), we obtain $65.66/kW for high voltage (industrial), $68.39/kW for primary voltage (commercial), and $72.13/kW for low voltage (residential and small commercial).[5]

Based on a peakload concept of pricing customer class responsibility for the utility's incurrence of its cost of generating capacity, each customer class's total annual capacity charges can be obtained by multiplying its adjusted marginal cost of capacity per kilowatt (column [2]) by its consumption in kilowatts during the peak peeriod (column [1]). Results for each customer class are presented in column (3). The next step is to determine how these charges are to be collected from consumers. One must determine the time period or periods for which capacity charges apply, and one must decide whether charges will be assessed on a dollar per kilowatt basis (for demand measured on each customer's premises) or whether the charges will be based on kilowatt-hours consumed. In the first case, if time-of-use pricing is being used, one must determine peak and off-peak responsibilities for the utility's capacity costs. In the second, the number of units of expected customer class consumption (kW or kWh) must be forecasted for each period over which capacity charges will be collected, depending on the form of the rate ($/kW or ¢/kWh) for collecting each customer class's total annual capacity charges.

---

[5]For a more detailed description of this and other methods of determining marginal capacity-related costs see Roger K. McElroy et al., op. cit.

TABLE 4-2

CALCULATING MONTHLY MARGINAL COST-BASED CAPACITY CHARGES FOR CUSTOMER CLASSES BASED ON CONSUMPTION AT PEAK

Customer Classification	(1) Consumption during Peak (kW)	(2) System Marginal Cost of Capacity by Voltage Level ($/kW/yr.)	(3) Annual Charge for Capacity Based on Peak Period Consumption [(1) x (2)] ($)	(4) Average Monthly Noncoincident Peak Demand[a] (kW)	(5) Monthly Class Capacity Charge[b]
Regular Service	1,320,000	N/A	N/A	N/A	N/A
Industrial (69 KV)	120,000	65.66	7,879,200	100,000	6.566
Commercial (12.5 KV)	400,000	68.39	27,356,000	240,000	9.499
Residential (220/120 V)	800,000	72.13	57,704,000	450,000	10.686
Interruptible					
Industrial (69 KV)	40,000	65.66	2,626,400	100,000	2.189

[a]Equal to the sum of monthly class noncoincident peak demands divided by 12.

[b]This calculation does not take into account customer diversity within classes.

Source: Roger K. McElroy et al., op. cit., table 5-1, p. 64

In this illustration, we assume that time-of-use pricing is not being used and we calculated a dollar per kilowatt capacity charge.[6] We are assuming that capacity charges are assessed every month according to the reading of a demand meter for each customer. This is not the way charges are made to most customers in most circumstances, except for the company's largest consumers, but doing so here helps one to compare the levels of charges by customer class. Column (4) lists average monthly noncoincident peak demand for the year by customer class. Column (5) presents marginal cost based monthly capacity charges in dollars per kilowatt by customer class, unadjusted for class diversity factors. They are calculated by dividing the customer class total annual capacity charge by the sum of their monthly noncoincident demands (or average monthly noncoincident demand multiplied by 12).

The monthly capacity charge for interruptible service is $2.189 per kilowatt, and regular service customers at the same voltage are charged $6.566 per kilowatt. Remember that the system marginal cost of increased consumption on-peak ($63.96/kW) is the same for both customer classes, but the monthly marginal cost based capacity charges for each class are quite different. This result is a direct consequence of the utility's ability to curtail interruptible customers at the time when the most severe upward pressure on utility generating requirements exists.

This method determines the generating capacity-related costs for interruptible service based on a marginal cost methodology. The method may be employed, however, using average (or embedded) capacity costs as well.

---

[6]Since most utilities in the United States do not have time-of-use rates, using the whole year as a homogeneous pricing period corresponds to the ratemaking situation that most face. However, while industrial and other large-volume users are often billed on a basis of the dollar per kilowatt of measured demand each month, other customer classes usually are not. Dollar per kilowatt charges based on anticipated kilowatts of demand are calculated here for each customer class to facilitate comparisons. Cents per kilowatt-hour charges can be calculated for any of the classes by dividing the class entry in column (3) by its anticipated kilowatt-hours of consumption instead of kilowatts of demand.

The important point here is that this method allows one to calculate the capacity component of interruptible rates based upon the peak responsibility of the various customer classes. This method avoids the threshold problem referred to earlier as well as the problem of estimating avoidable costs.

CHAPTER 5

SUMMARY AND CONCLUSIONS

Interruptible electric service offers potential benefits to a utility and its customers by allowing the utility to displace investment in generating and possibly in transmission equipment with investment in load management devices. This displacement may allow the utility to meet its system load requirements at an overall lower cost than if all customers received firm service, especially for those systems where load growth is likely to require expansion of the utility's facilities. Interruptible rates are also likely to have a positive effect on the utility's system load factor as system peak demand is reduced relative to system average demand. These rates also allow the utility to diversify its service offerings by allowing customers some degree of flexibility in choosing the level of service reliability that suits their needs.

Interruptible rates are affected by value-of-service considerations, in that the reduction in cost of this service below that for firm service may be more than offset by a decline in the value of service to customers. This problem may be addressed by providing interruptible service on a voluntary basis so that only those customers who feel that they can achieve real cost savings will opt for interruptible service.

Several methods of estimating costs upon which to base interruptible service rates have been developed. The most commonly used method is to base these rates on avoided costs. Avoided costs are those costs of plant and equipment that would need to be built and operated if interruptible service were not available, net of any necessary additions to load control equipment. In applying these costs to the determination of interruptible service rates, it is also necessary to define the utility's peak period (the time during which service interruptions are likely to occur) and the number of kilowatts of interruptible load and maximum length of interruption for each customer.

A peak responsibility method for pricing interruptible service has also been developed that bases the price for this service and for firm service on each customer class's relative contribution to the system peak. This method avoids the "threshold" problem, wherein the utility must establish some minimum level of interruptible load before it will provide the service.

It is generally recognized that rates for interruptible service (as for all types of electric service) should be based on the actual costs incurred by the utility, whether measured on a marginal cost or average cost basis. In this respect, it is important for a state utility commission to assure that service supplied under interruptible rate tariffs is actually in the manner specified within the tariffs. Otherwise, these customers may receive service at a higher level of customer reliability and cost than that reflected in the rates. This situation may result in interruptible customers being inappropriately subsidized by those customers receiving firm service.

An assessment of the reasonableness of interruptible rates involves determining whether or not these rates adequately reflect the cost of providing this service. This may be achieved by employing one of the methods outlined in this report to estimate the cost of interruptible service. The method selected may be based on marginal costs or average costs. Once the cost for interruptible service is estimated, it may be compared with the rate proposed by the utility.

An upward limit on the price for interruptible service is the price charged for firm service. Certainly, an interruptible customer would not pay more than that amount, since he receives a reduced level of service reliability as compared to the firm customer.

In determining the capacity discount (or rate reduction) associated with interruptible service, the maximum reasonable discount is equal to the utility's "avoided" cost as defined in this report. A discount greater than this amount is likely to be based on value-of-service considerations rather than on cost of service.

The minimum reasonable price for interruptible service is equal to the utility's short-run variable costs (fuel costs and variable operation and maintenance costs). Any rate lower than this would not cover the utility's out-of-pocket costs.

These criteria determine a "zone of reasonableness" for interruptible rates. Any rate falling within this "zone" may be termed "reasonable." The analyst, then, must use judgment based on the information contained in this report and cost data provided by the utility to determine if the proposed interruptible rate adequately reflects cost of service.

It is important to recognize that utility companies are in the business of producing and selling electricity. Interruptible rates, as a type of load management, are a device intended to result in lower sales and revenues to the utility. It is doubtful that many utilities will enthusiastically provide interruptible service unless they are able to share in the benefits (in terms of lower costs of service) provided through this mechanism. Including the cost of metering and other load control equipment necessary for interruptible service in the utility's rate base, rather than having each interruptible customer bear these costs, is a method of sharing the benefits. This procedure can also be jusitifed on the grounds that all customers, not only interruptible customers, derive benefits from this service. These benefits are in the form of reduced utility investment costs, resulting in lower service rates to all customers; lower fuel costs, resulting from less intensive use of fuel-inefficient peaking plants; and improved environmental quality, resulting from reduced expansion of utility plant and reduced fuel consumption.

APPENDIX

Representative interruptible service rate schedules obtained from the NRRI Regulatory Information Exchange Program and outlined in chapter 3 are presented in the following pages.

EXHIBIT A

Original Sheet No.

PRIMARY INTERRUPTIBLE SERVICE
(CONTRACT RATE "I")

Availability:

Open to any customer desiring interruptible service where the billing demand is 5,000 kW or more at a single delivery point. The individual maximum capacity of a customer served under this schedule shall be limited to 100,000 kW. The aggregate maximum capacity of all customers served under this schedule shall be limited to 200,000 kW. This rate is not available for auxiliary or standby service, streetlighting service or for resale purposes.

Nature of Service:

Alternating current, 60 hertz, three phase, 2,400 nominal volts or more, the particular nature of the supply voltage in each case to be determined by the Company.

Monthly Rate:

Capacity Charge:

$2.75 per kW of billing demand for all kW

Energy Charge:

1.90¢ per kWh for all kWh consumed during the on-peak period,

1.70¢ per kWh for all kWh consumed during the off-peak period.

Fuel Cost Adjustment and Purchased Power Cost Adjustment Charges:

This rate is subject to the Company's Fuel Cost Adjustment and Purchased Power Cost Adjustment as set forth in Rule 16 of the Company's Standard Rules and Regulations.

Conditions of Service:

(1) The interruptible load shall be separately served and metered and shall at no time be connected to facilities serving the customer's firm load. The customer shall bear any expense incurred by the Company in providing a separate service for the interruptible portion of an existing customer load. The customer must provide space suitable for the separate metering of the interruptible load.

(2) The period of interruption shall be limited to no more than 600 hours per calendar year, nor more than 14 hours per day. The Comoany will endeavor to provide notice in advance of probable interruption, and if possible, a second notice of positive interruption; however, this service shall be interrupted immediately upon notice should the Company deem such interruption necessary.

(3) The customer will own and maintain the necessary switching equipment to interrupt electric service supplied under this rate. The switching equipment must meet with the approval of the Company.

(4) Failure by a customer to comply with an interruption order of the Company shall be considered as unauthorized use and billed at the rate of $10.00 per kW for the highest 15-minute kW demand created during the interruption period, in addition to the prescribed monthly rate.

Tax Adjustment:

(1) Bills shall be increased within the limits of political subdivisions which levy special taxes, license fees or rentals against the Company's property, or its operation, or the production and/or sale of electric energy, to offset such special charges and thereby prevent other customers from being compelled to share such local increases.

Tax Adjustment: (Continued)

(2) Bills shall be increased to offset any new or increased specific tax or excise imposed by any governmental authority upon the Company's generation or sale of electrical energy.

Minimum Charge:

The capacity charge included in the rate.

Delayed Payment Charge:

A delayed payment charge of 2% of the total net bill shall be added to any bill which is not paid on or before the due date shown thereon. The due date shall be 21 days following the date of mailing.

Billing Demand:

The billing demand shall be the kilowatts (KW) supplied during the 15-minute period of maximum use in the billing month, but not less than 60% of the highest billing demand of the preceding 11 months, nor less than 5,000 KW.

Adjustment for Power Factor:

This rate requires a determination of the average power factor maintained by the customer during the billing period. Such average power factor will be determined through metering of lagging kilovarhours and kilowatthours during the billing period. The calculated ratio of lagging kilovarhours to kilowatthours will then be converted to the average power factor for the billing period by using the appropriate conversion factor. Whenever the average power factor during the billing period is above .899 or below .800, the capacity charge will be adjusted as follows:

(a) If the average power factor during the billing period is .900 or higher, the capacity charge will be reduced by 2%. This credit shall not in any case be used to reduce the prescribed minimum charge or the capacity charge when based upon 60% of the highest billing demand of the preceding 11 months.

(b) If the average power factor during the billing period is less than .800, the capacity charge will be increased by the ratio that .800 bears to the customer's average power factor during the billing period.

Term and Form of Contract:

Minimum term on written contract subject to negotiation.

Rules and Regulations:

Service is governed by Company's Standard Rules and Regulations.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this rate.

Interruptions beyond the Company's control, described in Rules 1 and 15 of the Company's Standard Rules and Regulations, shall not be considered as interruptions for purposes of this rate.

Rules and Regulations: (Continued)

Should the Company be ordered by Governmental authority during a national or state emergency to supply firm instead of interruptible service, billing shall be made on an applicable firm power schedule.

Adjustment for Metering:

Where the Company elects to measure the service at a nominal voltage above 25,000 volts, 2% will be deducted, for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 volts, 3% will be added for billing purposes, to the demand and energy measurements thus made.

Adjustment for Customer-Owned Facilities:

Where service is supplied at a nominal voltage of 25,000 volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where service is supplied at a nominal voltage of more than 25,000 volts, and the customer provides all of the necessary transforming, controlling, and protective equipment for all of the service, there shall be deducted from the capacity charge herein provided for, the following monthly credit per kW (after the 2% deduction or the 3% addition referred to above) for the maximum integrated demand created during the month or for the billing demand, whichever is greater. For those customers where part of their load is served through customer-owned equipment, the credit shall be based on the maximum integrated demand (after the 2% deduction or the

Adjustment for Customer-Owned Facilities: (Continued)

3% addition referred to above) created during the month through such customer-owned equipment.

(1) Supply Voltage 46,000 Volts or Less

$.60 per kW for the first 1,500 kW
$.25 per kW for the next 3,500 kW
$.10 per kW for all over 5,000 kW

(2) Supply Voltage Over 46,000 Volts

$.60 per kW for the first 5,000 kW
$.20 per kW for the next 10,000 kW
$.10 per kW for all over 15,000 kW

These credits shall not be used to reduce the prescribed minimum charges included in the rate.

Exhibit 11-1
1 of 3

RATE "I" - INTERRUPTIBLE POWER SERVICE

Former RATE "I"

AVAILABILITY

Available for completely interruptible power service at not less than 69,000 volts at points of supply designated by the Company to the extent that the Company, in its sole judgment, determines that it has capacity for such service at the point of supply. Contract Demand shall not be less than 10,000 kilowatts.

MONTHLY RATE

CAPACITY CHARGE (D)

First 10,000 kilowatts or less of Demand for	$15,143.00	
Next 10,000 kilowatts of Demand at	$1.58	per kilowatt
Additional kilowatts of Demand at	$1.47	per kilowatt

ENERGY CHARGE (D)

175 kilowatt-hours per kilowatt of Demand at	1.01¢	per kilowatt-hour
Additional kilowatt-hours at	0.50¢	per kilowatt-hour

TRANSMISSION CHARGE

One and one-tenth (1.1) per cent per month on the total investment in transmission facilities necessary to serve the customer and furnished by the Company in addition to general transmission facilities.

MINIMUM CHARGE (D)

The Minimum Charge shall be the sum of (a) $1.95 per kilowatt for the highest Demand previously established during the life of the contract but not less than $19,500.00 and (b) the Transmission Charge.

RIDERS

Bills rendered under this schedule are subject to the charges stated in any applicable rider.

PROMPT PAYMENT DISCOUNT

The above rate states net prices. Standard bills will show the net amount and a gross amount 1% greater than the net amount. Upon payment of the bill within 15 days from mailing date a prompt payment discount equal to the difference between the gross and net amounts will be allowed.

STANDARD CONTRACT RIDERS

For modifications of the above rate under special conditions, see "Standard Contract Riders".

(Continued)

(D) Indicates Decrease

METROPOLITAN EDISON COMPANY

Exhibit 11-3
1 of 6

LARGE PRIMARY POWER SERVICE
RATE SCHEDULE LP

AVAILABILITY:

Available to Customers using electric power and/or lighting service through a single delivery location at distribution line nominal voltages of 13,200 volts or 34,500 volts and who contract for not less than 3,500 kilowatts. Choice of voltage shall be at the option of the Company. All substation and transformer equipment required for utilization of the delivery voltage shall be owned and maintained by Customer.

NET RATE PER MONTH: (C)(I)

DEMAND CHARGE:
$3.00 per kW

PLUS AN ENERGY CHARGE:
1.36c per kWh for the first 250 kWh per kW of Billing Demand
0.94c per kWh for the next 200 kWh per kW of Billing Demand
0.77c per kWh for all additional kWh

DETERMINATION OF BILLING DEMAND:

The demand will be measured by recording instruments and the billing demand will be the greatest integrated 15-minute use of energy taken at any time during the month. The billing demand in the current month shall be whichever is greater: (a) 3,500 kW, (b) the billing demand established in the current month; or (c) 50% of the highest billing demand established during the contract term. All measured demands will be corrected to 90% power factor by multiplying the measured demand by the ratio of 90% power factor to the measured power factor except that no reduction in measured demands shall be made for power factor in excess of 90%. The power factor measured at the time of the maximum 15-minute demand in the month, to the nearest 0.1% will be used for billing purposes. (C)

MINIMUM CHARGE:

The minimum monthly charge shall be the Demand Charge based on the Billing Demand.

RIDERS:

Bills rendered under this rate schedule are subject to the charges stated in any applicable Rider.

PAYMENT TERMS:

Bills will be calculated on the rates stated herein, and this is the net amount due and payable on or before fifteen days from the postmarked date of mailing of the bill to Customer. The gross amount is the net bill plus 5% of the first $200 thereof and plus 2% of the remainder. The gross amount is due and payable when the full amount of the net bill is not paid within fifteen days from the postmarked date of mailing of the bill. Company's standard payment terms stated in Rule 19 of the General Rules and Regulations apply to all bills rendered under this rate schedule.

TERM OF CONTRACT:

The term of contract shall be not less than one year, subject to renewal for successive one-year terms unless longer renewal terms shall be provided in the contract.

(C) Change
(I) Increase

Continued

Issued July 9, 1976

METROPOLITAN EDISON COMPANY

Rate LP – Continued

GENERAL PROVISION:

(a) OFF-PEAK SERVICE: Where a Customer (1) expects to take service in such manner that the maximum demand occurs during Company's off-peak period, and (2) makes written request to be billed under this General Provision (a), the Company will determine Customer's demand for billing as follows: (C)

(1) If the maximum off-peak demand exceeds the maximum on-peak demand by more than 350 kW, the demand in the month for billing purposes shall be whichever is greater: (a) the maximum demand established in the month during on-peak hours; (b) 60% of the maximum demand established in the month during off-peak hours; (c) the contract use-of-capacity.

(2) The measured demand for billing in all cases shall be adjusted for power factor as heretofore provided in this rate schedule.

The hours to be considered as on-peak are from 9 A.M. to 9 P.M. on weekdays. Off-peak periods are the remaining hours of weekdays and all day on Saturdays, Sundays and holidays. On -peak and off-peak hours are subject to change from time to time by Company giving notice of such change to customers.

(b) AUXILIARY, BREAKDOWN, STANDBY OR SUPPLEMENTAL SERVICE. Company may, at its option, supply service under this Rate Schedule to Customers who generate a portion of the power requirements of the premises or who obtain from any other source a portion of the power requirements. Such service will be supplied only at locations where in Company's sole judgment there exists lines and equipment of sufficient capacity to supply the service requested by Customer, or where Customer enters into adequate contractual arrangements to support the investment required of Company. The Minimum Monthly Charge for service under this General Provision shall be $6.35 per kilowatt of demand (adjusted for power factor), based on whichever is greater: (1) the highest demand established in the current month or the eleven preceding months, (2) 75% of the highest demand established during the contract term, or (3) the contract demand. Company shall have the right to require Customer to install demand-limiting devices as a condition of furnishing service hereunder, but the use of such devices shall not preclude the use of the highest established demand for purposes of determining Billing Demand and Minimum Monthly Charge. Temporary service will not be supplied under any other rate schedule or under conditions other than this Provision while Customer's generating equipment or other source of supply is being repaired, inspected, maintained, or overhauled. Customer's generators or other source of supply may not be operated in parallel with Company's lines except upon written consent of Company. (I)

(c) CURTAILABLE SERVICE: A credit for each kilowatt of curtailable load will be applied to the monthly bill provided that such credit shall not serve to reduce the bill below the minimum charge, provided that such customer (C)

(1) has a curtailable load of one (1) megawatt or greater and

(2) agrees to curtail its load to a predetermined level equal to its non-curtailable service requirements (such level to be determined in advance by the customer subject to approval by Company) upon fifteen minutes advance notice from the Company. The aggregate period of curtailment will not exceed 150 hours per calendar year. The level of noncurtailable service requirements may be revised annually by customer as conditions warrant subject to approval by the Company.

(3) The monthly credit for the curtailable load shall be $1.36 per kW.

(4) Term of contract for this provision shall be three (3) years.

The amount of curtailable load to be used in computing the monthly credit shall be the difference between the maximum 15-minute on-peak integrated demand registered by the customer in the current month and the customer's non-curtailable load as approved by the Company.

Exhibit 11-
3 of 6

RATE LP

LARGE POWER

AVAILABILITY:

Available in the entire territory of the Company for industrial service to customers with bil ing demands of not less than 12,000 kw.

CHARACTER OF SERVICE:

Alternating current, 3 phase, 60 cycles, 23,000 volts or over.

NET RATE (Per Month):

Demand Charge (I

Active (Kilowatts)

All kw of billing demand	@	$2.05 per kw

Reactive (Kilovars)

Maximum registered reactive demand (kvars) in excess of one-third of the kilowatt billing demand	@	22.0¢ per kvar

Energy Charge

First 300 kwh per kw of billing demand	@	0.90¢ per kwh
Next 200 kwh per kw of billing demand	@	0.75¢ per kwh
Over 500 kwh per kw of billing demand	@	0.55¢ per kwh

A credit adjustment of 0.10¢ per kilowatthour shall apply to the off-peak kilowatthours.

OFF-PEAK AND ON-PEAK PERIODS:

The on-peak hours shall be from 9:00 a.m. to 9:00 p.m. Monday through Friday, excluding holidays. All other hours shall be considered off-peak. The following holidays shall be considered off-peak days: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

The Company reserves the right to change the on-peak hours and off-peak hours specified abov in accordance with the operating conditions on the Company's system.

MINIMUM MONTHLY CHARGE:

The kilowatt demand charge based on 12,000 kilowatts or on one-half of the highest kilowatt mand billed during the preceding eleven months, whichever is greater.

DETERMINATION OF BILLING DEMAND:

The monthly billing demand shall be the highest of the following:

(1) The average of the maximum 15-minute integrated demands registered during on-peak hours each of the four weekly periods during the month. The four weekly periods of the month shall be the initial partial day of the billing month plus seven full days, the second seven full days, the third seven full days, and the remaining days of the billing month.

(I) Increase
(C) Change

Cont

RATE LP (Continued)

(2) 60% of the maximum 15-minute integrated demand registered at any time during the month.

(3) 12,000 kw.

RIDERS:

Bills rendered under this rate schedule are subject to the charges stated in any applicable Rider.

PAYMENT TERMS:

Bills will be calculated on the rates stated herein, and this is the net amount due and payable on or before fifteen days from the postmarked date of mailing of the bill to customer. The gross amount is the net bill plus 5% of the first $200 thereof and plus 2% of the remainder. The gross amount is due and payable when the full amount of the net bill is not paid within fifteen days from the postmarked date of mailing of the bill. Company's standard payment terms stated in Rule 14 of the General Rules and Regulations apply to all bills rendered under this rate schedule.

TERM OF CONTRACT:

The contract shall be written for a term of not less than five years, automatically renewable from year to year after the expiration of the original term, unless written notice of cancellation is given by one party to the other at least 90 days in advance of the expiration date.

SPECIAL PROVISIONS:

(a) Multi-point Delivery: This provision is restricted as of June 18, 1976, to existing loads at existing locations. Where the load of an industrial customer located on single or contiguous premises becomes greater than the capacity of the standard circuit or circuits established by the Company to supply the customer, additional delivery points may be established for such premises upon written request of the customer, provided multi-point delivery is not disadvantageous to the Company. When such additional points of delivery are established billing shall be based on the sum of the meter readings. Locations and loads billed under this provision may not continue to be so served if there is a substantial increase in load necessitating any increase in the capacity of the Company's facilities or in the capacity of the customer's service entrance wiring.

(b) 115,000 Volt Delivery: Upon request Company will furnish service at 115,000 volts where available provided customer furnishes all necessary transformer and terminal equipment. When service is supplied at 115,000 volts the active kilowatt demand charge per month shall be decreased 20¢ (C) per kw of billing demand.

(c) Less than 23,000 Volt Delivery: At the option of the Company service may be rendered at less than 23,000 volts, but not less than 10,000 volts, provided that such delivery is not disadvantageous to the Company and can be made economically in a single transformation from available transmission lines of 115,000 volts or above.

(d) Curtailable Service: A credit of $1.33 per kw of curtailable load will be applied to the (C) monthly bill provided that such credit shall not serve to reduce the bill below the minimum charge, provided that such customer

(1) has a curtailable load of one (1) megawatt or greater and

(2) agrees to curtail its load to a predetermined level equal to its noncurtailable service requirements (such level to be determined in advance by the customer subject to approval by Company) upon fifteen minutes advance notice from the Company. The aggregate period of curtailment will not exceed 150 hours per calendar year. The level of noncurtailable service requirements may be revised annually by customer as conditions warrant subject to approval by the Company.

(C) Change

Exhibit 1
5 of 6

RATE LP (Continued)

(3) Term of contract for this provision shall be three (3) years.

The amount of curtailable load to be used in computing the monthly credit shall be the differe between the average of the maximum 15-minute integrated demands registered during on-peak hours in each of the four weekly periods during the month by the customer in the current month and the customer's non-curtailable load as approved by the Company.

If in any month the customer fails to reduce load when requested, to the predetermined level as agreed upon, this credit shall not be applicable to the current monthly billing. In lieu of a credit, the customer's bill shall be computed based on demand and energy charges that are ten (10) percent greater than the standard charges.

A monthly charge of 1-1/2% of the original cost of all the Company's communication facilities provided for customer's sole use for the purpose of facilitating customer's performance of its obligations hereunder shall be made. Customer shall also be charged for the actual cost to the Company of the maintenance and repair thereof in addition to all other charges for service under th provision, together with out-of-pocket operating expense such as rental or tolls for communication circuits.

The number of curtailments requested by the Company will not exceed twenty (20) per calendar year.

The Company limits the capacity which is available to supply service under this tariff. Such capacity on the aggregate basis of all customers served hereunder is limited to 5% of the Company's annual peak demand in the preceding calendar year.

RATE SCHEDULE LP-6
(8-26-76)

LARGE GENERAL SERVICE AT 66,000 VOLTS OR HIGHER
10,000 BILLING KW MINIMUM

APPLICATION OF SCHEDULE

This rate schedule is for large general service from available lines of 66,000 volts or higher when customer furnishes and maintains all equipment necessary to transform the energy from line voltage.

NET MONTHLY RATE (I)

$23,700 for the first 10,000 kilowatts of the Billing KW.
2.15 per kilowatt for all additional kilowatts of the Billing KW.
The above charges entitle customer to use 50 KWH for each kilowatt of the Billing KW.
1.50 cts. per KWH for the next 50 KWH per kilowatt of the Billing KW.
.73 cts. per KWH for the next 150 KWH per kilowatt of the Billing KW.
.58 cts. per KWH for the next 150 KWH per kilowatt of the Billing KW.
.51 cts. per KWH for all additional KWH.

The Fuel Adjustment Clause applies to all KWH supplied under this rate.

Customers who elect to curtail their operations during any two consecutive clock-hours on Mondays to Fridays inclusive, holidays excluded, as designated by Company from time to time, may earn a credit on the monthly bill for such curtailment. When customer gives previous written notice that during the current month his operation will be so curtailed, and during that month the average kilowatts supplied during the 15 minute period of maximum use during the specified hours (not less than 10,000 kilowatts) is at least 2,000 kilowatts below the average kilowatts supplied during the 15 minute period of maximum use during the on-peak hours of the current month, a reduction of 35 cents per kilowatt of such difference is made in the charges for that month.

BILLING KW

The Billing KW is the sum of the average kilowatts supplied during the 15 minute period of maximum use during the on-peak hours of the current month plus one half of any amount by which the average kilowatts supplied during the 15 minute period of maximum use during other than on-peak hours exceeds the maximum on-peak demand.

The minimum Billing KW is 10,000 kilowatts.

ON-PEAK HOURS

Mondays to Fridays Inclusive (Excluding Holidays): 7 A.M. to 7 P.M.

Holidays are New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

.. ıpany reserves the right to change from time to time the hours specified above in accordance with the operating conditions on Company's system.

TAX ADJUSTMENT SURCHARGE

The Tax Adjustment Surcharge included in this Tariff is applied to charges under this rate except for charges made under the Fuel Adjustment Clause.

PAYMENT

The above net rate applies when bills are paid on or before the due date specified on the bill, which is not less than 15 days from the date bill is mailed. When not so paid the gross rate applies which is the above net rate plus 5% on the first $200.00 of the then unpaid balance of the monthly bill and 2% on the remainder thereof.

CONTRACT PERIOD

Not less than 1 year.

(I) Indicates Increase

RATE GS

GENERAL SERVICE - SMALL

AVAILABILITY:

Available in the entire territory of the Company to customers using the Company's standard service for general light and power purposes not included within the availability of RATE RS, RESIDENTIAL SERVICE, with Billing Demands not in excess of 10 kw. When the Billing Demand in two consecutive months exceeds 10 kw, the customer shall be transferred to Rate GM, GENERAL SERVICE - MEDIUM for a minimum period of twelve months.

CHARACTER OF SERVICE:

Alternating current, 60 cycles; supplied at 120/240 volts, single phase; and 240 volts polyphase in the entire service area except in network areas where only 120/208 volts is available.

NET RATE (Per Month):

Demand Charge (C)

First 5 kw of demand		No Charge
Additional kw of demand	@	\$3.50 per kw

Energy Charge (I)(C)

First	20 kwh or less		\$2.25
Next	330 kwh	@	6.10¢ per kwh
Next	350 kwh	@	5.00¢ per kwh
Next	800 kwh	@	3.00¢ per kwh
All over	1500 kwh	@	2.00¢ per kwh

Maximum Charge (C)

No bill shall be rendered in an amount greater than \$3.50 plus 11.25¢ per kwh, except by reason of the minimum monthly charge.

DETERMINATION OF BILLING DEMAND:

The Company shall install suitable demand meters to determine the maximum 15-minute integrated demand when customer's total monthly consumption exceeds 1,000 kilowatthours for two consecutive months. The billing demand shall be the sum of the individual demands of each metered service. The individual demand of each metered service shall be determined separately. Service rendered under Special Provision (e) shall be excluded herefrom.

MINIMUM CHARGE:

The minimum monthly charge shall be \$2.25 for the first 5 kw, or less, of billing demand; for billing demands in excess of 5 kw it shall be the demand charge, based on the highest billing demand established during the current month or the preceding eleven months. (C)

In no event shall the minimum charge be less than any monthly guarantee established under Rule 19 - Extension of Company's Facilities.

RIDERS:

Bills rendered under this rate schedule are subject to the charges stated in any applicable Rider.

(I) Increase
(C) Change

Exhibit 11-5
2 of 5

RATE GS (Continued)

PAYMENT TERMS:

Bills will be calculated on the rates stated herein, and this is the net amount due and payable on or before fifteen days from the postmarked date of mailing of the bill to customer. The gross amount is the net bill plus 5% of the first $200 thereof and plus 2% of the remainder. The gross amount is due and payable when the full amount of the net bill is not paid within fifteen days from the postmarked date of mailing of the bill. Company's standard payment terms stated in Rule 14 of the General Rules and Regulations apply to all bills rendered under this rate schedule.

TERM OF CONTRACT:

Contract for installations of a permanent nature shall be written for a period of not less than one year. A separate contract shall be written for each location.

SPECIAL PROVISIONS:

(a) Off-Peak Water Heating Service: Off-peak service will be rendered for automatic storage water heaters in regular use for the total running hot water requirements of the customer's premises. Heaters shall be of a capacity, design and type approved by the Company and installed in accordance with its specifications. The heating elements shall be non-inductive with no individual element requiring more than 33 watts per gallon of storage tank capacity.

The Company shall install a meter and time control device on the customer's wiring to measure the energy used off-peak. The rate for such off-peak energy shall be 1.61¢ per kilowatthour, subject to a minimum monthly charge of $2.25 per installation. (I)

Off-peak service shall be rendered for not less than ten consecutive hours per day. Off-peak periods shall be specified from time to time by the Company.

(b) Temporary Service: Service of a temporary nature will be rendered at the charges set forth herein, provided that the customer reimburses the Company for all costs of installing and removing the service installation, including costs of poles, conductors, transformers, meters and other equipment, together with all labor and other expenses incurred, less the salvage recovered from all materials and equipment removed after termination of service. Service will not be connected until the customer has made an advance payment equal to the estimated charges for installation and removal of service.

(c) Service to Schools: Service to public schools and parochial schools will be rendered at the charges set forth herein, provided that the minimum monthly charge may be waived during three consecutive months of each calendar year. Any kilowatthours used during the period of waiver will be included in subsequent billing.

(d) Combined Billing: This provision is restricted as of June 18, 1976, to existing loads at existing locations. Combined billing will not be permitted except where customers are supplied with single phase and polyphase service at secondary voltages at a single location. In such instances, only one single phase and one polyphase service may be combined for billing purposes. Locations and loads billed under this provision may not continue to be so served if there is a substantial increase in load necessitating any increase in the capacity of the Company's facilities or in the capacity of the customer's service entrance wiring. (C)

(e) Space Heating Service: Upon request, space heating service may be supplied through a separate metered circuit for customers utilizing electricity as the primary method of space heating. Air conditioning and cooking equipment may also be connected to the heating circuit. All energy supplied hereunder shall be billed at the rate of 2.47¢ per kilowatthour, subject to a minimum monthly charge of $2.47. Service rendered under this provision shall have no effect on the application of other charges and provisions of the rate schedule to customer's other service. (I)(C)

(f) Service to Churches: Service to churches and adjacent buildings which are operated in conjunction therewith (other than schools, residences, and camp sites) will be rendered at the charges set forth herein, provided that the billing demand shall be taken as 5 kw. The minimum monthly charge may be waived during three consecutive months of each calendar year. Any kilowatthours used during the period of waiver will be included in subsequent billing.

(I) Increase
(C) Change

RATE CWH
CONTROLLED OFF – PEAK SERVICE
FOR WATER HEATING

AVAILABILITY

This Rate is available for the exclusive operation of heat storage water heating equipment located at premises where other service is supplied under Company's nonresidential rates, subject to the provisions hereinafter set forth. Any residential Customer served prior to March 1, 1961 under former Rate WH shall have the option of continuing service under Rate CWH.

CHARACTER OF SERVICE

Alternating current, 60 cycles, single or three phase, 120-208 volts, 3 or 4 wire; 120-240 volts, 3 wire; or 240 volts, 2 or 3 wire.

CONTRACT TERM AND BILLING

Term of contract shall be not less than one (1) year, with monthly payments for service taken.

RATE TABLE (I)

For all energy used .... 1.87¢ per kilowatt-hour
Minimum Monthly Charge $1.58

The Power Adjustment Clause applies to all KWH supplied under this rate.

TAX ADJUSTMENT SURCHARGE

The Tax Adjustment Surcharge included in this Tariff is applied to charges under this rate except for charges made under the Power Adjustment Clause.

PAYMENT TERMS

The rates set forth above state net prices. Standard bills will show the net amount and a gross amount 3% greater than the net amount. If payment is made on or before the last day for payment as specified on the bill, prompt payment discount equal to the difference between the gross and net amounts will be allowed.

SPECIAL PROVISIONS

(1) Service under this Rate shall be limited to the hours specified from time to time by the Company, and shall be controlled by a clock of type approved, set, and sealed by the Company.

(2) Water Heaters shall be of a type approved by Company.

(3) In view of the low rate at which this service is rendered, no additional investment or facilites shall be required of the Company for any installation other than the service and meter necessary to deliver and measure the energy used.

(4) Monthly Guarantees, apportionment and adjustment of guarantees, and waiver of guarantee, as set forth under Rule 13-a shall not be affected by any payments for service under this schedule.

(5) All wiring from meter to water heater shall be in conduit or approved cable, continuous with no splices or outlet boxes from meter to water heater.

(I) Indicates Increase

Exhibit 11-5
4 of 5

CONTROLLED WATER HEATING SERVICE

Rate Schedule WH

Availability:

Available for residential and commercial water heating service to permanent automatic storage type water heater installations arranged so as to take service through a separate meter to which no other equipment may be connected and subject to the provisions set forth below.

Service:

Alternating current, sixty (60) hertz, single phase, nominal voltage 208 or 240 as available.

Rate:

The net monthly charge per customer shall be:

Energy Charge: (I)

1.88¢ per KWH for the first 85 KWH
1.81¢ per KWH for all over 85 KWH

Minimum Charge: (I)

$1.60 per month

Riders:

Bills rendered under this schedule are subject to the charges stated in any applicable rider

Terms of Payment: (C)

The net amount billed is due and payable within a period of twenty-one days. If the net amount is not paid on or before the date shown on the bill for payment of the net amount, the gross amount, which is 5% more than the net amount, is due and payable.

Temporary Discontinuance of Service: (I)

Where service has been discontinued at customer's request, the Company shall not be obliged to resume service to the same customer at the same premises within twelve months, unless it shall first receive a payment for each of the intervening months of $1.60 per month, except that where the service is reestablished at the same time that the residential or general service is reestablished, no charge will be made for the intervening months of the water heating service.

Contract:

A written application may be required.

Rules and Regulations:

The Company's Standard Rules and Regulations shall apply to the installation and use of electric service.

Water heaters may be equipped with one heating element or, at the customer's option, with two heating elements. When equipped with two heating elements, each shall be controlled by an individual and independent thermostat, interlocked so that only one heating element can be in operation at any time. The maximum capacity of the heating element or elements that may operate at one time in a tank shall not exceed 5,500 watts or 40 watts per gallon, whichever is greater. The minimum tank capacity shall be 30 gallons.

Service may be controlled by the Company, but will be available not less than 14 hours per day; the hours of service to be determined by the Company.

(I) Indicates Increase
(C) Indicates Change

RECEIVED
Penna. Public Utility Comm.
MAR 24 1977

Philadelphia Electric Company

Exhibit 11
5 of 5

RATE WH WATER HEATING SERVICE

AVAILABILITY.

In conjunction with Rates R and R-H and with residence service under Rates GLP and GS, for any Customer receiving service at 120-240 volts, 3 wires, for the operation of water heating equipment of a type approved by the Company, when the demand or load of the water heating installation does not exceed the Customer's demand for service to his other residence load and where the supply of service is confined to a single connection, separately metered. (C

(Not available when the source of supply is service purchased from a neighboring company under a borderline-purchase agreement.)

UNRESTRICTED SERVICE.

The supply of service shall be confined to water heating hot water installations used for all domestic purposes except as a source of space heating to the premises. (C

RATE: 2.27¢ per kWh.

MINIMUM CHARGE: $1.53 per month.

STATE TAX ADJUSTMENT CLAUSE and FUEL ADJUSTMENT CLAUSE apply.

OFF-PEAK SERVICE. (C

To domestic hot water heating or thermal storage installations for space heating where the daily period of use shall be limited by a control device. The off-peak periods shall be established by the Company and may vary from Customer to Customer; however, the number of off-peak hours shall be the same for all customers.

The control devide furnished by the Company shall be suitable for use with loads up to 4.5 kW. For loads greater than 4.5 kW, a load interrupting device shall be furnished, maintained and installed by the Customer adjacent to the meter. The load interrupting device shall be adequate for the load controlled and shall meet Company specifications. The Customer shall pay for the cost of any change in local distribution facilities required to provide off-peak service other than the control device and meter.

RATE: 2.01¢ per kWh for the first 400 kWh per month
1.69¢ per kWh for the additional kWh.

MINIMUM CHARGE: $1.53 per month.

STATE TAX ADJUSTMENT CLAUSE and FUEL ADJUSTMENT CLAUSE apply.

ELECTRICAL CHARACTERISTICS OF EQUIPMENT.

The water heating installations shall be 240 volts, alternating current, 2 wires, single-phase, 60 hertz.

TERM OF CONTRACT.

Annual.

PAYMENT TERMS.

Standard.

(C) Indicates change.

Final Report on

A REVIEW OF POWER POOLING ARRANGEMENTS OF MAJOR COLORADO ELECTRIC UTILITIES

Prepared by

Whitfield A. Russell & Associates
Public Utility Consultants

on behalf of

THE NATIONAL REGULATORY RESEARCH INSTITUTE
2130 Neil Avenue
Columbus, Ohio 43210

for the

Colorado Public Utilities Commission

in partial fulfillment of

Contract No. 900342

May 1981

PREFACE

This report was prepared by Whitfield A. Russell & Associates and The National Regulatory Research Institute (NRRI) under a contract (Contract #900342) between the NRRI and The Colorado Public Utilities Commission. The Colorado commission requested, as one part of the contract, a study of the power pooling and/or power brokering arrangements of selected power pools across the United States, a critique of the power pooling and/or power brokering methods employed by major electric utilities in Colorado, and a comparison of the methods employed by the two groups of utilities.

The NRRI subcontrated with Whitfield A. Russell & Associates to perform the required analysis. This report is the end product of that analysis.

Part 1 of this report and its appendixes A and B describe the power pooling and power brokering arrangements of major Colorado electric utilities as well as other major electric utilities in the west and southwest sections of the United States. Part 1 also describes the power pooling and power brokering arrangements of several major power pools in the United States. The pooling arrangements discussed in this report are those of the New England Power Pool, the Pennsylvania-New Jersey-Maryland Interconnection, the Florida Electric Power Coordinating Group, and the Mid-Continent Area Power Pool.

Part 2 presents an approach for evaluating and comparing the pooling arrangements of Colorado electric utilities with those of the major power pools discussed in Part 1.

Part 3 presents a computer model simulation study performed by Whitfield A. Russell and Associates of the consolidated control areas of Public Service Company of Colorado, Public Service Company of New Mexico, and El Paso Electric Company. This simulation is intended to indicate the nature of power pooling transactions that would be feasible among these companies and the general level of savings that would result from those transactions. This information provides additional evidence of potential benefits from power pooling arrangements among utilities within, and adjacent to, Colorado.

Part 4 of this report contains the results of a review of the report undertaken by Dr. Stephen A. Sebo, Professor of Electrical Engineering at The Ohio State University at the request of the NRRI.

PART 1

A REVIEW OF POWER POOLING ARRANGEMENTS

OF MAJOR COLORADO ELECTRIC UTILITIES

TABLE OF CONTENTS

Introduction and Background

This report contains results of further study on coordination and power pooling efforts by utilities serving Colorado and adjoining states and is an extension of prior investigations of this issue by the Colorado Public Utilities Commission. The Commission and the National Regulatory Research Institute ("NRRI") have funded this additional study. Findings of prior Commission investigations were reported in Case No. 5693 (1977 and 1980) and in a joint study (1978) with the National Regulatory Research Institute ("NRRI").

Further study has been undertaken in part because of recent power supply developments in the Colorado area which have substantially altered the prospects for regional pooling. A principal development is the 1980 termination of negotiations directed toward forming the Cactus Pool. A second development is the realignment of Federal power marketing programs in order to increase the amounts of marketable power and to serve Federal power customers with entitlements from several instead of a few resources. A third development is the initiation of a power brokering system under the auspices of the Western Systems Coordinating Council (WSCC). A fourth and final development is related to intensified efforts by California's utilities to acquire resources located in and near Colorado because of the slowed pace of power development in California.

I.A. Summary Conclusions and Recommendations

A major portion of this additional study is devoted to comparisons of the operating and planning practices of the Inland Power Pool ("IPP") with those of the:

(i) Pennsylvania-New Jersey-Maryland Interconnection ("PJM"),

(ii) New England Power Pool ("NEPOOL"),

(iii) Florida Electric Power Coordinating Group ("FCG"),

(iv) Mid-Continent Area Power Pool ("MAPP")

These comparisons indicate that the IPP, despite increased efforts in recent years, remains far behind all except the FCG in achieving essential pooling objectives.

A number of IPP members were among the utilities which attempted for six years without success to form the Cactus Pool. Had the Cactus Pool Agreement been signed, the Cactus Pool would have been committed to mandatory installed and operating reserve sharing as are PJM, NEPOOL and MAPP. The Cactus Pool would thus have represented a major advance over the IPP because the IPP obligates members to share only operating reserves on a mandatory basis. However, the IPP does not and the Cactus Pool would not have involved centralized unit commitment or automatic generating unit dispatch, two major operating attributes of pooling. Neither MAPP nor FCG have these attributes, although FCG and MAPP engage in power brokering which is a proxy for centralized economic dispatch. As noted previously, WSCC has established a power brokering system.

Colorado-based members of the IPP have for many years made transmission services available to other utilities. As a result, planning of Colorado's utilities has not been hampered by the limited availability of transmission services as have the planning processes of FCG, PJM */ and, to some extent, NEPOOL. NEPOOL makes a member's access to pool transmission facilities ("PTF") contingent upon the member's adherence to mandatory pool planning practices, a relatively beneficial purpose. However, FCG's progress has been retarded by the refusal of some members dominant in transmission to transmit except at onerous rates and in accordance with cumbersome contracting procedures. The FCG, despite its late development, is several years ahead of the IPP in analyzing pooling problems, negotiating and litigating solutions and designing hardware and software which advance the state of FCG coordinated operations.

The comparisons also indicate that the success of pooling is unrelated to the number of States served by the pool's members, the

*/ PJM members make no transmission charge and impose no loss discounts when members engage in purchases or sales as a pool. However, non-pool transactions are not so favored. The Three Mile Island incident caused General Public Utilities (GPU) to seek power from low-cost resources owned by non-PJM members, primarily coal-based utilities located west of PJM. This is regarded as a non-pool transaction because GPU alone retains all the savings resulting from it. Had the same purchase been made by PJM as a pool, GPU would have realized only a fraction of those savings.

Unless GPU had obtained such power on a bilateral, non-pool basis, it would have been forced to purchase that and other power through PJM at a split savings rate which is set half way between (i) GPU's very high replacement costs and (ii) the average cost of all PJM sellers. Other PJM members have been seeking bilateral transactions like those which GPU entered into, but they must arrange their own transmission for such non-PJM transactions just as GPU has.

number of pool members, the fuel base of the pool, the absolute or relative generating capacity of pool members, the nature of the power supply of the pool members 1/, load diversity 2/, the size of the pool 3/, or the nature of the ownership of the pool members 4/. Instead, the success of pooling seems to result more from the members' willingness to view themselves as an economic unit and grant one another some binding legal power over each other's planning and operation. However, members of fully developed pools have by no means submerged their individual identities. Disputes continue to develop over the economic consequences of pool action or inaction upon individual members. One advantage of pooling is that it provides a forum and contractual framework for identifying, analyzing and ameliorating inequities that might otherwise continue to exist indefinitely.

1/ NEPOOL has many members without control areas or sufficient generation to meet their entire needs. A utility which is not self-sufficient is called a partial requirements customer of some other utility.

2/ PJM members have almost no seasonal load diversity.

3/ NEPOOL is a fraction of the size of PJM measured by energy or peak demands.

4/ NEPOOL, FCG and MAPP include many membership types including Federal power marketing agencies ("PMA's"), investor-owned utilities ("IOU's"), cooperatives and municipal utilities.

I.B. Termination of the Cactus Pool Negotiations

When negotiations terminated in 1980, the Cactus Pool had been under consideration since August 1974 by representatives of Arizona Public Service Company, the Salt River Project, Tucson Electric Power Company (formerly Tucson Gas & Electric Company), the Public Service Company of New Mexico and the El Paso Electric Company. During some stages of the negotiations, Community Public Service Company, Nevada Power Company, the City of Farmington, New Mexico and San Diego Gas & Electric Company had also participated. At the time negotiations terminated, several parties had already become members of, or were seeking membership in, the Inland Power Pool which for many years has included the major systems serving Colorado.

This is an auspicious development from Colorado's narrow point of view. Colorado's utilities have developed cooperative working relationships and should, to some extent, be able to control the pace and direction of the Inland Pool's expansion. Had the Cactus Pool been formed, Colorado's utilities would not have been charter members nor would they have been expected to control or direct its progress. The Cactus Pool may also have limited the expansion of the Inland Power Pool and attracted IPP members away.

Cactus Pool negotiations reportedly broke down over

1. Installed reserve criteria
2. The reserve sharing formula
3. The scope of pool coordination

4. The scope of pool planning.

It is inauspicious that termination of the Cactus Pool negotiations was attributed to these issues because the Inland Power Pool has commenced negotiations directed toward expanding the scope of the IPP's functions, particularly the planning function on which the Cactus Pool negotiations foundered. If the parties to the Cactus Pool negotiations bring those same irreconcilable positions to the IPP bargaining table, progress toward mandatory joint planning and reserve sharing by the IPP could be slowed or halted. At least one new IPP member seems opposed to a tightly-structured pool. Tucson Electric Power Company ("TEPCO") joined the IPP on May 24, 1979. A July 1, 1977, "Report on the Cactus Pool" attributes the following statements to TEPCO:

> "However, our analysis of the subject to date indicates that there were not any significant identifiable benefits that would inure to TG&E and its customers solely by reason of participation in the Cactus Pool arrangement. As indicated at the public hearing on March 29, 1977, TG&E believes that it is already receiving benefits associated with existing joint planning arrangements and its participation in various joint ownership projects."

Several other potential IPP members have expressed lukewarm support for mandatory reserve sharing. Public Service Company of New Mexico (PSNM), El Paso Electric Company (EPE) and Plains G&T Cooperative stated in their June 24, 1977, comments to the Arizona Corporation Commission that they preferred the implementation of effective operating procedures which preserve the <u>independent</u> nature of the respective pool members. PSNM joined the IPP on October 28, 1979, and applications of EPE and Plains to join were pending as of June 28, 1980.

In the course of negotiating the Cactus Pool Agreement, PSNM, EPE and Plains formed an entity entitled "Pool of Western Energy Resources" ("POWER") which subscribes to a set of specific principles related to joint planning and operation. These principles are discussed in more detail in Appendix A.

I.C. Realignment of Federal Power Marketing

The Federal presence is a substantial factor in the West's power industry and this is particularly true in the Colorado region. Colorado utilities receive the output of 15 plants controlled by the Denver Area of the Western Area Power Administration (WAPA) and another seven WAPA plants operated as part of the Colorado River Storage Project (CRSP). During a normal water year, CRSP produces 5,250 GWH and has a firm capability of 1,456 MW 1/ to serve a load of 6,145 GWH with a maximum demand of 1,324 MW. Fifteen plants under the control of the Denver Area office of WAPA have a capacity of 391 MW.

1/ Not including the Mt. Elbert I and II pumped storage project, 100 MW each, scheduled to begin service 7/81 and 8/83.

In 1978, WAPA considered consolidating the marketing of power from CRSP with the United States entitlement to the Navajo Project (546.76 MW and 3,654 GWH entitlements from three 750 MW coal-fired steam units) and the Parker-Davis Projects (372 MW and 1,388 GWH). However, the second draft of WAPA's Consolidated Marketing Plan (published by the Boulder City, Nevada office of WAPA on December 12, 1980) no longer includes CRSP among resources to be integrated for consolidated marketing. Substituted for CRSP in the second draft Plan is Hoover Dam. By letters of April 2 and October 29, 1980, the City of Bountiful, Utah requested development of a consolidated marketing plan covering all sources on the Colorado River. 1/ However, no explanation for excluding CRSP has yet been given.

The Federal power presence serves to distinguish the Colorado region from most other regions where pooling has been developed, although the substantial Federal resources in the Mid-Continent Area Power Pool (MAPP) region make it somewhat similar to the Colorado region in this respect. Despite the impact of Federal power marketing agencies (PMAs) upon local power developments, PMAs are outside the jurisdiction of State regulatory bodies. Indeed, PMAs cannot be subjected to FERC PURPA

1/ Letters of Mr. W. Berry Hutchings to WAPA-Boulder City dated April 2 and October 29, 1980.

proceedings seeking interconnections. (Section 210(a) (2) of the Federal Power Act - PURPA Section 202.) 1/

Fortunately, the position of PMAs on coordination has historically been favorable and remains so. 2/ It appears that

---

1/ Section 210 (a) (2) provides:

> "(2) Any State regulatory authority may apply to the Commission for an order for any action referred to in subparagraph (A),(B),(C),or(D) of paragraph (1). No such order may be issued by the Commission with respect to a Federal power marketing agency upon application of a State regulatory authority."

Paragraph 210 (a) (1) provides:

> "Upon application of any electric utility, Federal power marketing agency, qualifying cogenerator, or qualifying small power producer, the Commission may issue an order requiring
>
> (A) the physical connection of any cogeneration facility, small power production facility, or the transmission facilities of any electric utility, with the facilities of such applicant,
>
> (B) such action as may be necessary to make effective any physical connection described in subparagraph (A), which physical connection is ineffective for any reason, such as inadequate size, poor maintenance, or physical unreliability,
>
> (C) such sale or exchange of electric energy or other coordination, as may be necessary to carry out the purposes of any order under subparagraph (A) or (B), or
>
> (D) such increase in transmission capacity as may be necessary to carry out the purposes of any order under subparagraph (A) or (B)."

2/ In a January 11, 1980, letter to all utilities operating in WAPA's Flatiron Load Control Area, Mr. Peter G. Ungerman, Denver Area Manager of WAPA, proposed to offer coordination agreements which would in essence extend the benefits of power brokering to a region which included the hydro-based systems of the Lower Missouri system.

Federal resources on the Colorado River would be more fully integrated with regional utilities but for historical developments which left unexploited substantial power potential along the river. These developments resulted from legal confrontations between PMAs and investor-owned utilities ("IOUs") of the Pacific Southwest over market shares, confrontations exacerbated by the preference granted to cooperatives and public bodies in the sale of Federal power. Because many utilities now seeking to join the Inland Pool and develop and acquire resources in Colorado were parties to those earlier confrontations, it is useful to examine those events. A summary has been included as Appendix B.

I.D. Regulatory Agency Role In Power Pooling

An important aspect of power pooling is the role which regulatory agencies can and should take in studying and encouraging coordination among utilities. The history of the development of the FCG is an example of the way in which a state commission exercised its influence and authority to encourage power pooling (see pages 42 to 46).

Pooling has several obvious impacts upon State regulation. First, capital expansion programs can be substantially affected by the degree of pooling or the availability of joint ventures to construct large base load generating units. In recent years, constructing generation units or placing units in service has precipitated many requests for retail rate relief. Second, the degree to which utilities operating within the jurisdiction of a state commission can be centrally dispatched and operated has a material effect upon the cost of energy. This effect can be a source of rate volatility in those many states which allow revenues from interchange sales and costs of purchased power to be flowed through fuel adjustment clauses automatically with little or no prior State commission review. Centralized economic dispatch tends to ameliorate the volatile swings in energy costs which often accompany outages of the generating units. Pooling also makes the pricing, if not the cost, of replacement energy more predictable than it does a less structured industry organization.

Despite the significance of interchange upon retail rates, interchange rates are beyond the jurisdiction of State commissions.

State regulatory agencies possess two major tools which may be employed to encourage coordination among utilities -- the authority to certify and license facilities and the authority to control sales and rates. The established power pools analyzed in this report operate in eighteen states. The regulatory agencies in all but one of these states have the authority to regulate sales to ultimate customers by investor-owned utilities, have the authority to regulate sales by public authorities, and, in nine states to regulate sales by cooperatives. Approximately one-third have authority to regulate intrastate sales for resale, to regulate rates for transmission on account of others, and to prescribe rates for interchange power. More than half have the authority to authorize and require interconnections. Appendix C provides detail of the regulatory agency authority in these areas and indicates that agencies in states served by Inland Power Pool members also possess these authorities.

The Federal Energy Regulatory Commission (FERC) alone has jurisdiction over the terms and conditions of power pool transactions, but has no power to mandate the creation of power pools. As a result, a bewildering array of cost allocations, reserve requirements, energy pricing, capacity pricing and ranges of available services has been deemed permissible by the Federal Power Commission (FPC) and FERC.

FERC's exclusive jurisdiction over pooling and interchange does not preclude a state role in deciding pooling issues. Indeed, several facets of the Federal Power Act expressly enable State commissions to acquire jurisdiction over pooling matters that would otherwise be beyond their control.

State commissions are granted the power to seek interconnections under Section 202 of PURPA, which is Section 210 of the Federal Power Act ("FPA"), and under Section 209 of the FPA may seek referrals of matters from FERC, hold joint hearings or conferences with FERC and seek assistance of FERC experts on rates, valuation or other topics. When FERC refers matters to a board composed of members from the States, Section 209 provides that:

> "Any such board shall be vested with the same power and be subject to the same duties and liabilities as in the case of a member of the Commission when designated by the Commission to hold hearings. The action of such board shall have such force and effect and its proceedings shall be conducted in such manner as the Commission shall by regulations prescribe. The board shall be appointed by the Commission from persons nominated by the State Commission of each State affected, or by the Governor of such State if there is no State commission."

Section 207 of the Federal Power Act expressly grants State commissions that power to initiate FERC proceedings. 1/

The first prerequisite to a State commission's improving pooling and coordination is a thorough knowledge of the existing contracts and capabilities of utilities serving the States and surrounding States, including utilities over which State commissions have no jurisdiction. The acquisition of this knowledge is often more difficult after a pool is formed because nearly every pooling and coordination agreement establishes committees to which major pooling functions are delegated. For the most part, the deliberations and decisions of these bodies are not documented in public files. Legal discovery against the pool and its members is usually required in order to obtain documents relating to the actions of pool committees. Even in discovery proceedings against a member company, the Pennsylvania-New Jersey-Maryland (PJM) Interconnection policy is to release only

---

1/ "FURNISHING OF ADEQUATE SERVICE

Sec. 207. Whenever the Commission, upon complaint of a State commission, after notice to each State commission and public utility affected and after opportunity for hearing, shall find that any interstate service of any public utility is inadequate or insufficient, the Commission shall determine the proper, adequate, or sufficient service to be furnished, and shall fix the same by its order, rule, or regulation: Provided, that the Commission shall have no authority to compel the enlargement of generating facilities for such purposes, nor to compel the public utility to sell or exchange energy when to do so would impair its ability to render adequate service to its customers." [49 Stat. 853; 16 U.S.C. 824f] that information to a State commission concerning members operating under the Commission's jurisdiction. Needless to say, this policy serves to limit State knowledge of the PJM Interconnection.

Pool committees typically make many informative studies and critical decisions on accounting, pricing, maintenance scheduling and other utility actions which affect the retail cost of service. State commissions are often without access to such information. Where, as in Colorado, the Commission is taking steps to foster pooling, it is advisable to assure that information on the pool's development and operations can be easily obtained.

The need for such assurances has become clear in this study. TEPCO and Plains G&T Cooperative, potential members of IPP, have both declined to answer data requests of the Colorado PUC. Neither entity operates in Colorado.

The pooling capabilities of any aggregation of utilities is also difficult to define. The benefits of enhanced coordination or pooling are typically defined by elaborate simulations of future operations under alternative expansion plans based upon data largely unavailable to the public. Again, discovery is required together with analytical capability. These studies require more funding and human resources than are typically available to a State commission. Fortunately, States which certify the construction of generating and transmission facilities have a logical forum in which to require regulated utilities to perform the necessary studies.

A quantitative study of the potential benefits of enhancing the operational integration of the Inland Power Pool will be described in a subsequent section of this report. Completion of that study is contingent on the availability of additional funding.

II. INTRINSIC POOLING ISSUES */

II.A. Background

A system planner is charged with developing a plan for expanding an electric utility system which is expected to minimize the capital costs and operating costs of rendering adequate service during some future time period. Usually, planners rank plans economically by estimating the present worth of the future revenue requirement under each alternative plan.

The starting point for such a plan is the sequence of projected annual peak demands and the pattern of variation (load shape) in the demand between annual peaks. Because electricity cannot be economically stored (except in the form of elevated

*/ Intrinsic pooling issues are those pooling issues not of unique concern to state regulators.

water), the planner must develop a sequence of facility additions which are sufficient to produce and deliver the requisite power coincident with the pattern of occurrence of, and the estimated growth in, demands. One major benefit of pooling is that load diversity between pool members tends to make their combined peak loads lower than the sum of their individual peak loads.

II.B. Optimal Mix

Each system has a daily, weekly, seasonal and annual load variation pattern which can be served optimally with an appropriate "mix" of generating usage types. The optimal "mix" for a pool can often require less capacity and lower costs than the combined optimal mixes of pool members.

Among systems, such as those in Colorado which contain large amounts of hydroelectric capacity and which have large amounts of thermal capacity, the pool capacity requirement can be much less than the combined requirements of members operating in isolation. Hydroelectric capacity is an important source of peaking energy in many parts of the United States. Most hydro capacity is limited to water runoff in its dependable ability to produce energy. The value of hydro power is often determined by the cost of energy from thermal resources which would have to be built and operated in its absence. This value is usually higher for a pool than for the pool member owning hydro capacity.

To take account of (i) the finite probability of failure associated with every piece of equipment, (ii) the possibility that demands will exceed those forecast and (iii) the chance of delays in constructing new facilities, the planner deliberately causes redundancy in his planned system by designing increments of reserve production and transmission capacity.

II.C. Installed Reserve

The redundant production and transmission capacity is referred to as installed reserve. It is provided in addition to the amounts of capacity which planners forecast will be needed to serve peak period demands. In the case of generation, installed reserve typically varies from 10% to 25% of the anticipated annual peak demand.

II.D. Transmission Reserve

Transmission reserve provides redundancy for both transmission outages (to enable continued deliveries during transmission outages) and generation outages (to enable the importation of distant resources when local production resources experience outages). In the absence of equipment outages, the amount of unused transmission capability during peak period is typically 100% of the capacity being used, or approximately one-half of the installed transmission capacity.

II.E. Operating Reserve

Once the system is built, system operators also take into account the finite probability of equipment failure by continuously operating their facilities so that an outage of one or two critical facilities can be withstood without interrupting service to customers. With this end in mind, a utility connected to others in a coordinated group typically operates unloaded generating capacity equal to 5-7% of estimated daily peak demands. This unloaded but available capacity is called <u>operating reserve</u>.

In general, coordination and pooling enable utilities to lower reserve margins, install less expensive capacity and operate more efficiently. These benefits are attributable to the synergism which results from coordination. Fewer coordinated resources need to be utilized to render service at an equal or improved level of reliability and cost, as compared to that achievable with isolated resources.

II.F. <u>Economies Of Scale-Generation</u>

Many factors must be considered in selecting a generating unit size. Because capital cost per megawatt decreases and efficiency increases as the capability of a generating unit is increased -- at least until units attain a size of several hundred megawatts -- the designer of a small electric utility system desires to add as large a unit as practicable. One rule of thumb is that

$$\left[\frac{\text{Capital cost of large unit}}{\text{Capital cost of small unit}}\right] = \left[\frac{\text{Capacity of large unit}}{\text{Capacity of small unit}}\right]^{0.8}$$

Accordingly, a doubling of unit capacity would increase cost by only 74%.

Units of 1,300 MW are now in utility service but are obviously too large for individual systems as small as those operating in Colorado. Irrespective of a unit's capacity in absolute terms, installing a unit which is extraordinarily large compared to the peak demand and other existing units of a system would require ratepayers to absorb large costs for excess capacity until demands grew to a point at which the new capacity would be fully utilized. This is one fundamental problem facing all utilities: Long-term growth in demand occurs continuously in small increments but optimally priced generating capacity must be added in large amounts.

Additional impediments to the installation of large, efficient units face a small system on a day-to-day basis. In order to assure continuity of service, operators continuously operate unloaded capacity (spinning reserve) sufficient to absorb the loss of the largest load-serving facility. Fully loading a large new unit may increase the spinning reserve requirement. On the other hand, operating a large, new unit at substantially reduced output would be wasteful because the most efficient loading on a generating unit is at or near its maximum design capacity.

A small utility system is especially advantaged by pooling. If isolated, a small system must carry unduly large installed and operating reserve margins and forego the efficiencies and capital savings attributable to large base load units if it is to operate with a modicum of reliability. Even the large systems serving Colorado are relatively small by industry standards.

Each of these limitations can be mitigated or eliminated if a small system can build high capacity interconnections with one or more other utilities and then coordinate its planning and operations with other utility systems. These same principles apply to coordination of much larger systems, although the percentage savings are less significant, when compared to total costs, than the percentage savings realizable through coordinating small systems.

A small system can reduce its economic risks if it can purchase small entitlements in a number of separate, large generating units and thereby "diversify" its resources portfolio. These significant advantages of coordination also provide the small system with insurance against extended outages of existing, low-cost resources and against unforeseen delays in constructing its own capacity independently. One objective of enhanced pooling should be a contractual mechanism which enables all members the opportunity to participate in major new resources constructed by pool members.

High capacity (or strong) interconnections with neighboring systems provide a market for, and a source of, excess capacity. Most importantly, the largest contingency of a coordinated group is a lesser percentage of the group's combined peak than that percentage would be for any individual utility in isolation thereby reducing operating reserve requirements. In addition, percentage installed reserve requirements are reduced for the combined group.

Large generating units are beneficial, even in the absence of economies of scale, because of the institutional hurdles which the proponents of a new resource must clear. A 100 MW resource faces the same hurdles in most cases as does a 1,300 MW resource. Accordingly, judicious planning calls for clearing the hurdles with as large a resource as possible. 1/

Reliability is also enhanced by strong ties. As more potential sources of supply are made available to serve loads through such ties, the probability decreases that simultaneous outages of generating equipment will occur in amounts sufficiently large to cause interruptions of service. The measurement of such probabilities and the selection of a proper design probability are important aspects of a good system plan.

1/ It appears that a utility would risk "putting all its eggs in one basket" by seeking to construct one large facility instead of several smaller facilities. Nonetheless, at least two additional reasons support the choice of large units. First, a proponent of several small generating units could be legitimately criticized for despoiling several sites instead of one. Second, the proponent of a large unit can mitigate its risk by trading a percentage entitlement in its new plant for a similar entitlement in a large new plant of another utility, thereby reducing the risk that <u>all</u> its new capacity will be delayed. This principle applies to both large and small utilities.

Another important aspect of coordination is the economy of scale associated with transmission. As large units are constructed by large coordinated groups, transmission requirements can increase substantially, both for emergency and economy purposes. Larger units mean that larger contingencies must be withstood. As a result, more transmission capacity must be built which is not normally used for power deliveries but is instead "held in reserve" to carry the incremental power flows which result from unplanned outages of generating or transmission facilities.

Transmission of power, both within and between large systems, can be accomplished in large MW blocks over long distances with Extra High Voltage ("EHV") transmission at very low per unit prices, losses and right-of-way requirements compared to costs of transmission at lower voltages. The Bonneville Power Administration determined that the relative costs per megawatt mile of the capacity to transmit power in 10,000 MW-mile blocks are 4.4 for 230 kV lines and 1.0 for 500 kV lines.

II.G. The Effect Of Coordination Upon Operating Costs

As noted above, substantial operating savings can be achieved by a coordinated group in the commitment and dispatching (loading) of generating units.

II.G.1. Unit Commitment

"Commitment of units" is the process of starting up and synchronizing generators. For generators driven by steam turbines, this can be a time consuming and expensive process. For hydroelectric and internal combustion turbines, the commitment process consumes considerably less expense and time.

Most steam units (specially-designed cycling units excluded) cannot be started up and shut down in the course of a day's operation without creating substantial thermal stress on unit components. 1/ Therefore, steam units committed for service beginning on a Monday are usually operated for at least five days.

By coordinating their unit commitment, utilities in a coordinated group can often reduce the number of steam units which must be started and thereby assure that the units which are started are more heavily and efficiently loaded.

1/ Additional problems are introduced when steam units are required to undergo daily megawatt "turndown" to some minimum load. In recent years, increasing numbers of large-size nuclear and fossil fuel units have been constructed which are not, or cannot be, "turned down." This puts a burden on previously-constructed fossil-steam units to meet the needs of daily system load pickup and minute-to-minute system regulation, needs they were often not intended to serve.

II.G.2. Economic Dispatch

Economic dispatch is the process by which an operator (or computer) determines how to allocate most economically increments or decrements of loads between the available and operating generating units. This is an important matter to an electric utility (or pool of such utilities) because the demand on its total plant is constantly changing, and, in large systems, there are large numbers of generating units to be controlled. Hence, selection of the proper loading combination can achieve substantial savings over the production costs incurred by operating suboptimal combinations of generating units.

The system which performs this dispatch function is based upon a well-known principle that the available production sources will serve the load at the lowest total cost when each such unit or production source not fully loaded is operating at the identical incremental cost. A substantial benefit of fully integrated operations is that a centrally-dispatched pool can and does eliminate, on a minute-to-minute basis, the discrepancies between incremental operating costs of generating units. In the absence of central dispatching, such discrepancies could well exist and result in a substantial waste of resources. This unnecessary waste is undoubtedly occurring in the areas served by the Inland Power Pool members and will continue until a unified approach is taken to dispatching the Pool's units.

II.G.3. Control Area

Interconnected electric utilities are customarily subdivided into control areas along corporate or ownership boundaries principally for historical reasons. From a technical standpoint, the boundaries are largely arbitrary, with the result that the number of control areas in nearly every region of the country could be reduced sharply, and the geographic and electrical coverage of the remaining control areas increased, with salutary results. A formal power pool requires such a consolidation of control areas in order to achieve optimal savings.

Once the appropriate resources have been committed in the course of an operating day, generating units under an optimal dispatching scheme automatically serve incremental load on a second-to-second basis from the unit which has the lowest incremental cost. The total and incremental load which must be served by a given control area are determined by obtaining the algebraic sum of power flowing into and out of the area through all its interconnections with adjoining control areas. If, in addition, an export is planned, additional generation in the amount of the export plus associated losses would be scheduled for the control area. The information on power flows to and from a control area is brought to a central processer where the scheduled amount of exports and imports is compared to the measured exports or imports. If there is an excess of area generation over that required by the schedule, then a signal is sent to the appropriate generators to lower output. If, in contrast, the schedule shows an insufficient amount of power being exported (or too much power being imported), then a signal goes to the generating units to raise generation. A control area cannot direct power to another specific control area unless it is connected radially to only that control area. Instead, the receiving control area must reduce generation at the same time and in the same amounts as the simultaneous increase in production in the sending control area. Unless control areas are consolidated, there can be no assurance that the optimal combinations of generators are loaded to the optimal levels.

The manner in which four existing power pools are dealing with issues delineated thus far in this report is analyzed in the following section. The pools - the New England Power Pool, the Pennsylvania-New Jersey-Maryland Interconnection, the Florida Electric Power Coordinating Group and the Mid-Continent Area Power Pool - were chosen as subjects of discussion due to the diversity of agreements, membership, arrangements and operations.

III. OVERVIEW OF EXISTING COORDINATION ARRANGEMENTS

III.A. THE NEW ENGLAND POWER POOL (NEPOOL)

III.A.1. Summary of Pool Statistics

The combined resources of NEPOOL represent 21,217 MW of capacity with systems ranging from 1 MW (Princeton Electric Light) to 4,477 MW (New England Power Company). The 64 systems on NEPOOL represent 12 investor-owned utilities, 32 municipally-owned utilities, and the Vermont Electric Power Company (six investor-owned utilities, twelve municipally-owned utilities and two rural electric cooperatives). Annual sales of NEPOOL members range from 6606 MWH (Princeton Electric Light) to 19,963,677 MWH (Northeast Utilities). Appendix C, Table 1 compares the members of NEPOOL on the basis of capacity, summer and winter peaks and annual sales.

III.A.2. Area, Members, History of Development

The New England Power Pool (NEPOOL) provides 99% of the electricity generated in New England. Its membership consists of forty-five utilities - twelve investor-owned, thirty-two municipally-owned, and the Vermont Electric Power Company which represents six investor-owned utilities, twelve municipally-owned utilities and two rural electric cooperatives.

NEPOOL has evolved to its present stage in an effort to coordinate to the extent possible the operations of utilities in New England. The early efforts focused on joint development of power supplies. In 1920, three utilities created the Montaup Electric Company which was to become the major power supplier for the three utilities. In 1954, ten New England utilities formed the Yankee Atomic Electric Company to construct a nuclear plant in Massachusetts.

A proposal to form a power pool was developed in 1966 by the nine largest utilities in New England. After several editions of the proposal were reviewed, the NEPOOL Working Committee was established in 1969 to draft a formal agreement. At the same time the New England Power Exchange (NEPEX), the central dispatch operation of NEPOOL, was established. The current NEPOOL agreement was signed on November 1, 1971 and has since been amended several times.

III.A.2. Description of Arrangements

The New England Power Exchange (NEPEX) serves as the operating arm of NEPOOL, with responsibility for central dispatching of bulk power facilities. Plans for expansion and regional load forecasting studies are developed by NEPLAN, the planning arm of NEPOOL. Voting rights of each NEPOOL member are based on the adjusted annual peak load of that member utility. Seventy-five percent affirmative Management Committee votes are required to constitute a decision.

III.A.3. Pricing

The exchange of energy and operating reserves among NEPOOL members involves continuous transactions. As the units are scheduled and dispatched on the marginal cost principle, ownership of the unit does not enter into the dispatch decision. Additionally, as transmission lines between members are free flowing, there are no "individual" transactions occurring, or at least no transactions capable of being identified as such. Therefore, members of NEPOOL cannot compute the cost of providing or receiving service at the time of the transaction. Costs are determined after the transaction has occurred.

Three steps are involved in determining services rendered and costs incurred for economy flow service, scheduled and unscheduled outage services and deficiency service:

1. The dispatch of each participant's sytem is simulated after-the-fact to determine how that participant would have met its load in the absence of NEPEX. The result is referred to as the participant's Own Load Dispatch.
2. The operation of each generating unit of each participant under the Own Load Dispatch assumption is then compared with the actual NEPEX dispatch results, and the differences in level of output for each hour are classified as services either received from or provided to NEPEX.

3. The participant then makes payments to or receives payments from NEPEX for these services according to the decremental or incremental costs associated with the differences in level of output (plus adjustments, in certain cases).

Payments to and from NEPEX based on the three steps above are debited or credited to the NEPEX Savings Fund. Usually, the Fund receives more payments than it disburses, and the residual is deemed to be savings. Savings are disbursed to members according to a calculation of shares. Shares are derived as follows: one share for each MWH of energy or MW operating reserve service furnished to the pool for an hour; and one share for each MWH of economy flow service or MW operating reserves received from the pool for an hour.

III.A.4. Maintenance

Standards for maintenance and maintenance schedules are coordinated through the Maintenance Scheduling Task Force (a subcommittee of the NEPOOL Operations Committee). In developing schedules, the Task Force takes into account peak period diversities among members. A member may request that the Task Force alter schedules and, if dissatisfied with the Task Force decision, the member may appeal further to the Operations Committee. Maintenance scheduling decisions made by the Operations Committee are final.

The billing procedures for scheduled outages encourage members to adhere to the maintenance schedule. A system receiving scheduled outage service must pay its applicable decremental costs (based on Own Load Dispatch) plus a loader equal to the amount by which the weighted average incremental cost of scheduled outage service provided to all members during the power year exceeds the weighted average decremental cost paid by the member at the time it receives the service. In order for this system to be self-sustaining, some entities pay more for scheduled outage energy than their decremental cost at the time of use in order to reimburse entities in the opposite situation. This system eliminates the disadvantage which a member would otherwise incur by having to conduct maintenance when replacement power costs were high.

Members furnishing scheduled outage service are paid their incremental cost of providing that service.

III.A.5. Transmission

The NEPOOL Management Committee is responsible for the review of members' transmission plans, in order to ensure the existence of the optimal transmission grid in New England. The NEPOOL Management Committee has the authority to deny a member utility permission to build additional facilities or require a member utility to construct additional facilities. Members of NEPOOL are guaranteed access to all pool transmission facilities (PTFs) for transferring economy energy, scheduled outage service, unscheduled outage service, deficiency service, and long-term commitments.

III.A.6. Planning

NEPOOL provides planning guidelines and serves as the coordinating body for future plans, which are developed by the individual utilities. Planning guidelines are prepared on the assumption that NEPOOL members operate as a single unit. The guidelines are developed by the Planning Committee, approved by the Management Committee, and disseminated to member utilities of NEPOOL. It is intended that the guidelines influence the individual members in their planning for types and sizes of additional facilities.

A facility planned by an individual member may be eligible for "Pool-Planned" status. This status has important financial ramifications for the member; a facility which is thus designated receives revenue from other members for use of the facility. Additionally, a Pool-Planned facility has unlimited access to the regional transmission grid (Pool Transmission Facilities or "PTF"). Pricing of these PTF transactions is conducted according to PTF billing procedures described below. The benefits associated with being designated Pool-Planned encourage members to adhere to the NEPOOL Planning guidelines.

In the event that the Management Committee finds a member's plan would have an adverse effect on the reliability of

NEPOOL, the Committee has the authority to instruct the member to develop alternate plans or construct other facilities.

III.A.7. Transmission Pricing

The pricing of transmission transactions within NEPOOL is divided between Extra-High-Voltage (EHV-PTF) billing procedures (230 Kv or more) and lower voltage PTF procedures.

Transmission costs *per se* are not factored into the price of a participation transaction. To cover the cost of transmission, a reliability charge is assessed on each member on a daily basis. The daily reliability for a member is the product of:

1) The wheeling rate for EHV-PTF, derived by determining aggregate EHV-PTF costs for the previous years, and dividing that sum by either

   i) NEPOOL objective capability or

   ii) actual NEPOOL capability on June 30 of the previous year -

   whichever is less.

2) The difference between outage services (both scheduled and unscheduled) received by the member and the capacity of the member that was available to NEPEX but not used by NEPEX. This component is determined on an hourly basis.

3) The quotient of KW located on the member's own transmission system divided by the member's system capability.

Daily reliability charges are credited to the transmission fund. Funds are distributed monthly to members on the basis of the member's percentage of total EHV-PTF ownership costs.

III.A.8. Lower Voltage PTF

Lower voltage pricing is based on lower voltage PTF cost per peak KW of demand, an adjustment factor, and kilowatts of entitlement subject to transfer. Lower voltage PTF cost per peak KW of demand is derived by dividing the aggregate annual cost to the owner of the lower voltage PTF by the sum of the adjusted annual peaks of both the owner and those segments of other systems served over the owner's lower voltage PTF. The Adjustment Factor is the sum of the adjusted annual peaks of all members divided by NEPOOL capability.

The product of these three factors, divided by 12, yields the monthly payment made by the user of the lower voltage PTF to the owner.

III.B. PENNSYLVANIA-NEW JERSEY-MARYLAND INTERCONNECTION

III.B.1. Summary of Pool Statistics

The eight large investor-owned utilities and three associate members of the PJM interconnection have a combined capacity of 44,891 MW. The lowest capacity member in PJM has 115 MW (Luzerne Electric Division) and the highest has 9023 MW (Public Service Electric and Gas Company). Annual sales of PJM members total 122,755,842 MWH, ranging from 5,274,640 MWH (Atlantic City Electric Company) to 29,341,889 MWH (Public Service Electric and Gas Company). Appendix C, Table 2 contains a comparison of PJM membership with respect to capacity, summer and winter peaks and annual sales.

III.B.2. Area, Members, History of Development

In 1979, the Pennsylvania-New Jersey-Maryland Interconnection (PJM) supplied 47% of the energy generated and transmitted in the Northeast region, and nearly all of the electric power generation and sales in all or parts of five states and the District of Columbia. The membership of PJM includes eight large investor owned utilities and three associate members.

PJM was organized in 1927 and began operating in 1928 under a formal agreement.

III.B.3. Description of Arrangements

The PJM Management Committee is the focal point for PJM decisions and policymaking. Member utilities appoint one representative to serve on the Committee. Decisions must be unanimous and are binding on all members. The Staff reporting to the Management Committee is responsible for operation and maintenance of the bulk power supply facilities, coordination of facilities with other pools, and recording interchange accounting.

Each member of the Management Committee of PJM assigns representatives to the Operating Committee, the Planning and Engineering Committee and other committees established by the Management Committee.

III.B.4. Planning

The Planning and Engineering (P&E) Committee is responsible for the development of a recommended "Forecast Requirement" for generating capacity of the Interconnection. The Forecast Requirement, and the resulting allocation of forecast obligation to each member of PJM, are based on studies conducted by the Capacity and Transmission Subcommittee, the Generator Unavailability Subcommittee and the Load Analysis Subcommittee. In addition, the P&E Committee reviews the plans of PJM members. It may inform a member that its plans have potential adverse effects upon the Interconnection and request the member to modify plans.

The recommendations of the P&E Committee are considered by the Management Committee which ratifies the Forecast Requirement and allocation to members. Prior to each planning period, each member is obligated to install or otherwise arrange for sufficient Contract Capacity and associated transmission facilities to carry its equitable share of the Forecast Requirement.

Members of PJM are responsible for an equitable share of the "Accounted-For" Requirement, which is determined and allocated in the course of each planning period. The Accounted-For Requirement of each member is equal to its Forecast Obligation for a Planning Period, specifically adjusted for differences between (i) actual average weekly peak loads from those forecast and (ii) the actual average capability of units from those forecast. A member that has less Contract Capacity than its equitable share of the Accounted-For Requirement is considered deficient by the amount of the difference. Contract capacity is defined as the sum of the net capabilities of all generating units of a member company increased by purchases and decreased by (1) transmission limitations or other factors which limit simultaneous utilization of those units (determined by the Operating Committee) and (2) sales to PJM members and others.

Each member meets its Forecast Obligation by submitting to the Management Committee a plan incorporating (1) its installation of generating capacity, (2) purchases of generating capacity and energy outside the terms of the PJM Agreement and (3) purchases of additional capacity from sources within PJM.

The PJM Interconnection is assumed to conduct all transactions as a single system with economic dispatch and free flowing ties. The units of all members are centrally dispatched by computer from the PJM control center in Valley Forge, Pennsylvania. As is the case with NEPOOL, PJM transactions are determined after-the-fact. A PJM member which is identified after-the-fact as a purchasing company is deemed to have purchased energy from the pool and not a specific other party.

The operation of the PJM Interconnection, a power pool with approximately 48,000 MW of installed generating capacity, illustrates the possible degree of coordinated pool operations. Mr. Jon R. Tieman of Baltimore Gas and Electric Company described the PJM operation to the Public Service Commission of Maryland in 1978 in Case No. 6807 (Phase II) as follows.

> "PJM operates as one system with free-flowing intercompany tie lines. This fully coordinated operation assures greater reliability and economy than if each company operated independently. Through a computer complex, vital information is exchanged between the Interconnection Control Center Office in Valley Forge, Pennsylvania, and operations centers of member companies and adjacent pools. On a daily basis, the company dispatchers notify the Interconnection dispatchers of

available generating units and the planned outage of transmission facilities in their systems. Forced outages of both generation and transmission are, of course, updated continuously. PJM dispatchers constantly analyze the flow of power and dispatch the most efficient generating units while safeguarding the integrity of the system. Within PJM, 54 tie lines permit pooled operation from 547 generating units at 117 power stations. To assist the dispatchers in this analysis, a computer at the PJM control center analyzes the power needs of the PJM companies' customers. Every 15 minutes the computer simulates unplanned outages to determine any overload conditions that would exist if the outage were to occur. Five times each minute line loads are monitored, and every 3 1/2 seconds the computer reviews generation within all PJM companies."

When a party receives energy from the Interconnection in an hour, it is charged at a rate per KWH half-way between its replacement value per KWH and the weighted average cost per KWH of all parties supplying energy to the Interconnectiion during that hour. When a party supplies energy to the Interconnection in an hour, it receives a credit at the rate per KWH half-way between its own cost per KWH and the weighted average replacement value per KWH of all parties receiving energy from the Interconnection.

III.B.5. Emergency Procedures

During emergency situations, PJM continues to operate as a single unit. Members must make every effort to assist a troubled system up to the point during the emergency where such action could be detrimental to PJM equipment or reliability. At this point, PJM policy is to open interarea transmission lines in order to retore normal operations. PJM's emergency procedures conform with the standards established by North American Power Systems Interconnection Committee (NAPSIC).

III.B.6. Maintenance

Maintenance schedules for PJM members are developed by the Maintenance Committee, which attempts to coordinate individual members for a specific schedule. PJM members, unlike NEPOOL members, have no direct incentive to follow a maintenance schedule closely; systems desiring not to comply with schedules adopted by the Maintenance Committee must take their grievances to the Management Committee.

III.B.7. Transmission

Transmission costs asociated with the various transactions among PJM members are separately negotiated between the individual members. However, the PJM agreement follows the principle that each member will provide adequate transmission to serve its own customers, and make any excess transmission capacity available to the pool. The nature of the PJM agreement (central dispatch with free flowing ties) guarantees PJM members access to necessary transmission capacity. No separate charges for transmission services are incurred on transactions between pool members or on transactions carried out on the pool's behalf with non-members. However, a single member must arrange for its own transmission of bilateral (non-pool) transactions with non-members.

III. C. FLORIDA ELECTRIC POWER COORDINATING GROUP

III.C.1. Summary of Pool Statistics

Appendix C, Table 3 shows the membership of FCG, their capacities at the time of summer and winter peaks and their annual sales. Of the total combined capacities of FCG members, the highest is represented by Florida Power and Light - 10,941 MW - and the lowest capacity is that of Reedy Creek Utility Company. Members represented on Table 3 as having zero capacity purchase their required capacity from other FCG members. Annual sales of FCG members range from 17,046,741 MWH (Florida Power Corporation) to 40,602 MWH (Florida Power and Light Company).

III.C.2. Area, Members, History of Development

In 1972, as part of an effort to further encourage coordination between utilities in Florida, and reap the benefits from increased coordination, the Florida Operating Committee (FOC) created the Florida Electric Power Coordinating Group (FCG). The FOC had been in existence since 1959, when its original three members built interties in order to ensure coordination during emergency outages and maintenance periods. The membership of FCG consists of four large investor-owned utilities, two small investor-owned utilities, eighteen municipally-owned utilities, and thirteen rural electric cooperatives. In 1978, the combined resources of the FCG represented 23,124 MW of generating capacity or 99% of the generation and transmission capacity in the State of Florida.

III.C.3. Description of the Arrangement

FCG currently conducts its energy transactions using a computerized energy broker system. The system was installed in 1979, after studying the savings realized from a teletype energy broker system in use from March to December, 1978. Each member utility provides FCG with hourly price quotes, for both purchases and sales, as well as the incremental and decremental costs associated with each. A time-sharing system matches those members willing to buy with those willing to sell energy on an hourly basis. Savings resulting from these transactions are shared among members. The formula for sharing savings is based on the pairing of buyers and sellers according to the spread between the seller's cost and the buyer's value. Savings are shared equally between the two utilities involved in the transaction.

Members of FCG continue to develop bilateral agreements for transmission arrangements and interconnection arrangements. Informal agreements are developed to cover such issues as (1) access to capacity, (2) installed capacity, (3) operating reserves, (4) emergency procedures and (5) maintenance scheduling.

III.C.4. Transmission

The majority of transmission facilities in Florida are owned by Florida Power and Light Company (FPL) and Florida Power Corporation (FPC); each handles transmission pricing differently.

Florida Power Corporation levies a standard transmission tariff, regardless of distance, entry or exit points.

Florida Power & Light negotiates separate transmission agreements with any utility within FCG wishing to use transmission facilities. The agreements specify charges according to distance wheeled, and entry and exit points. In 1978, the agreements numbered 50.

The dual nature of transmission pricing within FCG may cause difficulties for a utility wishing to wheel power to a utility located outside FCG. Particularly in the case of economy energy transactions, savings may not be realized if the utility providing the service must wheel over lines owned by both FPC and FPL. In this case, the transmission charge would be higher than if a uniform system for pricing transmission transactions were developed by FCG members.

FCG develops and updates guidelines for operating reserves on an annual basis. Although the agreements governing operating reserves policies are informal, guidelines have been adopted by FCG members. According to the Guidelines, recommended spinning reserve levels equal at least the peak capacity rating of the largest unit within FCG, and recommended daily spinning reserve and supplemental reserve levels equal at least the peak capacity of the two largest units within FCG.

The System Planning Committee within FCG undertakes the task of increasing coordination among FCG members. In line with this responsibility, it conducts transmission studies, evaluates the transmission plans of members, and makes recommendations on plans. The Committee, however, has no enforcement power and therefore cannot reject the plans of FCG members.

III.C.5. Maintenance

The majority of FCG's members develop their maintenance schedules independently. However, those utilities which sell 88% of the electricity sold in Florida coordinate their maintenance schedules through FCG. The maintenance schedules of the six large utilities are disseminated to other FCG members, who plan their maintenance outages accordingly. This aspect of FCG is overseen by the Operating Committee which reviews the maintenance schedules of all FCG members. As is the case with the System Planning Committee, the Operating Committee has no authority to mandate maintenance schedules. Individual utilities comply with requests to change schedules at their discretion.

III.C.6. Emergency Procedures

The Guidelines issued by the North American Power Systems Interconnection Committee (NAPSIC) serve as the basis for informal agreements regarding emergency procedures. All utilities are expected to cooperate in providing emergency power. FCG's guidelines delineate 11 phases of emergency operations including recommended courses of action should these emergency situations occur.

III.D. MID CONTINENT AREA POWER POOL (MAPP)

III.D.1. Summary of Pool Statistics

The membership of MAPP consists of 12 investor-owned utilities, 9 generation and transmission facilities including the Federal Western Area Power Administration, 3 public power districts and 3 municipally-owned utilities. As Appendix C, Table 4 demonstrates, capacity of MAPP members (totaling 25,580 MW) ranges from 24 MW (Heartland Consumers Power District) to 2,492 MW (Western Area Power Administration-Billings Area). Annual sales of all MAPP members total 81,958,634 MWH; Northern States Power Company has the highest annual sales (20,754,496 MWH) and the Dairyland Power Cooperative has the lowest annual sales (84,478 MWH).

III.D.2. Area, Members, History of Development

The Mid-Continent Area Power Pool (MAPP) represents more than 90% of the generating capability in all of Iowa, Minnesota, Nebraska, North Dakota, most of South Dakota and portions of Illinois, Montana and Wisconsin.

The membership of MAPP consists of 12 investor-owned utilities, 9 generation and transmission utilities, 3 public power districts, and 3 municipals; the pool had its origins in the coordination and cooperation of the Upper Mississippi Valley Power Pool, the Iowa Power Pool and the Nebraska Public Power Systems.

III.D.3. Description of Arrangments

Unlike PJM, FCG and NEPOOL, MAPP does not operate from a unique control center; it has fairly decentralized operations. The location of the control center is determined by the Management Committee (see below), which contracts with a MAPP member to serve as the control center. Each member is responsible for negotiating a contract with the control center, although associate members of the pool pay a standard fee. The structure of the fee is as follows:

a. $100 for each fiscal year where the Annual System Demand for the previous fiscal year is 5,000 kilowatts or less, plus

b. $30 for each 5,000 or fraction thereof by which Annual System Demand exceeds 5,000 kilowatts.

This fee structure is of benefit to members, who are free to negotiate the costs of services with the control center, but leaves Associate Members at a disadvantage.

The MAPP Agreement stipulates in Section 14.04 that

> "Each party shall retain the sole responsibility for the operation of its system and the utilization of the information which may be provided from the Center."

The agreement governing MAPP is administered by the Management Committee; membership and voting on the Management Committee is determined by the member's proportion of system demand.

The voting structure of the membership committee is as follows:

a. One vote for each 25 megawatts, or fraction thereof, of annual system demand up to 300 megawatts.

b. One vote for each 50 megawatts, or fraction thereof, of annual system demand from 301 to 600 megawatts.

c. One vote for each 100 megawatts, or fraction thereof, of annual system demand over 600 megawatts.

A "majority" (undefined in the MAPP Agreement) of Management Committee votes constitutes a decision, unless a dissenting member of the Management Committee takes the decision to arbitration.

This system tends to give a greater number of votes to large systems but grants to small systems a number of votes which are disproportionate for their small size.

Each representative on the Management Committee appoints a representative to the Pool Administration Committee, which is responsible for the planning and operations functions of the pool.

Planning functions are overseen by the Planning Committee. This committee recommends to the Pool Administrative Committee policies on size and types of new generating units, locations of new facilities, time frame for new facilities and ownership of new facilities.

The Management Committee determines the capacity requirements of the pool and allocates the requirement among the members. A condition of membership in MAPP is the provision of generating capacity; membership in MAPP may be cancelled should the member be found to be deficient in capacity by the Membership Committee. A member lacking sufficient capacity may purchase capacity from member and/or non-member utilities.

Dispatch is controlled by individual members although energy brokerage is controlled by an automatic brokering system located in the control center. In addition, the control center staff collects and disseminates cost information to members.

The MAPP agreement specifies operating reserve at 15% of the size of the largest online generating unit within MAPP. A member's share of operating reserve is based on its most heavily loaded unit.

Charges for spinning reserve purchases are based on either 110% of the incremental cost of the supplier, or the incremental cost plus 50% of the savings made possible to the purchaser by buying spinning reserve, whichever is greatest.

Members of MAPP are not required to provide economy energy unless the difference between the decremental cost of the buyer and the incremental cost of the supplier exceeds 0.4 mills per KWH. The price of economy energy is the incremental cost to the suplier of the energy plus 50% of the savings involved in the transaction.

A member of MAPP who is planning maintenance will be supplied scheduled outage service by another member an amount of energy up to that member's capability not required to meet its Operating Reserve obligation. If the supplier feels that by supplying scheduled outage service a hardship would be created, it is not obligated to supply the service.

The member receiving scheduled outage service pays 4.5

mills per KWH, or 110% of incremental costs to the supplier, or 110% of the receiver's decremental cost, whichever of the three is greatest.

III.D.4. Transmission

MAPP members agree to provide wheeling of sales and purchases and are reimbursed for losses and increased operating expenses involved in wheeling transactions. Transmission is handled under multilateral agreements developed separately from the MAPP agreement.

III.D.5. Emergency Procedures

During emergency periods, MAPP members will, when requested, supply and wheel emergency energy to the member experiencing the emergency; the exception to this generalization is the situation where supply of emergency energy interferes with other obligations in which case the member need not provide emergency energy. The buyer of emergency energy pays the greater of either 1.75¢ per KWH or 110% of the seller's incremental cost.

III.E.1. The Inland Power Pool (IPP)

Appendix C, Table 5, the Inland Power Pool, has been included in this report for the purposes of comparison with the other pools discussed. The 13 members of IPP represent 12,420 MW of capacity ranging from 45 MW (Plains G&T) to 2,835 MW (Salt River Project). Annual sales range from 36,200,000 MWH (Bureau of Reclamation-WAPA) to 1,235,095 MWH (Plains G&T).

APPENDIX A

Pool of Western Energy Resources and the Cactus Pool as of February 1979

The Pool of Western Energy Resources ("POWER" of New Mexico) was formed by PSNM, EPE and Plains G&T during the course of negotiating the Cactus Pool Agreement, despite continuing interest in joining the Cactus Pool on the part of POWER members. The POWER Agreement served as the basis for the joint development of the New Mexico station; its unique provisions for installed and operating reserve are worthy of further examination here.

Joint planning is governed by the desire of the parties to provide protection against the loss of the generating capacity of the pool's largest single hazard (PLSH) which was limited to a maximum of 550 MW or 15% of the projected peak, whichever was less. In a unique definition, the PLSH is equated to the loss of net generation plus the auxiliary load at the failed generating station that must, after an outage, be maintained from other generating units. A Member's Installed Reserve Responsibility (MIRR) is determined by a product of the pool installed reserve requirement times the ratio of (i) the member's peak load plus two times the member's largest single hazard to (ii) the sum of those quantities for all pool members. The pool installed reserve requirement is equal to the largest pool hazard plus 5% of the pool's projected peak demand or 18% of the pool peak load, whichever is greater. This discrepancy between the pool objective planning reserve of 15% and the minimum installed reserve requirement of 18% apparently resulted in a very unusual provision in the POWER agreement which requires no reserve sharing unless a member has installed reserves equal to 85% of its member installed reserve responsibility. The documents describing this discrepancy give no further explanation as to why a pool should plan for a lower reserve margin than it would initially establish as a minimum reserve requirement.

If a member has not provided adequate data proving that it will have sufficient available capacity to achieve the 85% MIRR level, that member is required to purchase additional installed reserve capacity from other pool members, if such capacity is available, at a rate of $4.00 per KW month.

With respect to <u>operating reserve</u> requirements, the parties agree to maintain pool operating reserves of not less than the on-line Pool Largest Single Hazard plus 1% of the hourly expected pool load. This is allocated based upon a ratio of (1) the sum of a member's load plus two times the member's largest single hazard to (2) the sum for all members of the load plus two times the member's largest single hazard. In no event is the member's operating reserve requirement to be less than 7% of the member's load or 40% of its largest single hazard, whichever is the greater for a current clock hour. Up to 25% of the operating reserve requirement may be comprised of ready reserve (available within ten minutes) or interruptible load and the remaining 75%

must be available as spinning reserve. If a member is purchasing capacity to meet its 85% of Member Installed Reserve Requirement, that member is entitled to use the purchased capacity in meeting its operating reserve obligation. However, on such a purchase the member must pay additional amounts for start-up and no load fuel charges on the selling system's units.

Cactus Pool Draft of February 1979

The Cactus Pool requirements were established somewhat differently than were those for POWER. The overall installed reserve requirement for the Cactus Pool was to be that level of reserve which achieved a loss of load probability (LOLP) of one day in three years after May 1, 1982. This is a substantially less stringent standard than that stipulated by many pool agreements. For example, the Pacific Northwest Coordination Agreement governing relationships between owners of hydroelectric resources on the Columbia River, calls for capacity sufficient to achieve a loss of load probability of one day in twenty years. The PJM region constructs capacity with a view to achieving a loss of load probability (LOLP) of one day in ten years. That LOLP has required a reserve of approximately 28% in recent years. However, penalties for being deficient are not assessed unless a PJM member's reserve margin falls below a lower, specific percentage (20 to 22%) of planning period peak demand. This PJM departure from a "1 in 10" standard resulted from load conservation induced by the 1973 Arab Oil Embargo. PJM's LOLP at the reduced reserve levels called for by the contract modification were as low as 1 day in 2 years. Therefore, the POWER and Cactus Pool LOLP standards are not as lax as might at first appear.

The two small members of the Cactus Pool, Arizona Electric Power Cooperative (AEPCO) and Plains Electric Generation & Transmission Cooperative (Plains) both sought an installed reserve requirement which did not unduly penalize small systems. One reason the Cactus Pool did not file its agreement at FERC is that Plains and AEPCO had objections to the reserve sharing problem and were expected to challenge the FERC filing and let the issue be resolved by that agency.

AEPCO stated that a certain amount of flexibility had to be sacrificed in order to create a strong pool which would operate in the most advantageous manner, and further, that the method of reserve allocation presented in Service Schedules A and D were not equitable. Specifically, AEPCO stated that the proposed allocation method assumed that a 750 MW unit imposed the same hazard on the Pool as did a 175 MW unit, when in fact the forced outage rate for a 750 MW unit is typically three to four times higher than that for a 175 MW unit. AEPCO believed that Service Schedule B, "Coordination of Interconnected Transmission Systems" contained relatively weak principles which should be strengthened rather than discarded. AEPCO concluded that a pool which would evolve from the then on-going negotiations would be relatively weak and ineffective.

Arizona Public Service Company (APS) believed that reserve sharing should be based upon "capacity equalization" as called for by Service Schedule A. Salt River Project stated that the "capacity equalization" concept does not provide for a commitment by each party to carry its proportionate share of installed reserves, does not provide for before-the-fact reserve sharing and does not require joint commitment to a joint plan. Salt River Project further stated that the Cactus Pool reserve allocation method required smaller utilities with larger relative hazards to carry proportionately greater reserves, but disagreed with AEPCO and Plains that such a reserve allocation method would disproportionately burden smaller systems. This concept has been rejected by PJM and NEPOOL, which look to the effect of a unit's outages upon the pool as a whole, rather than the effect of a unit's outage upon an individual member. Indeed, the PJM agreement imposes larger installed reserve margins upon members whose forced outage rates are higher than the average forced outage rates of the Pool, irrespective of the size of the member's generators. The number of PJM units comprising a member's resources and the relative size of the peak demands and large units of an individual member are ignored in establishing reserve margins.

The February 1979 version of the Cactus Pool Power Coordinating Agreement has several desirable pooling properties. First, Article 17 allows any additional publicly-, privately-or cooperatively-owned public utility in the business of generating and transmitting any power to become a party. The membership requirements of the Cactus Power Pool include:

1. One year written notice
2. The proposed party must own generation and transmission facilities or the contractual equivalent thereof, and be interconnected with at least one party.
3. The generation and transmission facilities of the proposed party must be such that its operation as part of the pool would not create a material adverse impact on the operations of any existing Party or Parties nor materially detract from the benefits contemplated under the agreement.
4. The proposed party must agree to accept all obligations, duties, rates, and all other provisions of the agreement and all then-existing practices and procedures, guidelines, and decisions all of the Committees established under the agreement.

Service Schedule B, entitled "Reserve Sharing", defines the arrangements under which the Parties would have shared installed and operating reserves and provide for Emergency and Scheduled Outage Assistance to a Party. The parties agree to allow all other parties to review power transactions and emergency assistance agreements with other utilities which are to be used to meet the requirements of service Schedule B and, if required, to allow the executive committee to adjust loads and resource data used in the formulae of the service schedule.

Section 5.6 of Service Schedule B defines the Installed Reserve Responsibility (IRR) as the reserve responsibility ratio for any party multiplied by the pool installed reserve requirement. A Party's IRR shall not exceed 16% of the Party's projected annual peak load prior to May 1, 1982 or 20% of the Party's projected annual peak load between May 1, 1982 and May 1, 1986. These percentage limitations have no force and effect after May 1, 1986 when the pool installed reserve requirement under Section 5.16.2 is the greater of (i) the Pool's largest single hazard plus 5% or (ii) 16% of the projected non-coincidental pool annual peak load until May 1, 1982. After May 1, 1982, the pool installed reserve requirement shall equal those reserves required to achieve a one day in three years loss of load probability, provided that the Pool's requirement shall not exceed 20% of the projected non-coincidental pool annual peak demand. The reserve responsibility ratio of a party is equal to the sum of that party's projected peak load plus the party's projected largest single hazard for the period divided by the summation of the similar sums determined for all the parties for the same time period. For operating reserve requirements, the reserve responsibility ratio of a party was to be recalculated monthly.

Article 6.1 of the Reserve Schedule B states that the parties will agree to simultaneously offer surplus capacity to pool members and grant a first option on a "first come-first serve" basis to purchase surplus capacity. A party may meet its installed reserve requirement by installing capacity, purchasing capacity or dropping load. The ability to meet installed reserve requirements by dropping load is unusual. Under Article 6.3 of Reserve Schedule B, any party which has not demonstrated by April 1 of each year that it will have sufficient capacity available to meet its reserve requirement for each of the twelve months beginning on May 1, will be required to purchase additional capacity in amounts necessary to achieve its requirement. Any Parties having available capacity in excess of their individual requirements may sell to those Parties deemed deficient and such purchases shall be made from the sellers in proportion to the amount of capacity available from each seller at a rate of $4.00 per KW per month. The party purchasing such capacity shall be entitled to contingent capacity on the supplying party's system. Contingent capacity is what is commonly known in the industry as a unit entitlement. Apparently, the seller may specify the unit or units from which the sale of capacity under Paragraph 6.3 occurs.

Service Schedule C governs coordination of interconnected transmission systems. It is unusual in several regards.

maintain a record of the transaction which occur pursuant to the pool agreement.

Service Schedule E governs economy transactions. This is unusual in the Cactus Pool because Economy Energy may be received by a Party when no alternative sources of supply are immediately available to that Party. This is similar to the PJM agreement in which all transactions occur at a split savings rate except when no alternative source of energy or capacity is available to the buyer. In such a case, the buyer pays the pool's highest cost plus 20%. However, no party to the Cactus Pool would have been entitled to use economy energy as a substitute for providing adequate power resources. Moreover, as is the case with emergency and scheduled outages services, the parties agree that all transmission for economy energy services shall be rendered at 1 mill per kilowatt hour plus transmission losses on intervening parties.

First of all, the parties would not alter their transmission systems in a way which would increase the subsynchronous resonance (SSR) of the interconnected network.*/ Secondly, Article 5 of Service Schedule B entitles each Party to the inherent and unused transmission capability already existing in that Party's system or to any increased transmission capability on that Party's system whether such increased transmission capacity results from the addition of new transmission facilities by the party or the addition of new facilities by another party or a third party which increases the possible use of inherent capacity in the Party's system. Thirdly, the parties agree to make every reasonable effort to furnish temporary alternate transmission capacity to a party affected by an outage or curtailment of any generating unit, circuit, or element of the interconnected transmission system which causes the transmission capacity for any established bulk power transfer to be insufficient.

Service Schedule D would have established a Pool Coordinator in order to facilitate the coordinated operation of the interconnected systems of the parties and to account for and

---

*/ SSR results from undesirable undamped oscillations in generator outputs resulting from the interaction of transmission and generating facilities. If uncontrolled, SSR can snap the shafts of generating units. SSR was first analyzed in depth by WSCC utilities.

APPENDIX B

Historical Developments Affecting Pooling in the Pacific Southwest

In July 1964, Congress authorized construction of the Pacific Northwest-Southwest Intertie ("Intertie").*/ The Intertie was intended to solve several problems for the Bonneville Power Administration.

Bonneville Power Administration ("BPA") foresaw that there would be a need in the mid-1960's to market Canadian Entitlement Power ("CEP") which would result from the construction by Canada of reservoirs on Canadian portions of the Columbia River. Those reservoirs could be operated in a manner which increased the dependable power producible at dams of the United States Government and other entities on portions of the Columbia River located downstream from the Canadian dams and within the United States. The additional firm power that could be produced by United States dams was divided equally between the United States and Canada pursuant to a treaty at the time the Intertie was being negotiated in the early 1960's. The United States guaranteed Canada payment for the Canadian portion of the power during an initial period of years because Canada, at the time it entered into the treaty, had no market for such power.

---

*/ Pacific Intertie transactions are accomplished through two 500 kV a.c. transmission lines plus the direct Northwest to California 800 Kv d.c. line which terminates in the Edison and Los Angeles Department of Power & Water (LADWP) transmission

(continued on next page)

Northwest entities looked to California and other regions in the Pacific Southwest as a market for Canadian Power and other Northwest power which resulted from entering into the Canadian treaty. In addition, BPA and other Northwest entities experienced a glut of power during years of high water run-off in the Columbia River Basin. During such years, water was spilled over dams because there was no way to produce energy and deliver it to a market. Although availability of this power depends upon hydrological conditions, it is a source of very low-cost energy. Therefore, the Intertie was to serve an additional purpose of delivering this temporary and intermittent excess Northwest power to California and other regions in the Pacific Northwest.

Another impetus to construction of the Intertie was BPA's recognition of diversity between peak loads in the Pacific Northwest and Pacific Southwest. By tying the two regions together, BPA hoped to be able to draw upon the Pacific Southwest for firm power during peak periods in the Southwest in return for delivery of firm power to the Pacific Northwest during peak periods in the Southwest, which did then and still does occur during the summer.

(continued from page 62)

systems. The combined a.c. and d.c. lines are capable of delivering 4,000 Mw to the Pacific Southwest.

The a.c. portion of the Intertie begins at John Day Dam on the Columbia River out of which two 500 Kv a.c. lines extend south to Los Angeles.

(continued on next page)

At about this same time, Southern California utilities were looking eastward for plant sites outside the Los Angeles Basin. Under investigation were sites for coal-fired plants at Mohave, Four Corners, Page, Arizona (Navajo), San Juan and Kaiparowits. Mohave and Four Corners received the earliest attention. Transmission lines planned and built by the Los Angeles Department of Water and Power (LADWP) and the Southern California Edison Company (Edison) as well as other entities in connection with those developments were to be integrated with the Intertie system. The manner of that integration became an important consideration in later efforts by LADWP and Edison to obtain waivers of wheeling stipulations and unconditional water, land and mineral permits for the planned coal-fired steam plants and associated transmission lines. These stipulations expressly grant the United States the right to condemn, connect to, add capacity to and otherwise utilize IOU (or other entities') lines.

Waivers of the wheeling stipulations were important to IOUs because stipulations could have required the IOUs to transmit Federal power to preference customers over transmission

---

(continued from page 63)

The d.c. portion of the Intertie system between the Northwest and California utilizes the 800 Kv d.c. line from the Oregon-Nevada border, through Nevada and California, directly to the Sylmar converter station near Los Angeles. A second d.c. line was planned to link the Northwest to Las Vegas and, through 345 Kv lines, to Phoenix but the second d.c. line was never built.

facilities owned by IOUs. By obtaining waivers, IOUs increased their control over preference customer markets. Nearly every major transmission line constructed in the Pacific Southwest must cross Federal lands. Therefore, wheeling stipulations would have been widely applicable if not waived.

Entities entitled to a preference in the purchase of Federal power tend to have small loads. Their survival as competitors has often required that they develop economical and reliable bulk power supplies as joint venturers in large, base load generating plants at sites remote from their loads. At these sites, fuel can be provided less expensively and environmental strictures can be accomodated. Construction of an independent transmission system to connect their loads to such remote generating sites is impractical in most cases. Therefore, these preference entities must obtain access to an existing (or reinforced) network and entitlements in large generating resources constructed jointly with other entities. Given these economic imperatives, the wheeling stipulations take on added meaning.

A pooling agreement usually contains transmission provisions enabling member systems to serve local loads from remote sources by use of transmission facilities owned by other members. In the absence of pooling or generally available transmission rights, wheeling stipulations would have served an essential need of small systems. The general availability of transmission rights under a pooling agreement would be even more valuable to small systems because such rights could be exercised without Federal intervention and would be more widely applicable than wheeling stipulations which are exercised on a line-by-line basis.

By 1965, Western Energy Supply and Transmission Associates, (WEST Associates or "WEST") had been formed. WEST Associates is a group of utilities which was then planning transmission and new coal-fired baseload units in the Pacific Southwest.

Notes of a WEST negotiating Committee meeting with the RCCWW (Regional Coordinating Committee With West, a multi-regional group) held on September 21, 1965 in Las Vegas show that Mr. Gould of Edison expressed concern for the "perpetuity of preference". He stated that he was concerned with encouraging additional preference customers getting into the power business. Mr. W.T. Lucking (President, Arizona Public Service Company), was recorded as stating that he was increasingly concerned with the effect of loss of preference load on the rates to remaining customers. He reportedly stated that the long-term solution lay in area pooling with opportunity for participation by smaller preference and investor-owned utilities limited to that as purchasing members. These limitations have been found unnecessary in NEPOOL and FCG.

A November 30, 1965 United States Government memorandum from Mr. Byron L. Miller to Mr. E.V. Lindseth, Chairman of RCCWW, states:

"It has been our understanding that studies (Bureau of Reclamation-WEST system studies) are to be conducted on the basis of determining the total load in the area of study, the resources required to meet the load and the transmission system required regardless of ownership. It appears that the representatives of the participating members of WEST are departing from this 'one-world' approach and insisting upon identifying the particular loads or portions of the loads to be served by each agency including the Bureau of Reclamation.... The resources data ... indicates that the participating WEST entities plan the continued installation of thermal-generation with a resulting decrease in the quantities to be taken from the Pacific Northwest Intertie."

The Bureau of Reclamation was attempting to obtain a statement from entities planning power plants in the Southwest that they would coordinate the construction and operation of hydro-electric and thermal electric power generation and associated transmission facilities, both public and private. This was to be done so that the benefits achieved through such coordination could be shared by all consumers in the marketing area. In a January 13, 1966 meeting, Edison would not agree to language proposed for inclusion in a water permit which required coordination of hydro and thermal units prior to delivery of water under the contract.

On April 22, 1966, the Government waived the wheeling stipulations immediately in return for assurances from the Mohave plant participants that they would later make available reserve capacity to backup the Intertie when it was built (the segment to Phoenix was not built) and to negotiate in good faith a coordination agreement.

WEST continually evidenced its desire to limit the introduction of low-cost power sources. For example one Edison coordination agreement proposal was:

> "In this cooperative planning of resource development it is the intent of the parties that the Federal and WEST generating plant construction will not be authorized in such sequence or timing as to produce capacity surplus to the needs of the Southwest power market areas; which surplus would adversely affect the economies of the future power development or cause one party to mount power marketing programs to dispose of surpluses which will capture customers of others."

Negotiations on a coordination agreement continued on for several years. In a meeting held in Denver, on January 15, 1968, Mr. Gould of Edison was recorded in government minutes of the meeting as stating that any agreement:

> "must recognize the need for protection of IOUs' market."

In a July 25, 1968, memorandum, Assistant Commissioner of Reclamation, Mr. N.B. Bennett, Jr., reported to Secretary Udall on a meeting with Edison and other WEST members on July 25, 1968.

It states in part:

> "7. Power Coordination Agreement
>
> This Group seems to be making progress for the first time, based upon a banking arrangement designed to support 1,650 MW of Federal Hydro in the Colorado River Basin. The sticky problem is still that the utilities will not commit themselves to supply energy to support Federal capacity to 'pirate their customers.'"

This summary indicates the manner in which pooling and coordination have been limited in the Pacific Southwest by historical developments. Achievement of pooling benefits has been frustrated by the refusal of dominant Pacific Southwest utilities to foster any developments outside their control which were perceived as harmful to their market control, irrespective of whether their customers, consumers generally or the region would have benefitted. State Commissions apparently played little part in the resolution of the disputes, but State and consumer interests were clearly harmed by the manner in which IOUs sought to protect their markets.

TABLE 1

NEW ENGLAND POWER POOL

Company	State	MW Capacity	Peak Summer (MW)	Peak Winter (MW)	Annual Sales (MWh)
Investor-Owned					
Bangor Hydro-Electric Co.	ME	278	172.6	215.9	1,230,531
Boston Edison Co.	MA	2,763	2,332.0	2,179.0	11,627,183
Central Maine Power Co.	ME	1,290	948.8	1,173.3	5,877,784
Eastern Utilities Assoc.		953	NA	NA	NA
Fitchburg Gas & Electric Light Co.	MA	92	72.2	NG	398,544
New England Gas & Electric Assoc.		807	NA	NA	NA
New England Power Co.		4,477	NG	NG	16,669,045
Newport Electric Corp.	RI	52	62.4	73.1	352,867
Northeast Utilities		6,207	3,862.8	3,951.3	19,963,677
Public Service Co. of New Hampshire	NH	1,458	937	1,117	5,383,999
United Illuminating Co.		1,323	952.9	845.4	4,712,408
Vermont Electric Power Co. */	VT	945	NA	NA	NA
Municipal					
Ashburnham Municipal Plant Dept.	MA	2		3.3	14,919
Boylston Municipal Light Dept	MA	3	2.9	3.6	16,810
Braintree Electric Light Dept	MA	127	59	53	263,458
Chicopee Electric Light Dept	MA	---	54	51.7	271,862
Danvers Electric Dept.	MA	35	43.2	38.7	193,146
Georgetown Municipal Light Dept.		4	3.8	4.8	19,277
Groton Electric Light Dept.	MA	4	3.6	5.1	21,200
Hingham Municipal Lighting Plant	MA	16	18.5	20.6	93,297
Holden Municipal Light Dept.	MA	10	10.8	13.9	61,638
Holyoke Gas & Electric Dept.	MA	63	41.7	38.3	191,173

*/ Includes investor-owned utilities, municipals and rural electric cooperatives in Vermont.

TABLE 1

NEW ENGLAND POWER POOL

Company	State	MW Capacity	Peak Summer (MW)	Peak Winter (MW)	Annual Sales (MWh)
Municipal					
Hudson Light & Power Dept.	MA	34	20.4	24.3	103,277
Hull Municipal Light Dept.	MA	4	6.4	24.3	28,710
Ipswich Municipal Light Dept.	MA	13	6.4	13.6	61,437
Littleton Electric Light & Water Dept.	MA	11	10.7	13.0	56,461
Mansfield Muni. Elec Dept.	MA	20	20.0	23.6	116,748
Marblehead Muni. Light Dept.	MA	17	15.9	16.9	72,592
Middleborough Gas & Electric Dept.	MA	12	16.8	17.0	85,635
Middleton Municipal Light Dept.	MA	5	7.8	7.5	37,687
North Attleborough Munic. Electric Light Dept.	MA	17	20.0	20.0	92,588
Pascoag Fire District	RI	2	3.0	4.4	18,738
Paxton Electric Light Dept.	MA	3	2.1	4.1	15,005
Peabody Municipal Light Plant	MA	58	60.5	54.4	235,301
Princeton Municipal Light Dept.	MA	1	1.1	1.6	6,606
Reading Municipal Light Dept.	MA	37	76.2	69.7	371,484
Shrewsbury Municipal Light Dept.	MA	30	23.5	31.3	141,000
South Hadley Electric Light Dept.	MA		18.3	18.5	100,638
Sterling Municipal Elec. Light Dept.	MA	4	3.1	3.7	22,682
Taunton Municipal Lighting Plant	MA	82	63.0	66.0	227,000
Templeton Municipal Lighting	MA	8	NG	NG	NG

TABLE 1

PAGE 3 OF 3

NEW ENGLAND POWER POOL

Company	State	MW Capacity	Peak Summer (MW)	Peak Winter (MW)	Annual Sales (MWh)
Municipal					
Wakefield Municipal Light Dept.	MA	20	25.1	22.6	107,209
West Boylston Municipal Light Dept.	MA	8	7.4	8.5	41,661
Westfield Gas & Electric Light	MA	32	49.5	42.3	216,862
	SYSTEM TOTAL:	21,237			

*Source: Electrical World, 1979-80.

TABLE 2

PENNSYLVANIA-NEW JERSEY-MARYLAND INTERCONNECTION

Company	State	MW Capacity	Peak Summer	Peak Winter	Annual Sales (MWh)
Public Service Electric & Gas Company	NJ	9,023	6615.0	4925.0	29,341,889
Philadelphia Electric Company	PA	7,727	5667.0	4702.0	27,394,302
Atlantic City Electric Company	NJ	1,526	1177.4	1019.9	5,274,640
Delmarva Power & Light Company	DEL/MD/VA	2,226	1914.0	1689.9	7,248,249
Pennsylvania Power & Light Company	PA	6,335	3617.0	4701.0	21,844,000
Luzerne Electric Division-UGI Corporation	PA	115	N/A	N/A	N/A
Baltimore Gas & Electric Company	MD	5,162	3553.0	2850.0	16,170,224
General Public Utilities Corp. (Jersey Central Power & Light Company, Metropolitan Edison Company and Pennsylvania Electric Company)	NJ	7,707	N/A	N/A	N/A
Potomac Electric Power Company	DC	5,070	3714.0	2682.0	15,482,538
SYSTEM TOTALS:		44,891	26,257.40	22,569.80	122,755,842

TABLE 3

PAGE 1 OF 2

FLORIDA ELECTRIC COORDINATING GROUP

	State	MW Capacity	Peak (MW) Summer	Peak (MW) Winter	Annual Sales (MWH)
Investor-Owned Utilites					
Florida Power & Light Co.	FLA	10,941	8,345	8,791	40,602
Florida Power Corp.	FLA	3,647	3,521	4,135	17,046,741
Florida Public Utilities Co.	FLA	0	-	-	372,702
Gulf Power Co.	FLA	1,515	1,247	1,062	5,571,352
Reedy Creek Utility Co.	FLA	12	NG	NG	NG
Tampa Electric Co.	FLA	2,505	1,780	1,891	10,037,698
Municipals					
City of Bushnell	FLA	0	NG	NG	NG
Fort Pierce Utilities Authority	FLA	116	65	73	348,262
Gainesville/Alachua County Regional Utilities Board	FLA	257	179.4	151.6	732,933
City of Homestead	FLA	52	38	36	177,195
Jacksonville Electric Authority	FLA	1,942	1,253	1,123	5,811,933
City of Key West Utility Board	FLA	130	65	60.4	NG
City of Kissimmee	FLA	30	41.8	47.2	190,510
Lake Worth Utilities Authority	FLA	141	55.3	70.2	NA
City of Lakeland	FLA	372	251	281	1,136,390
City of New Smyrna Beach Utilities Commission	FLA	21	31.2	33.8	121,999
City of Ocala	FLA	0	101.5	87.8	436,003
Orlando Utilities Commission	FLA	742	459	459	2,061,725
City of Quincy	FLA	0	20.5	15.8	92,041
City of St. Cloud	FLA	24	21.1	19.2	68,293
Sebring Utilities Commission	FLA	25	29.0	35.5	NG
City of Starke	FLA	10	NG	NG	NG
City of Tallahassee	FLA	495	256	238	NA
City of Vero Beach	FLA	133	70.2	83.5	260,000

TABLE 3

PAGE 2 OF 2

FLORIDA ELECTRIC COORDINATING GROUP

	State	MW Capacity	Peak Summer	Peak Winter	Annual Sales (MWH)
Cooperatives					
Central Florida Electric Cooperative	FLA	0	25.3	25.2	100,266
Choctawhatchee Electric Cooperative	FLA	0	34.2	33.2	137,489
Clay Electric Cooperative	FLA	0	210.3	203.1	790,918
Glades Electric Cooperative	FLA	0	32.6	43.1	160,689
Lee County Electric Cooperative	FLA	0	185.5	258.2	807,504
Okefenokee Rural Electric Membership Cooperative	GA	0	42.0	40.0	172,616
Peace River Electric Cooperative	FLA	0	26.7	32.3	117,994
Seminole Electric Cooperative	FLA	14	NA	NA	105,038
Sumter Electric Cooperative	FLA	0	87.2	112.3	354,443
Suwannee Valley Electric Cooperative	FLA	0	27.4	20.8	104,078
Talquin Electric Cooperative	FLA	0	76.6	77.0	295,866
Tri-County Electric Cooperative	FLA	0	19.3	17.2	77,588
Withlacooche River Electric Cooperative	FLA	0	134.3	215.8	551,982
SYSTEM TOTALS:		23,124	1,873,140	19,772.20	48,282,850

MID-CONTINENT AREA POWER POOL
TABLE 4
PAGE 1 OF 3

Company	State	MW Capacity	Capacity Summer (MW)	Capacity Winter (MW)	Peak*/ Summer	Peak*/ Winter	Annual**/ Sales (MWh)	Fuel Type*/ % Oil	% Gas	% Coal	% Nuclear	% Hydro	% Waste Heat
MAAP Members													
Basic Electric Power Coop.	ND/SD	817	814	820	750.2	771.5	4,013,400	15.0%		85.0%			
Cooperative Power Association	MN/ND	350	347.81	351.45	452.9	508.2	2,259,139	19.4%		80.6%			
Dairyland Power Corp.	WI/MN	1,046	1,048.04	1,043.35	16.5	21.8	84,478	2.0%		91.6%	4.4%	2.0%	
Eastern Iowa Light & Power Cooperative	IA	91	90.70	90.70	55.9	71.5	282,000			100.0%			
Heartland Consumers Power District	MN	24	21.14	26.46	NG	NG	ND	100.0%					
Interstate Power Company	IA/MN	889	885.49	891.89	695.1	587.5	3,624,257	9.9%		90.1%			
Iowa Electric Light & Power Coop.	IA	1,271	1,227.26	1,315.06	822.6	715.6	3,861,459	23.8%		40.3%	34.9%		1.0%
Central Iowa Power Coop.													
Iowa-Illinois Gas and Electric Co.	IA/IL	1,288	1,266.26	1,309.33	883.4	638.6	3,898,069	22.7%		44.4%	29.9%	.1%	2.9%
Iowa Power and Light Co.	IA	1,119	1,102.50	1,136.30	1,063.7	776.9	4,306,910	33.5%	2.6%	63.9%			
Iowa Public Service Company Corn Belt Power Coop.	IA	1,416	1,384.48	1,447.58	735.6	609.8	3,022,173	23.7%		72.8%	3.5%		
Iowa Southern Utilities Company	IA	424	423.60	423.60	357.8	300.0	1,559,244	2.0%		98.0%			
Lake Superior District Power Co.	WI/MI	124	121.80	126.80	NG	NG	672,339	6.7%	15.4%	67.8%		10.1%	
Lincoln Electric System	NE	116	106.50	125.50	369.1	228.0	1,378,872	100.0%					
Minnesota Power and Light Co.	MN/ND/WI	1,264	1,264.20	1,263.10	1,038.4	1,187.8	7,992,067	11.8%		79.6%		8.6%	
Minnkota Power Coop.,	ND/MN	315	310.15	319.15	231.	348.	3,053,205	17.6%		82.4%			

*Peak season capacities used.
**Source: Electrical World 1979-80.

Company	State	MW Capacity	Capacity Summer (MW)	Capacity Winter (MW)	Peak* Summer (MW)	Peak* Winter (MW)	Annual Sales (MWh)	Fuel Type % Oil	% Gas	% Coal	% Nuclear	% Hydro	% Waste Heat
MAAP Members													
Missouri Basin Municipal Power Agency	MN/SD	125	113.85	136.62	ND	ND	ND	76.6%		23.4%			
Montana-Dakota Utilities Co.	SD/ND/MT	331	317.50	344.60	257.2	268.1	1,406,537	12.0%	14.2%	73.8%			
Muscatine Power and Water	IA	120	120.30	120.30	92.8	79.5	570,857			100.0%			
Nebraska Public Power District	NE	2,237	2,218.03	2,255.03	1,787.5	1,252.8	7,557,503	9.6%	8.2%	42.3%	34.5%	5.4%	
Northern States Power Company	MN/WI/SD	6,341	6,098.50	6,584.20	4,840.6	3,922.7	20,754,496	24.9%		47.6%	24.3%	3.2%	
Northwest Iowa Power Coop.	IA	101	100.69	100.69	172.4	177.8	564,719			100.0%			
Northwestern Public Service Co.	SD/IA	276	269.44	282.60	209.6	158.7	721,017	31.9%		68.1%			
Omaha Public Power District	NE	1,991	1,960.15	2,021.35	1,257.3	885.9	5,633,330	17.5%		59.9%	22.6%		

MID-CONTINENT AREA POWER POOL
TABLE 4
PAGE 3 OF 3

Company	State	MW Capacity	Capacity Summer (MW)	Capacity Winter (MW)	Peak* Summer (MW)	Peak* Winter (MW)	Annual Sales (MWh)	Fuel Type % Oil	% Gas	% Coal	% Nuclear	% Hydro	% Waste Heat
MAAP Members													
Otter Tail Power Company	SD/MN/ND	475	463.34	488.24	NG	NG	2,636,261	22.1%		77.0%		0.9%	
United Power Assoc.	ND/MN	537	524.55	549.59	351.5	428.0	2,106,302	20.2%		79.8%			
Western Area Power Administration Billings Area	SD/MT/ND/MT	2,492	2,557.00	2,427.00	NG	NG	NG					100.0%	
SYSTEMS TOTAL:		25,580	25,157.48	26,000.49	16,711.10	14,008.70	81,958,634						

TABLE 5
INLAND POWER POOL

Company	State	MW Capacity	1979-1982 Peak Demand Summer (MW)	Winter (MW)	1979 Annual Sales (MWH)	1979-1982 Net Capability Summer (MW)	Winter (MW)
Public Service Company of Colorado	CO	2584.	2624	2512	13,417,265*	2570	2599
Colorado-Ute Electric Association	CO	431	304	429	2,102,438	431	431
Platte River Power Authority	CO	76	N/A	N/A	881,559	76	75
Salt River Project	NM	2835	1944	1521	10,395,202	2830	2841
Tri-State Generation & Transmission	CO	420	N/A	N/A	3,672,787	395	445
Bureau of Reclamation WAPA	CO	2070	N/A	N/A	36,200,000	2113	2028
City of Colorado Springs	CO	345	283	307	1,622,082	353	356
Basin Electric Power Coop.	ND		N/A	N/A	4,013,400*	-0-	-0-
Public Service Company of New Mexico	NM	1082	695	625	4,960,451	1082	1082
Tucson Electric Power Co.	AZ	1570	903	605	4,150,982	1570	1570
Wyoming Municipal Power Agency	WY		N/A	N/A	N/A	N/A	N/A
El Paso Electric Company	NM	962	688	526	3,424,284	962	962
Plains G&T	NM	45	186	201	1,235,095	45	45
System Total		12,420	7627	6726	86,075,545	12,427	12,434

* 1978 Sales

Selected Areas of Regulatory Agency Authority
In Power Pool Territory

Agency Has Authority to Regulate or Control Sales To

	Ultimate Customers			Public Authorities For Public Use			U.S. Government (Not Resale)		
	Private	Public	Cooperative	Private	Public	Cooperative	Private	Public	Cooperative
NEPOOL									
Connecticut									
Massachusetts DPU	X	1/		X	1/		X	1/	
Maine PUC	X	X	X	X	X	X	X	X	X
New Hampshire PUC	X	X 3/	X	X	X 3/	X	X	X 3/	X
Vermont PSB	X	X	X	X	X	X	X	X	X
Rhode Island PUC									
PJM									
Delaware PSC	X		X	X		X	X		X
District of Columbia PSC	X			X		X	X	X	X
Maryland PSC	X	X	X	X		X	X	X	X
New Jersey PBU	X	4/	X	X		X	X		X
Pennsylvania PUC	X	X 5/		x	x 5/		x	x	
FCG									
Florida PSC	X	X 6/	X 6/	X	X 6/	X 6/	X	X 6/	X 6/
MAPP									
Iowa SCC	X		X	X		X	X		X
Minnesota PSC	X		7/	X		7/			X
Nebraska PSC 8/									
North Dakota PSC	X			X			X		
South Dakota PSC	X			X			X		
Illinois CC	X			X			X		
Montana PSC	X	X		X	X		X	X	
Wisconsin PSC	X	X	9/	X	X	9/	X	X	9/
IPP									
Colorado PUC	X	X 3/	X	X	X 3/	X	X	X 3/	X
New Mexico PSC	X	10/	X	X	10/	X	X	10/	X
Arizona CC	X		X	X		X	X		X
Wyoming PSC	X	X 12/	X	X	X 12/	X	X	X	10/ X
Utah PSC	X		X	X		X	X		X

Note: "X" indicates authority is specifically granted or implied from general statutory provisions.

Source: National Association of Regulatory Utility Commissioners, 1979 Annual Report on 'lity and Carrier Regulation.

Sales For Resale

Agency Has Authority to Regulate or Control Sales To

	Public Authorities For Resale			U.S. Government For Resale			Privately Owned For Resale			Publicly Owned For Resale		
	Private	Public	Cooperative	Private	Public	Cooperative	Private	Public	Cooperative	Private	Public	Cooperative
NEPOOL												
Connecticut												
Massachusetts DPU	X	1/		2/	2/		2/	2/		2/	2/	
Maine PUC									X			X
New Hampshire PUC	X	X 3/	X	X	X 3/	X	X	X 3/	X	X	X 3/	X
Vermont PSB												
Rhode Island PUC												
PJM												
Delaware PSC				X		X						
District of Columbia PSC												
Maryland PSC												
New Jersey PBU	X		X	X		X	X		X	X		X
Pennsylvania PUC												
FCG												
Florida PSC												
MAPP												
Iowa SCC												
Minnesota PSC												
Nebraska PSC 8/												
North Dakota PSC												
South Dakota PSC												
Illinois CC	X			X			X			X		
Montana PSC	X	X		X	X		X	X		X	X	
Wisconsin PSC	X	X	9/	X	X	9/	X	X	9/			
IPP												
Colorado PUC	X	X 3/	X	X	X 3/	X	X	X 3/	X	X	X 3/	X
New Mexico PSC	X 11/	10/	X 11/	X 11/	10/	X 11/	X 11/	10/	X 11/	X 11/	10/	X 11/
Arizona CC	X		X	X		X	X		X	X		X
Wyoming PSC	X	X 12/	X	X	X 12/	X	X	X 12/	X	X	X 12/	X
Utah PSC	X		X	X		X	X		X	X		X

Agency Has Authority to Regulate or Control Sales To

	Regulate Dates For Transmission On Account Of Others			Define And Prescribe Rates For Interchange Power		
	Private	Public	Cooperative	Private	Public	Cooperative
NEPOOL						
Connecticut						
Massachusetts DPU	X	X		X	X	
Maine PUC	X	X	X	X	X	X
New Hampshire PUC	X	X 3/	X	X 13/	X 13/	X 13/
Vermont PSB	X	X	X	X	X	X
Rhode Island PUC						
PJM						
Delaware PSC						
District of Columbia PSC						
Maryland PSC				X	X	X
New Jersey PBU						
Pennsylvania PUC	X	X 5/		X	X 5/	
FCG						
Florida PSC						
MAPP						
Iowa SCC						
Minnesota PSC						
Nebraska PSC 8/						
North Dakota PSC						
South Dakota PSC						
Illinois CC	X			X		
Montana PSC						
Wisconsin PSC	X	X	9/	X	X	9/
IPP						
Colorado PUC	X	X 3/	X	X	X 3/	X
New Mexico PSC	X	10/	X	X	10/	X
Arizona CC	X		X	X		X
Wyoming PSC	X	X 12/	X	X	X	X
Utah PSC	X		X			

Agency	Description Of Agency Regulations Over Municipal Electric And Gas Utilities
NEPOOL	
Connecticut	
Massachusetts DPU	Prescribe accounting, review permissible earnings under statute, insure statutes are followed as to street light rates, permit depreciation higher than statutory rquirement, regulate as to service, approve issues of revenue bonds, see that rates are not changed more often than once every three months.
Maine PUC	Jurisdiction over all facilities, services, rates and charges.
New Hampshire PUC	For those customers outside municipal limits, tariffs are required and rates are regulated, i.e., that portion of the municipal utility's business is subject to PUC jurisdiction as is the case of any public utility.
Vermont PSB	Total regulation: rates, approve sales of wholesale power through contracts, territories, new construction, tariff filings.
Rhode Island PUC	All types, including but not limited to tariffs, safety, plant repairs, etc.
PJM	
Delaware PSC	
District of Columbia PSC	
Maryland PSC	Identical to jurisdiction over private investor and cooperative utilities, involving rates, terms and conditions, standards of service and customer rights.
New Jersey PBU	The municipal utilities are subject to the jurisdiction, regulation, and control of this Board insofar as the rates that are charged to customers outside the municipal boundaries. The municipal utilities are required to file annual reports with the agency. Service complaints are directed to the agency for appropriate action.
Pennsylvania PUC	When a municipal corporation is deemed to be rendering public utility service beyond its corporate limits, it is then subject to exactly the same regulations as is any other public utility with regard to its extraterritorial service. Its rates must be just and reasonable with regard to its extraterritorial service. Its rates must be just and reasonable and its service and facilities must be adequate, efficient, safe and reasonable.
FCG	
Florida PSC	Territorial boundaries, rate structures (although not rate level), power pooling, interconnection (accounting-uniform system), and wheeling of electric utilities. Municipal gas utilities regulated only as to safety practices.

REGULATION OF MUNICIPAL ELECTRIC AND GAS UTILITIES

Table 6

Agency	Description Of Agency Regulations Over Municipal Electric And Gas Utilities
MAPP	
Iowa SCC	Regulation is limited to service rules, plant siting, and safety matters. Municipal utilities are exempt from rate regulation in accordance with Chapter 476 of Code of Iowa.
Minnesota PSC	
Nebraska PSC 8/	
North Dakota PSC	
South Dakota PSC	Territorial boundaries only.
Illinois CC	Gas pipeline safety jurisdiction over municipal gas utilities.
Montana PSC	Facilities, service and rates.
Wisconsin PSC	Regulates rates for service, utility plant construction, standards of service, rates for service including billing and customer deposit rules. The jurisdiction is identical to jurisdiction over private utilities, except the Commission does not regulate security issues of municipal utilities.
IPP	
Colorado PUC	Facilities, service rates and charges.
New Mexico PSC	NMPSC may disapprove rates, charges, and service conditions for electric customers served more than five (5) miles outside municipal boundaries; must approve issuance of revenue bonds, purchase of utility and refunding revenue bonds, and refunding utility or joint utility bonds; general jurisdiction over intercommunity water or natural gas supply associations; approve acquisition and operation of gas distribution facilities by one municipality in whole or in part within the boundary of another municipality.
Arizona CC	
Wyoming PSC	Regulates electric and gas utilities insofar as they extend outside corporate limits generally to the extent that other utilities are regualted; namely, certification of service area, construction safety, adequacy of service, environment, rates and tariffs, etc. Municipal financing accomplished under laws relating to municipalities is not requried by the PSC.
Utah PSC	

Interconnections

Agency Has Authority to Regulate Safety and Adequacy Standards By Authorized Interconnections Requiring Interconnection

	Private	Public	Cooperative	Private	Public	Cooperative
NEPOOL						
Connecticut						
Massachusetts DPU	X	X		X	X	
Maine PUC	X	X	X	X	X	X
New Hampshire PUC	X	X 14/	X			
Vermont PSB	X	X	X	X	X	X
Rhode Island PUC						
PJM						
Delaware PSC	X		X			
District of Columbia PSC						
Maryland PSC	X 15/	X	X	16/	X	X
New Jersey PBU	X	X 17/	X	X	X 17/	X
Pennsylvania PUC						
FCG						
Florida PSC	X			X		
MAPP						
Iowa SCC	X	X	X	18/	18/	18/
Minnesota PSC						
Nebraska PSC 8/						
North Dakota PSC	X					
South Dakota PSC	X			X		
Illinois CC	X			X		
Montana PSC						
Wisconsin PSC	X	X	X	X	X	X
IPP						
Colorado PUC 3/	X	X	X	X	X	X
New Mexico PSC	X		X	X		X
Arizona CC	X		X	X		X
Wyoming PSC	X	X 17/	X	X	X 17/	X
Utah PSC	X		X	X		X

FOOTNOTES TO TABLE 6

1/ Only if earnings exceed 8 percent of original cost of plant in service or if discrimination between customer classes.

2/ Primarily Federal Energy Regulatory Commission jurisdiction.

3/ Public utilities regulated when outside of municipal boundary only.

4/ Authority limited in individual cases by legislation or court decision.

5/ Only when service extends beyond the corporate limits of a publicly owned utility company.

6/ Basic rate structure regulation only.

7/ Has authority only at the election of the cooperative.

8/ Telephone is the only regulated utility.

9/ Not unless co-op extends activities to include functions that make it a public utility under the statutes (except no portion of co-op service withinin incorporated municipality as a result of annexation).

10/ Municipalty owned electric utilities are fully regulated with respect to service beyond five miles of municipal boundary.

11/ Authority limited to rate charged and manner of delivery.

12/ Public utilities regulated insofar as they are owned and operated outside corporate limits.

13/ When not subject to FERC.

14/ Only outside municipal limits.

15/ Interconnections authorized by exercise of certificate proceedings for construction of transmission line.

16/ Authority never actually tested.

17/ Commission regulates municipal utilities outside corporate limits.

18/ This commission may require after hearing.

19/ Intrastate rates are subject to state regulations.

PART 2

AN APPROACH TO EVALUATING POWER POOLS

FOR USE BY STATE COMMISSIONS

Our overview of four power pools indicates that many options are available for utilities to engage in power pooling.

However, not all formats will induce the lowest cost results nor avoid subsidization of one pool member's customers by another's. Moreover, some conduct that appears optimal for the pool or some of its members contravenes federal antitrust laws. For example, a pool which unduly restricts sales or services to nonmembers, allocates markets, allocates disportionate costs or too few benefits to small members or assesses extraordinary prices for transactions with nonmembers is clearly suspect. Nevertheless, such provisions have existed for years in many pools without being successfully attacked, presumably because potential plaintiffs consider themselves better off as part of an imperfect pool than they would be without a pool. On the other hand, pools which strictly limit membership or otherwise constrain access to pool benefits have been attacked.*/

State Commissions are without jurisdiction to implement pooling agreements, that being FERC's exclusive province, but undoubtedly have standing to litigate FERC's consideration of an unacceptable agreement. In some situations, failure to protest an unacceptable rate schedule will burden customers protected by State Commissions with high costs State Commissions cannot disallow. By invoking Sections 207 and 209 of the Federal Power Act, State Commissions can assert rights as FERC decisionmakers, rather

---

*/ The California Power Pool is one subject of antitrust complaints in FERC Docket No. E-7777 (Phase II). Some public agencies unsuccessfully attacked NEPOOL.

than being relegated to a supplicant's role like all other intervenors. States are the only FERC intervenors granted such rights.

Regardless of the role the State Commission may play in the pooling process, there are several attributes which are characteristic of a cost-effective pool which serve to set a true pool apart from a bilateral coordination agreement. They are:

(1) Mandatory installed reserve sharing, usually on an equalized percentage reserve basis. Deficient members are obligated to purchase capacity from members with excess capacity.

(2) A regional perspective. Under a regional approach, the basis of inducements and penalties is the effect of a proposed action upon the pool and not the effect upon any one pool member. This would be indicated, for example, by a mechanism for (i) allocating to all members a share of the cost of pool transmission facilities and (ii) assuring all members access to those facilities. This avoids the otherwise intractable problem of identifying relative gain achieved by each beneficiary of new transmission facilities and allocating costs commensurately. This problem has often frustrated the construction of necessary transmission facilities.

(3) A mechanism for identifying and carrying out all cost-effective energy and short term capacity transactions. For energy transactions, this mechanism can range from a voluntary power broker to a fully-automated computer-controlled economic dispatch system. For

It is advantageous to delineate the best characteristics of existing pools. These combined characteristics form a framework against which to compare potential pooling agreements. The major categories outlined above are treated in more detail in the following sections.

1. Central Dispatch

Potential pooling agreements should specify, or at least facilitate, central dispatch as this form of coordination has been demonstrated to provide the most savings to pool members. The most accurate and technologically advanced form of central dispatch involves the use of real time computers which constantly monitor system and individual utility costs and capabilities.

Central dispatch facilitates determinations of actual benefits derived from pooling and yields constant surveillance of opportunities created by the pool.

Insofar as possible, a pool should seek to operate as if all members were controlled by one enterprise as part of a single control area.

2. The Role of the Coordinating Committee

The establishment of a coordinating committee composed of representatives of pool members offers power pools a mechanism by which they may realize maximum savings. The allocation of voting rights within a coordinating group is an important consideration for utilities considering formation of a pool. Some capacity transactions, this is evidenced by an active market in operating capacity, primarily the spinning reserve component of operating capacity.

4. Mandatory sharing of the region's operating reserve requirements which is less as a percentage of the pool's load than are the operating reserves of most pool members as percentages of their respective loads.

5. Establishment of installed reserve and operating reserve requirements on a pool, as opposed to an individual member basis. In other words, reserve requirements should satisfy an objective level of risk for the pool as a whole instead of being governed by the largest contingency or generating unit of an individual member.

6. Membership should be open to all existing entities in the region and those formed in the future, without regard to whether such entities purchase a part of their power requirements from others.

7. Common carrier transmission system access. This goes hand-in-glove with a mechanism for allocating to all pool members the costs of all pool transmission facilities.

8. Coordinated pool planning of generation and transmission in accordance with objective engineering standards, preferably with economic inducements to adhere to the pool plan and pool standards.

aspect of the operation of individual members, such as annual peak load for a specific year, should be identified as the basis by which number of votes will be assigned provided that veto is provided to substantial minorities, such as 15% of the loads in NEPOOL.

Although all member utilities should have a say in the decisions affecting the operation of a pool, management functions should logically be delegated to subcommittees. The coordinating committee should have the following functions:

a. <u>Generation and Transmission Planning</u>

The Coordinating Committee should be empowered to undertake studies which determine the generation and transmission requirements of the entire pool (as opposed to individual members). Based on these studies, the Committee should be empowered to develop plans which will meet these needs in the most economical fashion. Provisions should be made by the Coordinating Committee for joint ownership of new facilities, and construction of large base load units and EHV transmission facilities.

Joint generation planning for a pool is enhanced by the availability of emergency power, economy energy, scheduled and unscheduled outage power, transmission and short term firm power.

Without these types of transactions, the potential economies available to pool members will be substantially decreased, especially for small utilities or partial requirements customers of other utilities. If these small customers are not able to acquire unit entitlements and withstand outages at a reasonable cost, a source of low-cost capital may be foregone. Most of these small entities are able to issue tax-exempt securities. Even an enterprise as large as PSCo cannot reasonably construct the largest possible baseload units on its own. Therefore, this type of arrangement will be generally beneficial in Colorado.

b. Operating Reserve Requirements

As discussed in this report, an obvious advantage of power pooling is the ability of members to lower operating reserves. Any future planning for power pooling in Colorado should delegate to a Coordinating Committee the task of determining overall system reserve requirements, and allocating this requirement proportionally among members of the pool. The IPP already carries out this important function.

c. Maintenance

Power pooling agreements that authorize a coordinating committee to develop a maintenance schedule increase the savings available to pool members. Adhering to a pool maintenance schedule avoids the cost of importing expensive forms of power and can levelize the cost and risk of providing maintenance for the pool as a whole. Unless some coordination occurs, all entities will seek to conduct maintenance when loads and replacement power costs are low, thereby increasing risk. Even with coordination the cost of maintenance may fall unevenly. The IPP members do take steps to assure adequate capacity is available after maintenance but make no attempt to levelize the economic burden of conducting maintenance on a schedule that minimizes risk for the region.

d. Emergency Procedures

An inherent benefit of power pooling is the ability of pool members to coordinate their actions in the event of an emergency. The central coordinating group should be responsible for the development of procedures which will allow for minimum disruption of service and coordinated pool action during forced outages including development of an equitable procedure for load shedding and reducing voltages. This function appears to be carried out well in Colorado by the IPP and others but the economic consequences of shedding load for other pool members has not been addressed.

e. Transmission Planning

The coordinating body of a pool should have oversight responsibilities for transmission between and among pool members. This function is inextricably linked to generation planning because high capacity interconnections serve to reduce installed reserve requirements on both sides of an interconnection, both for pool members and nonmembers to which such interconnections are linked. Establishing a transmission grid and rights of all pool members to it should therefore be one of the first tasks undertaken by a coordinating committee. In addition, the coordinating body should have responsibility for the review and approval of members' plans for the construction of transmission facilities to ensure that the facilities are constructed with sufficient capacity to serve all foreseeable pool needs. Should plans be deemed beneficial to the pool, revenues from all benefitted members should be made available to finance construction. The group charged with responsibility for transmission planning should also be authorized to direct member utilities jointly to finance and construct transmission facilities.

Billing procedures

This aspect of power pooling is one of the more complex, because it determines the allocation of costs among pool members. In Colorado, this complexity is further increased by the large amounts of energy - limited, low-cost hydro installations owned by the United States. As discussed above, the optimal operation of a pool is based on central dispatch; thus ownership considerations do not enter into the dispatch decision and after-the-fact identification of the suppliers and receivers of energy is difficult, if not impossible. Additionally, to achieve maximum benefits and and savings from pooling, transmission lines should be accessible to all members. There are, however, guidelines which if considered by potential power pools in Colorado will serve to minimize inequities in billing procedures.

An after-the-fact determination of how the individual utility would have met its load in the absence of the pool as compared to its actual dispatch, given the existence of the pool, will provide information as to the services provided to or received from the pool of the individual utility. The Flatiron, Colorado office of WAPA proposed a mechanism which would have done this for both hyrdo and thermal units, but Consultants are aware of no further developments. Based on an individual utility's incremental cost of providing the service or the decremental cost avoided by receiving the service, the bill to the individual utility would be computed.

An illustration may be helpful here. Assume a generating unit with the following level of operation and incremental/decremental costs:

Level of Operation (MW)	Incremental/Decremental Cost
350	--
350-400	14.83
400-500	15.10
500-600	15.52
600-642	15.81

Assume that a pool member's own-load dispatch */ for a specific hour is computed to be 525 MW, but that under central dispatch, the unit is operated at 450 MW. The utility is considered to have received 75 MW of economy energy service and the bill is determined as follows: **/

Range of output	MW	x	Decremental Cost ($/MW)	Payment
400 - 500	50		15.10	$ 755
500 - 600	25		15.52	388
			Total due from utility:	$1,143

---

*/ This is NEPOOL's term for the level at which a system's units would operate in the absence of pool tranactions.

**/ Example taken from "New England Power Pool: Description, Analysis, Implications" New England Regional Commission, Energy Program Technical Report: 76-2. March, 1976.

This simple illustration has been expanded by NEPOOL to take into consideration costs associated with scheduled outages, unscheduled outages and deficiency service. PJM ignores the reasons causing a member to buy power and prices all energy and operating capacity transactions on an economy basis.

One equitable system for allocating the benefits and costs of pooled operations requires the establishment of a central pool fund. Revenues received by the fund are used to cover costs associated with maintaining the central dispatch system and other pool associated costs. Accumulated revenues in the fund are distributed on a regular basis according to services provided to or received from the pool.

Transmission Pricing

Allocating costs of transmission service in a manner which accurately tracks costs and benefits is usually perceived as essential yet is one of the more difficult aspects of power pooling. The benefits of open access to pool transmission facilities more than outweigh difficulties encountered in solving the allocation problem. A framework for the development of equitable transmission billing procedures should include the following considerations:

1) Transmission rates should not vary according to the distance power is deemed to be transmitted, as this variation is often contrary to the facts of cost causation and will inhibit transfers between utilities which are separated by long distances. Should two utilities forego a transfer simply because of transmission charges or losses that would be carried if they were located closer to one another, the operation of the pool becomes less efficient. The

Bonneville Power Administration has recently proposed to abandon its distance-varying transmission rates in favor a postage stamp (distance-indifferent) rate. BPA may also abandon its distance-varying losses in favor of flat percentage losses.

2) Transmission rates should guarantee that each pool member shares a proportional cost of maintaining transmission facilities. If firm transactions of transmission facilities are made available to all member utilities, it follows that members should share in the cost, construction, and maintenance of facilities from which they will benefit.

SOURCES

"Colorado Power Pooling & Generation Dispatch Strategies" prepared by Whitfield A. Russell & Associates, P.C. for the National Regulatory Research Institute and the Colorado Public Utilities Commission. August, 1978.

"The National Power Grid Study" DOE/ERA-0056/1, Volume 1. U.S. Department of Energy, Economic Regulatory Administration. January, 1980.

"Report of NYPP-NEPOOL 1980-5 Interconnection Study" November, 1975.

"Power Pooling: Issues & Approaches" DOE/ERA/6485-1, U.S. Department of Energy, Economic Regulatory Administration under Contract No. EB-78-C-01-6385. January, 1980.

"New England Power Pool: Description, Analysis, Implications" New England Regional Commission, Energy Program Technical Report: 76-2. March, 1976.

"MARCA Regional Reliability Council Coordinated Bulk Power Supply Program" Mid-Continent Area Reliability Coordination Agreement. April, 1980.

"Power Pooling in the United States" FERC-0049, Federal Energy Regulatory Commission, Office of Electric Power Regulation. November, 1980.

PART 3

Colorado Public Utilities Commission
Simulation Study
I

In addition to conducting a study of utilities under the jurisdiction of the Colorado Public Utilities Commission, Whitfield A. Russell & Associates has simulated the consolidation of the control areas of Public Service Company of Colorado ("PSCo"), Public Service Company of New Mexico ("PNM"), and El Paso Electric Company ("EPE"). This simulation was intended to indicate the nature of the transactions which would be feasible during the first week of August 1980 under idealized conditions and the general level of the savings which would result from this consolidation.

This aspect of the study derived what is called the load division table for each of the three companies. A load division table indicates the amount of generation producable from each of the Company's generators and power purchases at each level of incremental cost. Moreover, this indicates that for any given level of total system load, the manner in which the load would be optimally shared among the Company's generating units. Examples of load division tables for the individual companies are reflected in Exhibits A, B, and C. Depicted on each of the load division tables in the left-most column are the levels of incremental cost of 1 mill per KWH ranging from 1 mill per KWH to a total of 100 mills/KWH. In each row corresponding to the incremental cost, is reflected the amount of generation producable at the incremental cost from each generator available and operating on the system. For purposes of this simulation, all generating units were assumed to be available for service since the simulation was intended to reflect incremental costs at the time of peak load. This is a somewhat optimistic picture of the amount of production available at each generating level because it does not reflect the possibility of scheduled outages, forced outages, and transmission limitations. These and other constraints lead to a departure from the theoretically optimal incremental cost. Nonetheless, the vast differences in incremental costs required for each of these companies to serve their hourly loads during August of 1980 indicate the potential for realizing substantial savings over the course of a year. The on-peak periods of simultaneously peaking (all summer peaking, for example) are typically less advantageous than off-peak periods for realizing savings.

The incremental cost at which each of the three Company's could serve its August, 1980 loads from their own generation has been simulated. This is depicted on Exhibit D in which the incremental costs of El Paso Electric are substantially higher in off-peak hour than those incurred by PNM and PSCo. In the final column of Exhibit D the incremental costs at which the combined loads of the three systems could be served by use of the combined generation of the three systems is indicated. Note that this incremental cost for the combined three systems is usually lower than that at which El Paso Electric would serve its own loads, but higher than that at which Public Service Company of New Mexico could serve its own loads and, in many hours, higher than that at which PSCo would meet its own loads.

These differences in incremental cost mean that El Paso Electric Company could economically reduce its generation by substantial amounts in order to purchase available but unloaded generation from PNM and PSCo. More importantly, these levels of incremental cost, even for EPE, are substantially lower than those of California utilities. As a consequence, after exhausting the possibility for opportunities to engage in economy transactions among the Inland Power Pool members of PNM, EPE and PSCo, there remains a substantial opportunity for the three simulated companies, and probably the other members of Inland Power Pool as well, to engage in sales to California that would produce substantial split savings or profits. Again, it is important to recognize that the effect of transmission losses, generating unit outages and other phenomena which limit the theoretically maximum achievement of economy transactions have not been simulated; nonetheless, the vast differences between the incremental costs experienced by California's utilities and those simulated under the production cost program indicate that the Inland Power Pool members will benefit from pooling among themselves and from engaging as a group in transactions with California.

II.

For each thermal generating unit, we obtained data from which to calculate the incremental cost of producing (or the value of avoiding) the next kWh of energy at each loading level of each unit. Exhibit E, the system load division table for all three companies, shows the results of that calculation for all units in August, 1980. Note that as each unit is loaded, its incremental cost increases. The average cost per kWh is high at low loading levels because many auxiliary devices must be furnished with power without regard to loading level. Accordingly, as the unit's loading level increases, the cost of providing power for auxiliary devices is spread across more and more units of production, thereby lowering average cost.

The guiding principle of the economic dispatching program is that incremental costs on all available units are equalized just as the incremental costs of units are equalized insofar as possible during real-time utility operations. For economic dispatch purposes, a unit is regarded as unavailable for producing additional energy if it is shut down <u>or</u> fully loaded. As hourly loads increase, the program identifies the units which can provide increased power at the lowest incremental costs. More specifically, the incremental costs of all units are raised in tandem until their combined outputs equal the required level of system load. A reverse logic governs the unloading of units as hourly loads decrease.

Due to lack of data, the application of the model to utilities in New Mexico and Colorado produced only the load division tables for the companies. This subroutine is explained fully below.

The total cost (input-output) curves for each unit is described by a set of equations having the form $y = a+bx+cx^2+dx^3$. The incremental heat rate curve of each unit is given by the equation $y^1 = b+2cx+3dx^2$ which is the first derivative of the input-output curve with respect to x, the loading on the unit. The coefficients a, b, c and d are fixed and are particular to a specific unit, x is the unit loading, y is total fuel consumption and y1 is incremental fuel consumption.

It is necesary to use an equation because, as discussed previously, both the total heat rate and incremental heat rate vary with the loading on a generating unit.

This last equation, $y^1 = b+2cx+3dx^2$ and a fuel cost factor (FC) are used to arrive at the incremental cost of energy for each unit. That is,

$$\text{Incremental cost} = [b+2cx+3dx^2]\ \text{FC}$$

FC is the fuel cost, and, as noted above b, c and d are coefficients from the original input-output equation. X is again the loading on the unit.

The program compiles a tabulation of the megawatts available from each unit, adjusted for EFOR, at each incremental cost of interest. For each level of incremental cost, the sum of megawatts available from all committed units is obtained. This sum, together with the arrays associated with each generating unit, constitute what is referred to as the "system load division table". Although the arrays for each unit change only for changes in fuel cost or EFOR, the array of total system megawatts and incremental cost is affected by unit commitments, especially base load unit commitments.

Although preparation of load division tables constitutes the major application of the model to the present analysis, it is important to note that for a given set of committed units and a given system load requirement, one can determine the expected level of system incremental cost and the optimal loading on each unit. Commitment of the proper combination of units is done by a separate subroutine. The loading point for each unit enables the program to compute cost for each unit and for the entire system, in addition, the model is also capable of determing the effect of production upon interchange.

Given the definition of economy transactions as those in which the buyer pays a price for energy set at some percentage of the amount separating the (i) buyer's decremental or avoided energy cost from (ii) the seller's incremental energy cost, the model can further compute the reduction or increase in generation necessary to achieve an incremental cost equal to the prevailing wholesale market price. In the most common transaction, the buyer and seller "split" the savings by carrying out the transaction at a price midway betwen the buyer's decremental cost and the seller's incremental cost, giving rise to the term "split savings" transactions. In some pools, operating capacity as well as energy is sold on an economy basis.

During any hour in which a Company's incremental cost is less than the prevailing market price, the program can determine the amount of additional energy it could generate before its incremental energy cost equalled the prevailing market price. That amount of additional energy can be sold in blocks at a split savings rate.

A more complete description of the model used in this simulation is provided in the next section.

Abbreviated Unit Names Used in Program

El Paso Electric Co.

EPRG01	Rio Grande	#1
EPRG02	Rio Grande	#2
EPRG03	Rio Grande	#3
EPRG04	Rio Grande	#4
EPRG05	Rio Grande	#5
EPRG06	Rio Grande	#6
EPRG07	Rio Grande	#7
EPRG08	Rio Grande	#8
EPNM01	Newman	#1
EPNM02	Newman	#2
EPNM03	Newman	#3
EPNM04	Newman	#4
EPCP01	Copper	#1
EPFC04	Four Corners	#4
EPFC05	Four Corners	#5

Public Service of New Mexico

NMFC04	Four Corners	#4
NMFC05	Four Corners	#5
NMLV01	Las Vegas	#1
NMPE01	Person	#1
NMPE02	Person	#2
NMPE03	Person	#3
NMPE04	Person	#4
NMPR07	Prager	#7
NMPR08	Prager	#8
NMPR09	Prager	#9
NMRE01	Reeves	#1
NMRE02	Reeves	#2
NMRE03	Reeves	#3
NMSJ01	San Juan	#1
NMSJ02	San Juan	#2
NMSJ03	San Juan	#3

Public Service of Colorado

PCVA01	Valmont #1
PCVA02	Valmont #2
PCVA03	Valmont #3
PCVA04	Valmont #4

PCVA05	Valmont #5
PCVA06	Valmont #6
PCCC01	Cabin Creek #1
PCCC02	Cabin Creek #2
PCBO01	Boulder #1
PCBO02	Boulder #2
PCGT01	Georgetown #1
PCGT02	Georgetown #2
PCPA01	Palisade #1
PCPA02	Palisade #2
PCSA01	Salida #1
PCSA02	Salida #2
PCSH01	Shoshore #1
PCSH02	Shoshore #2
PCCH01	Cherokee #1
PCCH02	Cherokee #2
PCCH03	Cherokee #3
PCCH04	Cherokee #4
PCZU01	Zuni #1
PCZU02	Zuni #2
PCCA01	Cameo #1
PCCA02	Cameo #2
PCCO01	Comanche #1
PCCO02	Comanche #2
PCFR01	Fruita #1
PCAL01	Alamosa #1
PCAL02	Alamosa #2
PCAL03	Alamosa #3
PCAL04	Alamosa #4
PCAL05	Alamosa #5
PCAL06	Alamosa #6
PCFL01	Ft. Lupton #1
PCFL02	Ft. Lupton #2
PCFV01	Ft. St. Vrain #1
PCAR01	Arapahoe #1
PCAR02	Arapahoe #2
PCAR03	Arapahoe #3
PCAR04	Arapahoe #4

Exhibit A

FUEL COST

SIMULATION

MODEL

THE FUEL COST SIMULATION MODEL

PUBLIC SERVICE COMPANY OF NEW MEXICO - FIRST WEEK OF AUGUST

VERSION 81:2

WHITFIELD A. RUSSELL & ASSOCIATES
PUBLIC UTILITY CONSULTANTS
1301 PENNSYLVANIA AVENUE N.W.
SUITE 350
WASHINGTON, D.C. 20004

LOAD DIVISION TABLE FOR MONTH 8

COST	NMFC04	NMFC05	NMSJ01	NMSJ02	NMSJ03	NMRE03	NMRE01	NMRE02	NMPE04	NMPE03	NMPE01	NMPE02	NMPR03
1	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
2	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
4	14.	14.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
5	14.	14.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
6	14.	14.	61.	71.	0.	0.	0.	0.	0.	0.	0.	0.	0.
7	14.	14.	153.	157.	0.	0.	0.	0.	0.	0.	0.	0.	0.
8	14.	14.	153.	157.	0.	0.	0.	0.	0.	0.	0.	0.	0.
9	14.	14.	153.	157.	238.	0.	0.	0.	0.	0.	0.	0.	0.
10	14.	14.	153.	157.	238.	0.	0.	0.	0.	0.	0.	0.	0.
11	14.	14.	153.	157.	238.	0.	0.	0.	0.	0.	0.	0.	0.
12	14.	14.	153.	157.	238.	0.	0.	0.	0.	0.	0.	0.	0.
13	14.	14.	153.	157.	238.	0.	0.	0.	0.	0.	0.	0.	0.
14	14.	14.	153.	157.	238.	0.	0.	0.	0.	0.	0.	0.	0.
15	14.	14.	153.	157.	238.	0.	0.	0.	0.	0.	0.	0.	0.
16	14.	14.	153.	157.	238.	0.	0.	0.	0.	0.	0.	0.	0.
17	14.	14.	153.	157.	238.	0.	0.	0.	0.	0.	0.	0.	0.
18	14.	14.	153.	157.	238.	0.	0.	0.	0.	0.	0.	0.	0.
19	14.	14.	153.	157.	238.	0.	0.	0.	0.	0.	0.	0.	0.
20	14.	14.	153.	157.	238.	0.	0.	0.	0.	0.	0.	0.	0.
21	14.	14.	153.	157.	238.	0.	0.	0.	0.	0.	0.	0.	0.
22	14.	14.	153.	157.	238.	0.	0.	0.	0.	0.	0.	0.	0.
23	14.	14.	153.	157.	238.	0.	0.	0.	0.	0.	0.	0.	0.
24	14.	14.	153.	157.	238.	0.	0.	0.	0.	0.	0.	0.	0.
25	14.	14.	153.	157.	238.	0.	0.	0.	0.	0.	0.	0.	0.
26	14.	14.	153.	157.	238.	0.	0.	0.	0.	0.	0.	0.	0.
27	14.	14.	153.	157.	238.	0.	0.	0.	0.	11.	0.	0.	0.
28	14.	14.	153.	157.	238.	39.	26.	26.	15.	13.	6.	6.	0.
29	14.	14.	153.	157.	238.	49.	36.	36.	19.	16.	8.	8.	0.
30	14.	14.	153.	157.	238.	59.	50.	50.	22.	18.	11.	11.	0.
31	14.	14.	153.	157.	238.	75.	50.	50.	26.	21.	13.	13.	0.
32	14.	14.	153.	157.	238.	75.	50.	50.	32.	23.	15.	15.	0.
33	14.	14.	153.	157.	238.	75.	50.	50.	32.	26.	18.	18.	0.
34	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	0.
35	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	0.
36	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	0.
37	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	0.
38	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	0.
39	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	0.
40	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	0.
41	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	0.
42	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	0.
43	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	0.
44	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	0.
45	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	0.
46	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
47	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
48	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
49	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
50	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
51	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
52	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
53	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
54	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
55	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.

LOAD DIVISION TABLE FOR MONTH 8

COST	NMFC04	NMFC05	NMSJ01	NMSJ02	NMSJ03	NMRE03	NMRE01	NMRE02	NMPE04	NMPE03	NMPE01	NMPE02	NMPR03
56	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
57	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
58	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
59	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
60	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
61	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
62	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
63	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
64	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
65	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
66	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
67	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
68	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
69	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
70	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
71	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
72	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
73	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
74	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
75	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
76	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
77	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
78	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
79	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
80	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
81	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
82	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
83	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
84	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
85	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
86	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
87	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
88	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
89	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
90	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
91	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
92	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
93	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
94	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
95	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
96	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
97	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
98	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
99	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.
100	14.	14.	153.	157.	238.	75.	50.	50.	32.	28.	18.	18.	11.

LOAD DIVISION TABLE FOR MONTH 8

COST	NMPR07	NMPR08	NMLV01	TOTAL
1	0.	0.	0.	0.
2	0.	0.	0.	0.
3	0.	0.	0.	0.
4	0.	0.	0.	27.
5	0.	0.	0.	27.
6	0.	0.	0.	159.
7	0.	0.	0.	337.
8	0.	0.	0.	337.
9	0.	0.	0.	575.
10	0.	0.	0.	575.
11	0.	0.	0.	575.
12	0.	0.	0.	575.
13	0.	0.	0.	575.
14	0.	0.	0.	575.
15	0.	0.	0.	575.
16	0.	0.	0.	575.
17	0.	0.	0.	575.
18	0.	0.	0.	575.
19	0.	0.	0.	575.
20	0.	0.	0.	575.
21	0.	0.	0.	575.
22	0.	0.	0.	575.
23	0.	0.	0.	575.
24	0.	0.	0.	575.
25	0.	0.	0.	575.
26	0.	0.	0.	575.
27	0.	0.	0.	586.
28	0.	0.	0.	707.
29	0.	0.	0.	747.
30	0.	0.	0.	796.
31	0.	0.	0.	822.
32	0.	0.	0.	835.
33	0.	0.	0.	844.
34	0.	0.	0.	846.
35	0.	0.	0.	846.
36	0.	0.	0.	846.
37	0.	0.	0.	846.
38	0.	0.	0.	846.
39	0.	0.	0.	846.
40	0.	0.	0.	846.
41	0.	0.	0.	846.
42	0.	0.	0.	846.
43	0.	0.	0.	846.
44	0.	0.	0.	846.
45	0.	0.	0.	846.
46	6.	5.	0.	868.
47	6.	5.	0.	868.
48	6.	5.	0.	868.
49	6.	5.	0.	868.
50	6.	5.	0.	868.
51	6.	5.	0.	868.
52	6.	5.	0.	868.
53	6.	5.	0.	868.
54	6.	5.	0.	868.
55	6.	5.	0.	868.

LOAD DIVISION TABLE FOR MONTH 8

COST	NMPR07	NMPR08	NMLV01	TOTAL
56	6.	5.	0.	868.
57	6.	5.	0.	868.
58	6.	5.	0.	868.
59	6.	5.	0.	868.
60	6.	5.	0.	868.
61	6.	5.	0.	868.
62	6.	5.	0.	868.
63	6.	5.	0.	868.
64	6.	5.	0.	868.
65	6.	5.	0.	868.
66	6.	5.	0.	868.
67	6.	5.	0.	868.
68	6.	5.	0.	868.
69	6.	5.	0.	868.
70	6.	5.	0.	868.
71	6.	5.	0.	868.
72	6.	5.	0.	868.
73	6.	5.	0.	868.
74	6.	5.	0.	868.
75	6.	5.	0.	868.
76	6.	5.	20.	888.
77	6.	5.	20.	888.
78	6.	5.	20.	888.
79	6.	5.	20.	888.
80	6.	5.	20.	888.
81	6.	5.	20.	888.
82	6.	5.	20.	888.
83	6.	5.	20.	888.
84	6.	5.	20.	888.
85	6.	5.	20.	888.
86	6.	5.	20.	888.
87	6.	5.	20.	888.
88	6.	5.	20.	888.
89	6.	5.	20.	888.
90	6.	5.	20.	888.
91	6.	5.	20.	888.
92	6.	5.	20.	888.
93	6.	5.	20.	888.
94	6.	5.	20.	888.
95	6.	5.	20.	888.
96	6.	5.	20.	888.
97	6.	5.	20.	888.
98	6.	5.	20.	888.
99	6.	5.	20.	888.
100	6.	5.	20.	888.

Exhibit B

```
****************************************************************************
****************************************************************************
****************************************************************************
****************************************************************************
****************************************************************************
*                                                                          *
*              FFFF  U  U  EEEE  L        CCCC  0000  SSSS   TTTTT         *
*              F     U  U  E     L        C     0  0  S        T           *
*              FFF   U  U  EEEE  L        C     0  0  SSSS     T           *
*              F     U  U  E     L        C     0  0     S     T           *
*              F     UUUU  EEEE  LLLL     CCCC  0000  SSSS     T           *
*                                                                          *
*                                                                          *
*       SSSS  IIIII  MM MM  U  U  L       A     TTTTT  IIIII  0000  N   N  *
*       S       I    M M M  U  U  L      A A      T      I    0  0  NN  N  *
*       SSSS    I    M   M  U  U  L     AAAAA     T      I    0  0  N N N  *
*          S    I    M   M  U  U  L     A   A     T      I    0  0  N  NN  *
*       SSSS  IIIII  M   M  UUUU  LLLL A     A    T    IIIII  0000  N   N  *
*                                                                          *
*                                                                          *
*                          MM MM  0000  DDD   EEEE  L                      *
*                          M M M  0  0  D  D  E     L                      *
*                          M   M  0  0  D  D  EEEE  L                      *
*                          M   M  0  0  D  D  E     L                      *
*                          M   M  0000  DDD   EEEE  LLLL                   *
*                                                                          *
****************************************************************************
****************************************************************************
****************************************************************************
*                                                                          *
*                      THE FUEL COST SIMULATION MODEL                      *
*                                                                          *
*        PUBLIC SERVICE COMPANY OF COLORADO - FIRST WEEK OF AUGUST         *
*                                                                          *
*                              VERSION 81:2                                *
*                                                                          *
*                  WHITFIELD A. RUSSELL & ASSOCIATES                       *
*                      PUBLIC UTILITY CONSULTANTS                          *
*                   1301 PENNSYLVANIA AVENUE  N.W.                         *
*                               SUITE 350                                  *
*                        WASHINGTON, D.C. 20004                            *
****************************************************************************
```

V-121

LOAD DIVISION TABLE FOR MONTH 8

COST	PCGH02	PCAS04	PCCA02	PCAR02	PCCO01	PCCH01	PCCH02	PCAR01	PCVA05	PCCH04	PCCO02	PCCH03	PCPA02
1	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2.
2	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2.
3	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2.
4	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2.
5	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2.
6	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2.
7	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2.
8	0.	0.	0.	0.	325.	104.	0.	0.	0.	0.	335.	61.	2.
9	0.	0.	0.	0.	325.	104.	107.	0.	0.	339.	335.	104.	2.
10	0.	0.	0.	0.	325.	104.	107.	0.	122.	339.	335.	156.	2.
11	0.	101.	0.	0.	325.	104.	107.	0.	175.	339.	335.	156.	2.
12	0.	101.	20.	29.	325.	104.	107.	0.	175.	339.	335.	156.	2.
13	0.	101.	32.	45.	325.	104.	107.	0.	175.	339.	335.	156.	2.
14	0.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
15	0.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
16	0.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
17	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
18	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
19	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
20	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
21	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
22	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
23	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
24	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
25	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
26	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
27	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
28	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
29	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
30	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	155.	2.
31	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
32	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
33	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
34	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
35	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
36	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
37	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
38	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
39	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
[illegible]	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
[illegible]	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
[illegible]	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
[illegible]	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
[illegible]	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
[illegible]	[illegible]	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
[illegible]	[illegible]	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
[illegible]	[illegible]	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
[illegible]	[illegible]	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
[illegible]	[illegible]	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
[illegible]	[illegible]	[illegible]	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
[illegible]	[illegible]	[illegible]	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
[illegible]	[illegible]	[illegible]	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
[illegible]	[illegible]	[illegible]	[illegible]	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
[illegible]	[illegible]	[illegible]	[illegible]	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	325.	104.	107.	45.	175.	339.	335.	156.	2.

V-122

LOAD DIVISION TABLE FOR MONTH 8

COST	PCSH02	PCAP04	PCCA02	PCAR02	PCCO01	PCCH01	PCCH02	PCAR01	PCVA05	PCCH04	PCCO02	PCCH03	PCPA02
56	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
57	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
58	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
59	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
60	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
61	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
62	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
63	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
64	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
65	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
66	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
67	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
68	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
69	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
70	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
71	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
72	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
73	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
74	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
75	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
76	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
77	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
78	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
79	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
80	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
81	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
82	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
83	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
84	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
85	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
86	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
87	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
88	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
89	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
90	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
91	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
92	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
93	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
94	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
95	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
96	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
97	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
98	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
99	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.
100	8.	101.	52.	45.	325.	104.	107.	45.	175.	339.	335.	156.	2.

LOAD DIVISION TABLE FOR MONTH 8

COST	PCSH01	PCCA01	PCGT02	PCPA01	PCGT01	PCAR03	PCBO01	PCBO02	PCFV01	PCCC02	PCCC01	PCSA01	PCSA02
1	8.	0.	0.	0.	0.	0.	0.	0.	0.	162.	0.	0.	0.
2	8.	0.	0.	0.	0.	0.	0.	0.	0.	162.	0.	0.	0.
3	8.	0.	0.	0.	0.	0.	0.	0.	0.	162.	0.	0.	0.
4	8.	0.	0.	0.	0.	0.	0.	0.	200.	162.	0.	0.	0.
5	8.	0.	0.	0.	0.	0.	0.	0.	200.	162.	0.	0.	0.
6	8.	0.	0.	0.	0.	0.	0.	0.	200.	162.	0.	0.	0.
7	8.	0.	0.	0.	0.	0.	0.	0.	200.	162.	0.	0.	0.
8	8.	0.	0.	0.	0.	0.	0.	0.	200.	162.	0.	0.	0.
9	8.	0.	0.	0.	0.	0.	0.	0.	200.	162.	0.	0.	0.
10	8.	0.	0.	0.	0.	0.	0.	0.	200.	162.	0.	0.	0.
11	8.	0.	0.	0.	0.	0.	0.	0.	200.	162.	0.	0.	0.
12	8.	0.	0.	0.	0.	0.	0.	0.	200.	162.	0.	0.	0.
13	8.	0.	0.	0.	0.	33.	0.	0.	200.	162.	0.	0.	0.
14	8.	15.	0.	0.	0.	45.	0.	0.	200.	162.	0.	0.	0.
15	8.	24.	0.	0.	0.	45.	0.	0.	200.	162.	0.	0.	0.
16	8.	24.	1.	2.	1.	45.	0.	0.	200.	162.	0.	1.	1.
17	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	0.	1.	1.
18	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	28.	1.	1.
19	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	50.	1.	1.
20	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	71.	1.	1.
21	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	93.	1.	1.
22	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	114.	1.	1.
23	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	136.	1.	1.
24	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
25	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
26	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
27	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
28	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
29	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
30	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
31	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
32	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
33	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
34	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
35	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
36	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
37	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
38	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
39	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
40	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
41	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
42	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
43	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
44	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
45	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
46	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
47	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
48	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
49	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
50	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
51	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
52	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
53	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
54	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
55	[illegible]	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	[illegible]

B-1

LOAD DIVISION TABLE FOR MONTH 8

COST	PCSH01	PCCA01	PCGT02	PCPA01	PCGT01	PCAR03	PCB001	PCB002	PCFV01	PCCC02	PCCC01	PCSA01	PCSA02
56	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
57	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
58	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
59	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
60	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
61	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
62	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
63	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
64	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
65	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
66	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
67	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
68	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
69	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
70	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
71	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
72	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
73	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
74	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
75	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
76	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
77	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
78	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
79	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
80	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
81	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
82	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
83	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
84	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
85	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
86	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
87	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
88	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
89	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
90	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
91	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
92	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
93	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
94	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
95	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
96	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
97	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
98	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
99	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.
100	8.	24.	1.	2.	1.	45.	10.	10.	200.	162.	162.	1.	1.

LOAD DIVISION TABLE FOR MONTH 8

COST	PCAL06	PCAL05	PCAL04	PCZU01	PCZU02	PCFL01	PCVA06	PCAL02	PCFL02	PCFR01	PCAL01	PCVA04	PCVA03
1	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
2	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
4	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
5	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
6	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
7	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
8	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
9	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
10	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
11	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
12	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
13	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
14	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
15	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
16	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
17	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
18	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
19	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
20	0.	0.	0.	0.	68.	0.	0.	0.	0.	0.	0.	0.	0.
21	0.	0.	0.	0.	68.	0.	0.	0.	0.	0.	0.	0.	0.
22	0.	0.	0.	0.	68.	0.	0.	0.	0.	0.	0.	0.	0.
23	0.	0.	0.	0.	68.	0.	0.	0.	0.	0.	0.	0.	0.
24	0.	0.	0.	0.	68.	0.	0.	0.	0.	0.	0.	0.	0.
25	0.	0.	0.	0.	68.	0.	0.	0.	0.	0.	0.	5.	0.
26	0.	0.	0.	0.	68.	0.	0.	21.	0.	0.	21.	6.	0.
27	0.	0.	0.	0.	68.	0.	0.	21.	0.	0.	21.	7.	6.
28	0.	0.	0.	0.	68.	0.	0.	21.	0.	0.	21.	7.	7.
29	0.	0.	0.	0.	68.	0.	0.	21.	0.	0.	21.	8.	7.
30	0.	0.	0.	0.	68.	0.	0.	21.	0.	0.	21.	9.	8.
31	0.	0.	0.	0.	68.	0.	0.	21.	0.	0.	21.	9.	9.
32	0.	0.	0.	0.	68.	0.	0.	21.	0.	0.	21.	10.	10.
33	0.	0.	0.	0.	68.	0.	0.	21.	0.	0.	21.	11.	11.
34	0.	0.	0.	0.	68.	50.	0.	21.	50.	0.	21.	11.	12.
35	0.	0.	0.	0.	68.	50.	0.	21.	50.	0.	21.	12.	13.
36	0.	0.	0.	0.	68.	50.	57.	21.	50.	0.	21.	13.	14.
37	0.	0.	0.	0.	68.	50.	57.	21.	50.	0.	21.	13.	15.
38	0.	0.	0.	0.	68.	50.	57.	21.	50.	0.	21.	14.	16.
39	0.	0.	0.	0.	68.	50.	57.	21.	50.	23.	21.	14.	17.
40	0.	0.	0.	0.	68.	50.	57.	21.	50.	23.	21.	15.	18.
41	0.	0.	0.	22.	68.	50.	57.	21.	50.	23.	21.	16.	19.
42	0.	0.	0.	24.	68.	50.	57.	21.	50.	23.	21.	16.	20.
43	0.	0.	0.	26.	68.	50.	57.	21.	50.	23.	21.	17.	21.
44	0.	0.	0.	28.	68.	50.	57.	21.	50.	23.	21.	18.	22.
45	0.	0.	0.	30.	68.	50.	57.	21.	50.	23.	21.	18.	23.
46	0.	0.	0.	32.	68.	50.	57.	21.	50.	23.	21.	19.	24.
47	0.	0.	0.	34.	68.	50.	57.	21.	50.	23.	21.	20.	25.
48	0.	0.	0.	37.	68.	50.	57.	21.	50.	23.	21.	20.	26.
49	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	21.	27.
50	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	22.	27.
51	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	22.	28.
52	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	23.	29.
53	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	24.	30.
54	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	24.	31.
55	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	25.	32.

LOAD DIVISION TABLE FOR MONTH 8

COST	PCAL06	PCAL05	PCAL04	PCZU01	PCZU02	PCFL01	PCVA06	PCAL02	PCFL02	PCFR01	PCAL01	PCVA04	PCVA[illegible]
56	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	26.	33.
57	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	26.	34.
58	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	27.	35.
59	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	28.	36.
60	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	28.	37.
61	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	29.	38.
62	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	30.	39.
63	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	30.	40.
64	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	31.	41.
65	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	31.	42.
66	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	32.	43.
67	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	33.	44.
68	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	33.	45.
69	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	34.	46.
70	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	35.	47.
71	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	35.	48.
72	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	36.	48.
73	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	37.	49.
74	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	37.	50.
75	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	38.	51.
76	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	39.	52.
77	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	39.	53.
78	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	40.	54.
79	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	41.	55.
80	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	41.	56.
81	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	42.	57.
82	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	43.	58.
83	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	43.	59.
84	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	44.	60.
85	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	45.	61.
86	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	45.	62.
87	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	46.	63.
88	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	47.	64.
89	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	47.	65.
90	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	48.	66.
91	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	48.	67.
92	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	49.	68.
93	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	50.	69.
94	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	50.	69.
95	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	51.	70.
96	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	52.	72.
97	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	52.	72.
98	0.	0.	0.	39.	68.	50.	57.	21.	50.	23.	21.	53.	72.
99	0.	5.	0.	39.	68.	50.	57.	21.	50.	23.	21.	54.	72.
100	0.	5.	0.	39.	68.	50.	57.	21.	50.	23.	21.	54.	72.

LOAD DIVISION TABLE FOR MONTH 8

COST	PCVA02	PCVA01	TOTAL
1	0.	0.	171.
2	0.	0.	171.
3	0.	0.	171.
4	0.	0.	371.
5	0.	0.	371.
6	0.	0.	371.
7	0.	0.	371.
8	0.	0.	1196.
9	0.	0.	1686.
10	0.	0.	1860.
11	0.	0.	2013.
12	0.	0.	2062.
13	0.	0.	2123.
14	0.	0.	2215.
15	0.	0.	2223.
16	0.	0.	2228.
17	0.	0.	2255.
18	0.	0.	2284.
19	0.	0.	2305.
20	0.	0.	2395.
21	0.	0.	2416.
22	0.	0.	2439.
23	0.	0.	2459.
24	0.	0.	2485.
25	0.	0.	2491.
26	0.	0.	2533.
27	0.	5.	2545.
28	0.	6.	2547.
29	0.	6.	2549.
30	0.	7.	2552.
31	0.	8.	2554.
32	0.	8.	2556.
33	6.	9.	2565.
34	8.	9.	2668.
35	10.	10.	2672.
36	11.	10.	2733.
37	13.	11.	2737.
38	14.	12.	2740.
39	16.	12.	2767.
40	18.	13.	2771.
41	19.	13.	2796.
42	21.	14.	2802.
43	22.	14.	2808.
44	24.	15.	2814.
45	26.	16.	2820.
46	27.	16.	2826.
47	29.	17.	2832.
48	30.	17.	2838.
49	32.	18.	2844.
50	34.	18.	2848.
51	35.	19.	2851.
52	37.	20.	2855.
53	38.	20.	2859.
54	40.	21.	2863.
55	42.	21.	2867.

LOAD DIVISION TABLE FOR MONTH 8

COST	PCVA02	PCVA01	TOTAL
56	43.	22.	2870.
57	45.	22.	2874.
58	46.	23.	2878.
59	48.	24.	2882.
60	50.	24.	2885.
61	51.	25.	2889.
62	53.	25.	2893.
63	54.	26.	2897.
64	56.	26.	2900.
65	57.	27.	2904.
66	59.	28.	2908.
67	61.	28.	2912.
68	62.	29.	2916.
69	64.	29.	2919.
70	65.	30.	2923.
71	67.	30.	2927.
72	69.	31.	2931.
73	70.	32.	2934.
74	72.	32.	2938.
75	72.	33.	2941.
76	72.	33.	2943.
77	72.	34.	2945.
78	72.	34.	2947.
79	72.	35.	2949.
80	72.	36.	2951.
81	72.	36.	2954.
82	72.	37.	2956.
83	72.	37.	2958.
84	72.	38.	2960.
85	72.	38.	2962.
86	72.	39.	2964.
87	72.	40.	2967.
88	72.	40.	2969.
89	72.	41.	2971.
90	72.	41.	2973.
91	72.	42.	2975.
92	72.	42.	2978.
93	72.	43.	2980.
94	72.	44.	2982.
95	72.	44.	2984.
96	72.	45.	2987.
97	72.	45.	2988.
98	72.	46.	2989.
99	72.	46.	2995.
100	72.	47.	2996.

Exhibit C

```
FFFF  U   U  EEEE  L        CCCC  0000  SSSS  TTTTT
F     U   U  E     L        C     0  0  S       T
FFF   U   U  EEEE  L        C     0  0  SSSS    T
F     U   U  E     L        C     0  0     S    T
F     UUUU   EEEE  LLLL     CCCC  0000  SSSS    T

SSSS  IIIII  MM MM  U  U  L        A      TTTTT  IIIII  0000  N   N
S       I    M M M  U  U  L       A A       T      I    0  0  NN  N
SSSS    I    M   M  U  U  L      AAAAA      T      I    0  0  N N N
   S    I    M   M  U  U  L      A   A      T      I    0  0  N  NN
SSSS  IIIII  M   M  UUUU  LLLL  A     A     T    IIIII  0000  N   N

MM MM  0000  DDD   EEEE  L
M M M  0  0  D  D  E     L
M   M  0  0  D  D  EEEE  L
M   M  0  0  D  D  E     L
M   M  0000  DDD   EEEE  LLLL
```

THE FUEL COST SIMULATION MODEL

ELPASO ELECTRIC COMPANY - FIRST WEEK OF AUGUST

VERSION 81:2

WHITFIELD A. RUSSELL & ASSOCIATES
PUBLIC UTILITY CONSULTANTS
1301 PENNSYLVANIA AVENUE N.W.
SUITE 350
WASHINGTON, D.C. 20004

C-1

LOAD DIVISION TABLE FOR MONTH 8

COST	EPFC04	EPFC05	EPNM04	EPNM03	EPNM02	EPNM01	EPRG08	EPRG07	EPRG06	EPRG05	EPRG04	EPRG03	EPCP01
1	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
2	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
4	4.	4.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
5	4.	4.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
6	4.	4.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
7	4.	4.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
8	4.	4.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
9	4.	4.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
10	4.	4.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
11	4.	4.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
12	4.	4.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
13	4.	4.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
14	4.	4.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
15	4.	4.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
16	4.	4.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
17	4.	4.	43.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
18	4.	4.	68.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
19	4.	4.	92.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
20	4.	4.	115.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
21	4.	4.	141.	0.	0.	0.	41.	0.	0.	0.	0.	0.	0.
22	4.	4.	165.	0.	0.	0.	52.	20.	0.	0.	0.	0.	0.
23	4.	4.	190.	0.	0.	0.	63.	24.	0.	0.	0.	0.	18.
24	4.	4.	224.	0.	0.	0.	75.	28.	0.	0.	0.	0.	22.
25	4.	4.	224.	0.	0.	0.	86.	31.	0.	0.	0.	0.	27.
26	4.	4.	224.	0.	0.	0.	97.	35.	18.	0.	0.	0.	31.
27	4.	4.	224.	0.	0.	21.	109.	39.	26.	0.	0.	0.	36.
28	4.	4.	224.	40.	22.	37.	120.	43.	34.	15.	0.	6.	40.
29	4.	4.	224.	49.	36.	53.	131.	47.	47.	18.	0.	9.	45.
30	4.	4.	224.	57.	51.	69.	147.	47.	47.	21.	17.	12.	50.
31	4.	4.	224.	66.	65.	86.	147.	47.	47.	25.	21.	15.	54.
32	4.	4.	224.	74.	79.	102.	147.	47.	47.	28.	25.	19.	59.
33	4.	4.	224.	83.	94.	118.	147.	47.	47.	32.	29.	19.	63.
34	4.	4.	224.	92.	108.	134.	147.	47.	47.	32.	34.	19.	68.
35	4.	4.	224.	106.	123.	151.	147.	47.	47.	32.	34.	19.	73.
36	4.	4.	224.	106.	137.	167.	147.	47.	47.	32.	34.	19.	73.
37	4.	4.	224.	106.	151.	183.	147.	47.	47.	32.	34.	19.	73.
38	4.	4.	224.	106.	166.	199.	147.	47.	47.	32.	34.	19.	73.
39	4.	4.	224.	106.	180.	216.	147.	47.	47.	32.	34.	19.	73.
40	4.	4.	224.	106.	194.	232.	147.	47.	47.	32.	34.	19.	73.
41	4.	4.	224.	106.	209.	248.	147.	47.	47.	32.	34.	19.	73.
42	4.	4.	224.	106.	223.	264.	147.	47.	47.	32.	34.	19.	73.
43	4.	4.	224.	106.	238.	281.	147.	47.	47.	32.	34.	19.	73.
44	4.	4.	224.	106.	252.	297.	147.	47.	47.	32.	34.	19.	73.
45	4.	4.	224.	106.	266.	313.	147.	47.	47.	32.	34.	19.	73.
46	4.	4.	224.	106.	281.	329.	147.	47.	47.	32.	34.	19.	73.
47	4.	4.	224.	106.	295.	346.	147.	47.	47.	32.	34.	19.	73.
48	4.	4.	224.	106.	309.	362.	147.	47.	47.	32.	34.	19.	73.
49	4.	4.	224.	106.	324.	378.	147.	47.	47.	32.	34.	19.	73.
50	4.	4.	224.	106.	338.	394.	147.	47.	47.	32.	34.	19.	73.
51	4.	4.	224.	106.	353.	410.	147.	47.	47.	32.	34.	19.	73.
52	4.	4.	224.	106.	367.	427.	147.	47.	47.	32.	34.	19.	73.
53	4.	4.	224.	106.	381.	443.	147.	47.	47.	32.	34.	19.	73.
54	4.	4.	224.	106.	396.	459.	147.	47.	47.	32.	34.	19.	73.
55	4.	4.	224.	106.	410.	475.	147.	47.	47.	32.	34.	19.	73.

V-131

LOAD DIVISION TABLE FOR MONTH 8

COST	EPFC04	EPFC05	EPNM04	EPNM03	EPNM02	EPNM01	EPRG08	EPRG07	EPRG06	EPRG05	EPRG04	EPRG03	EPCP01
56	4.	4.	224.	106.	424.	492.	147.	47.	47.	32.	34.	19.	73.
57	4.	4.	224.	106.	439.	508.	147.	47.	47.	32.	34.	19.	73.
58	4.	4.	224.	106.	453.	524.	147.	47.	47.	32.	34.	19.	73.
59	4.	4.	224.	106.	468.	540.	147.	47.	47.	32.	34.	19.	73.
60	4.	4.	224.	106.	482.	557.	147.	47.	47.	32.	34.	19.	73.
61	4.	4.	224.	106.	496.	573.	147.	47.	47.	32.	34.	19.	73.
62	4.	4.	224.	106.	511.	589.	147.	47.	47.	32.	34.	19.	73.
63	4.	4.	224.	106.	525.	605.	147.	47.	47.	32.	34.	19.	73.
64	4.	4.	224.	106.	539.	622.	147.	47.	47.	32.	34.	19.	73.
65	4.	4.	224.	106.	554.	638.	147.	47.	47.	32.	34.	19.	73.
66	4.	4.	224.	106.	568.	654.	147.	47.	47.	32.	34.	19.	73.
67	4.	4.	224.	106.	583.	670.	147.	47.	47.	32.	34.	19.	73.
68	4.	4.	224.	106.	597.	687.	147.	47.	47.	32.	34.	19.	73.
69	4.	4.	224.	106.	611.	703.	147.	47.	47.	32.	34.	19.	73.
70	4.	4.	224.	106.	626.	719.	147.	47.	47.	32.	34.	19.	73.
71	4.	4.	224.	106.	640.	735.	147.	47.	47.	32.	34.	19.	73.
72	4.	4.	224.	106.	654.	751.	147.	47.	47.	32.	34.	19.	73.
73	4.	4.	224.	106.	669.	768.	147.	47.	47.	32.	34.	19.	73.
74	4.	4.	224.	106.	683.	784.	147.	47.	47.	32.	34.	19.	73.
75	4.	4.	224.	106.	698.	800.	147.	47.	47.	32.	34.	19.	73.
76	4.	4.	224.	106.	712.	823.	147.	47.	47.	32.	34.	19.	73.
77	4.	4.	224.	106.	726.	823.	147.	47.	47.	32.	34.	19.	73.
78	4.	4.	224.	106.	741.	823.	147.	47.	47.	32.	34.	19.	73.
79	4.	4.	224.	106.	755.	823.	147.	47.	47.	32.	34.	19.	73.
80	4.	4.	224.	106.	769.	823.	147.	47.	47.	32.	34.	19.	73.
81	4.	4.	224.	106.	784.	823.	147.	47.	47.	32.	34.	19.	73.
82	4.	4.	224.	106.	798.	823.	147.	47.	47.	32.	34.	19.	73.
83	4.	4.	224.	106.	813.	823.	147.	47.	47.	32.	34.	19.	73.
84	4.	4.	224.	106.	827.	823.	147.	47.	47.	32.	34.	19.	73.
85	4.	4.	224.	106.	841.	823.	147.	47.	47.	32.	34.	19.	73.
86	4.	4.	224.	106.	864.	823.	147.	47.	47.	32.	34.	19.	73.
87	4.	4.	224.	106.	864.	823.	147.	47.	47.	32.	34.	19.	73.
88	4.	4.	224.	106.	864.	823.	147.	47.	47.	32.	34.	19.	73.
89	4.	4.	224.	106.	864.	823.	147.	47.	47.	32.	34.	19.	73.
90	4.	4.	224.	106.	864.	823.	147.	47.	47.	32.	34.	19.	73.
91	4.	4.	224.	106.	864.	823.	147.	47.	47.	32.	34.	19.	73.
92	4.	4.	224.	106.	864.	823.	147.	47.	47.	32.	34.	19.	73.
93	4.	4.	224.	106.	864.	823.	147.	47.	47.	32.	34.	19.	73.
94	4.	4.	224.	106.	864.	823.	147.	47.	47.	32.	34.	19.	73.
95	4.	4.	224.	106.	864.	823.	147.	47.	47.	32.	34.	19.	73.
96	4.	4.	224.	106.	864.	823.	147.	47.	47.	32.	34.	19.	73.
97	4.	4.	224.	106.	864.	823.	147.	47.	47.	32.	34.	19.	73.
98	4.	4.	224.	106.	864.	823.	147.	47.	47.	32.	34.	19.	73.
99	4.	4.	224.	106.	864.	823.	147.	47.	47.	32.	34.	19.	73.
100	4.	4.	224.	106.	864.	823.	147.	47.	47.	32.	34.	19.	73.

LOAD DIVISION TABLE FOR MONTH 8

COST	EPRG01	EPRG02	TOTAL
1	0.	0.	0.
2	0.	0.	0.
3	0.	0.	0.
4	0.	0.	8.
5	0.	0.	8.
6	0.	0.	8.
7	0.	0.	8.
8	0.	0.	8.
9	0.	0.	8.
10	0.	0.	8.
11	0.	0.	8.
12	0.	0.	8.
13	0.	0.	8.
14	0.	0.	8.
15	0.	0.	8.
16	0.	0.	8.
17	0.	0.	51.
18	0.	0.	75.
19	0.	0.	100.
20	0.	0.	124.
21	0.	0.	189.
22	0.	0.	245.
23	0.	0.	302.
24	0.	0.	356.
25	0.	0.	376.
26	0.	0.	414.
27	0.	0.	462.
28	0.	0.	589.
29	0.	0.	667.
30	0.	0.	750.
31	0.	7.	811.
32	5.	13.	877.
33	6.	13.	930.
34	7.	13.	979.
35	8.	13.	1030.
36	9.	13.	1062.
37	10.	13.	1093.
38	11.	13.	1125.
39	12.	13.	1156.
40	13.	13.	1188.
41	13.	13.	1219.
42	13.	13.	1249.
43	13.	13.	1280.
44	13.	13.	1311.
45	13.	13.	1341.
46	13.	13.	1372.
47	13.	13.	1402.
48	13.	13.	1433.
49	13.	13.	1464.
50	13.	13.	1494.
51	13.	13.	1525.
52	13.	13.	1555.
53	13.	13.	1586.
54	13.	13.	1617.
55	13.	13.	1647.

LOAD DIVISION TABLE FOR MONTH 8

COST	EPRG01	EPRG02	TOTAL
56	13.	13.	1679.
57	13.	13.	1709.
58	13.	13.	1739.
59	13.	13.	1770.
60	13.	13.	1800.
61	13.	13.	1831.
62	13.	13.	1862.
63	13.	13.	1892.
64	13.	13.	1923.
65	13.	13.	1953.
66	13.	13.	1984.
67	13.	13.	2015.
68	13.	13.	2045.
69	13.	13.	2076.
70	13.	13.	2107.
71	13.	13.	2137.
72	13.	13.	2168.
73	13.	13.	2198.
74	13.	13.	2229.
75	13.	13.	2260.
76	13.	13.	2297.
77	13.	13.	2311.
78	13.	13.	2326.
79	13.	13.	2340.
80	13.	13.	2354.
81	13.	13.	2369.
82	13.	13.	2383.
83	13.	13.	2397.
84	13.	13.	2412.
85	13.	13.	2426.
86	13.	13.	2449.
87	13.	13.	2449.
88	13.	13.	2449.
89	13.	13.	2449.
90	13.	13.	2449.
91	13.	13.	2449.
92	13.	13.	2449.
93	13.	13.	2449.
94	13.	13.	2449.
95	13.	13.	2449.
96	13.	13.	2449.
97	13.	13.	2449.
98	13.	13.	2449.
99	13.	13.	2449.
100	13.	13.	2449.

Exhibit D

D-1

Individual Company Incremental Cost vs. Pooled Incremental Cost

August 3, 1980

Hour	El Paso Load	El Paso IC	PSCOLO Load	PSCOLO IC	NEW MEX Load	NEW MEX IC	TOTAL Load	TOTAL IC
1	396	26	1611.5	9	400	8	2407.5	9
2	378	25	1667.3	9	383	8	2428.3	9
3	365	25	1597.8	9	376	8	2338.8	9
4	355	24	1555.1	9	369	8	2279.1	9
5	348	24	1543.2	9	369	8	2260.2	9
6	335	24	1507.8	9	373	8	2215.8	9
7	347	24	1466.8	9	378	8	2191.8	9
8	380	25	1576.7	9	410	9	2366.7	9
9	424	26	1598.0	9	440	9	2462.	9
10	452	27	1730.7	10	476	9	2658.7	11
11	477	28	1864.6	10	500	9	2841.6	13
12	495	27	1979.6	11	525	9	2999.6	17
13	508	28	2005.2	11	535	9	3048.2	17
14	513	28	2041.6	12	546	9	3100.6	20
15	514	28	2060.5	12	553	9	3127.5	20
16	518	28	2063.1	12	561	9	3142.1	20
17	516	28	2085.5	13	554	9	3155.5	20
18	506	28	2102.5	13	543	9	3151.5	20
19	486	27	2030.9	12	527	9	3043.9	17
20	522	28	2020.1	11	540	9	3082.1	19
21	514	28	2086.0	13	535	9	3135.	20
22	476	27	2095.2	13	485	9	3056.2	18
23	425	26	1871.0	10	431	9	2727.	11
24	397	26	1674.6	9	401	9	2472.6	9
	10647		43835.3		11210		65687.2	

Individual Company Incremental Cost vs. Pooled Incremental Cost
August 4, 1980

Hour	El Paso Load	El Paso IC	PSCOLO Load	PSCOLO IC	NEW MEX Load	NEW MEX IC	TOTAL Load	TOTAL IC
1	380	25	1657.3	9	382	8	2419.3	9
2	364	25	1569.5	9	370	8	2303.5	9
3	361	24	1527.6	9	360	8	2248.6	9
4	363	25	1521.3	9	357	8	2241.3	9
5	379	25	1504.4	9	368	8	2251.4	9
6	414	26	1587.3	9	404	9	2405.3	10
7	474	28	1660.8	9	483	9	2617.8	10
8	536	28	1830.7	10	561	9	2927.7	14
9	593	28	2064.4	12	604	27	3261.4	22
10	623	29	2207.6	14	633	28	3463.6	26
11	640	29	2288.2	18	649	28	3577.2	27
12	678	29	2335.6	20	656	28	3669.6	28
13	663	29	2371.3	20	674	28	3708.3	28
14	663	29	2409.9	21	683	28	3755.9	28
15	676	29	2401.0	21	677	28	3754.	28
16	662	29	2402.7	21	677	28	3741.7	28
17	639	29	2451.5	23	659	28	3749.5	28
18	589	28	2429.6	22	640	28	3658.6	28
19	584	28	2326.5	20	622	28	3532.5	27
20	604	29	2253.7	17	640	28	3497.7	26
21	592	28	2276.6	18	607	27	3475.6	26
22	552	28	2215.9	14	554	9	3321.9	23
23	461	27	2020.0	11	483	9	2964.	15
24	437	27	1849.9	10	438	9	2724.9	11
	12927		49163.3		13181		75271.3	

Individual Company Incremental Cost vs. Pooled Incremental Cost

August 5, 1980

Hour	El Paso Load	El Paso IC	PSCOLO Load	PSCOLO IC	NEW MEX Load	NEW MEX IC	TOTAL Load	TOTAL IC
1	409	26	1694.7	9	415	9	2518.7	10
2	397	26	1633.7	9	396	8	2426.7	9
3	384	26	1620.1	9	386	8	2390.1	9
4	375	25	1580.3	9	380	8	2335.3	9
5	387	26	1524.4	9	389	8	2300.4	9
6	424	26	1595.7	9	434	9	2453.7	10
7	466	27	1707.3	10	490	9	2663.3	11
8	543	28	1877.0	10	549	9	2969.0	14
9	591	28	2151.2	14	582	27	3324.2	23
10	620	29	2325.9	20	619	28	2564.9	27
11	643	29	2331.0	20	632	28	3606.0	28
12	651	29	2373.6	20	641	28	3665.6	28
13	673	29	2365.4	20	654	28	3692.4	28
14	682	29	2470.2	24	672	28	3824.2	28
15	673	29	2490.1	25	680	28	3843.1	28
16	662	29	2517.2	26	687	28	3866.2	29
17	619	29	2519.6	26	661	28	3799.6	28
18	623	29	2454.6	23	634	28	3711.6	28
19	600	28	2359.4	20	608	27	3567.4	27
20	614	29	2300.2	19	622	28	3536.2	26
21	599	28	2326.6	20	597	27	3522.6	26
22	547	28	2242.8	17	536	9	3325.8	23
23	488	27	2042.0	12	472	9	3002.0	17
24	437	27	1890.9	10	433	9	2760.9	11
	13107		50393.9		13169		76669.9	

Individual Company Incremental Cost vs. Pooled Incremental Cost

August 6, 1980

Hour	El Paso Load	El Paso IC	PSCOLO Load	PSCOLO IC	NEW MEX Load	NEW MEX IC	TOTAL Load	TOTAL IC
1	408	26	1781.4	10	405	9	2594.4	10
2	395	26	1641.2	9	392	8	2428.2	9
3	383	26	1638.0	9	384	8	2405.0	9
4	379	25	1619.8	9	380	8	2378.8	9
5	389	26	1586.3	9	393	8	2368.3	9
6	421	26	1658.9	9	424	9	2503.9	10
7	479	27	1778.1	10	495	9	2752.1	11
8	533	28	1945.9	11	573	9	3051.9	18
9	598	28	2199.0	14	613	28	3410.0	24
10	623	29	2350.9	20	649	28	3622.9	28
11	653	29	2524.4	26	667	28	3844.4	28
12	656	29	2586.3	34	675	28	3917.3	29
13	674	29	2625.4	34	692	28	3991.4	30
14	684	30	2683.6	36	706	28	4073.6	30
15	686	30	2680.8	35	712	28	4078.8	30
16	667	29	2679.1	35	716	28	4062.1	30
17	640	29	2666.5	34	696	28	4002.5	30
18	583	28	2563.9	33	683	28	3829.9	28
19	563	28	2456.0	23	656	28	3675.0	28
20	581	28	2389.1	20	660	28	3630.1	28
21	567	28	2399.3	20	631	28	3597.3	27
22	523	28	2348.5	20	564	9	3435.5	25
23	456	27	2192.0	14	494	9	3142.0	20
24	415	26	1969.3	10	448	9	2832.3	13
	12956		52963.7		13708		79627.7	

Individual Company Incremental Cost vs. Pooled Incremental Cost

August 7, 1981

Hour	El Paso Load	El Paso IC	PSCOLO Load	PSCOLO IC	NEW MEX Load	NEW MEX IC	TOTAL Load	TOTAL IC
1	392	26	1836.8	10	420	9	2648.8	11
2	380	25	1748.8	10	404	9	2532.8	10
3	369	25	1677.8	9	391	8	2437.8	9
4	365	25	1638.6	9	389	8	2392.6	9
5	378	25	1640.7	9	398	8	2416.7	9
6	407	26	1681.0	9	429	9	2517.	10
7	472	27	1826.2	10	492	9	2790.2	12
8	531	28	1985.6	11	567	9	3083.6	19
9	584	28	2267.8	18	612	28	3463.8	26
10	608	28	2428.8	22	646	28	3682.8	28
11	628	29	2586.3	34	659	28	3873.3	29
12	646	29	2666.1	34	663	28	3975.1	30
13	644	29	2715.2	36	681	28	4040.2	30
14	655	29	2777.7	40	697	28	4129.7	31
15	679	29	2776.7	40	704	28	4159.7	31
16	632	29	2768.7	39	702	28	4102.7	30
17	624	29	2744.5	38	688	28	4056.5	30
18	604	29	2675.8	35	631	28	3910.8	29
19	582	28	2597.5	33	620	28	3799.5	28
20	605	29	2504.3	26	631	28	3740.3	28
21	584	28	2496.1	25	596	9	3676.1	28
22	532	28	2392.2	20	540	9	3464.2	26
23	461	27	2335.7	20	473	9	3269.7	22
24	428	27	2037.5	12	425	9	2890.5	24
	12790		54806.4		13458		81054.4	

Individual Company Incremental Cost vs. Pooled Incremental Cost

August 8, 1980

Hour	El Paso Load	El Paso IC	PSCOLO Load	PSCOLO IC	NEW MEX Load	NEW MEX IC	TOTAL Load	TOTAL IC
1	412	26	1859.5	10	411	9	2682.5	11
2	351	24	1777.3	10	399	7	2527.3	10
3	381	25	1735.5	10	387	7	2503.5	10
4	361	24	1692.2	9	383	7	2436.2	9
5	375	25	1677.3	9	396	7	2448.3	9
6	405	26	1770.7	10	421	9	2596.7	10
7	447	27	1899.8	10	487	9	2833.8	13
8	540	28	2024.4	12	558	9	3122.4	20
9	584	28	2219.4	14	594	27	3397.4	24
10	618	29	2346.4	20	622	28	3586.4	27
11	635	29	2430.4	22	638	28	3703.4	28
12	637	29	2454.9	23	640	28	3731.9	28
13	657	29	2460.6	23	661	28	3778.6	28
14	659	29	2503.6	26	676	28	3838.6	28
15	659	29	2491.8	25	681	28	3831.8	28
16	646	29	2475.5	24	686	28	3807.5	28
17	628	29	2384.3	20	667	28	3679.3	28
18	605	29	2317.6	19	647	28	3569.6	27
19	576	28	2220.5	15	622	28	3418.5	24
20	589	28	2143.7	13	636	28	3368.7	23
21	578	28	2179.7	14	609	27	3366.7	23
22	526	28	2076.7	13	540	9	3142.7	20
23	473	27	1931.7	11	479	9	2883.7	14
24	431	27	1716.5	10	438	9	2585.5	10
	12773		50790.0		13278		46841.0	

Individual Company Incremental Cost vs. Pooled Incremental Cost
August 9, 1980

Hour	El Paso Load	El Paso IC	PSCOLO Load	PSCOLO IC	NEW MEX Load	NEW MEX IC	TOTAL Load	TOTAL IC
1	408	26	1569.5	9	410	9	2387.5	9
2	390	26	1512.5	9	391	7	2293.5	9
3	375	25	1453.4	9	375	7	2203.4	9
4	368	25	1472.2	9	371	7	2211.2	9
5	364	25	1521.5	9	374	7	2259.5	9
6	374	25	1537.9	9	375	7	2286.9	9
7	402	26	1580.8	9	400	9	2382.8	9
8	453	27	1545.7	9	451	9	2449.7	9
9	496	28	1717.0	10	506	9	2719.0	11
10	524	28	1867.2	10	539	9	2930.2	14
11	558	28	2000.4	11	560	9	3118.4	20
12	561	28	2092.8	13	569	9	3222.8	21
13	552	28	2144.6	13	575	9	3271.6	22
14	558	28	2135.1	13	588	27	3281.1	22
15	547	28	2181.3	14	591	27	3319.3	22
16	560	28	2177.2	14	600	27	3337.2	23
17	548	28	2166.6	14	611	28	3325.6	23
18	518	28	2223.5	15	593	27	3334.5	23
19	508	28	2093.9	13	569	9	3170.9	20
20	524	28	2018.3	11	572	9	3114.3	20
21	514	28	2036.6	12	554	9	3104.6	20
22	462	27	2017.1	11	509	9	2988.1	17
23	426	26	1876.9	10	464	9	2766.9	12
24	369	25	1706.5	9	427	9	2502.5	10
	11359		44648.5		11974		67981.5	

Exhibit E

```
FFFF  U  U  EEEE  L        CCCC  0000  SSSS   TTTTT
F     U  U  E     L        C     0  0  S        T
FFF   U  U  EEEE  L        C     0  0  SSSS     T
F     U  U  E     L        C     0  0     S     T
F     UUUU  EEEE  LLLL     CCCC  0000  SSSS     T

SSSS  IIIII  MM MM  U  U  L        A      TTTTT  IIIII  0000  N   N
S       I    M M M  U  U  L       A A       T      I    0  0  NN  N
SSSS    I    M   M  U  U  L      AAAAA      T      I    0  0  N N N
   S    I    M   M  U  U  L      A   A      T      I    0  0  N  NN
SSSS  IIIII  M   M  UUUU  LLLL  A     A     T    IIIII  0000  N   N

MM MM  0000  DDD   EEEE  L
M M M  0  0  D  D  E     L
M   M  0  0  D  D  EEEE  L
M   M  0  0  D  D  E     L
M   M  0000  DDD   EEEE  LLLL
```

THE FUEL COST SIMULATION MODEL

POOLED UNITS - FIRST WEEK OF AUGUST

VERSION 81:2

WHITFIELD A. RUSSELL & ASSOCIATES
PUBLIC UTILITY CONSULTANTS
1301 PENNSYLVANIA AVENUE N.W.
SUITE 350
WASHINGTON, D.C. 20004

LOAD DIVISION TABLE FOR MONTH 8

COST	NMPE01	NMPE01	NMPE02	NMPE04	FPRG04	EPRG02	EPRG01	PCFL02	PCFL01	PCVA02	PCVA06	PCFR01	PCZU01
1	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
2	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
4	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
5	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
6	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
7	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
8	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
9	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
10	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
11	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
12	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
13	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
14	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
15	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
16	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
17	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
18	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
19	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
20	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
21	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
22	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
23	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
24	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
25	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
26	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
27	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
28	26.	6.	6.	15.	0.	0.	0.	0.	0.	0.	0.	0.	0.
29	36.	8.	8.	19.	0.	0.	0.	0.	0.	0.	0.	0.	0.
30	50.	11.	11.	22.	17.	0.	0.	0.	0.	0.	0.	0.	0.
31	50.	13.	13.	26.	21.	7.	0.	0.	0.	0.	0.	0.	0.
32	50.	15.	15.	32.	25.	13.	5.	0.	0.	0.	0.	0.	0.
33	50.	18.	18.	32.	29.	13.	6.	0.	0.	6.	0.	0.	0.
34	50.	18.	18.	32.	34.	13.	7.	50.	50.	8.	0.	0.	0.
35	50.	18.	18.	32.	34.	13.	8.	50.	50.	10.	0.	0.	0.
36	50.	18.	18.	32.	34.	13.	9.	50.	50.	11.	57.	0.	0.
37	50.	18.	18.	32.	34.	13.	10.	50.	50.	13.	57.	0.	0.
38	50.	18.	18.	32.	34.	13.	11.	50.	50.	14.	57.	0.	0.
39	50.	18.	18.	32.	34.	13.	12.	50.	50.	16.	57.	23.	0.
40	50.	18.	18.	32.	34.	13.	13.	50.	50.	18.	57.	23.	0.
41	50.	18.	18.	32.	34.	13.	13.	50.	50.	19.	57.	23.	22.
42	50.	18.	18.	32.	34.	13.	13.	50.	50.	21.	57.	23.	24.
43	50.	18.	18.	32.	34.	13.	13.	50.	50.	22.	57.	23.	26.
44	50.	18.	18.	32.	34.	13.	13.	50.	50.	24.	57.	23.	28.
45	50.	18.	18.	32.	34.	13.	13.	50.	50.	26.	57.	23.	30.
46	50.	18.	18.	32.	34.	13.	13.	50.	50.	27.	57.	23.	32.
47	50.	18.	18.	32.	34.	13.	13.	50.	50.	29.	57.	23.	34.
48	50.	18.	18.	32.	34.	13.	13.	50.	50.	30.	57.	23.	37.
49	50.	18.	18.	32.	34.	13.	13.	50.	50.	32.	57.	23.	39.
50	50.	18.	18.	32.	34.	13.	13.	50.	50.	34.	57.	23.	39.
51	50.	18.	18.	32.	34.	13.	13.	50.	50.	35.	57.	23.	39.
52	50.	18.	18.	32.	34.	13.	13.	50.	50.	37.	57.	23.	39.
53	50.	18.	18.	32.	34.	13.	13.	50.	50.	38.	57.	23.	39.
54	50.	18.	18.	32.	34.	13.	13.	50.	50.	[illegible]	[illegible]	[illegible]	[illegible]
55	50.	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

V-143

LOAD DIVISION TABLE FOR MONTH 8

COST	NMRE01	NMPE01	NMPE02	NMPE04	EPRG04	EPRG02	EPRG01	PCFL02	PCFL01	PCVA02	PCVA06	PCFR01	PCZU01
56	50.	18.	18.	32.	34.	13.	13.	50.	50.	43.	57.	23.	39.
57	50.	18.	18.	32.	34.	13.	13.	50.	50.	45.	57.	23.	39.
58	50.	18.	18.	32.	34.	13.	13.	50.	50.	46.	57.	23.	39.
59	50.	18.	18.	32.	34.	13.	13.	50.	50.	48.	57.	23.	39.
60	50.	18.	18.	32.	34.	13.	13.	50.	50.	50.	57.	23.	39.
61	50.	18.	18.	32.	34.	13.	13.	50.	50.	51.	57.	23.	39.
62	50.	18.	18.	32.	34.	13.	13.	50.	50.	53.	57.	23.	39.
63	50.	18.	18.	32.	34.	13.	13.	50.	50.	54.	57.	23.	39.
64	50.	18.	18.	32.	34.	13.	13.	50.	50.	56.	57.	23.	39.
65	50.	18.	18.	32.	34.	13.	13.	50.	50.	57.	57.	23.	39.
66	50.	18.	18.	32.	34.	13.	13.	50.	50.	59.	57.	23.	39.
67	50.	18.	18.	32.	34.	13.	13.	50.	50.	61.	57.	23.	39.
68	50.	18.	18.	32.	34.	13.	13.	50.	50.	62.	57.	23.	39.
69	50.	18.	18.	32.	34.	13.	13.	50.	50.	64.	57.	23.	39.
70	50.	18.	18.	32.	34.	13.	13.	50.	50.	65.	57.	23.	39.
71	50.	18.	18.	32.	34.	13.	13.	50.	50.	67.	57.	23.	39.
72	50.	18.	18.	32.	34.	13.	13.	50.	50.	69.	57.	23.	39.
73	50.	18.	18.	32.	34.	13.	13.	50.	50.	70.	57.	23.	39.
74	50.	18.	18.	32.	34.	13.	13.	50.	50.	72.	57.	23.	39.
75	50.	18.	18.	32.	34.	13.	13.	50.	50.	72.	57.	23.	39.
76	50.	18.	18.	32.	34.	13.	13.	50.	50.	72.	57.	23.	39.
77	50.	18.	18.	32.	34.	13.	13.	50.	50.	72.	57.	23.	39.
78	50.	18.	18.	32.	34.	13.	13.	50.	50.	72.	57.	23.	39.
79	50.	18.	18.	32.	34.	13.	13.	50.	50.	72.	57.	23.	39.
80	50.	18.	18.	32.	34.	13.	13.	50.	50.	72.	57.	23.	39.
81	50.	18.	18.	32.	34.	13.	13.	50.	50.	72.	57.	23.	39.
82	50.	18.	18.	32.	34.	13.	13.	50.	50.	72.	57.	23.	39.
83	50.	18.	18.	32.	34.	13.	13.	50.	50.	72.	57.	23.	39.
84	50.	18.	18.	32.	34.	13.	13.	50.	50.	72.	57.	23.	39.
85	50.	18.	18.	32.	34.	13.	13.	50.	50.	72.	57.	23.	39.
86	50.	18.	18.	32.	34.	13.	13.	50.	50.	72.	57.	23.	39.
87	50.	18.	18.	32.	34.	13.	13.	50.	50.	72.	57.	23.	39.
88	50.	18.	18.	32.	34.	13.	13.	50.	50.	72.	57.	23.	39.
89	50.	18.	18.	32.	34.	13.	13.	50.	50.	72.	57.	23.	39.
90	50.	18.	18.	32.	34.	13.	13.	50.	50.	72.	57.	23.	39.
91	50.	18.	18.	32.	34.	13.	13.	50.	50.	72.	57.	23.	39.
92	50.	18.	18.	32.	34.	13.	13.	50.	50.	72.	57.	23.	39.
93	50.	18.	18.	32.	34.	13.	13.	50.	50.	72.	57.	23.	39.
94	50.	18.	18.	32.	34.	13.	13.	50.	50.	72.	57.	23.	39.
95	50.	18.	18.	32.	34.	13.	13.	50.	50.	72.	57.	23.	39.
96	50.	18.	18.	32.	34.	13.	13.	50.	50.	72.	57.	23.	39.
97	50.	18.	18.	32.	34.	13.	13.	50.	50.	72.	57.	23.	39.
98	50.	18.	18.	32.	34.	13.	13.	50.	50.	72.	57.	23.	39.
99	50.	18.	18.	32.	34.	13.	13.	50.	50.	72.	57.	23.	39.
100	50.	18.	18.	32.	34.	13.	13.	50.	50.	72.	57.	23.	39.

LOAD DIVISION TABLE FOR MONTH 8

COST	PCAL02	PCAL01	EPRG06	NMPE03	PCVA03	EPNM01	PCVA01	EPRG05	EPNM03	EPRG03	NMRE03	EPNM02	NMPE02
1	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
2	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
4	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
5	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
6	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
7	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
8	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
9	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
10	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
11	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
12	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
13	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
14	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
15	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
16	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
17	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
18	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
19	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
20	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
21	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
22	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
23	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
24	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
25	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
26	21.	21.	18.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
27	21.	21.	26.	11.	6.	21.	5.	0.	0.	0.	0.	0.	0.
28	21.	21.	34.	13.	7.	37.	6.	15.	40.	6.	39.	22.	26.
29	21.	21.	47.	16.	7.	53.	6.	18.	49.	9.	49.	36.	36.
30	21.	21.	47.	18.	8.	69.	7.	21.	57.	12.	59.	51.	50.
31	21.	21.	47.	21.	9.	86.	8.	25.	66.	15.	75.	65.	50.
32	21.	21.	47.	23.	10.	102.	8.	28.	74.	19.	75.	79.	50.
33	21.	21.	47.	26.	11.	118.	9.	32.	83.	19.	75.	94.	50.
34	21.	21.	47.	28.	12.	134.	9.	32.	92.	19.	75.	108.	50.
35	21.	21.	47.	28.	13.	151.	10.	32.	106.	19.	75.	123.	50.
36	21.	21.	47.	28.	14.	167.	10.	32.	106.	19.	75.	137.	50.
37	21.	21.	47.	28.	15.	183.	11.	32.	106.	19.	75.	151.	50.
38	21.	21.	47.	28.	16.	199.	12.	32.	106.	19.	75.	166.	50.
39	21.	21.	47.	28.	17.	216.	12.	32.	106.	19.	75.	180.	50.
40	21.	21.	47.	28.	18.	232.	13.	32.	106.	19.	75.	194.	50.
41	21.	21.	47.	28.	19.	248.	13.	32.	106.	19.	75.	209.	50.
42	21.	21.	47.	28.	20.	264.	14.	32.	106.	19.	75.	223.	50.
43	21.	21.	47.	28.	21.	281.	14.	32.	106.	19.	75.	238.	50.
44	21.	21.	47.	28.	22.	297.	15.	32.	106.	19.	75.	252.	50.
45	21.	21.	47.	28.	23.	313.	16.	32.	106.	19.	75.	266.	50.
46	21.	21.	47.	28.	24.	329.	16.	32.	106.	19.	75.	281.	50.
47	21.	21.	47.	28.	25.	346.	17.	32.	106.	19.	75.	295.	50.
48	21.	21.	47.	28.	26.	362.	17.	32.	106.	19.	75.	309.	50.
49	21.	21.	47.	28.	27.	378.	18.	32.	106.	19.	75.	324.	50.
50	21.	21.	47.	28.	27.	394.	18.	32.	106.	19.	75.	338.	50.
51	21.	21.	47.	28.	28.	410.	19.	32.	106.	19.	75.	353.	50.
52	21.	21.	47.	28.	29.	427.	20.	32.	106.	19.	75.	367.	50.
53	21.	21.	47.	28.	30.	443.	20.	32.	106.	19.	75.	381.	0.
54	1.	21.	47.	28.	31.	459.	21.	32.	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

LOAD DIVISION TABLE FOR MONTH 8

COST	PCAL02	PCAL01	EPRG06	NMPE03	PCVA03	EPNM01	PCVA01	EPRG05	EPNM03	EPRG03	NMRE03	EPNM02	NMRE02
56	21.	21.	47.	28.	33.	492.	22.	32.	106.	19.	75.	424.	50.
57	21.	21.	47.	28.	34.	508.	22.	32.	106.	19.	75.	439.	50.
58	21.	21.	47.	28.	35.	524.	23.	32.	106.	19.	75.	453.	50.
59	21.	21.	47.	28.	36.	540.	24.	32.	106.	19.	75.	468.	50.
60	21.	21.	47.	28.	37.	557.	24.	32.	106.	19.	75.	482.	50.
61	21.	21.	47.	28.	38.	573.	25.	32.	106.	19.	75.	496.	50.
62	21.	21.	47.	28.	39.	589.	25.	32.	106.	19.	75.	511.	50.
63	21.	21.	47.	28.	40.	605.	26.	32.	106.	19.	75.	525.	50.
64	21.	21.	47.	28.	41.	622.	26.	32.	106.	19.	75.	539.	50.
65	21.	21.	47.	28.	42.	638.	27.	32.	106.	19.	75.	554.	50.
66	21.	21.	47.	28.	43.	654.	28.	32.	106.	19.	75.	568.	50.
67	21.	21.	47.	28.	44.	670.	28.	32.	106.	19.	75.	583.	50.
68	21.	21.	47.	28.	45.	687.	29.	32.	106.	19.	75.	597.	50.
69	21.	21.	47.	28.	46.	703.	29.	32.	106.	19.	75.	611.	50.
70	21.	21.	47.	28.	47.	719.	30.	32.	106.	19.	75.	626.	50.
71	21.	21.	47.	28.	48.	735.	30.	32.	106.	19.	75.	640.	50.
72	21.	21.	47.	28.	48.	751.	31.	32.	106.	19.	75.	654.	50.
73	21.	21.	47.	28.	49.	768.	32.	32.	106.	19.	75.	669.	50.
74	21.	21.	47.	28.	50.	784.	32.	32.	106.	19.	75.	683.	50.
75	21.	21.	47.	28.	51.	800.	33.	32.	106.	19.	75.	698.	50.
76	21.	21.	47.	28.	52.	823.	33.	32.	106.	19.	75.	712.	50.
77	21.	21.	47.	28.	53.	823.	34.	32.	106.	19.	75.	726.	50.
78	21.	21.	47.	28.	54.	823.	34.	32.	106.	19.	75.	741.	50.
79	21.	21.	47.	28.	55.	823.	35.	32.	106.	19.	75.	755.	50.
80	21.	21.	47.	28.	56.	823.	36.	32.	106.	19.	75.	769.	50.
81	21.	21.	47.	28.	57.	823.	36.	32.	106.	19.	75.	784.	50.
82	21.	21.	47.	28.	58.	823.	37.	32.	106.	19.	75.	798.	50.
83	21.	21.	47.	28.	59.	823.	37.	32.	106.	19.	75.	813.	50.
84	21.	21.	47.	28.	60.	823.	38.	32.	106.	19.	75.	827.	50.
85	21.	21.	47.	28.	61.	823.	38.	32.	106.	19.	75.	841.	50.
86	21.	21.	47.	28.	62.	823.	39.	32.	106.	19.	75.	864.	50.
87	21.	21.	47.	28.	63.	823.	40.	32.	106.	19.	75.	864.	50.
88	21.	21.	47.	28.	64.	823.	40.	32.	106.	19.	75.	864.	50.
89	21.	21.	47.	28.	65.	823.	41.	32.	106.	19.	75.	864.	50.
90	21.	21.	47.	28.	66.	823.	41.	32.	106.	19.	75.	864.	50.
91	21.	21.	47.	28.	67.	823.	42.	32.	106.	19.	75.	864.	50.
92	21.	21.	47.	28.	68.	823.	42.	32.	106.	19.	75.	864.	50.
93	21.	21.	47.	28.	68.	823.	43.	32.	106.	19.	75.	864.	50.
94	21.	21.	47.	28.	69.	823.	44.	32.	106.	19.	75.	864.	50.
95	21.	21.	47.	28.	70.	823.	44.	32.	106.	19.	75.	864.	50.
96	21.	21.	47.	28.	72.	823.	45.	32.	106.	19.	75.	864.	50.
97	21.	21.	47.	28.	72.	823.	45.	32.	106.	19.	75.	864.	50.
98	21.	21.	47.	28.	72.	823.	46.	32.	106.	19.	75.	864.	50.
99	21.	21.	47.	28.	72.	823.	46.	32.	106.	19.	75.	864.	50.
100	21.	21.	47.	28.	72.	823.	47.	32.	106.	19.	75.	864.	50.

LOAD DIVISION TABLE FOR MONTH 8

COST	PCAL02	PCAL01	EPRG06	NMPE03	PCVA03	EPNM01	PCVA01	EPRG05	EPNM03	EPRG03	NMRE03	EPNM02	NMPE02
1	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
2	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
4	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
5	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
6	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
7	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
8	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
9	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
10	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
11	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
12	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
13	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
14	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
15	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
16	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
17	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
18	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
19	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
20	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
21	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
22	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
23	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
24	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
25	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
26	21.	21.	18.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
27	21.	21.	26.	11.	6.	21.	5.	0.	0.	0.	0.	0.	0.
28	21.	21.	34.	13.	7.	37.	6.	15.	40.	6.	39.	22.	26.
29	21.	21.	47.	16.	7.	53.	6.	18.	49.	9.	49.	36.	30.
30	21.	21.	47.	18.	8.	69.	7.	21.	57.	12.	59.	51.	50.
31	21.	21.	47.	21.	9.	86.	8.	25.	66.	15.	75.	65.	50.
32	21.	21.	47.	23.	10.	102.	8.	28.	74.	19.	75.	79.	50.
33	21.	21.	47.	26.	11.	118.	9.	32.	83.	19.	75.	94.	50.
34	21.	21.	47.	28.	12.	134.	9.	32.	92.	19.	75.	108.	50.
35	21.	21.	47.	28.	13.	151.	10.	32.	105.	19.	75.	123.	50.
36	21.	21.	47.	28.	14.	167.	10.	32.	106.	19.	75.	137.	50.
37	21.	21.	47.	28.	15.	183.	11.	32.	106.	19.	75.	151.	50.
38	21.	21.	47.	28.	16.	199.	12.	32.	106.	19.	75.	166.	50.
39	21.	21.	47.	28.	17.	216.	12.	32.	106.	19.	75.	180.	50.
40	21.	21.	47.	28.	18.	232.	13.	32.	106.	19.	75.	194.	50.
41	21.	21.	47.	28.	19.	248.	13.	32.	105.	19.	75.	209.	50.
42	21.	21.	47.	28.	20.	264.	14.	32.	106.	19.	75.	223.	50.
43	21.	21.	47.	28.	21.	281.	14.	32.	106.	19.	75.	238.	50.
44	21.	21.	47.	28.	22.	297.	15.	32.	106.	19.	75.	252.	50.
45	21.	21.	47.	28.	23.	313.	16.	32.	106.	19.	75.	266.	50.
46	21.	21.	47.	28.	24.	329.	16.	32.	106.	19.	75.	281.	50.
47	21.	21.	47.	28.	25.	346.	17.	32.	106.	19.	75.	295.	50.
48	21.	21.	47.	28.	26.	362.	17.	32.	106.	19.	75.	309.	50.
49	21.	21.	47.	28.	27.	378.	18.	32.	106.	19.	75.	324.	50.
50	21.	21.	47.	28.	27.	394.	18.	32.	106.	19.	75.	338.	50.
51	21.	21.	47.	28.	28.	410.	19.	32.	106.	19.	75.	353.	50.
52	21.	21.	47.	28.	29.	427.	20.	32.	106.	19.	75.	367.	50.
53	1.	21.	47.	28.	30.	443.	20.	32.	106.	19.	75.	381.	[illegible]
54	[illegible]	21.	47.	28.	31.	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

LOAD DIVISION TABLE FOR MONTH 8

COST	PCAL02	PCAL01	EPRG06	NMPE03	PCVA03	EPNM01	PCVA01	EPRG05	EPNM03	EPRG03	NMRE03	EPNM02	NMRE02
56	21.	21.	47.	28.	33.	492.	22.	32.	106.	19.	75.	424.	50.
57	21.	21.	47.	28.	34.	508.	22.	32.	106.	19.	75.	439.	50.
58	21.	21.	47.	28.	35.	524.	23.	32.	106.	19.	75.	453.	50.
59	21.	21.	47.	28.	36.	540.	24.	32.	106.	19.	75.	468.	50.
60	21.	21.	47.	28.	37.	557.	24.	32.	106.	19.	75.	482.	50.
61	21.	21.	47.	28.	38.	573.	25.	32.	106.	19.	75.	496.	50.
62	21.	21.	47.	28.	39.	589.	25.	32.	106.	19.	75.	511.	50.
63	21.	21.	47.	28.	40.	605.	26.	32.	106.	19.	75.	525.	50.
64	21.	21.	47.	28.	41.	622.	26.	32.	106.	19.	75.	539.	50.
65	21.	21.	47.	28.	42.	638.	27.	32.	106.	19.	75.	554.	50.
66	21.	21.	47.	28.	43.	654.	28.	32.	106.	19.	75.	568.	50.
67	21.	21.	47.	28.	44.	670.	28.	32.	106.	19.	75.	583.	50.
68	21.	21.	47.	28.	45.	687.	29.	32.	106.	19.	75.	597.	50.
69	21.	21.	47.	28.	46.	703.	29.	32.	106.	19.	75.	611.	50.
70	21.	21.	47.	28.	47.	719.	30.	32.	106.	19.	75.	626.	50.
71	21.	21.	47.	28.	48.	735.	30.	32.	106.	19.	75.	640.	50.
72	21.	21.	47.	28.	48.	751.	31.	32.	106.	19.	75.	654.	50.
73	21.	21.	47.	28.	49.	768.	32.	32.	106.	19.	75.	669.	50.
74	21.	21.	47.	28.	50.	784.	32.	32.	106.	19.	75.	683.	50.
75	21.	21.	47.	28.	51.	800.	33.	32.	106.	19.	75.	698.	50.
76	21.	21.	47.	28.	52.	823.	33.	32.	106.	19.	75.	712.	50.
77	21.	21.	47.	28.	53.	823.	34.	32.	106.	19.	75.	726.	50.
78	21.	21.	47.	28.	54.	823.	34.	32.	106.	19.	75.	741.	50.
79	21.	21.	47.	28.	55.	823.	35.	32.	106.	19.	75.	755.	50.
80	21.	21.	47.	28.	56.	823.	36.	32.	106.	19.	75.	769.	50.
81	21.	21.	47.	28.	57.	823.	36.	32.	106.	19.	75.	784.	50.
82	21.	21.	47.	28.	58.	823.	37.	32.	106.	19.	75.	798.	50.
83	21.	21.	47.	28.	59.	823.	37.	32.	106.	19.	75.	813.	50.
84	21.	21.	47.	28.	60.	823.	38.	32.	106.	19.	75.	827.	50.
85	21.	21.	47.	28.	61.	823.	38.	32.	106.	19.	75.	841.	50.
86	21.	21.	47.	28.	62.	823.	39.	32.	106.	19.	75.	864.	50.
87	21.	21.	47.	28.	63.	823.	40.	32.	106.	19.	75.	864.	50.
88	21.	21.	47.	28.	64.	823.	40.	32.	106.	19.	75.	864.	50.
89	21.	21.	47.	28.	65.	823.	41.	32.	106.	19.	75.	864.	50.
90	21.	21.	47.	28.	66.	823.	41.	32.	106.	19.	75.	864.	50.
91	21.	21.	47.	28.	67.	823.	42.	32.	106.	19.	75.	864.	50.
92	21.	21.	47.	28.	68.	823.	42.	32.	106.	19.	75.	864.	50.
93	21.	21.	47.	28.	68.	823.	43.	32.	106.	19.	75.	864.	50.
94	21.	21.	47.	28.	69.	823.	44.	32.	106.	19.	75.	864.	50.
95	21.	21.	47.	28.	70.	823.	44.	32.	106.	19.	75.	864.	50.
96	21.	21.	47.	28.	72.	823.	45.	32.	106.	19.	75.	864.	50.
97	21.	21.	47.	28.	72.	823.	45.	32.	106.	19.	75.	864.	50.
98	21.	21.	47.	28.	72.	823.	46.	32.	106.	19.	75.	864.	50.
99	21.	21.	47.	28.	72.	823.	46.	32.	106.	19.	75.	864.	50.
100	21.	21.	47.	28.	72.	823.	47.	32.	106.	19.	75.	864.	50.

LOAD DIVISION TABLE FOR MONTH 8

COST	PCVA05	PCAR04	PCAR03	PCAR02	PCAR01	PCCA02	PCCA01	EPNM04	PCZU02	EPRG08	EPRG07	EPCP01	PCVA04
1	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
2	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
4	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
5	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
6	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
7	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
8	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
9	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
10	122.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
11	175.	101.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
12	175.	101.	0.	29.	0.	20.	0.	0.	0.	0.	0.	0.	0.
13	175.	101.	33.	45.	0.	32.	0.	0.	0.	0.	0.	0.	0.
14	175.	101.	45.	45.	45.	52.	15.	0.	0.	0.	0.	0.	0.
15	175.	101.	45.	45.	45.	52.	24.	0.	0.	0.	0.	0.	0.
16	175.	101.	45.	45.	45.	52.	24.	0.	0.	0.	0.	0.	0.
17	175.	101.	45.	45.	45.	52.	24.	43.	0.	0.	0.	0.	0.
18	175.	101.	45.	45.	45.	52.	24.	68.	0.	0.	0.	0.	0.
19	175.	101.	45.	45.	45.	52.	24.	92.	0.	0.	0.	0.	0.
20	175.	101.	45.	45.	45.	52.	24.	116.	58.	0.	0.	0.	0.
21	175.	101.	45.	45.	45.	52.	24.	141.	58.	41.	0.	0.	0.
22	175.	101.	45.	45.	45.	52.	24.	165.	58.	52.	20.	0.	0.
23	175.	101.	45.	45.	45.	52.	24.	190.	58.	63.	24.	18.	0.
24	175.	101.	45.	45.	45.	52.	24.	224.	58.	75.	28.	22.	0.
25	175.	101.	45.	45.	45.	52.	24.	224.	58.	86.	31.	27.	5.
26	175.	101.	45.	45.	45.	52.	24.	224.	58.	97.	35.	31.	6.
27	175.	101.	45.	45.	45.	52.	24.	224.	58.	109.	39.	36.	7.
28	175.	101.	45.	45.	45.	52.	24.	224.	58.	120.	43.	40.	7.
29	175.	101.	45.	45.	45.	52.	24.	224.	58.	131.	47.	45.	8.
30	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	50.	9.
31	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	54.	9.
32	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	59.	10.
33	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	63.	11.
34	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	68.	11.
35	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	12.
36	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	13.
37	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	13.
38	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	14.
39	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	14.
40	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	15.
41	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	16.
42	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	16.
43	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	17.
44	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	18.
45	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	18.
46	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	19.
47	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	20.
48	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	20.
49	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	21.
50	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	22.
51	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	22.
52	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	23.
53	[illegible]5.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	[illegible]
54	[illegible]	101.	45	45	45.	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

V-149

LOAD DIVISION TABLE FOR MONTH 8

COST	PCVA05	PCAR04	PCAR03	PCAR02	PCAR01	PCCA02	PCCA01	EPNM04	PCZU02	EPRG08	EPRG07	EPCP01	PCVA04
56	175.	101.	45.	45.	45.	52.	24.	224.	68.	147.	47.	73.	26.
57	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	26.
58	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	27.
59	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	28.
60	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	29.
61	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	29.
62	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	30.
63	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	30.
64	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	31.
65	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	31.
66	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	32.
67	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	33.
68	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	33.
69	175.	101.	45.	45.	45.	52.	24.	224.	68.	147.	47.	73.	34.
70	175.	101.	45.	45.	45.	52.	24.	224.	68.	147.	47.	73.	35.
71	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	35.
72	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	36.
73	175.	101.	45.	45.	45.	52.	24.	224.	68.	147.	47.	73.	37.
74	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	37.
75	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	38.
76	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	39.
77	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	39.
78	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	40.
79	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	41.
80	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	41.
81	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	42.
82	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	43.
83	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	43.
84	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	44.
85	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	45.
86	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	45.
87	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	46.
88	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	47.
89	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	47.
90	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	48.
91	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	48.
92	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	49.
93	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	50.
94	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	50.
95	175.	101.	45.	45.	45.	52.	24.	224.	68.	147.	47.	73.	51.
96	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	52.
97	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	52.
98	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	53.
99	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	54.
100	175.	101.	45.	45.	45.	52.	24.	224.	58.	147.	47.	73.	54.

LOAD DIVISION TABLE FOR MONTH 8

COST	NMSJ03	NMSJ02	NMSJ01	EPFC05	EPFC04	NMFC04	NMFC05	PCCH01	PCC001	PCC002	PCCH04	PCCH03	PCCH02
1	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
2	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
4	0.	0.	0.	4.	4.	14.	14.	0.	0.	0.	0.	0.	0.
5	0.	0.	0.	4.	4.	14.	14.	0.	0.	0.	0.	0.	0.
6	0.	71.	61.	4.	4.	14.	14.	0.	0.	0.	0.	0.	0.
7	0.	157.	153.	4.	4.	14.	14.	0.	0.	0.	0.	0.	0.
8	0.	157.	153.	4.	4.	14.	14.	104.	325.	335.	0.	61.	0.
9	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	104.	107.
10	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
11	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
12	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
13	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
14	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
15	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
16	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
17	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
18	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
19	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
20	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
21	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
22	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
23	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
24	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
25	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
26	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
27	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
28	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
29	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
30	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
31	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
32	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
33	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
34	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
35	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
36	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
37	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
38	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
39	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
40	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
41	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
42	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
43	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
44	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
45	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
46	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
47	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
48	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
49	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
50	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
51	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
52	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
53	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
54	238.	157.	153.	4.	4.	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

LOAD DIVISION TABLE FOR MONTH 8

COST	NMSJ03	NMSJ02	NMSJ01	EPFC05	EPFC04	NMFC04	NMFC05	PCCH01	PCC001	PCC002	PCCH04	PCCH03	PCCH02
56	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
57	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
58	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
59	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
60	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
61	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
62	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
63	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
64	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
65	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
66	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
67	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
68	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
69	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
70	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
71	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
72	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
73	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
74	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
75	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
76	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
77	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
78	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
79	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
80	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
81	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
82	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
83	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
84	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
85	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
86	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
87	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
88	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
89	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
90	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
91	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
92	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
93	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
94	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
95	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
96	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
97	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
98	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
99	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.
100	238.	157.	153.	4.	4.	14.	14.	104.	325.	335.	339.	156.	107.

LOAD DIVISION TABLE FOR MONTH 8

COST	PCGT01	PCGT02	PCSA01	PCSA02	PCPA02	PCPA01	PCBO02	PCBO01	PCSH02	PCSH01	PCCC02	PCCC01	PCFV01
1	0.	0.	0.	0.	2.	0.	0.	0.	0.	8.	162.	162.	0.
2	0.	0.	0.	0.	2.	0.	0.	0.	0.	8.	162.	162.	0.
3	0.	0.	0.	0.	2.	0.	0.	0.	0.	8.	162.	162.	0.
4	0.	0.	0.	0.	2.	0.	0.	0.	0.	8.	162.	162.	200.
5	0.	0.	0.	0.	2.	0.	0.	0.	0.	8.	162.	162.	200.
6	0.	0.	0.	0.	2.	0.	0.	0.	0.	8.	162.	162.	200.
7	0.	0.	0.	0.	2.	0.	0.	0.	0.	8.	162.	162.	200.
8	0.	0.	0.	0.	2.	0.	0.	0.	0.	8.	162.	162.	200.
9	0.	0.	0.	0.	2.	0.	0.	0.	0.	8.	162.	162.	200.
10	0.	0.	0.	0.	2.	0.	0.	0.	0.	8.	162.	162.	200.
11	0.	0.	0.	0.	2.	0.	0.	0.	0.	8.	162.	162.	200.
12	0.	0.	0.	0.	2.	0.	0.	0.	0.	8.	162.	162.	200.
13	0.	0.	0.	0.	2.	0.	0.	0.	0.	8.	162.	162.	200.
14	0.	0.	0.	0.	2.	0.	0.	0.	0.	8.	162.	162.	200.
15	0.	0.	0.	0.	2.	0.	0.	0.	0.	8.	162.	162.	200.
16	1.	1.	1.	1.	2.	2.	0.	0.	0.	8.	162.	162.	200.
17	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
18	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
19	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
20	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
21	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
22	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
23	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
24	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
25	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
26	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
27	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
28	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
29	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
30	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
31	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
32	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
33	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
34	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
35	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
36	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
37	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
38	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
39	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
40	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
41	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
42	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
43	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
44	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
45	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
46	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
47	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
48	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
49	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
50	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
51	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
52	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
53	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	[illegible]
54	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

LOAD DIVISION TABLE FOR MONTH 8

COST	PCGT01	PCGT02	PCSA01	PCSA02	PCPA02	PCPA01	PCB002	PCB001	PCSH02	PCSH01	PCCC02	PCCC01	PCFV01
56	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
57	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
58	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
59	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
60	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
61	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
62	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
63	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
64	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
65	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
66	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
67	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
68	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
69	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
70	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
71	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
72	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
73	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
74	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
75	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
76	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
77	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
78	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
79	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
80	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
81	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
82	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
83	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
84	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
85	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
86	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
87	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
88	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
89	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
90	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
91	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
92	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
93	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
94	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
95	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
96	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
97	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
98	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
99	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.
100	1.	1.	1.	1.	2.	2.	10.	10.	8.	8.	162.	162.	200.

LOAD DIVISION TABLE FOR MONTH 8

COST	NMPR07	NMPR08	NMPR09	NMLV01	PCAL06	TOTAL
1	0.	0.	0.	0.	0.	333.
2	0.	0.	0.	0.	0.	333.
3	0.	0.	0.	0.	0.	333.
4	0.	0.	0.	0.	0.	568.
5	0.	0.	0.	0.	0.	568.
6	0.	0.	0.	0.	0.	700.
7	0.	0.	0.	0.	0.	878.
8	0.	0.	0.	0.	0.	1703.
9	0.	0.	0.	0.	0.	2430.
10	0.	0.	0.	0.	0.	2604.
11	0.	0.	0.	0.	0.	2758.
12	0.	0.	0.	0.	0.	2807.
13	0.	0.	0.	0.	0.	2868.
14	0.	0.	0.	0.	0.	2960.
15	0.	0.	0.	0.	0.	2968.
16	0.	0.	0.	0.	0.	2973.
17	0.	0.	0.	0.	0.	3044.
18	0.	0.	0.	0.	0.	3068.
19	0.	0.	0.	0.	0.	3092.
20	0.	0.	0.	0.	0.	3185.
21	0.	0.	0.	0.	0.	3250.
22	0.	0.	0.	0.	0.	3306.
23	0.	0.	0.	0.	0.	3363.
24	0.	0.	0.	0.	0.	3417.
25	0.	0.	0.	0.	0.	3442.
26	0.	0.	0.	0.	0.	3522.
27	0.	0.	0.	0.	0.	3593.
28	0.	0.	0.	0.	0.	3842.
29	0.	0.	0.	0.	0.	3964.
30	0.	0.	0.	0.	0.	4097.
31	0.	0.	0.	0.	0.	4186.
32	0.	0.	0.	0.	0.	4268.
33	0.	0.	0.	0.	0.	4338.
34	0.	0.	0.	0.	0.	4494.
35	0.	0.	0.	0.	0.	4548.
36	0.	0.	0.	0.	0.	4641.
37	0.	0.	0.	0.	0.	4676.
38	0.	0.	0.	0.	0.	4711.
39	0.	0.	0.	0.	0.	4770.
40	0.	0.	0.	0.	0.	4805.
41	0.	0.	0.	0.	0.	4861.
42	0.	0.	0.	0.	0.	4898.
43	0.	0.	0.	0.	0.	4934.
44	0.	0.	0.	0.	0.	4971.
45	0.	0.	0.	0.	0.	5007.
46	6.	5.	11.	0.	0.	5065.
47	6.	5.	11.	0.	0.	5102.
48	6.	5.	11.	0.	0.	5138.
49	6.	5.	11.	0.	0.	5175.
50	6.	5.	11.	0.	0.	5209.
51	6.	5.	11.	0.	0.	5244.
52	6.	5.	11.	0.	0.	5278.
53	6.	5.	11.	0.	0.	5313.
54	6.	5.	11.	0.	0.	5347.

LOAD DIVISION TABLE FOR MONTH 8

COST	NMPR07	NMPR08	NMPR09	NMLV01	PCAL06	TOTAL
56	6.	5.	11.	0.	0.	5416.
57	6.	5.	11.	0.	0.	5450.
58	6.	5.	11.	0.	0.	5485.
59	6.	5.	11.	0.	0.	5519.
60	6.	5.	11.	0.	0.	5553.
61	6.	5.	11.	0.	0.	5588.
62	6.	5.	11.	0.	0.	5622.
63	6.	5.	11.	0.	0.	5656.
64	6.	5.	11.	0.	0.	5691.
65	6.	5.	11.	0.	0.	5725.
66	6.	5.	11.	0.	0.	5760.
67	6.	5.	11.	0.	0.	5794.
68	6.	5.	11.	0.	0.	5828.
69	6.	5.	11.	0.	0.	5863.
70	6.	5.	11.	0.	0.	5897.
71	6.	5.	11.	0.	0.	5932.
72	6.	5.	11.	0.	0.	5966.
73	6.	5.	11.	0.	0.	6000.
74	6.	5.	11.	0.	0.	6035.
75	6.	5.	11.	0.	0.	6068.
76	6.	5.	11.	20.	0.	6127.
77	6.	5.	11.	20.	0.	6144.
78	6.	5.	11.	20.	0.	6160.
79	6.	5.	11.	20.	0.	6177.
80	6.	5.	11.	20.	0.	6193.
81	6.	5.	11.	20.	0.	6210.
82	6.	5.	11.	20.	0.	6226.
83	6.	5.	11.	20.	0.	6243.
84	6.	5.	11.	20.	0.	6259.
85	6.	5.	11.	20.	0.	6276.
86	6.	5.	11.	20.	0.	6301.
87	6.	5.	11.	20.	0.	6303.
88	6.	5.	11.	20.	0.	6305.
89	6.	5.	11.	20.	0.	6307.
90	6.	5.	11.	20.	0.	6310.
91	6.	5.	11.	20.	0.	6312.
92	6.	5.	11.	20.	0.	6314.
93	6.	5.	11.	20.	0.	6316.
94	6.	5.	11.	20.	0.	6318.
95	6.	5.	11.	20.	0.	6320.
96	6.	5.	11.	20.	0.	6323.
97	6.	5.	11.	20.	0.	6324.
98	6.	5.	11.	20.	0.	6326.
99	6.	5.	11.	20.	0.	6327.
100	6.	5.	11.	20.	0.	6328.

FUEL COST SIMULATION MODEL

Abstract

The Whitfield A. Russell & Associates' fuel cost simulation model (FCSM) calculates hourly fuel costs by unit over a specified time frame. The model is written in FORTRAN and is composed of a main routine and 23 (twenty-three) subroutines. The model incorporates structural and economic parameters to derive a least-cost mix of generating units during a weekly planning horizon. The current version simulates operation of a power system composed of up to seventy generating units and reports monthly tables documenting unit and system; generation, fuel costs, and running rates.

FUEL COST SIMULATION MODEL

Table of Contents

I. Electric Utilities And Electric Utilities Systems Fundamentals Employed In WARA Fuel Cost Simulation Model.

In most cases the load pattern of a typical electric utility can be served optimally with various types of generating units. The consideration of generation by system load pattern follows from an analysis of the annual peak load, annual energy and use pattern. Each electric utility has a daily, weekly, seasonal and annual load variation pattern which can be served optimally with an appropriate "mix" of generating usage types. Figure No. 1, entitled "Annual Load Duration Curve Demonstrating Use of Generation Types" illustrates this point. On this Figure is plotted a curve of the hourly demands on a typical electric utility in descending order of magnitude from the highest annual value to the lowest. Such a curve may be plotted using either megawatts (MW) or percent of annual peak megawatts as the ordinate and either total annual hours or percent of annual hours as the abscissa. This curve is known as the "annual load duration curve." Similar curves can be constructed for any time period and are an important tool for system planning analyses.

Also shown on Figure No. 1 are portions of the load served by three types of generating units commonly used by utilities. The so-called base load unit operates a large percentage of the time during the year; the cycling generating units, being less economical, only operate to produce additional capacity and energy as needed after the base load units are operating to full capacity. Finally, the peaking units operate a small percentage of the time. Although the cost of energy from a thermal peaking unit is higher than the energy costs associated with cycling and base load generation, the peaking unit does not add much to the total annual production cost of a system when used in the peaking mode because it operates relatively few hours. The daily operation of these types of units can be demonstrated by reference to a typical daily load curve of a summer peaking electric utility, Figure No. 2. On this curve is indicated the kinds of generation mentioned previously, the base load, the cycling, and the peaking type generation. This curve, also shows higher cost semi-peaking units and fuels used for each classification of generation.

Furthermore, other than the hours of service for which a generating unit is designed, and which tend to identify it as base load, cycling or peaking are its (i) production costs and (ii) capital costs. The base load plant requires the highest per unit capital investment, but is lowest in overall production cost. This type of generating unit is designed to operate continuously except when taken off the line for maintenance or when forced off the line during emergencies. Cycling generating units have somewhat higher production costs and require somewhat lower per unit investment. Older generating units which previously provided base load power often serve this function. Because of their design, (or because they are old units which are more flexible or dispensable), cycling units are often better able to follow changing loads than large base load generating units, and may be placed in and out of service on short notice. The peaking unit has the lowest per unit investment cost, but its production cost is considerably higher than that of other types on a unit cost basis. Peakers are the most flexible operationally and can be started in a matter of minutes instead of hours required by cycling and base load units. Table 1 demonstrates an approximate ranking of the three types of capacity.

TABLE 1

COMPARISON OF:
BASE, CYCLING AND PEAKING
TYPES OF GENERATING CAPACITY

Type	Relative Cost/KW %	Relative Operating Expense/KWH %	Typical Annual Hours Operation
Base	100	10	6000-7000
Intermediate	60	20	3000-4000
Peaking	30	100	To 2000

The annual operating hours of the base load plant are high compared to those associated with peaking units which are placed on and off the line on a daily and seasonal basis and operate generally less than one fourth of the time. These comparisons illustrate that excessive outages of base load generating units will increase production costs as base energy is replaced by purchased, intermediate or peaking energy.

Electric utilities/generation capacity is generally utilized on an annual cycle as shown on Figure No. 3. This figure demonstrates the typical annual utilization cycle of generating capacity for a summer peaking electric utility including maintenance and reserves. The items represented on this Figure are: first, the monthly peak load which must be met with generation; second, moving up on the curve, the operating reserve which is being provided for system regulation and reliability, and third, scheduled maintenance periods for the operating units. Note that at the time of system annual peak demand, the represented utility does not schedule any generating maintenance, an unsurprising result.

The top of the curve represents the total installed generating capacity. This capacity is comprised of numerous generating units with different dependable capacity ratings, which ratings are dictated by ambient and cooling water temperatures. The nominal generating rating is usually reduced during the hottest period of the year. During winter months, a higher rating of dependable capacity is assigned because of lower exhaust pressure on the system turbines resulting from lower ambient and cooling water temperatures.

In addition to the benefits obtained by optimizing the use of generating units, coordination and pooling enable utilities to lower reserve margins, install less expensive capacity and operate more efficiently. These other benefits are attributable to the synergism which results from coordination.

Fewer coordinated resources need be utilized to render service at an equal or improved level of reliability and cost compared to the cost and reliability achievable with isolated resources.

The level of reliability is also enhanced by coordination or pooling of resources because more potential sources of supply are made available to serve loads and thereby decrease the probability that simultaneous outages of generating equipment will occur in amounts sufficiently large to cause interruptions of service. Of course, the capacity of transmission linking members of a pool or coordinated group can limit the support obtainable from a pool. This limit can be lifted by pooling as a result of another important aspect of coordination, the economy of scale associated with transmission.

Transmission of power, both within and between large systems, can be accomplished in large MW blocks over long distance with Extra High Voltage ("EHV") transmission at very low per unit prices and losses. When systems coordinate, they enhance the opportunity for achieving economies of scale in transmission as well as generation.

Also, substantial operating savings can be achieved by a coordinated group of utilities in the commitment and dispatching (loading) of generating units. As utilities interconnect and coordinate their operations, the largest contingency which must be continuously guarded against and withstood by the coordinated group is of the same magnitude in megawatts as the largest contingency of the groups in isolation. The operating reserve requirements of a coordinated group are smaller as a percent of daily peak load or installed capacity than such requirements would be for each of the members of the group if operated in isolation.

The commitment of generating units, referred to above, means the process of starting up and synchronizing generators. For generators driven by steam turbines, this can be a lengthy and expensive process. For hydroelectric and internal combustion turbines, the commitment process consumes considerably less expense and time.

Most steam units (specially-designed cycling units excluded) cannot be started up and shut down in the course of a day's operation without creating substantial thermal stress on unit components. Therefore, steam units committed for service beginning on a Monday are usually operated for at least the ensuing period of 5 week days. Of course, departures from this general rule are made when conditions and economics so dictate. From day to day, based upon the forecast of the following day's load pattern, peak demand, units available, partial and forced outages, and interchange schedules, revisions are made in the daily commitment of generating units. For example, if a weather front is expected to pass through the service territory and/or partial or complete forced outages occur on previously committed units, then an additional resource will be required. Depending upon economics, this may require a control area to arrange an import of capacity from some other control area or else commit (start-up and synchronize) a generating unit less efficient than that originally planned.

By coordinating their unit commitments, utilities in a coordinated group can often reduce the number of steam units which must be started and thereby assure that the units which are started are more heavily and efficiently loaded.

Usually, the amount of steam capacity committed is an amount approximately equal to the base load and cycling portions of the forecast week's load plus an increment sufficient to provide any otherwise unserved operating reserve. The operating reserve requirement is usually 6% to 7% of the forecast daily peak and is furnished partially from quick-start hydro and combustion turbine units.

The economic dispatch of generating units, referred to above, is the process by which an operator (or computer) determines how to allocate most economically increments or decrements of loads between the available and operating generating units. This is an important matter to an electric utility (or pool of such utilities) because the demand on its total plant is constantly changing, and, in large systems, there are large numbers of generating units to be controlled. Hence, selection of the proper loading combination can achieve substantial savings over the production costs incurred by operating suboptimal combinations of generating units.

The system which performs this dispatch function is based upon a well-known principle of economics generally, and utililty economics in particular, which holds (with exceptions not significant at this point) that the available production sources will serve the load at the lowest total cost when each such unit or production source not fully loaded is operating at the identical incremental cost. A substantial benefit of fully integrated operations is that a centrally dispatched pool can and does eliminate, on a minute-to-minute basis, the discrepancies between incremental operating costs of generating units. In the absence of central dispatching, such discrepancies could well exist and result in a substantial waste of resources.

Interconnected electric utilities are customarily subdivided into control areas along corporate or ownership boundaries principally for historical reasons. From a technical standpoint, the boundaries are largely arbitrary, with the result that the number of control areas in nearly every region of the country could be reduced sharply, and the geographic and electrical coverage of the remaining control areas increased, with salutary results. A formal power pool can consolidate control areas in order to achieve optimal savings.

In the course of an operating day, once the appropriate resources have been committed in a given control area, the generating units under an optimal dispatching scheme automatically serve incremental load on a second-to-second basis from the unit which has the lowest incremental cost. The load and increments thereof which must be served by a given control area are determined by obtaining the algebraic sum of power flowing into and out of the area through all its interconnections with adjoining control areas. If, in addition, an export is planned, additional generation in the amount of the export plus associated losses would be scheduled for the control area. The information on power flows to and from a control area is brought to a central processer where the scheduled amount of exports and imports is compared to the measured exports or imports. This comparison usually occurs every few seconds. If there is an excess of area generation over that required by the schedule, then a signal is sent to the appropriate generators to lower output. If, in contrast, the schedule shows an insufficient amount of power being exported (or too much power being imported), then a signal goes to the generating units to raise generation. From data stored in the central processor, a signal to raise generation would go that unit under control which is then generating at the highest incremental cost. As described earlier, after each adjustment, the incremental cost from each unit that can serve more load should be the same. A comprehensive description of this topic would take account of tie-line bias, voltage regulation, "must-run" generating units and a plethora of other factors which compete for the attention of electric utility operators.

Not all units are necessarily under the control of an economic dispatch system. For example, the controls are deemed impractical for use on combustion turbines in many cases because the units are too small to justify the expense and the fluctuation in output resulting from responses to controls would degrade efficiency. Moreover, some base load generating units always have the lowest incremental cost in a control area and need not be controlled. Therefore, controls are sometimes not applied to such units.

II. Model Overview

The WARA FCSM is a FORTRAN program composed of a main routine and twenty-three subroutines. The model flow diagram is shown in Figure No. 5.

The main program reads in all of the data, properly aligns data for the particular month to be analyzed, and then calls the various subroutines to determine unit commitment, unit generation, and unit cost. The order of execution is consistent with the objective of meeting a given load with the least cost configuration of units over time. The hydro units are dispatched first, and the pumped storage and natural storage units are used as peak load shavers whenever possible. The base load units are then temporarily assumed to run at full load. The "load" available to cycling units is then calculated as the original load less hydro generation plus reserve requirements less base load generation. The cycling units are then committed in ascending economic dispatch order until load is met or capacity is reached.

At this point, the model determines the loading of each unit which is available and committed in accordance with a load division table to minimize cost. These estimates are adjusted to insure that committed cycling and base units are generating at a minimum or greater loads. If excess generation results, the program backs down units in descending economic dispatch order. Combustion turbine peaking units are assumed to be run at maximum generation only, and any excess generation resulting from their use must be deducted from the cycling units.

When interchange transactions are to be modeled, the program then compares the modeled utility's running rate to the selling utility's running rate. If the difference is greater than two mills then the model allows interchange transactions to occur. If the incremental cost is above the selling utility's running rate, then the modeled Utility's units are backed down (but not below minimum) until the running rates are equalized. If the modeled utility's incremental cost is below the selling utility's running rate, then the modeled utility's units are loaded until all capacity is utilized or the running rates are within a specified differential per kWh. The model computes the cost of generation, sales price, and split savings at each block in the production function and sums these figures for each hour.

The program flags hours where load cannot be met or where over generation occurs from existing unit commitments to enable the analyst to assess the results.

The incremental heat rate curve of each unit is given by the equation $y^1 = b+2cx+$ which is the first derivative of the input-output curve $y=a+bx+cx^2$ with respect to x, the loading on the unit. The coefficients a, b and c are fixed and are particular to a specific unit, x is the unit loading, y is total fuel consumption and y^1 is incremental fuel consumption.

It is necessary to use an equation because both the total heat rate and incremental heat rate vary with the loading on a generating unit.

This last equation, $y^1 = b+2cx$ and a fuel cost factor (FC) are used to arrive at the incremental cost of energy for each unit. That is,

$$\text{Incremental cost} = [b+2cx]\ FC$$

FC is the fuel cost, and, as noted above b and c are coefficients from the original input-output equation. X is again the loading on the unit.

The program compiles a tabulation of the megawatts available from each unit, adjusted for outages at each incremental cost of interest. For each level of incremental cost, the sum of megawatts available from all committed units is obtained. This sum, together with the arrays associated with each generation unit, constitute what is referred to as the "system load division table". (Figure No. 5 to 6). Although the arrays for each unit change only for changes in fuel cost or outages, the array of total system megawatts and incremental cost is affected by unit commitments, especially base load unit commitments.

For a given set of committed units and given system load requirement, the model determines the expected level of system incremental cost and the optimal loading on each unit. (See Figure No. 5 to 6). Commitment of the proper combination of units is done by a separate subroutine. The loading point for each unit enables the program to compute cost for each unit and for the entire system. Both the megawatt loadings and costs for each unit and the system are accumulated for the periods of interest enabling the analyst to determine expected production and fuel cost for each unit in each time period.

The following is a brief description of each model component.

- Main Routine - Reads the case parameters and data files for unit parameters, outages, loads, diversity interactions, and running rates. Controls the flow of data thoughout the program.
- FILPTS - Sets index values for days to be analyzed.
- FILL - Loads the outage data for each unit.
- DTOD - Calculates the number of days between two dates.

- DDAY - Calculates the day of the week for each date.
- INITIAL - Initializes all arrays.
- HEADER - Prints the report title page.
- TABRPT - Prints the monthly load division table (optional).
- RESERV - Controls the calculation of reserves.
- TYPE1 - Calculates reserves as a percent of hourly load.
- TYPE2 - Calculates reserves a a percent of daily peak.
- TYPE3 - Calcualtes reserves as a percent of largest (or specified) unit.
- BASU - Calculates the energy availabe from base units.
- HEAP - Sorts data in descending order.
- HYDRO1 - Calculates dispatch of run of river hydro units.
- HYDRO2 - Calculates dispatch of natural storage hydro units.
- HYDRO 3 - Calculates dispatch of pump storage hydro units.
- ECDISP - Produces monthly load division tables.
- CRONID - Calculates load and total cost given a running rate (incremental cost) or calculates a running rate and total cost given a load.
- CYMAIN - Controls the commitment of cycling units.
- COMMIT - Calculates the commitment of cycling unit.
- EEVAL - Calculates the comparative economics of cyclers and peakers.
- RECON - Calculates unit loadings consistent with commitment schedule for all non-hydro units. Calculates sales/purchases to other utilities (pool).
- RPTWTR - Produces final reports.

III. Data Requirements

To execute the WARA FCSM the following data is required:

A. System level

1) Hourly loads
2) Diversity-In (Optional)
3) Diversity-Out (Optional)
4) Reserve Requirements
5) Pool running rate (Optional)

B. Unit level

1) All units

a) name
b) fuel type
c) generation type
d) economic dispatch order number
e) minimum load
f) maximum load (summer/winter)
g) fuel cost
h) outages
i) heat rate coefficients
j) start up costs
k) minimum down time
l) minimum up time

2) Hydro units

a) monthly estimated energy
b) minimum release schedule (Optional)
c) pumping efficiency *
d) maximum effective storage *

* required only is unit is pump storage hydro

ANNUAL LOAD DURATION CURVE
DEMONSTRATING
USE OF GENERATION TYPES

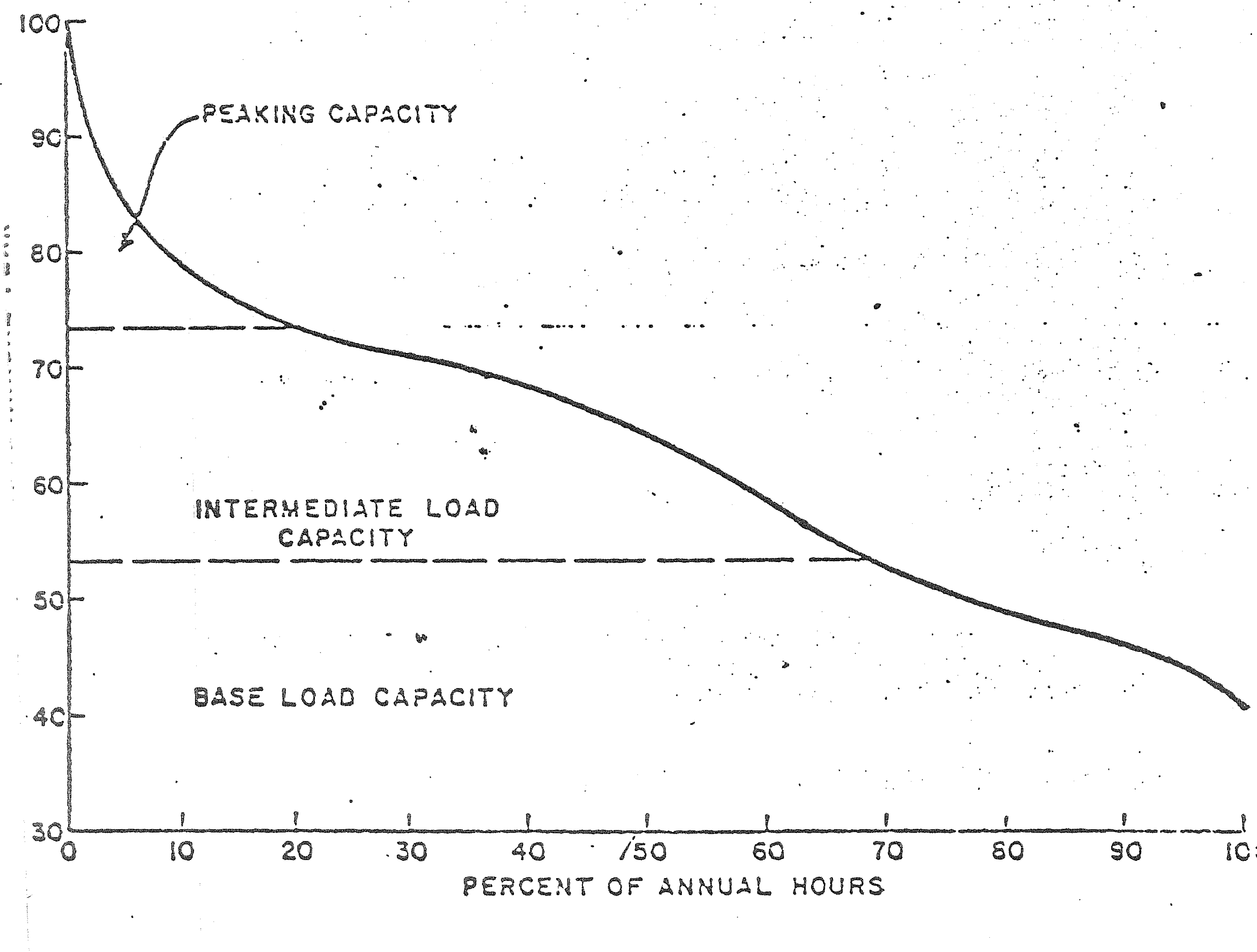


Figure 1

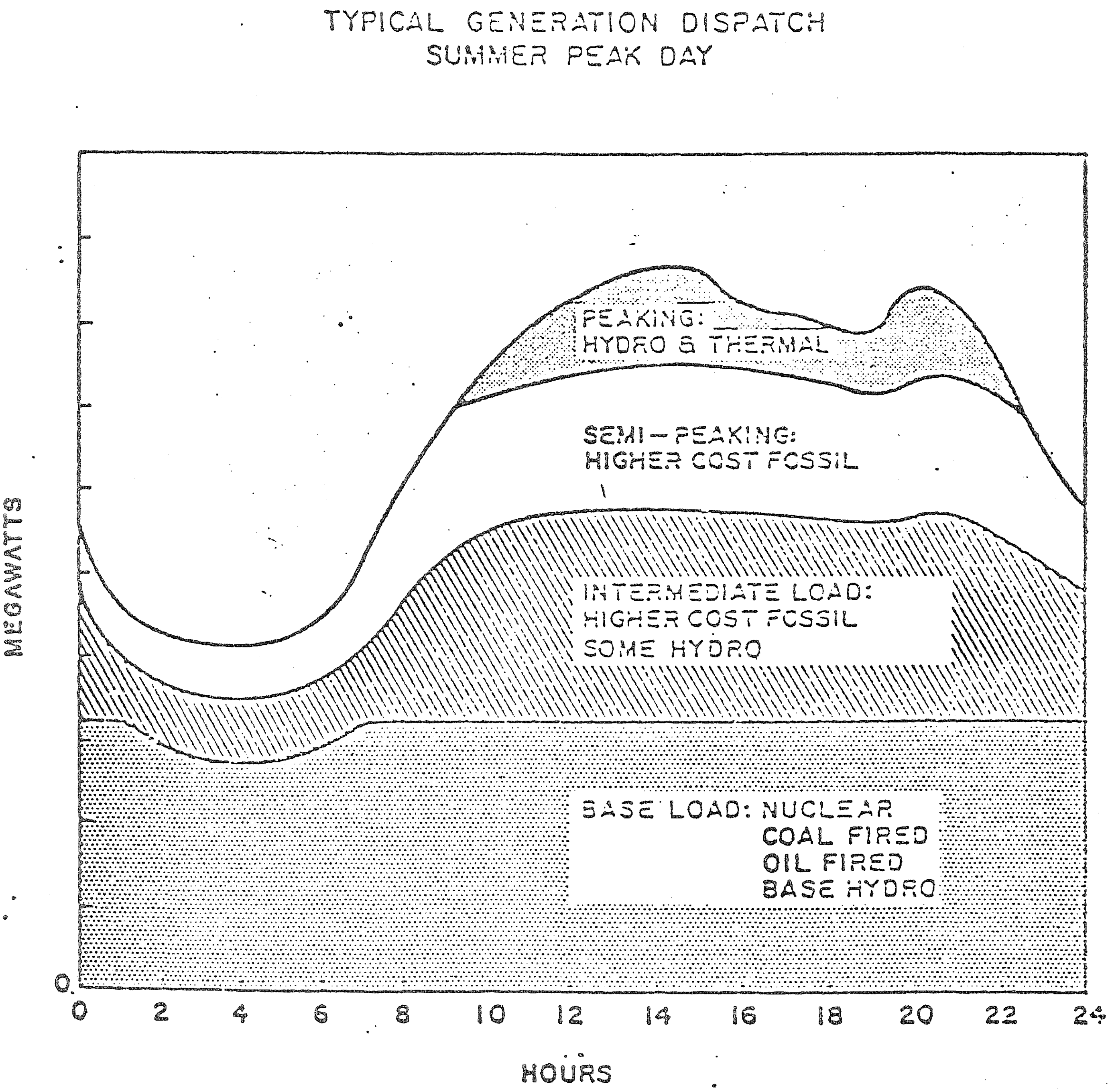

TYPICAL GENERATION DISPATCH
SUMMER PEAK DAY
PEAKING:
HYDRO & THERMAL
SEMI-PEAKING:
HIGHER COST FOSSIL
INTERMEDIATE LOAD:
HIGHER COST FOSSIL
SOME HYDRO
BASE LOAD: NUCLEAR
COAL FIRED
OIL FIRED
BASE HYDRO
MEGAWATTS
0
0
2
4
6
8
10
12
14
16
18
20
22
24
HOURS

Figure 2

UTILIZATION OF INSTALLED
GENERATING CAPACITY
(SUMMER PEAKING REGION)

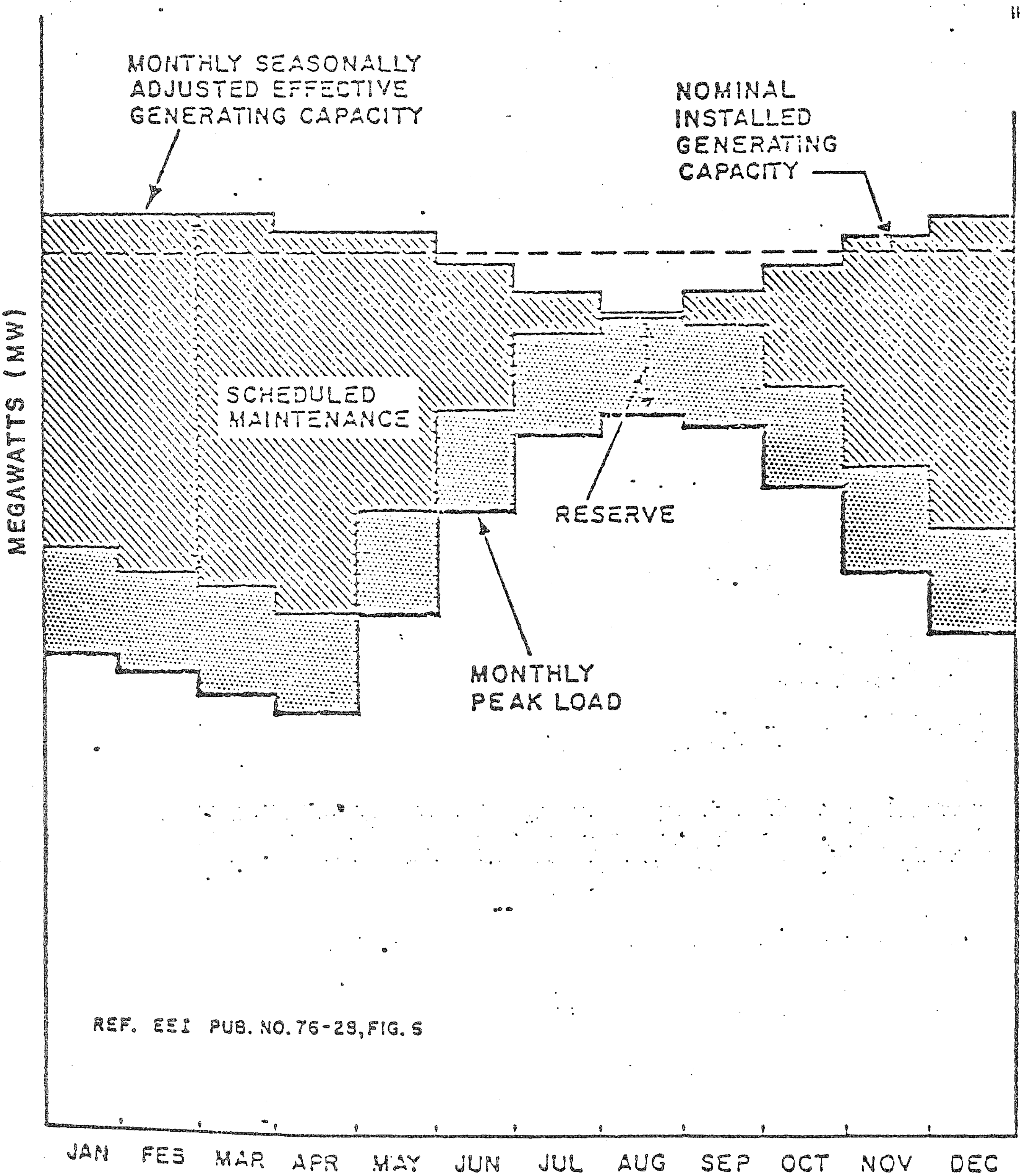
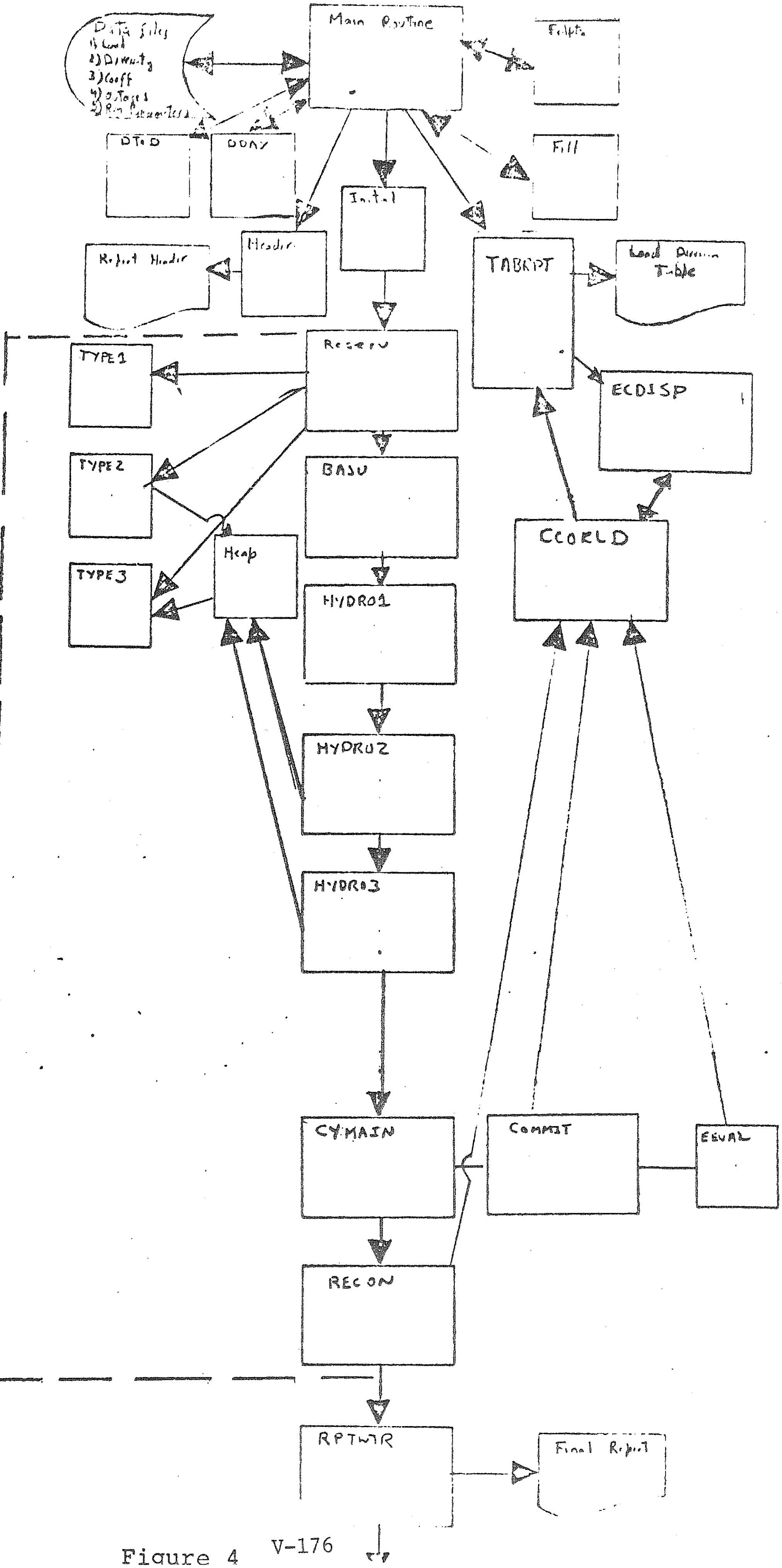


Figure 3



Data files
1) Load
2) Diversity
3) Coeff
4) O.Types
5) Run parameters
Main Routine
Fdpts
DTOD
DDAY
Fill
Initial
Header
Report Header
TABRPT
Load Duration Table
WEEKLY SCHEDULING HORIZON
Reserv
TYPE1
TYPE2
TYPE3
Heap
BASU
HYDRO1
HYDRO2
HYDRO3
ECDISP
CCORLD
CYMAIN
COMMIT
EEVAL
RECON
RPTWR
Final Report

Figure 4

LOAD DIVISION TABLE FOR MONTH 7

COST	STORM3	STORM2	STORM1	BREM04	PORTS4	CHEST4	CHEST6	BREM03	CHEST5	POSSM4	POSSM5	YORKT2	CHEST3
65	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
66	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
67	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
68	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
69	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
70	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
71	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
72	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
73	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
74	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
75	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
76	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
77	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
78	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
79	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
80	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
81	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
82	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
83	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
84	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
85	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
86	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
87	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
88	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
89	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
90	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
91	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
92	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
93	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
94	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
95	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
96	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
97	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
98	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
99	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
100	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
101	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
102	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
103	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
104	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
105	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
106	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
107	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
108	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
109	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
110	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
111	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
112	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
113	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
114	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
115	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
116	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
117	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
118	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
119	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
120	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.

Figure 5 V-177

Schedule No.

LOAD DIVISION TABLE FOR MONTH 7

COST	STORM3	STORM2	STORM1	ARFMC4	PORTS4	CHEST4	CHEST6	BREMO3	CHEST5	POSSM4	POSSM5	YORKT2	CHEST3
121	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
122	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
123	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
124	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
125	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
126	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
127	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
128	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
129	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.
130	560.	553.	553.	164.	233.	161.	658.	72.	333.	233.	805.	170.	100.

Figure 6 V-178

Schedule No. ____

PART 4

TO: D.N. Jones, Director
National Regulatory Research Institute

FROM: S.A. Sebo, Professor
Electrical Engineering

DATE: April 3, 1981

SUBJ.: Review of
"A ROLE FOR THE COLORADO PUBLIC UTILITIES COMMISSION IN POWER POOLING"

1. The purpose of the draft report written by Whitfield A. Russell & Associates (Washington, DC) is to review some aspects of the power pooling efforts by utilities serving Colorado and adjoining states. Initial efforts called for the formation of the so-called Cactus Pool. Negotiations were terminated without success in 1980. The study states that the present regional power pool (Inland Power Pool, IPP) remains behind several other pools in achieving essential pooling objectives. Section I.B. analyzes the reasons for the termination of the Cactus Pool negotiations. These reasons were related to reserve criteria, and the scope of pool coordination and pool planning.

2. Power pooling of electric utility companies means the interconnection and coordination of the power systems (including their generation, transmission and distribution facilities) owned by the individual utility companies in order to obtain better technical performance and economic benefits. Specific advantages are:

   - elimination of the necessity of each system standing on its own
   - coordination of system operation
   - better utilization of facilities and resources
   - reduction of normal spinning and cold reserves
   - utilization of generation and load diversity and time-zone differences
   - energy supply from the lowest-cost source
   - maintenance coordination
   - modification of construction plants
   - utilization of larger unit sizes
   - better economy of the entire coordinated system
   - better utilization of personnel
   - better reliability of power supply

3. The study summarizes several aspects of power pooling in general, and power pooling of certain groups of electric utilities in particular (Section I.D.). One aspect of power pooling is the role of the regulatory agencies; another one is the impact of power pooling upon regulation. More important contributing factors to determine the latter are:

- availability of joint ventures to construct large base-load generating units
- the degree of centralized economic dispatch and operation
- pricing since it is more predictable than in case of a less structured organization

4. Intrinsic pooling issues are reviewed in Section II of the study. The study lists the following items:

- pattern of demand (load) variation
- optimal mix of generating unit types
- installed reserve in terms of generation and transmission capacity (this is the redundant production and transmission capacity)
- operating (spinning) reserve in terms of generation capacity (this is the unloaded but available generating capacity, usually equal to 5-7% of the estimated daily peak demand, or the peak capacity rating of the largest unit within the power pool)
- economy-of-scale units, a rule of thumb is presented:

$$\frac{\text{capital cost of large unit}}{\text{capital cost of small unit}} = \left(\frac{\text{capacity of large unit}}{\text{capacity of small unit}}\right)^{0.8}$$

- unit commitment (the process of starting up and synchronizing generating units) coordination
- economic dispatch of loads between the available and operating generating units, especially if a central dispatching facility is available for the entire (combined) control area
- the number of control areas can be reduced sharply

5. Section III summarizes arrangements of the New England Power Pool (NEPOOL), the Pennsylvania-New Jersey-Maryland (PJM) Interconnection, the Florida Electric Power Coordinating Group (FCG) and the Mid-Continent Area Power Pool (MAPP). The following aspects are summarized:

- number of participating companies, agencies and cooperatives