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

APPROACH TO SETTING COST BASED ELECTRIC RATES IN NEVADA

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FOREWORD

The National Regulatory Research Institute (NRRI) was established at the Ohio State University in 1977 by the National Association of Regulatory Utility Commissioners to provide state regulatory commissions with technical assistance and timely, high level policy research on regulatory issues.

This report is one of a series of publications resulting from on-site technical assistance projects supported by the U. S. Department of Energy (DOE) and directed by the NRRI. The purpose of these technical assistance projects is to provide in-depth studies in specific areas of utility regulation as requested by various state regulatory agencies. A concern of the DOE is for the prudent management and conservation of our national energy resources. Accordingly, it is believed that assistance should be provided to state regulatory agencies in husbanding the energy resources within their state boundaries. Funding availability has limited these efforts such that not all state agencies requesting assistance could be served at first. One criterion for selecting a particular state assistance project was the potential for that project to possibly provide guidance to other regulatory agencies with similar or related problems. It is with that thought in mind that the results of several of the individual state technical assistance projects are being published and made available to others.

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Introduction

The Nevada Public Service Commission is responsible for regulating retail rates charged by utilities for electric power in Nevada. In designing rates, the Commission has two objectives: that rates be equitable for all customer groups, and that they encourage consumers to conserve energy.

Rates based on cost of service to consumers can achieve both these objectives. Specifically, rates will be equitable if consumer groups are charged on the basis of their relative demand on the system, consumption, and need for related services. And because cost-based rates generally increase as the value for these factors increase, customers will be motivated to conserve energy.

Utility cost-of-service studies that include a determination of unit costs can provide public service commissions with the data for basing customer rates on costs. Essentially, a cost-of-service study provides an estimate of the proportion of the utility's total costs attributable to each customer group served (e.g., residential, commercial, industrial). For each customer group, costs are distributed in detail among four functions (generation, transmission, distribution, and general), and three cost categories (demand-related, energy-related, and customer-related). Supplemented by other analyses (e.g., calculation of net operating income), this cost breakdown can be translated into unit costs for use in rate design. The cost-of-service study is also useful for: estimating rate of return earned on each customer group, determining revenue requirements from each group, and evaluating past rate decisions.

Recognizing the benefits of cost-of-service studies and their potential for helping meet its goals, the Commission is evaluating the feasibility of using cost of service as a basis for Nevada ratesetting. To assist the Commission in establishing a basis for its decision, the National Regulatory Research Institute (NRRI) retained Resource Planning Associates, Inc. (RPA). After a series of discussions with the Commission and NRRI, we were requested to evaluate and select appropriate methodologies for determining cost of service and unit costs for Nevada Power Co. and Sierra Pacific Power Co., and to identify the basic prerequisites for conducting and using the study results (for example, minimum filing requirements).

To evaluate the applicability of alternative methodologies for each company, we examined accounting, load-research, and engineering data; load and sales forecasts; and current rate schedule data for each utility. Based on this analysis, we selected steps for a broad methodology that will be appropriate, with some adjustments, for both companies. We were also able to identify several general actions that the Commission and utilities should take before cost-of-service studies could be conducted and used in Nevada. Our recommended six-step methodology for determining cost of service and unit costs, with illustrations of how the cost data can be used to estimate rates of return, revenue requirements, and the impacts of rate decisions, is presented in Chapter 1; our preliminary implementation plan is presented in Chapter 2. We recommend that the Commission adopt and refine the methodology for conducting cost-of-service studies in Nevada. Although other factors (e.g., state economic goals, social objectives) must be considered in ratesetting and identifying revenue requirements, we agree with the Commission that cost of service should be the principal determinant.

1 METHODOLOGY FOR DETERMINING COST OF SERVICE AND UNIT COSTS

Determining cost of service and unit costs requires a systematic analysis and arrangement of the utility's costs to generate, transmit, and distribute power, and to provide related services to customers. This analysis, called a cost-of-service study, reflects the specific characteristics of the company and, in some complex areas, the judgment of the preparers. No two cost-of-service studies, therefore, are alike, and no single methodology is workable in all cases.

Although the details of a methodology must be developed by the public service commission and utilities who will conduct and use the studies, some sound fundamental guidelines can be established. Based on an examination of utility load and operating characteristics; interviews with personnel from the Commission, Nevada Power, and Sierra Pacific; and a review of Nevada jurisdictional allocation studies,* we have selected a broad methodological approach for use by Nevada Power and Sierra Pacific. It consists of six steps (see Exhibit 1), with particular emphasis on the more subjective aspects of cost-of-service studies:

1. Select a test period
2. Select a system of accounts

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* Jurisdictional allocation studies include estimates of the portion of total revenues, plant investment, and expenses to be assigned to retail customers in Nevada. Nevada Power operates in jurisdictions regulated by the Federal Energy Regulatory Commission (FERC) and the Commission. Sierra Pacific operates in jurisdictions regulated by FERC, the Commission, and the California Public Utilities Commission.

Exhibit 1

Recommended Methodology for Nevada Power and Sierra Pacific

Methodology	Source
1. Select a test period	Jurisdictional requirements
2. Select a system of accounts	FERC
3. Assign costs by function	
—generation	NARUC or EEI
—transmission	NARUC or EEI
—distribution	NARUC or EEI
—general	NARUC or EEI
4. Classify costs within functions	
—demand-related	NARUC or EEI
—energy-related	NARUC or EEI
—customer-related	NARUC
5. Allocate costs to customer groups	
—select customer groups	Current rate schedules
—allocate demand-related generation and transmission costs	Coincident peak, summer (Nevada Power); coincident peak, summer and winter average (Sierra Pacific)
—allocate demand-related distribution costs	Noncoincident peak
—allocate energy-related costs	kWh sales adjusted for line losses
—allocate customer-related costs	Number of customers
6. Estimate unit costs for rate design	Cost-of-service study data

3. Assign costs by function
4. Classify costs within functions
5. Allocate costs to customer groups
6. Estimate unit costs for rate design.

Working out the details of this methodology and the adjustments necessary for a particular utility (some of which we indicate in our discussion), is a dynamic process. It will require many discussions between the Commission and each utility, and, most likely, periodic revision based on evaluation during rate cases. In developing the methodology, we recommend the Commission and utilities draw on the two principal references on cost-of-service methodologies: the proceedings of Edison Electric Institute's (EEI) cost-of-service symposium,* and the National Association of Regulatory Utility Commissioners' (NARUC) cost allocation manual.**

SELECT A TEST PERIOD

The test period is the time period for which costs will be estimated, usually 12 months and called a "test year." An historical test year (e.g., the year 1977 or the 12 months ending June 30, 1978) or a future test year (e.g., the year 1979) may be selected. Calculating costs for a future test year requires forecasts of investments, expenses, loads, sales, and customers.

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* Edison Electric Institute, Cost of Service Symposium, September 21-23, 1970. During the course of our work, we provided copies of this document to the Commission and each utility.

** Doran, J.J., et al., Electric Utility Cost Allocation Manual, National Association of Regulatory Utility Commissioners, Washington, D.C., 1973.

We recommend that cost-of-service studies to be used in general rate case proceedings be performed for both historical and future test years. Although the analysis for a future test year is based on more uncertain data (e.g., expense forecasts), failure to base rate decisions on their potential future impacts can unexpectedly and adversely affect a utility's earnings and the revenues obtained from each customer group. The Commission may choose to establish revenue requirements and set rates using historical test year data, and to use the future test year data to evaluate the effects of its decisions. We believe that such an approach would be beneficial both to customers and to the utility's stockholders.

SELECT A SYSTEM OF ACCOUNTS

Costs used in a cost-of-service study are typically the accounting costs from the utility's books. Utilities generally maintain their books according to a uniform system of accounts prescribed by law. We recommend that Nevada utilities be required to use FERC's Uniform System of Accounts.* This basic system specifies the plant and operating and maintenance expense accounts assigned to particular functions, and can be modified, at the direction of regulatory commissions, to accommodate state regulatory practices. Given that Nevada utilities currently provide the Commission with jurisdictional allocation studies based on the modified FERC system, this recommendation can be easily implemented.

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* See U.S. Federal Power Commission [FERC], Uniform System of Accounts Prescribed for Public Utilities and Licensees: Classes A, B, C, and D, Washington, D.C.: U.S. Government Printing Office, 1973. In 1936 NARUC adopted a uniform system of accounts similar to FERC's; the NARUC system is used primarily by state regulatory commissions.

ASSIGN COSTS BY FUNCTION

The first major step in calculating cost of service to each consumer group is to assign a utility's costs to either the generation, transmission, distribution, or general function. Basically, the specific costs are assigned as follows:

Generation	Transmission	Distribution	General
Generating electricity Power purchased from another system Delivering power to the bulk transmission system	Transferring power from generation sources to load centers within service areas, or to or from other utilities	Transferring power from the transmission system to consumers	Plant investment or expenses not directly related to any other function (e.g., sales promotion, administration)

Depending on the technical configuration of the utility's system, it may be desirable to further disaggregate costs into subfunctions for a more precise allocation to customer groups. For example, distribution costs could be disaggregated into primary and secondary distribution according to voltage level.

To assign costs by function, we recommend the Commission develop a suitable method using the NARUC cost allocation manual and the proceedings of the EEI cost-of-service symposium (the FERC uniform system of accounts could also be used to assign costs by function). Both of these documents detail the costs assigned to each function and the rationale for their assignment. Costs that are not directly related to the three major functions should be closely examined to determine whether assignment to a major function can be justified; if not, they should be assigned to the general cost function.

CLASSIFY COSTS WITHIN FUNCTIONS

The costs assigned to each function must be further classified as one of the following:

Demand-related. Demand-related costs are the fixed costs of meeting customer demands (e.g., transmission facilities). They are a function of the kilowatts (kW) of demand imposed on the generation, transmission, and distribution segments of the utility system.

Energy-related. Energy-related costs are the costs of operating facilities to meet customer energy requirements (e.g., fuel). They are a function of the kilowatt-hours (kWh) consumed by customer groups.

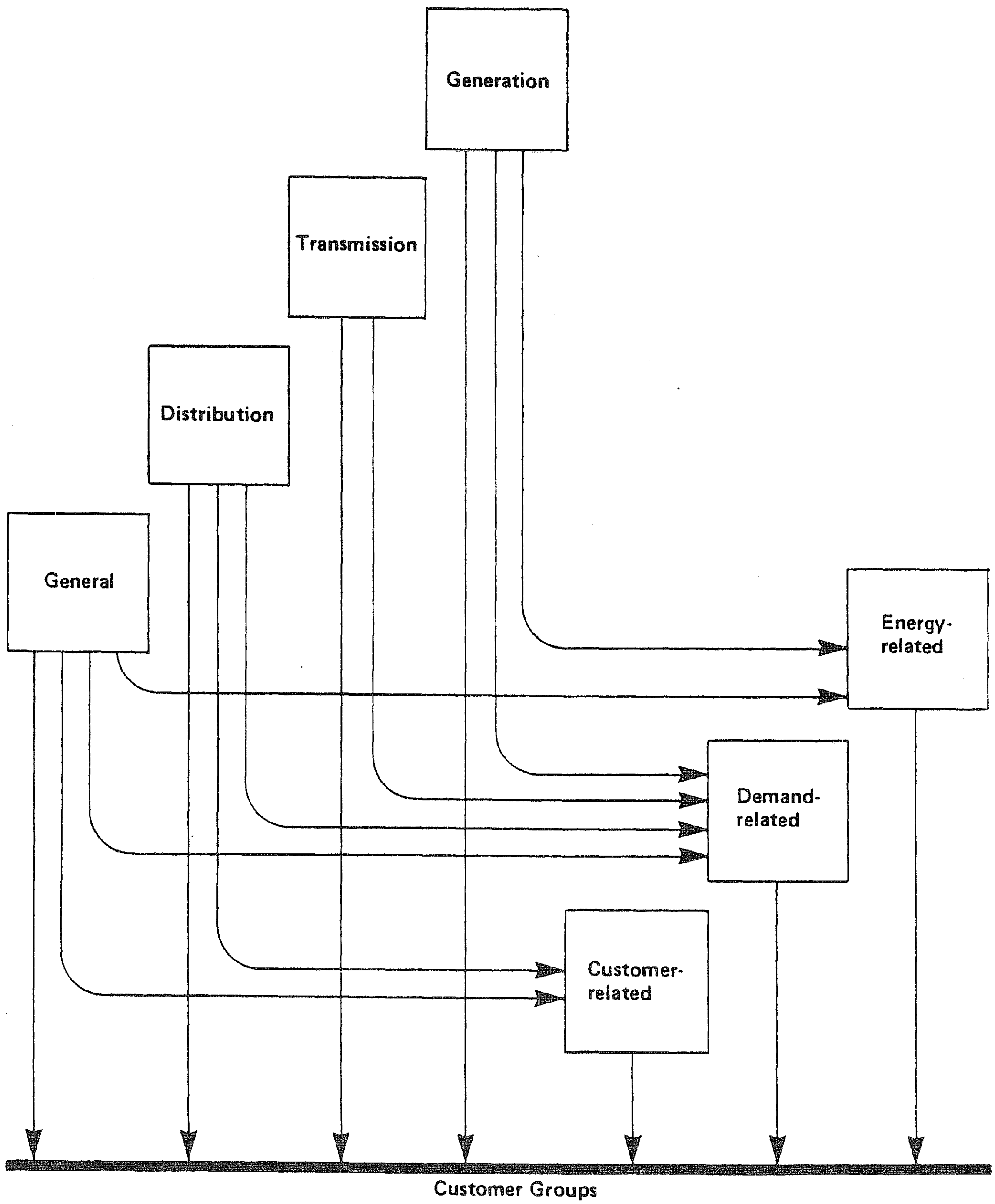
Customer-related. Customer-related costs are the costs of providing customer services; they therefore are a function of the number of customers served by a utility. Customer-related costs include portions of the distribution investment, meter equipment, meter reading, and billing (see Exhibit 2).

In classifying costs, we recommend that the Commission use the methods described in the NARUC cost allocation manual and the proceedings of the EEI cost-of-service symposium. Most costs are relatively simple to classify. Specifically, generation costs can usually be clearly classified as demand- and energy-related to reflect the fixed (i.e., annual carrying costs of generating units) and variable (i.e., fuel) components of generation investments and expenses. Transmission costs are classified as demand-related because a transmission system is specifically designed for meeting peak loads (i.e., it is a fixed cost). General function costs can be classified into one, two, or all three categories. For example, general costs such as customer accounting expenses can be directly classified as customer-related, and general plant investments can be divided among the demand-, energy-, and customer-related categories.

Distribution costs, however, are not as easily classified. Although a portion of the costs of the distribution system is incurred in meeting maximum customer demands (and thus varies with maximum kW demand), another portion varies with the number of customers and represents the costs of distribution facilities required

Exhibit 2

Distribution of Total System Costs



to meet customer minimum loads (e.g., the need for line transformers is a function of both the number of customers and their peak demand). The fixed and variable cost method appropriate for demand- and energy-related classification is therefore insufficient for this demand- and customer-related classification; more sophisticated analytical techniques and an element of judgment are required.

There are essentially two methods for estimating the customer-related portion of distribution costs: the minimum-size method and the zero-intercept method (see the NARUC cost allocation manual, pp. 56-71, for details). The ultimate distribution of costs among customer groups, and hence the utility's revenue requirements, will depend on the method used.

Under the minimum-size method, distribution costs for nominal service are estimated based on the average book value of the smallest distribution equipment installed in the system. These costs are classified as customer-related, and the remaining distribution costs are classified as demand-related. Under the zero-intercept method, regression techniques are used to estimate the costs of serving a hypothetical load of zero kW or amperes. The costs of meeting the zero-intercept load are the customer-related component of distribution costs, and remaining costs form the demand-related component. The zero-intercept method requires substantially more data than the minimum-size method, and generally produces relatively smaller customer-related, and larger demand-related, cost estimates.

The use of regression analyses and additional data in the zero-intercept method largely eliminates the need for judgment. We therefore recommend the use of the zero-intercept method provided the necessary load data are available. (See Exhibits 3 and 4 for facsimiles of a utility's cost classifications.)

Exhibit 3

Facsimile of a Cost Classification for an Electric Utility (Rate Base)

CLASSIFICATION OF ELECTRIC RATE BASE

FPC Uniform System of Accounts' Account No.	Description	Demand Related	Energy Related	Customer Related
	Intangible Plant			
1301	Organization	x	x	x
	Production Plant			
1310-1316	Steam production	x	x	-
1320-1325	Nuclear production	x	x	-
1340-1346	Other production	x	x	-
	Transmission Plant			
1350-1359	All transmission plant accounts	x	-	-
	Distribution Plant			
1360	Land and Land Rights	x	-	x
1361	Structures and Improvements	x	-	-
1362	Station Equipment	x	-	-
1364	Poles, Towers and Fixtures	x	-	x
1365	Overhead Conductors and Devices	x	-	x
1366	Underground Conduit	x	-	x
1367	Underground Conductors and Devices	x	-	x
1368	Line Transformers	x	-	x
1369	Services	x	-	x
1370	Meters	-	-	x
1371	Installations on Customers' Premises (1)	-	-	-
1373	Street Lighting and Signal Systems (1)	-	-	-
	General Plant (Including Common)			
1389-1398	All general plant accounts	x	x	x

(1) "Exclusive use" costs are assigned directly to customer class which exclusively uses such facilities.

Exhibit 4

Facsimile of a Cost Classification for an Electric Utility (Expenses)

CLASSIFICATION OF ELECTRIC EXPENSES

FPC Uniform System of Accounts' Account No.	Description	Demand Related	Energy Related	Customer Related
	Production			
	Steam Power Generation			
	Operation			
501	Fuel	x	x	-
502	Steam Expenses	x	-	-
505	Electric Expenses	x	-	-
506	Miscellaneous Steam Power Expenses	x	-	-
507	Rents	x	-	-
	Maintenance			
511	Structures	x	-	-
512	Boiler Plant	x	x	-
513	Electric Plant	x	x	-
514	Miscellaneous Steam Plant	x	-	-
	Nuclear Power Generation			
	Operation			
518	Nuclear Fuel Expense	x	x	-
519	Coolants and Water	x	-	-
520	Steam Expenses	x	-	-
521	Steam From Other Sources	x	-	-
522	Steam Transferred - Credit	x	-	-
523	Electric Expenses	x	-	-
524	Miscellaneous Nuclear Power Expenses	x	-	-
525	Rents	x	-	-
	Maintenance			
529	Structures	x	-	-
530	Reactor Plant Equipment	x	x	-
531	Electric Plant	x	x	-
532	Miscellaneous Nuclear Plant	x	-	-
	Other Power Generation			
	Operation			
547	Fuel	x	x	-
548	Generation Expenses	x	-	-
549	Miscellaneous Other Power Expenses	x	-	-
550	Rents	x	-	-

Exhibit 4 (continued)

Facsimile of a Cost Classification for an Electric Utility (Expenses)

CLASSIFICATION OF ELECTRIC EXPENSES(cont.)

FPC Uniform System of Accounts' Account No.	Description	Demand Related	Energy Related	Customer Related
	Maintenance			
552	Structures	x	-	-
553	Generating and Electric Equipment	x	x	
554	Miscellaneous Other Power Plant	x		
	Other Power Supply Expenses			
555	Purchased Power	x	x	-
556	System Control & Load Dispatching	x	-	-
557	Other Expenses	x	x	-
	Transmission			
	Operation			
561	Load Dispatching	x	-	-
562	Station Expenses	x	-	-
563	Overhead Line Expenses	x	-	-
564	Underground Line Expenses	x	-	-
565	Transmission of Electricity by Other	x	-	-
567	Rents	x	-	-
	Maintenance			
569	Structures	x	-	-
570	Station Equipment	x	-	-
571	Overhead Lines	x	-	-
572	Underground Lines	x	-	-
	Distribution			
	Operation			
582	Station Expenses	x	-	-
583	Overhead Line Expenses	x	-	x
584	Underground Line Expenses	x	-	x
585	Street Lighting and Signal System Expenses (1)	-	-	-
586	Meter Expenses	-	-	x
587	Customer Installations Expenses	-	-	x
589	Rents	x	-	x

Exhibit 4 (continued)

Facsimile of a Cost Classification for an Electric Utility (Expenses)

CLASSIFICATION OF ELECTRIC EXPENSES (continued)

FPC Uniform System of Accounts' Account No.	Description	Demand Related	Energy Related	Customer Related
	Maintenance			
591	Structures	x	-	-
592	Station Equipment	x	-	-
593	Overhead Lines	x	-	x
594	Underground Lines	x	-	x
595	Line Transformers	x	-	x
596	Street Lighting and Signal Systems (1)	-	-	-
597	Meters	-	-	x
	Other Operating Accounts			
901-905	Customer Accounts	-	-	x
907-910	Customer Service and Informational	-	-	x
911-916	Sales	-	-	x
920-932	Administrative and General	x	x	x

(1) "Exclusive use" costs are assigned directly to customer class which exclusively uses such facilities.

ALLOCATE COSTS TO CUSTOMER GROUPS*

Costs must be allocated between regulatory jurisdictional groups (e.g., between wholesale and retail sales, which are regulated by FERC and the state regulatory commission, respectively), and then among customer groups within a given regulatory jurisdiction. Currently, the Commission uses jurisdictional allocation studies to determine the costs of serving the Nevada retail customers of Nevada Power and Sierra Pacific. Our method for allocating costs to customer groups is therefore limited to customers within the Commission's regulatory jurisdiction. It consists of five tasks:

- Identify customer groups
- Allocate demand-related generation and transmission costs
- Allocate demand-related distribution costs
- Allocate energy-related costs
- Allocate customer-related costs.

<u>Identify customer groups</u>. To identify customer groups within the Commission's regulatory jurisdiction, we recommend that utilities be required to use existing rate schedules. The multiple street lighting schedules for both utilities, however, could be combined as a single group to facilitate preparation of the study.

<u>Allocate demand-related generation and transmission costs</u>. There are three principal methods, with many variations,** of allocating demand-related generation and

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* Some costs, such as plant investments used exclusively by a particular group, can be directly assigned to that group without being classified as demand-, energy-, or customer-related.

** Electric Power Research Institute identified 29 methods of allocating demand-related costs in <u>Rate Design and Load Control: Issues and Directions</u>, prepared for the Electric Utility Rate Design Study, November 1977, p. 26.

transmission costs: coincident peak (CP) responsibility, noncoincident peak (NCP) responsibility, and average and excess (A&E) demand. This range of methods introduces an unavoidable element of subjectivity into the results of a cost-of-service study.

Under the CP responsibility method, demand-related costs are allocated to each customer group in proportion to the group's coincident demand at the time of the system peak. This method is appropriate if system peak demands are assumed to be the primary determinant of demand-related costs. A multiple CP responsibility method may be used when a utility has successively larger seasonal peaks or expects the peak season to change (e.g., from summer to winter).

When the NCP responsibility method is used, demand-related costs are divided among customer groups in proportion to each group's maximum peak demand, regardless of the time of occurrence. The allocation of costs on the basis of each group's peak demand is based on the assumption that if each customer group were served independently, facilities would be needed to meet its peak demand. The NCP method, by distributing system-diversity benefits equally to all customer groups, fails to recognize that very high and very low load-factor customer groups do not contribute to system diversity.*

Under the A&E method, a portion of demand-related costs (derived by multiplying the total demand-related costs by the system load factor) is allocated to each customer group on the basis of each group's average demand for the year, measured in kWh per hour. The remaining demand-related costs are allocated to groups based on group maximum-demand and system average-demand relationships. The A&E method results in customer groups with

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* System-diversity benefits occur when the individual customer groups make their maximum demands on the system at different times, enabling the system to meet the coincident maximum demands with a lower level of capacity than the sum of the individual group maximum demands. Under the NCP method, therefore, a very low or high load-factor group that peaks with the system (i.e., one that does not contribute to system diversity), nonetheless reaps the diversity benefits.

high load factors receiving fewer system-diversity benefits than customer groups with low load factors; a customer group with a 100-percent load factor would receive no benefits. Groups with load factors equal to the system load factor receive the same system-diversity benefits they would receive under the NCP method. In effect, then, the A&E method recognizes that the probability of a customer group's maximum demand coinciding with the system peak increases as the group's load factor increases.

Of the three basic methods for allocating demand-related generation and transmission costs, we recommend that Nevada Power and Sierra Pacific use CP responsibility. Specifically, we recommend that Nevada Power use the customer-group peaks that coincide with the summer system peak*, and that Sierra Pacific use the average of the customer-group peaks that coincide with the summer and winter system peaks. Nevada Power's summer peak is currently about one and one-half times its winter peak (see Exhibit 5). The recent rapid growth in its summer peak and the expected continuation of this growth implies that Nevada Power is building capacity primarily to meet summer peak demands. Thus, customers who contribute to the growth of the summer peak should bear major responsibility for building this capacity. Use of the CP method to allocate demand-related generation and transmission costs will achieve this.

In contrast to Nevada Power, Sierra Pacific's summer and winter system peaks are nearly identical (see Exhibit 6) and are expected to grow at a constant rate. Furthermore, Sierra Pacific's annual load factor is approximately 70 percent, indicating that customers utilize generating facilities at a relatively high level throughout the year. We therefore believe that an average of the summer and winter peaks is an appropriate basis for allocating demand-related generation and transmission costs to customer groups.

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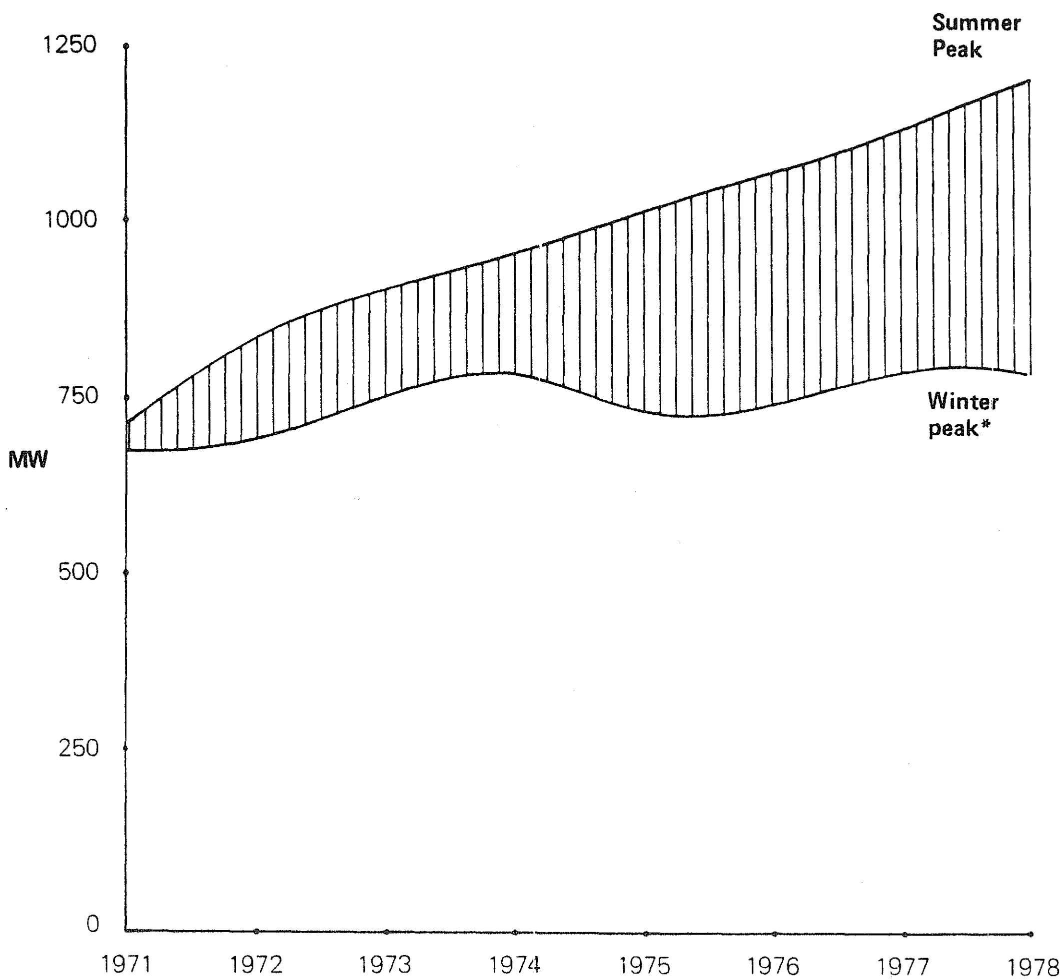
* In discussions with officials of Nevada Power, we learned that the company believes the average daily peak demands during the weekdays of the summer peak is a better measure of CP responsibility than the single system peak demand. We feel that any reasonable measure of CP responsibility based on the summer peak would be appropriate.

Exhibit 5

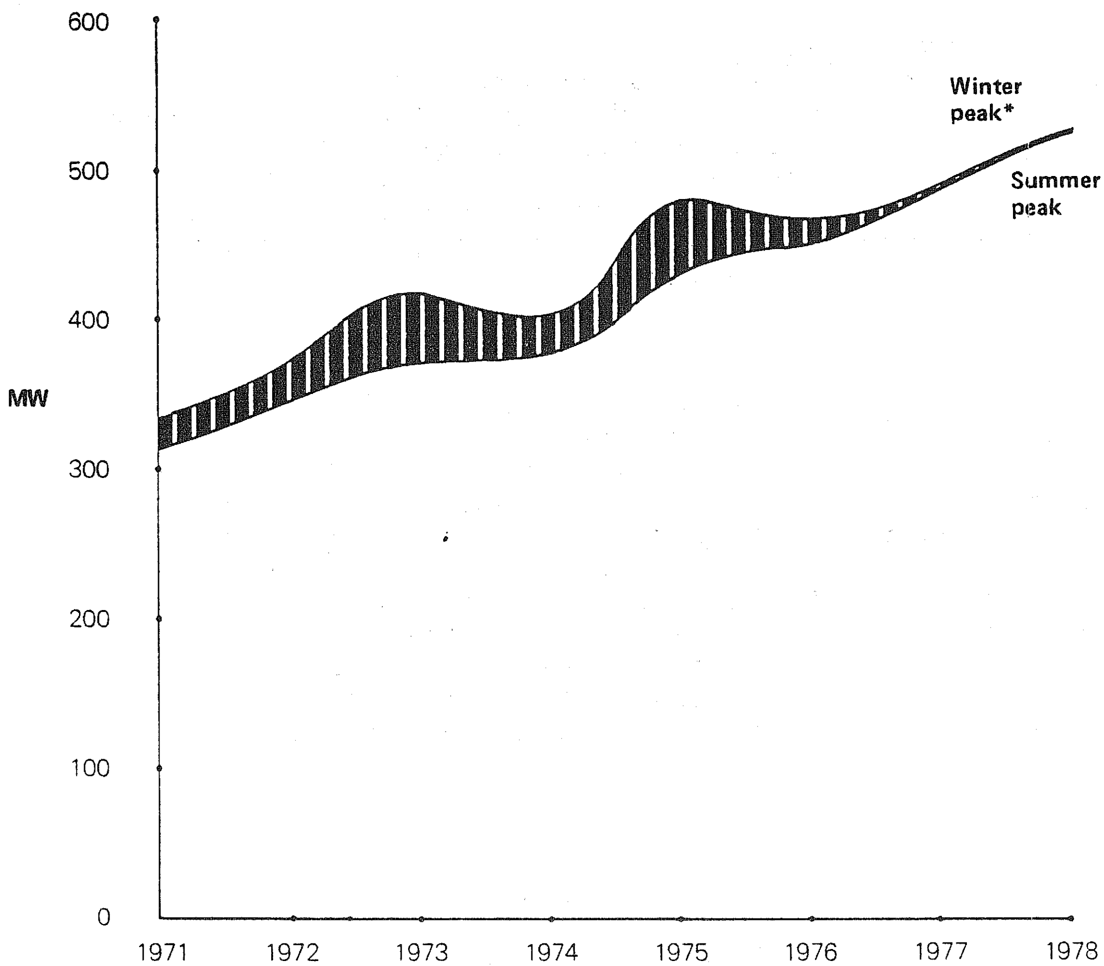
Seasonal System Peaks for Nevada Power Company



*Winter peak for a given year is for the winter season at the beginning of that year. For example, the winter peak for 1971 is the peak demand of the 1970/1971 winter season.

Exhibit 6

Seasonal System Peaks for Sierra Pacific Power Company



NOTE: 1978 summer peak is based on Sierra Pacific forecast.

*Winter peak for a given year is the winter season at the beginning of that year. For example, the winter peak for 1971 is the peak demand of the 1970/1971 winter season.

Allocate demand-related distribution costs. We recommend using the NCP responsibility method to allocate demand-related distribution costs. The distribution system is built and maintained to meet maximum customer demands whenever they occur. It is therefore most appropriate to allocate demand-related distribution costs based on maximum individual group demands (i.e., NCPs). The non-coincident demands used should be estimated at the distribution level (e.g., primary and secondary distribution voltage levels) at which a customer group receives service, and adjusted for demand losses.

Allocate energy-related costs. We recommend that energy-related costs be allocated to customer groups on the basis of energy (kWh) consumed, adjusted for line losses. For example, the ratio of residential kWh consumption (adjusted for line losses) to total kWh generated could be used to allocate energy-related costs to the residential customer group. This procedure requires mostly readily available and reliable data, and involves little subjectivity.

Allocate customer-related costs. The allocation of customer-related costs should be based on the number of customers within each group relative to the total number of customers served by a utility; customer differences within and among groups (e.g., location, size, type of distribution equipment required for service) also should be accounted for. If distribution costs are identified by subfunction (e.g., primary and secondary distribution voltage levels), the allocation of the customer-related portion of costs within each subfunction should be based on the number of customers served at each voltage level.

ESTIMATE UNIT COSTS FOR RATE DESIGN

We recommend that utilities be required to develop unit costs based on their cost-of-service studies. This requirement would assist the Commission in determining whether the customer group rates proposed by the utilities produce both an equitable rate of return among customer groups and an efficient recovery of the utilities' costs of service.

Unit costs are the costs of serving customers within a group, expressed as dollars per kW, dollars per kWh, and dollars per customer (i.e., demand-, energy-, and customer-related costs, respectively). In other words, unit costs represent the revenue a utility must collect to recover the costs of meeting each kW of peak demand, delivering each kWh of energy, and serving each customer.

Deriving unit costs requires the completion of seven steps:

1. Select the rate of return to be earned from each customer group.

2. Estimate the demand, energy, and customer components of the portion of total rate base assigned to each group. (These estimates can be obtained from the cost-of-service study.) Total rate base consists of the net value of the utility's electric plant and equipment in service, construction work in progress, plant held for future use, materials and supplies, and an allowance for working capital.

3. Estimate the demand, energy, and customer components of net operating income obtained from each group. Net operating income is total operating revenues less the sum of operating and maintenance expenses, depreciation expenses, and taxes (e.g., federal income taxes, state gross receipts taxes, property and payroll taxes). The net operating income is determined by multiplying the selected rate of return by the group's rate base, which also is divided into demand, energy, and customer components.

4. Separate the expenses of serving each group into demand, energy, and customer components. (This distribution can be obtained from the cost-of-service study.)

5. Determine the revenue requirement for each group (i.e., revenue that must be collected to produce the selected rate of return on rate base). Each group's revenue requirement is the sum of net operating income and operating expenses.

6. Separate group revenue requirements into demand, energy, and customer components. These components are derived by adding each component of net operating income to its related operating expense component.

7. Divide the demand, energy, and customer components of group revenue requirements by each group's coincident peak demand,* total kWh consumption, and average number of customers, respectively.

The unit costs derived by this method can be used as a first step in designing rates. For example, a residential rate consisting of a monthly customer charge and an energy charge can be developed using the components of the residential revenue requirement. A three-part residential rate, consisting of demand, energy, and customer charges, cannot be used because residential-customer meters only measure kWh consumption.

To derive the monthly customer charge, unit customer costs are divided by 12. The energy charge is derived by dividing the demand and energy components of the residential revenue requirement by total kWh sales to residential customers. The customer and energy charges developed by this process will recover the cost of serving an average residential customer (i.e., a customer whose annual load factor and consumption equals the group's average load factor and consumption) in an equitable and efficient manner.

A two-part residential rate derived from unit costs may, however, require modification to reflect seasonal load patterns. For example, Nevada Power's low system load factor, rapidly growing summer peak, and high saturation of air conditioners in the residential class indicate that the utility's residential rate should contain a seasonal rate differential. That is, customers should be charged a higher rate during the summer months than during other months. The seasonal rate differential, which could be derived from unit demand and energy costs, would promote conservation and efficiency in electricity consumption.

A seasonal rate differential can be derived by setting the ratio of summer to winter energy charges equal to the

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* Noncoincident group demands are used by some utilities instead of peak demands.

ratio of summer to winter coincident peak demands for the residential customer group. For example, if the group's summer coincident demand is 1.5 times its winter coincident peak demand, the equations for determining summer and winter kWh charges are:

(1) $x = 1.5y$

(2) $(a \cdot x) + (b \cdot y) = z$

where:

x = the summer energy charge

y = the winter energy charge

a = summer kWh sales

b = winter kWh sales

z = demand and energy revenue requirement.

Substituting the expression for x (i.e., 1.5y) in equation (2) and solving for y yields the winter energy charge. Substituting the value of y in equation (1) and solving for x yields the summer energy charge.

2 PRELIMINARY IMPLEMENTATION PLAN

Before our recommended methodology can be applied, it is necessary to develop the structural apparatus for conducting and using cost-of-service studies for rate-setting. Our preliminary implementation plan consists of four broad actions that should provide the Commission and utilities with the essential framework:

- Develop load and loss data
- Establish report formats and minimum filing requirements
- Develop computer programs
- Establish schedule and responsibility for studies.

DEVELOP LOAD AND LOSS DATA

Data required to determine cost of service and unit costs can be obtained from a utility's accounting, customer billing, property, and engineering records; load research studies; and system forecasts of load and sales growth. Nevada Power and Sierra Pacific can readily obtain all data except the necessary load and loss data. These data are required to develop allocation ratios to assign demand- and energy-related costs to customer groups and, combined with customer data, to develop unit demand, energy, and customer costs for designing rates. Consequently, Nevada Power and Sierra Pacific need to develop, for each customer group, monthly CP and NCP demand estimates, the coincidence factor (i.e., the ratio of coincident to noncoincident maximum demand), the diversity factor (i.e., the inverse of the coincidence factor), and demand and energy losses.

We feel that Nevada Power will need to expand its load research program* to develop the required load and loss data**. Nevada Power's load research program consists of approximately 50 magnetic tape meters installed on residential customers; another 30 meters may be installed during 1979. Thus, load data are being collected on only 50 of the nearly 140,000 residential customers served by Nevada Power, and no time-of-use load data are being collected from its 15,000 commercial customers.

Sierra Pacific has 100 magnetic tape meters measuring consumption by residential customers in Nevada and 100 meters on large commercial and industrial customers. The company is installing magnetic tape meters to measure consumption by 120 residential customers in the company's California service area, and also plans to install meters on a random sample of 60 small general service customers (i.e., customers with demands less than 500 kW). Sierra Pacific therefore will shortly have about 380 magnetic tape meters collecting load and consumption data that can be used in a cost-of-service study. With a 1977 average monthly service of 134,000 customers in Nevada and California (about 75 percent located in Nevada), Sierra Pacific's load research sample will encompass about 0.3 percent of its retail customers. This percentage constitutes an adequate sample for a utility of Sierra Pacific's size.

We believe the Commission should work closely with Nevada Power to expand its load research program to include commercial customers and additional residential customers. The necessary sample size for each customer group can be

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* Both utilities have adequate load data for their large general service customers (i.e., those with monthly demands exceeding 500 kW), whose consumption is measured by magnetic tape recording meters. In 1977, Nevada Power served about 130 such customers per month, and Sierra Pacific about 100.

** Both companies estimate energy losses for the system, but not for a particular customer group.

determined using statistical sampling methods.* Once the sample sizes have been determined, Nevada Power can purchase and install magnetic tape meters and begin collecting the required data. Although Sierra Pacific's load research program is sufficient, we also recommend that the Commission examine their sample selection process to ensure that an adequate number of customers from each customer group is included in the company's load research.

ESTABLISH REPORT FORMATS AND MINIMUM FILING REQUIREMENTS

Cost-of-service studies, and associated data used in general rate cases, should be presented complete and in a format that will facilitate their translation into cost-based rates.

We recommend a summary report format for cost-of-service studies that requires documentation of the electric rate base, revenues, revenue deductions, net operating income allocated to each customer group, and rate of return earned by each group (see Exhibit 7).** In addition, we recommend that the allocation of items included in the electric rate base and operating expenses be presented using formats similar to those shown in Exhibits 8 and 9. These formats separate the electric rate base and expenses by account and customer group for greater efficiency.

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* For an excellent discussion of the means of developing load research samples, see a 1975 unpublished report prepared by the Association of Edison Illuminating Companies titled, "Applied Statistics in Load Research, Volume III."

** The formats shown in Exhibits 7, 8, and 9 are currently used by an eastern utility. A simplified presentation format is presented on page 81 of the NARUC cost allocation manual, which also contains examples of the formats used by certain utilities (pp. 112, 118-119, and 124).

Exhibit 7

Facsimile of Cost-of-Service Study Report (Summary Sheet)

ALLOCATION OF ELECTRIC RATE BASE, REVENUES, REVENUE DEDUCTIONS, AND OPERATING INCOME TO CUSTOMER CLASSES
BASED ON 13-MONTH AVERAGE RATE BASE (SEPTEMBER 30, 1975 TO SEPTEMBER 30, 1976) AND REVENUES AND REVENUE DEDUCTIONS FOR TWELVE MONTHS ENDED SEPTEMBER 30, 1976

	1	2	3	4	5	6	7	8	9	10	
								Special Contracts			
Line No.	Item	Total	Residential Schedule R	General Service Schedule G	Industrial Schedule T	Street Lighting Schedule SL	Private Area Lighting Schedule PL	Bethlehem Steel Corp.	Consolidated Rail Corp.	Interdepartmental Sales	Line No.
1	Rate Base	$1,887,603,713	$919,829,069	$493,636,192	$334,273,930	$31,564,787	$3,242,120	$89,646,447	$15,411,168	$ -	1
2	Operating Revenues	$ 522,745,513	$201,962,060	$171,437,382	$108,175,225	$11,129,279	$1,195,664	$23,301,209	$ 4,696,601	$848,093	2
	Operating Revenue Deductions										
3	Production Expense	$ 181,896,954	$ 67,511,457	$ 51,100,116	$ 46,922,828	$ 1,508,264	$ 195,025	$12,394,325	$ 2,264,939	$ -	3
4	Transmission Expense	7,194,757	3,303,422	1,922,917	1,445,775	60,334	9,439	378,209	74,661	-	4
5	Distribution Expense	26,294,151	14,606,967	5,842,188	2,698,496	2,957,699	67,129	102,622	19,050	-	5
6	Customer Accounts Expense	11,700,418	10,196,757	1,335,357	121,077	35,566	-	6,263	5,398	-	6
7	Customer Service & Informational Expense	1,393,965	391,710	822,451	97,579	69,699	12,546	-	-	-	7
8	Sales Expense	3,216	904	1,897	225	161	29	-	-	-	8
9	Administrative and General Expense	37,335,624	15,688,360	9,973,531	8,379,920	755,358	46,526	2,105,583	386,346	-	9
10	Subtotal	$ 265,819,105	$111,699,577	$ 70,998,457	$ 59,665,900	$ 5,387,081	$ 330,694	$14,987,002	$ 2,750,394	$ -	10
11	Expense Offset (Interdepartmental Sales)	-	(356,368)	(226,552)	(190,352)	(17,159)	(1,057)	(47,829)	(8,776)	848,093	11
12	Subtotal	$ 265,819,105	$111,343,209	$ 70,771,905	$ 59,475,548	$ 5,369,922	$ 329,637	$14,939,173	$ 2,741,618	$848,093	12
13	Depreciation	49,894,396	25,324,756	12,924,987	8,119,472	1,080,689	97,835	2,011,502	335,155	-	13
14	Taxes Other Than Income Taxes	49,060,458	23,253,369	13,468,596	8,713,435	1,065,886	94,329	2,089,978	374,865	-	14
15	Income Taxes	16,736,536	(4,612,147)	16,105,539	4,615,666	530,360	166,797	(217,919)	148,240	-	15
16	Investment Tax Credit Adjustment	3,808,507	2,087,363	969,301	516,043	116,392	9,199	94,131	16,078	-	16
17	Total Operating Revenue Deductions	$ 385,319,002	$157,396,550	$114,240,328	$ 81,440,164	$ 8,163,249	$ 697,797	$18,916,865	$ 3,615,956	$848,093	17
18	Operating Income	$ 137,426,511	$ 44,565,510	$ 57,197,054	$ 26,735,061	$ 2,966,030	$ 497,867	$ 4,384,344	$ 1,080,645	$ -	18
19	Allowance For Funds Used During Construction	17,227,489	7,828,424	4,563,484	3,435,921	142,988	22,373	1,053,312	180,987	-	19
20	Interest On Customers' Deposits	(125,365)	(113,565)	(11,643)	(68)	(89)	-	-	-	-	20
21	Total Operating Income	$ 154,528,635	$ 52,280,369	$ 61,748,895	$ 30,170,914	$ 3,108,929	$ 520,240	$ 5,437,656	$ 1,261,632	$ -	21
22	Rate of Return on Rate Base	8.19%	5.68%	12.51%	9.03%	9.85%	16.05%	6.07%	8.19%	-	22

( ) Denotes reduction in operating revenue deductions.

Exhibit 8

Facsimile of a Cost-of-Service Study Report (Rate Base)

ALLOCATION OF ELECTRIC RATE BASE, BASED ON 13-MONTH AVERAGE
RATE BASE (SEPTEMBER 30, 1975 TO SEPTEMBER 30, 1976)

	1		2	3	4	5	6	7	8	9	10	
									Special Contracts			
Line No.	Item	Account Number	Total	Residential Schedule R	General Service Schedule G	Industrial Schedule T	Street Lighting Schedule SL	Private Area Lighting Schedule PL	Bethlehem Steel Corp.	Consolidated Rail Corp.	Interdepart-mental Sales	Line No.
1	Intangible Plant - Organization	1301	$ 1,265,402	$ 616,700	$ 330,855	$ 224,015	$ 21,214	$ 2,209	$ 60,136	$ 10,273	$ -	1
	Production Plant											
	Production Plant - Steam											
2	Land and Land Rights	1310	$ 4,168,158	$ 1,896,095	$ 1,103,728	$ 829,880	$ 34,596	$ 5,419	$ 254,674	$ 43,766	$ -	2
3	Structures and Improvements	1311	84,515,245	37,335,388	22,598,131	17,614,371	701,477	106,849	5,258,529	900,500	-	3
4	Boiler Plant Equipment	1312	144,641,059	63,897,007	38,674,792	30,145,238	1,200,521	182,865	8,999,509	1,541,127	-	4
5	Turbogenerator Units	1314	86,821,946	38,354,336	23,214,921	18,095,168	720,622	109,765	5,402,056	925,078	-	5
6	Accessory Electric Equipment	1315	30,628,194	13,530,485	8,189,488	6,383,281	254,214	38,722	1,905,666	326,338	-	6
7	Miscellaneous Power Plant Equipment	1316	8,984,403	3,968,796	2,402,326	1,872,602	74,570	11,359	559,021	95,729	-	7
8	Total Production Plant - Steam		$ 359,759,005	$158,982,107	$ 96,183,386	$ 74,940,540	$2,986,000	$ 454,979	$22,379,455	$ 3,832,538	$ -	8
	Production Plant - Nuclear											
9	Land and Land Rights	1320	$ 2,190,645	$ 996,525	$ 580,083	$ 436,157	$ 18,182	$ 2,848	$ 133,848	$ 23,002	$ -	9
10	Structures and Improvements	1321	188,286,598	85,559,024	49,876,499	37,553,478	1,562,778	244,521	11,512,198	1,978,100	-	10
11	Reactor Plant Equipment	1322	344,473,611	156,531,657	91,249,936	68,704,789	2,859,131	447,355	21,061,774	3,618,969	-	11
12	Turbogenerator Units	1323	122,391,328	55,615,657	32,421,059	24,410,764	1,015,848	158,945	7,483,237	1,285,818	-	12
13	Accessory Electric Equipment	1324	66,070,245	30,022,890	17,501,788	13,177,603	548,383	85,803	4,039,658	694,120	-	13
14	Miscellaneous Power Plant Equipment	1325	8,435,012	3,832,926	2,234,410	1,682,361	70,010	10,954	515,734	88,617	-	14
15	Total Production Plant - Nuclear		$ 731,847,439	$332,558,679	$193,863,775	$145,965,152	$6,074,332	$ 950,426	$44,746,449	$ 7,688,626	$ -	15
	Production Plant - Other Production											
16	Land and Land Rights	1340	$ 222,040	$ 101,006	$ 58,796	$ 44,208	$ 1,843	$ 289	$ 13,567	$ 2,331	$ -	16
17	Structures and Improvements	1341	3,445,007	1,532,389	919,074	710,533	28,594	4,384	213,451	36,582	-	17
18	Fuel Holders, Producers and Accessories	1342	3,141,539	1,397,418	838,110	647,931	26,075	3,998	194,647	33,360	-	18
19	Prime Movers	1343	14,424,920	6,416,469	3,848,330	2,975,107	119,726	18,356	893,756	153,176	-	19
20	Generators	1344	46,284,054	20,588,057	12,347,806	9,545,936	384,157	58,900	2,867,717	491,481	-	20
21	Accessory Electric Equipment	1345	5,244,574	2,332,906	1,399,161	1,081,664	43,530	6,674	324,948	55,691	-	21
22	Miscellaneous Power Plant Equipment	1346	174,322	77,541	46,506	35,955	1,446	222	10,801	1,851	-	22
23	Total Production Plant - Other Production		$ 72,936,456	$ 32,445,786	$ 19,457,783	$ 15,041,334	$ 605,371	$ 92,823	$ 4,518,887	$ 774,472	$ -	23
24	Total Production Plant		$1,164,542,900	$523,986,572	$309,504,944	$235,947,026	$9,665,703	$1,498,228	$71,644,791	$12,295,636	$ -	24

Exhibit 8 (continued)

Facsimile of a Cost-of-Service Study Report (Rate Base)

ALLOCATION OF ELECTRIC RATE BASE, BASED ON 13-MONTH AVERAGE
RATE BASE (SEPTEMBER 30, 1975 TO SEPTEMBER 30, 1976)

	1		2	3	4	5	6	7	8	9	10	
									Special Contracts			
Line No.	Item	Account Number	Total	Residential Schedule R	General Service Schedule G	Industrial Schedule T	Street Lighting Schedule SL	Private Area Lighting Schedule PL	Bethlehem Steel Corp.	Consolidated Rail Corp.	Interdepartmental Sales	Line No.
	Transmission Plant											
25	Land and Land Rights	1350	$ 28,036,615	$ 12,743,283	$ 7,417,871	$ 5,577,327	$ 232,640	$ 36,417	$ 1,591,053	$ 438,024	$ -	25
26	Structures and Improvements	1352	7,629,308	3,488,552	2,030,662	1,526,778	63,735	9,969	444,865	64,747	-	26
27	Station Equipment	1353	97,264,931	44,403,434	25,847,040	19,433,525	811,042	126,890	5,782,642	860,358	-	27
28	Towers and Fixtures	1354	26,727,090	12,121,758	7,056,108	5,305,354	221,246	34,641	1,544,639	443,344	-	28
29	Poles and Fixtures	1355	12,774,155	5,866,903	3,415,044	2,567,590	107,263	16,765	549,116	251,474	-	29
30	Overhead Conductors and Devices	1356	41,120,613	18,847,352	10,971,028	8,248,830	344,125	53,860	2,266,006	389,412	-	30
31	Underground Conduit	1357	15,577,440	7,086,177	4,124,906	3,101,469	129,293	20,251	951,781	163,563	-	31
32	Underground Conductors and Devices	1358	17,787,610	8,342,596	4,856,047	3,650,928	152,643	23,839	649,876	111,681	-	32
33	Roads and Trails	1359	32,152	13,821	8,046	6,050	252	39	1,857	2,087	-	33
34	Total Transmission Plant		$ 246,949,914	$112,913,876	$ 65,726,752	$ 49,417,851	$ 2,062,239	$ 322,671	$13,781,835	$ 2,724,690	$ -	34
	Distribution Plant											
35	Land and Land Rights	1360	$ 6,243,976	$ 3,111,655	$ 1,700,585	$ 1,364,390	$ 57,992	$ 9,354	$ -	$ -	$ -	35
36	Structures and Improvements	1361	12,347,270	6,134,492	3,341,563	2,720,776	114,330	18,440	17,669	-	-	36
37	Station Equipment	1362	75,871,484	37,464,576	20,402,320	16,583,876	698,238	112,619	609,855	-	-	37
38	Poles, Towers and Fixtures	1364	46,126,555	32,042,523	9,631,895	3,537,222	443,935	74,384	396,596	-	-	38
39	Overhead Conductors and Devices	1365	59,446,880	41,356,339	13,447,334	3,556,360	746,162	119,959	220,726	-	-	39
40	Underground Conduit	1366	11,886,128	7,116,756	2,865,571	1,755,435	78,874	13,261	56,231	-	-	40
41	Underground Conductors and Devices	1367	79,819,633	45,217,321	23,085,729	9,530,127	1,243,903	89,496	653,057	-	-	41
42	Line Transformers	1368	66,829,249	46,839,455	18,902,575	438,378	571,754	77,087	-	-	-	42
43	Services	1369	24,462,190	18,207,561	6,254,629	-	-	-	-	-	-	43
44	Meters	1370	30,334,326	22,686,407	6,499,262	1,104,341	756	-	33,969	9,591	-	44
45	Installations on Customers' Premises	1371	826,175	-	-	-	-	826,175	-	-	-	45
46	Street Lighting and Signal Systems	1373	15,124,497	-	-	-	15,124,497	-	-	-	-	46
47	Total Distribution Plant		$ 429,318,363	$260,177,085	$106,131,463	$ 40,590,905	$ 19,080,441	$1,340,775	$ 1,988,103	$ 9,591	$ -	47
48	General Plant Including Apportionment of Common Plant	1389-1398	$ 42,524,876	$ 20,724,669	$ 11,118,697	$ 7,528,250	$ 712,897	$ 74,212	$ 2,020,889	$ 345,262	$ -	48
49	Utility Plant Held For Future Use	105.1	$ 3,520,424	$ 1,662,695	$ 958,964	$ 657,615	$ 30,980	$ 4,929	$ 175,317	$ 29,924	$ -	49
50	Merchandise Property		$ (518,166)	$ (252,526)	$ (135,483)	$ (91,732)	$ (8,687)	$ (904)	$ (24,624)	$ (4,208)	$ -	50
51	Total Rate Base		$1,887,603,713	$919,829,069	$493,636,192	$334,273,930	$ 31,564,787	$3,242,120	$89,646,447	$15,411,168	$ -	51

( ) Denotes decrease in rate base.

Exhibit 9

Facsimile of a Cost-of-Service Study Report (Operating Expenses)

ALLOCATION OF ELECTRIC OPERATING EXPENSES, BASED ON 12 MONTHS ENDED SEPTEMBER 30, 1976

Line No.	Item	Account Number	Total	Residential Schedule R	General Service Schedule G	Industrial Schedule T	Street Lighting Schedule SL	Private Area Lighting Schedule PL	Special Contracts Bethlehem Steel Corp.	Special Contracts Consolidated Rail Corp.	Interdepart-mental Sales	Line No.
	1		2	3	4	5	6	7	8	9	10	
	Production Expenses											
	Operation - Steam Power Generation											
1	Fuel	501	$150,050,098	$54,174,886	$42,503,882	$39,859,409	$1,245,416	$156,761	$10,368,236	$1,741,508	$ -	1
2	Steam Expenses	502	4,294,570	1,953,600	1,137,202	855,049	35,645	5,583	262,398	45,093	-	2
3	Electric Expenses	505	3,303,095	1,502,578	874,660	657,646	27,416	4,294	201,819	34,682	-	3
4	Miscellaneous Steam Power Expenses	506	3,654,386	1,662,381	967,681	727,588	30,331	4,751	223,283	38,371	-	4
5	Rents	507	33,741	15,348	8,935	6,718	280	44	2,062	354	-	5
6	Total Operation - Steam Power Generation		$161,335,890	$59,308,793	$45,492,360	$42,106,410	$1,339,088	$171,433	$11,057,798	$1,860,008	$ -	6
	Maintenance - Steam Power Generation											
7	Maintenance of Structures	511	$ 929,710	$ 422,924	$ 246,188	$ 185,105	$ 7,717	$ 1,209	$ 56,805	$ 9,762	$ -	7
8	Maintenance of Boiler Plant	512	7,503,371	2,656,441	2,135,791	2,030,503	62,278	7,696	522,956	87,706	-	8
9	Maintenance of Electric Plant	513	3,779,575	1,337,651	1,075,921	1,023,115	31,370	3,875	263,459	44,184	-	9
10	Maintenance of Miscellaneous Steam Plant	514	394,637	179,521	104,499	78,573	3,275	513	24,112	4,144	-	10
11	Total Maintenance - Steam Power Generation		$ 12,607,293	$ 4,596,537	$ 3,562,399	$ 3,317,296	$ 104,640	$ 13,293	$ 867,332	$ 145,796	$ -	11
	Operation - Nuclear Power Generation											
12	Nuclear Fuel Expense	518	$ 15,646,493	$ 5,685,550	$ 4,424,926	$ 4,130,498	$ 129,866	$ 16,445	$ 1,078,042	$ 181,166	$ -	12
13	Coolants and Water	519	455,569	207,240	120,634	90,704	3,781	592	27,835	4,783	-	13
14	Steam Expenses	520	1,148,626	522,510	304,156	228,691	9,534	1,493	70,181	12,061	-	14
15	Electric Expenses	523	826,773	376,098	218,930	164,611	6,862	1,075	50,516	8,681	-	15
16	Miscellaneous Nuclear Power Expenses	524	3,405,837	1,549,316	901,865	678,102	28,268	4,428	208,097	35,761	-	16
17	Total Operation - Nuclear Power Generation		$ 21,483,298	$ 8,340,714	$ 5,970,511	$ 5,292,606	$ 178,311	$ 24,033	$ 1,434,671	$ 242,452	$ -	17
	Maintenance - Nuclear Power Generation											
18	Maintenance of Structures	529	$ 292,727	$ 133,161	$ 77,514	$ 58,281	$ 2,430	$ 381	$ 17,886	$ 3,074	$ -	18
19	Maintenance of Reactor Plant Equipment	530	1,151,994	443,865	320,823	286,204	9,561	1,280	77,220	13,041	-	19
20	Maintenance of Electric Plant	531	481,924	184,965	134,355	120,241	4,000	534	32,365	5,464	-	20
21	Maintenance of Miscellaneous Nuclear Plant	532	330,645	150,411	87,555	65,831	2,744	430	20,202	3,472	-	21
22	Total Maintenance - Nuclear Power Gen.		$ 2,257,290	$ 912,402	$ 620,247	$ 530,557	$ 18,735	$ 2,625	$ 147,673	$ 25,051	$ -	22
	Operation-Other Power Generation											
23	Fuel	547	$ 2,345,757	$ 898,838	$ 654,256	$ 586,324	$ 19,470	$ 2,592	$ 157,664	$ 26,613	$ -	23
24	Generation Expenses	548	260,462	118,484	68,971	51,857	2,162	339	15,914	2,735	-	24
25	Miscellaneous Other Power Generation	549	50,567	23,002	13,391	10,067	420	66	3,090	531	-	25
26	Total Oper.-Other Power Generation		$ 2,656,786	$ 1,040,324	$ 736,618	$ 648,248	$ 22,052	$ 2,997	$ 176,668	$ 29,879	$ -	26

Exhibit 9 (continued)

Facsimile of a Cost-of-Service Study Report (Operating Expenses)

ALLOCATION OF ELECTRIC OPERATING EXPENSES, BASED ON 12 MONTHS ENDED SEPTEMBER 30, 1976

	1		2	3	4	5	6	7	8	9	10	
Line No.	Item	Account Number	Total	Residential Schedule R	General Service Schedule G	Industrial Schedule T	Street Lighting Schedule SL	Private Area Lighting Schedule PL	Special Contracts: Bethlehem Steel Corp.	Special Contracts: Consolidated Rail Corp.	Interdepartmental Sales	Line No.
	Maintenance - Other Power Generation											
27	Maintenance of Structures	552	$ 56,997	$ 25,928	$ 15,093	$ 11,348	$ 473	$ 74	$ 3,463	$ 598	$ -	27
28	Maintenance of Generating & Elec. Equip.	553	1,659,611	578,242	474,232	455,714	13,775	1,677	116,462	19,509	-	28
29	Maint. of Misc. Other Power Generation Plant	554	(8,361)	(3,803)	(2,214)	(1,665)	(69)	(11)	(511)	(88)	-	29
30	Total Maintenance-Other Power Gen.		$ 1,708,247	$ 600,367	$ 487,111	$ 465,397	$ 14,179	$ 1,740	$ 119,434	$ 20,019	$ -	30
	Other Power Supply Expenses											
31	Purchased Power	555	$(22,196,295)	$(8,217,699)	$(6,310,498)	$(5,844,736)	$ (185,709)	$(23,754)	$(1,534,167)	$ (79,732)	$ -	31
32	System Control & Load Dispatching	556	1,326,803	603,563	351,337	264,167	11,012	1,725	81,068	13,931	-	32
33	Other Expenses	557	717,642	326,456	190,031	142,883	5,956	933	43,848	7,535	-	33
34	Total Other Power Supply Expenses		$(20,151,850)	$(7,287,680)	$(5,769,130)	$(5,437,686)	$ (168,741)	$(21,096)	$(1,409,251)	$ (58,266)	$ -	34
35	Total Production Expenses		$181,596,954	$67,511,457	$51,100,116	$46,922,828	$1,508,264	$195,025	$12,394,325	$2,264,939	$ -	35
	Transmission Expenses											
	Operation											
36	Load Dispatching	561	$ 821,339	$ 377,619	$ 219,812	$ 165,268	$ 6,897	$ 1,079	$ 43,234	$ 7,430	$ -	36
37	Station Expenses	562	2,012,418	925,233	538,573	404,936	16,898	2,644	105,930	18,204	-	37
38	Overhead Line Expenses	563	76,739	35,281	20,536	15,441	645	101	4,039	694	-	38
39	Underground Line Expenses	564	65,112	29,934	17,427	13,102	547	86	3,427	589	-	39
40	Transmission of Electricity By Others	565	1,544,545	710,122	413,359	310,792	12,969	2,029	81,302	13,972	-	40
41	Rents	567	130,689	59,936	34,888	26,232	1,094	171	6,862	1,506	-	41
42	Total Operation - Transmission		$ 4,650,842	$ 2,138,125	$ 1,244,597	$ 935,771	$ 39,050	$ 6,110	$ 244,794	$ 42,395	$ -	42
	Maintenance											
43	Maintenance of Structures	569	$ 67,923	$ 31,227	$ 18,179	$ 13,668	$ 571	$ 89	$ 3,575	$ 614	$ -	43
44	Maintenance of Station Equipment	570	743,841	341,990	199,070	149,675	6,246	977	39,154	6,729	-	44
45	Maintenance of Overhead Lines	571	1,421,030	649,039	377,806	284,058	11,854	1,855	74,309	22,109	-	45
46	Maintenance of Underground Lines	572	311,121	143,041	83,265	62,603	2,613	408	16,377	2,814	-	46
47	Total Maintenance - Transmission		$ 2,543,915	$ 1,165,297	$ 678,320	$ 510,004	$ 21,284	$ 3,329	$ 133,415	$ 32,266	$ -	47
48	Total Transmission Expenses		$ 7,194,757	$ 3,303,422	$ 1,922,917	$ 1,445,775	$ 60,334	$ 9,439	$ 378,209	$ 74,661	$ -	48

Exhibit 9 (continued)

Facsimile of a Cost-of-Service Study Report (Operating Expenses)

ALLOCATION OF ELECTRIC OPERATING EXPENSES, BASED ON 12 MONTHS ENDED SEPTEMBER 30, 1976

Line No.	1 Item	Account Number	2 Total	3 Residential Schedule R	4 General Service Schedule G	5 Industrial Schedule T	6 Street Lighting Schedule SL	7 Private Area Lighting Schedule PL	8 Special Contracts Bethlehem Steel Corp.	9 Special Contracts Consolidated Rail Corp.	10 Interdepartmental Sales	Line No.
	Distribution Expenses											
	Operation											
49	Station Expenses	582	$ 3,778,377	$ 1,879,699	$ 1,023,627	$ 831,989	$ 35,032	$ 5,650	$ 2,380	$ -	$ -	49
50	Overhead Line Expenses	583	2,849,253	1,986,951	691,720	126,488	29,218	4,492	10,384	-	-	50
51	Underground Line Expenses	584	1,555,508	845,927	518,415	156,317	20,518	1,644	12,687	-	-	51
52	Street Lighting & Signal System Expenses	585	1,980,576	-	-	-	1,980,576	-	-	-	-	52
53	Meter Expenses	586	3,735,385	2,952,449	608,494	136,715	-	-	18,677	19,050	-	53
54	Customer Installations Expenses	587	1,843,249	761,998	545,234	426,896	68,938	40,183	-	-	-	54
55	Rents	589	1,048,046	298,936	352,648	273,950	115,893	788	5,831	-	-	55
56	Total Operation - Distribution		$ 16,790,394	$ 8,725,960	$ 3,740,138	$ 1,952,355	$2,250,175	$ 52,757	$ 49,959	$ 19,050	$ -	56
	Maintenance											
57	Maintenance of Structures	591	$ 70,466	$ 35,011	$ 19,071	$ 15,527	$ 653	$ 105	$ 99	$ -	$ -	57
58	Maintenance of Station Equipment	592	687,909	341,877	186,175	151,323	6,372	1,028	1,134	-	-	58
59	Maintenance of Overhead Lines	593	6,231,063	4,327,375	1,360,673	418,291	70,248	11,420	43,056	-	-	59
60	Maintenance of Underground Lines	594	1,014,585	584,140	281,893	123,315	15,751	1,212	8,274	-	-	60
61	Maintenance of Line Transformers	595	559,753	379,392	171,614	3,519	4,621	607	-	-	-	61
62	Maintenance of Street Lighting & Signal Sys.	596	609,879	-	-	-	609,879	-	-	-	-	62
63	Maintenance of Meters	597	330,102	213,212	82,624	34,166	-	-	100	-	-	63
64	Total Maintenance - Distribution		$ 9,503,757	$ 5,881,007	$ 2,102,050	$ 746,141	$ 707,524	$ 14,372	$ 52,663	$ -	$ -	64
65	Total Distribution Expenses		$ 26,294,151	$ 14,606,967	$ 5,842,188	$ 2,698,496	$2,957,699	$ 67,129	$ 102,622	$ 19,050	$ -	65
66	Customer Accounts Expenses	901-905	$ 11,700,418	$ 10,196,757	$ 1,335,357	$ 121,077	$ 35,566	$ -	$ 6,263	$ 5,398	$ -	66
67	Customer Service & Informational Expenses	907-910	$ 1,393,985	$ 391,710	$ 822,451	$ 97,579	$ 69,699	$ 12,546	$ -	$ -	$ -	67
68	Sales Expenses	911-916	$ 3,216	$ 904	$ 1,897	$ 225	$ 161	$ 29	$ -	$ -	$ -	68
69	Administrative and General Expenses	920-932	$ 37,335,624	$ 15,688,360	$ 9,973,531	$ 8,379,920	$ 755,358	$ 46,526	$ 2,105,583	$ 386,346	$ -	69
70	Total Operating Expenses Before Expense Offset (Interdepartmental Sales)		$265,819,105	$111,699,577	$70,998,457	$59,665,900	$5,387,081	$330,694	$14,987,002	$2,750,394	$ -	70
71	Expense Offset (Interdepartmental Sales)		-	(356,368)	(226,552)	(190,352)	(17,159)	(1,057)	(47,829)	(8,776)	848,093	71
72	Total Operating Expenses		$265,819,105	$111,343,209	$70,771,905	$59,475,548	$5,369,922	$329,637	$14,939,173	$2,741,618	$848,093	72

( ) Denotes decrease in operating revenue deductions.

The Commission should also specify that utilities file, with each application for a general rate increase, all data and information used to prepare the cost-of-service study and needed to design rates for specific groups or subclasses (e.g., rates for those customers with all-electric homes or those with nonelectric space heating). We recommend that the following data be required:

- Copies of the jurisdictional allocation study for the test years (historical and future), including all applicable work papers
- One copy of the bill frequency and hours-use analyses for the test years and each month in the test years
- Annual load forecasts for the summer and winter peaks in each of the 10 years succeeding the test period
- With each rate schedule, the following for the test years and the five calendar years preceding the historical year:
    - kWh sales (system and Nevada retail)
    - electric-rate revenues with fuel clause revenues identified separately (system and Nevada retail)
    - number of bills (system and Nevada retail)
    - peak demands coincident with the summer and winter system peaks
    - NCP demands during the months of the summer and and winter system peak
    - kWh sales and number of bills during the months of the summer and winter system peaks
    - NCP maximum demands
- For the test years and the five calendar years preceding the historical year:
    - total kWh sales (system and Nevada retail)
    - total kWh generated
    - number of customers (system and Nevada retail)
    - peak demands at the generation level and the meter level

- Estimated line losses by customer group or delivered voltage

- Unit demand, energy, and customer costs, for each rate schedule, calculated on the basis of current and proposed revenue requirements. All related work papers (e.g., the demand-, energy-, and customer-related rate base and deductions from electric operating revenues) should be included.

The Commmission may find that additional data are required to translate the cost study results into rates. However, we believe the data we have outlined will provide the Commission with the basic information required.

DEVELOP COMPUTER PROGRAMS

Because of the amount of data and calculations required to determine cost of service and unit costs, we recommend that the utilities develop computer programs to perform all required data manipulation. We further recommend that a program be developed to print out the studies in formats similar to those suggested.

It should not be necessary to design completely new software to handle retail cost-of-service studies. We have informed the utilities of two options to meet their's and the Commission's requirements: adapting existing computer programs for performing jurisdictional allocation studies, and adapting a retail cost-of-service study program obtainable from the New York Public Service Commission for a nominal fee.

ESTABLISH SCHEDULE AND RESPONSIBILITY FOR STUDIES

The Commission and utilities should prepare a schedule for the initial cost-of-service studies based on estimates of the availability of data and computer programs. We believe a realistic time frame for collecting data, developing computer programs, and conducting the first cost-of-service studies, is 18 to 24 months.

Each utility should prepare its own cost-of-service study; the Commission should take responsibility for reviewing the results and using them in rate cases. Both the utilities and the Commission should train personnel to assist in these tasks.