Customer System Efficiency Improvement Assessment: Description and Examination of System Characterization Data

**J. W. Callaway
J. G. DeSteele**

December 1986

**Prepared for the
Bonneville Power Administration
under a Related Services Agreement
with the U.S. Department of Energy
Contract DE-AC06-76RLO 1830**

**Pacific Northwest Laboratory
Operated for the U.S. Department of Energy
by Battelle Memorial Institute**

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor Battelle Memorial Institute, nor any of their employees, makes any warranty, expressed or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government of any agency thereof, or Battelle Memorial Institute. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof, or Battelle Memorial Institute.

PACIFIC NORTHWEST LABORATORY
operated by
BATTELLE
for the
UNITED STATES DEPARTMENT OF ENERGY
under Contract DE-AC06-76RLO 1830

Printed in the United States of America
Available from
National Technical Information Service
United States Department of Commerce
5285 Port Royal Road
Springfield, Virginia 22161

NTIS Price Codes
Microfiche A01

Printed Copy

Pages	Price Codes
001-025	A02
026-050	A03
051-075	A04
076-100	A05
101-125	A06
126-150	A07
151-175	A08
176-200	A09
201-225	A010
226-250	A011
251-275	A012
276-300	A013

CUSTOMER SYSTEM EFFICIENCY IMPROVEMENT
ASSESSMENT: DESCRIPTION AND EXAMINATION
OF SYSTEM CHARACTERIZATION DATA

J. W. Callaway
J. G. DeSteele

December 1986

Prepared for
the Office of Conservation
Bonneville Power Administration
under a Related Services Agreement
with the U.S. Department of Energy
under Contract DE-AC06-76RLO 1830

Pacific Northwest Laboratory
Richland, Washington 99352

SUMMARY

This report describes three data bases that were developed in the Customer System Efficiency Improvement (CSEI) Assessment Project to help characterize transmission and distribution (T&D) system losses experienced by utility customers in the Pacific Northwest. The CSEI Project is being conducted by the Pacific Northwest Laboratory (PNL) for the Bonneville Power Administration (BPA), Office of Conservation. A principal objective of this project is to assess the potential for electric energy conservation in the T&D systems of BPA's utility customers.

The three data bases provide essential input on the number and operating characteristics of T&D component stocks that was used in another task of the CSEI Project to estimate the conservation supply functions that result from replacing existing stocks with more efficient components (Tepel et al. 1986). This document describes the three data bases, provides a guide to their use, and presents a summary characterization of the principal loss-generating components (lines and transformers) of the region's T&D systems.

The first data base (called INVTRY) contains time series data for the annual power requirements and sectoral and total sales of electricity for all customers (utilities and other primary users of electrical power) in the BPA region. Data are for the years 1976 through 1983. The second data base, called QUEST, contains general information about loss recovery practices and other system loss-related features for about half of the approximately 140 electrical utilities in the region. This information was collected in a voluntary survey conducted by PNL in late 1984. Finally, SYSTEMS, the third data base, contains extensive and detailed data on the T&D component characteristics. This information was provided by a subset of the utilities that responded to the survey. These three data bases are described in greater detail below.

First, the requirement and sales data base INVTRY was developed from data provided by BPA's Power Requirement Branch. Using a standard definition of energy losses as the difference between annual requirements and annual sales (in megawatt hours), this data base was used to determine both the magnitude

and distribution, by customer type, of the energy losses that occur on the nonfederal portion of the region's T&D network. Annual energy losses at the utility level were also calculated to identify possible loss patterns of individual utility systems. Demand, or peak, losses were not examined in this part of the CSEI Assessment.

Analysis of these data shows the following relationships between requirements and losses for each utility class:

- Investor-owned utilities (IOUs) require approximately 48% of the region's electricity, but their systems are responsible for over 60% of the region's total losses (in megawatt hours). This disproportionality can be explained, at least in part, by the fact that these utilities maintain extensive high voltage transmission systems that supplement the federally-owned transmission system operated by BPA. Losses for this category of utility therefore reflect the combined inefficiencies of both the T&D system and a substantial transmission network.
- Nongenerating public utilities (NGUs), by contrast, require 15% of the region's electricity, but contribute only 10% of regional losses. The losses that occur on these systems generally do not include much high voltage transmission loss, as most NGUs rely on the federal network to deliver power to their bulk delivery points. Therefore, their distribution systems, on average, contain only short stretches of transmission line. Losses for this group of utilities are typically attributable to line loss on feeders and load losses on transformers.
- Generating public utilities (GPUs) have T&D losses approximately proportional to their loads (21% of regional load, 22% of regional losses).
- Direct service industries (DSIs), requiring about 15% of the region's power in 1983, were responsible for only 7% of the regional losses.

This is consistent with DSIs typically having points of delivery near site boundaries and very compact distribution systems within the site.

The second data base QUEST provides loss recovery information for about half of the utilities in the Pacific Northwest region. However, this information may not be statistically representative of Northwest utilities, because the utilities that volunteered this information may have greater-than-average interest in loss analysis and recovery. The general survey data do provide a representative description of current utility activities that deal with system losses. Moreover, the technical component data collected in the survey are some of the most detailed and comprehensive ever obtained for a regional system.

The information in the QUEST data base indicates the following trends:

- On average, utilities' own estimates of the distribution of their losses by component closely match the loss allocations in published research.
- Northwest utilities appear to be installing a substantial number of T&D system efficiency improvements. These improvements are probably the result of normal system maintenance and growth requirements, and any loss reduction is viewed as a secondary benefit.
- Reconductoring, transformer replacement (to increase efficiency), and capacitance additions are the most frequent improvements reported by the utilities.

The third data base SYSTEMS was used to estimate the total regional stock of four basic distribution system components, and to determine potential resource recovery from improving the efficiency of these components through replacement or other modifications. Analyzing the sample data revealed a number of interesting operating characteristics:

- The average age of distribution system components is estimated to be about 13 to 14 years.

- Many components were apparently oversized when installed, probably because the utilities expected that the high-demand growth rates experienced during the 1970s would continue into the 1980s. As a result, current peak loads on substation transformers are, on the average, only about 60% of installed capacity; distribution transformers show a similar, but less dramatic, under-loading. In comparison, the national average for peak-to-installed capacity is over 100% for distribution transformers.
- The regional load factor for the distribution system network is about 0.4, well below the reported national average of over 0.6. A wide range of load factors exists over the various sizes of each component. Load factors also varied widely among different utility categories.

The information contained in SYSTEMS was used to estimate the regional stock of four principal loss generating components (substation transformers, distribution transformers, primary feeders, and transmission lines). These estimates were then used as input to other analytical tasks of the CSEI Project. Estimates of substation transformers and transmission line stocks in the region are easy to obtain because these components are relatively few in number, and are easily inventoried. However, adequate estimates of the existing distribution transformer stock by size and feeder circuit miles have not been available previously. The resulting estimates of the region's stock of these four components were determined to contain:

- about 1.3 million distribution transformers, ranging in size from less than 7.5 kVA to over 500 kVA
- about 1,200 substation transformers, ranging in size from about 1.0 MVA to over 60 MVA
- about 60,000 circuit miles of primary feeder, with nominal voltages ranging from about 11 kV to 33 kV
- about 24,000 circuit miles of nonfederal transmission lines, with operating voltages of 34.5 kV to 230 kV.

The development of these three data bases was essential for estimating regional supply functions for T&D conservation measures. Despite variations in data quality and consistency, the data bases provide the most accurate and detailed basis for assessing regional T&D system characteristics yet available. The initial purpose of these data bases was to provide inputs for estimating conservation supply curves for region-wide T&D equipment upgrading. However, the information developed for this effort regarding T&D losses and component stocks has the potential for much broader use in future assessments of T&D system conservation options, plans, and policies.

ACKNOWLEDGMENTS

The authors acknowledge and appreciate the efforts of the many individuals in the Pacific Northwest utility industry who responded to the system characterization surveys and members of BPA's Area Office staff, who facilitated these contacts.

A number of PNL staff made significant contributions to this work. Mike King participated in early task planning activities. As Task Leader for the initial portion of the study, Lisa Skumatz helped to develop the questionnaire and conduct the survey of utilities. Audrey Lyke collected information from representatives of the direct service industries. Jim Johnston provided the cluster analysis that guided the conduct of the utility survey in this and a previous task of the CSEI Assessment Project. Annet Dittmer and Elinor Edin performed much of the data entry and computer manipulation of the data bases. Bill Doggett reviewed the databases, eliminated data of doubtful validity, and performed the calculations that resulted in the figures in Section 5.0. Finally, but not the least in importance, Donna Debrodt and Cary Counts edited the manuscript.

Several members of BPA's Headquarters staff greatly assisted this research by providing data and advice. Camilla Downing, in particular, played an important role in supplying basic sales and requirements data and in assisting PNL staff in its interpretation. Barry Kennedy and Clair Loosli provided much helpful information. The authors also thank the BPA Project Manager, Mike Warwick, for his interest and encouragement during the course of the study.

CONTENTS

SUMMARY	iii
ACKNOWLEDGMENTS	ix
1.0 INTRODUCTION	1.1
2.0 CSEI DATA MANAGEMENT SYSTEM AND BACKGROUND INFORMATION	2.1
2.1 RELATIONAL DATA BASES	2.1
2.2 RBASE 4000® SYSTEM CHARACTERISTICS	2.2
2.3 LOTUS 1-2-3® USES	2.3
2.4 BACKGROUND INFORMATION ON CSEI DATA BASES	2.3
2.4.1 The CSEI Data Bases	2.3
2.4.2 Use of the CSEI Data Bases	2.4
3.0 THE SALES AND REQUIREMENTS DATA BASE	3.1
3.1 DATA SOURCES	3.1
3.1.1 Data Received from BPA	3.1
3.1.2 Supplemental Data	3.3
3.2 DATA MODIFICATION EFFORTS	3.3
3.2.1 Customer Identification	3.3
3.2.2 Error Correction	3.4
3.2.3 Data Merges	3.5
3.3 PRESENT CONTENTS OF INVTRY	3.5
3.3.1 Group 1: Identification Relations	3.5
3.3.2 Group 2: Original Data Relations	3.5
3.3.3 Group 3: Sales and Requirements Relations	3.6
3.3.4 Group 4: Supplementary Data Relations	3.9
3.4 SUMMARY OF INVTRY DATA	3.11

4.0	SURVEY PART 1: DATA BASE	4.1
4.1	BACKGROUND INFORMATION	4.1
4.2	DATA QUALITY	4.5
4.3	CONTENTS OF THE QUEST DATA BASE	4.5
4.4	HIGHLIGHTS OF QUEST DATA	4.7
4.4.1	Estimated Losses by Component	4.7
4.4.2	Power Factor and Equipment Replacement	4.10
5.0	SURVEY PART 2: THE SYSTEMS DATA BASE	5.1
5.1	CONTENTS OF THE SYSTEMS DATA BASE	5.1
5.2	DATA QUALITY	5.2
5.2.1	Background	5.2
5.2.2	Evaluation of 1984 Survey Data	5.5
5.3	SUMMARY HIGHLIGHTS OF THE SYSTEMS DATA BASE	5.7
6.0	CONCLUSIONS	6.1
	REFERENCES	R.1
	APPENDIX A--REQUEST FOR INFORMATION FORM SENT TO UTILITIES	A.1
	APPENDIX B--BPA REGION UTILITIES BY CLUSTER	B.1
	APPENDIX C--NAMES OF VARIABLES OR ATTRIBUTES USED IN DATA BASES	C.1
	APPENDIX D--CLUSTER ANALYSIS	D.1

FIGURES

3.1	1983 Requirements and Losses by Customer Type	3.12
4.1	Utilities Estimates of Losses	4.8
5.1	Portion of Corrected Transmission Line Worksheet with Loss Calculation	5.8
5.2	Distribution of Distribution Transformers by Size Category	5.9
5.3	Detail from Figure 5.2 for Distribution Transformers Greater than 75 kVA	5.9
5.4	Distribution of Substation Transformers by Size Category	5.10
5.5	Distribution of Feeders by Size Category	5.10
5.6	Distribution of Transmission Lines by Size Category	5.11
5.7	Peak Load Ratios of Distribution Transformers	5.13
5.8	Peak Load Ratios of Substation Transformers	5.13
5.9	Comparison of Average Loads to Peak Loads for Substation Transformers, 1984	5.14
5.10	Comparison of Average Loads to Peak Loads for Distribution Transformers, 1984	5.15
5.11	Comparison of Average Loads to Peak Load for Feeders, 1984	5.16
5.12	Comparison of Average Loads and Peak Loads for Transmission Lines, 1984	5.16
5.13	Comparison of System and Components Load Factors by Utility Cluster, 1984	5.17

TABLES

3.1	Identification Relations in INVTRY	3.6
3.2	Original Data Relations in INVTRY	3.7
3.3	Sales and Requirements Relations	3.8
3.4	Supplementary Data Relations	3.10
4.1	Response to Request for Information, by Type of Information and Utility Cluster	4.2
4.2	Utilities' Estimates of Loss Reduction Potential	4.9
4.3	Distribution of Utility Responses: Efficiency Improvements in 1984 and 1985	4.10
4.4	Summary of Power Factor by Point of Delivery	4.11
5.1	Matrix of Files and Variables in SYSTEMS Data Base	5.3
5.2	Estimated Number of Components in the BPA Region	5.12
5.3	Distribution Transformers: Categories and Estimated Operating Characteristics of Regional Stock	5.18
5.4	Substation Transformers: Categories and Operating Characteristics	5.19
5.5a	Primary Feeders: Operating Characteristics of Sample Data	5.20
5.5b	Primary Feeders: Categories and Estimated Operating Characteristics of Regional Stock	5.20
5.6a	Transmission Lines: Operating Characteristics of Sample Data	5.21
5.6b	Transmission Lines: Categories and Estimated Operating Characteristics of Regional Stock	5.21

1.0 INTRODUCTION

This report describes the results of one part of the CSEI Assessment Project. The project is being conducted by PNL for the BPA Office of Conservation. A principal objective of the CSEI Assessment Project is to assess the potential for conservation in the T&D systems of BPA's customers. By focusing on customer power systems, the CSEI project complements BPA's ongoing assessments of conservation potential in the residential, commercial, agricultural, and industrial sectors and in its own electric power T&D system. The project's other objective is to respond to Action Item 11.2 in the 1983 Northwest Conservation and Electric Power Plan issued by the Northwest Power Planning Council. In Action Item 11.2, the Council requested that BPA study ways to improve the efficiency of electric power generation, transmission, and distribution. The CSEI project thus focuses on all T&D systems in the Pacific Northwest except systems owned by the federal government.

Determining the magnitude of reducing T&D losses for individual utility systems and for the region's nonfederal transmission and distribution network involves developing conservation supply curves for loss reduction options. These supply curves represent the amount of energy that could be recovered at various economic costs to the region by reducing energy losses on the T&D network. Estimating this conservation resource requires several types of information:

- an inventory of various T&D loss-generating components in the region by component size
- an adequate characterization of existing components stock to determine current energy losses for each size of each component
- a characterization of more efficient components to estimate the loss reduction potential for each size of each component

- an estimation of the costs (capital and labor) to replace inefficient equipment
- an estimation of the age distribution of T&D components.

Most of this information did not exist for the regional system before the CSEI Assessment Project began. Data were available for portions of a limited number of utility systems as a result of utility-sponsored engineering studies and construction plans. However, a characterization of the larger regional network had never been attempted. In addition, while estimates of the quantity of transmission line and substation transformers had been made, they were of questionable reliability and were generally nonspecific. For example, no data existed on the number and sizes of distribution transformers, or on feeder mileage in the region. Therefore, the primary data needed for generating supply curves were not available prior to this study.

These data gaps were filled by collecting a large quantity of data from regional utilities. Initial plans called for a pilot survey to determine the capability of utilities to supply detailed component descriptions and loss-related operating data. This survey was to have been followed by a stratified random sample of utilities or components based on the results of the pilot survey. However, before the latter survey was conducted, nontechnical policy considerations by BPA resulted in a decision to postpone any attempts to develop region-wide T&D efficiency improvement programs. Accordingly, the need for highly detailed cost and conservation potential information diminished. The supply curve estimation proceeded, but was based instead on the data acquired in the pilot survey that are subsequently integrated into two of the three data bases described in this report.

This report presents descriptions and a guide to the use of the data bases developed to support the CSEI Assessment Project. The three data bases, which were developed for use on an IBM microcomputer, contain 1) extensive sales and energy requirement data for all BPA customer utilities for the years 1976 through 1983, and 2) detailed system component characterization information for a large, nonstatistical sample of customer distribution systems in the BPA service area.

This document consists of five sections. Section 2.0 provides an introduction to the characteristics and use of the relational data base system that was used to organize and provide access to the data. General background information on the three data bases developed in this task is also discussed. The data base created to examine the trend of sales, requirements, and losses of BPA customers is described in Section 3.0. The two remaining data bases contain information derived from data that were provided by regional utilities. These two data bases are discussed in Sections 4.0 and 5.0, respectively.

2.0 CSEI DATA MANAGEMENT SYSTEM AND BACKGROUND INFORMATION

The first phase of the CSEI analysis drew upon three large data bases of information about the 170 BPA customers and the components in their distribution systems. These data bases (called INVTRY, QUEST, and SYSTEMS) are discussed in detail in Sections 3.0, 4.0, and 5.0 of this report. At the time this report was written, these data bases required about seven megabytes of storage on a personal computer and contain information for approximately 80 variables. The sales data base (described below) contains time series data for eight years (1976-1983). This data base was developed on IBM personal computers using an RBASE 4000® relational data base system and LOTUS 1-2-3® spreadsheets. These software systems are briefly discussed below.

2.1 RELATIONAL DATA BASES

In general terms, a relational data base is a system for organizing and storing information so that it can be displayed in two-dimensional tables, or relations, that consist of horizontal rows and vertical columns. Tables within a relational data base can be compared, combined, and manipulated for a broad range of uses. Information (records) within a single table also can be sorted or extracted in a variety of ways.

A fundamental concept of relational information management is that while no two rows of data are identical within a given relation, there must be a field or combination of fields with values that will uniquely identify each row. The value of the characteristic (or attribute) contained in this field is labeled a "key" variable. This key feature makes it possible for relations containing rows of different kinds of information to be electronically manipulated a number of different ways.

® RBASE 4000 is a trademark of Microrim, Inc.

® LOTUS 1-2-3 is a trademark of Lotus Development Corporation.

2.2 RBASE 4000® SYSTEM CHARACTERISTICS

The RBASE 4000® series is a relational data base system for microcomputers that is produced and distributed by Microrim, Inc., a Seattle-based software company. RBASE 4000® has a number of features that made it desirable for managing the CSEI Assessment data bases. These features include:

- an ability to manage large quantities of data
- high transportability of data between RBASE 4000® and other data base systems, including DBase II® and III®, spreadsheet software packages such as LOTUS 1-2-3®, and other microcomputer, minicomputer and main-frame systems
- ease of use due to logical structure, format and language syntax
- extensive report writing capabilities
- an ability to interface with programming languages such as FORTRAN and BASIC to increase data manipulation options.

As with any software, there are also certain disadvantages with RBASE 4000® that were encountered in the CSEI analysis. Two problems were identified, but both were easily solved by using the inherent flexibility and high degree of data transportability found in RBASE 4000®. First, RBASE 4000® can perform only limited calculations within the data base. Energy losses for system components using sample data were calculated with other software (primarily LOTUS 1-2-3® and APL). Second, RBASE 4000® limits each defined data base to 400 attribute columns, no matter how many relations are contained in that data base. For those CSEI data bases that contain relations holding large numbers of attributes, this limitation made it difficult to perform manipulations such as appending, intersecting, or similar operations (that resulted in additional relations) after a certain number of relations had been created. This problem was dealt with by periodic "housecleaning" of the data base to eliminate relations that were duplicative or were not needed as a permanent grouping of information.

® DBase II and III are trademarks of Ashton-Tate.

2.3 LOTUS 1-2-3® USES

LOTUS 1-2-3® is a multi-use, spreadsheet-type data analysis and management tool created by LOTUS Development Corporation. It has become one of the leading personal computer business software programs, with application in a wide variety of settings in business, industry, and research. In addition to the use of RBASE 4000® to create the CSEI data base, extensive portions of the data base technical (component) information also reside in LOTUS 1-2-3® spreadsheet files. The LOTUS 1-2-3® format allowed more extensive data manipulation to estimate component loss recovery potential than RBASE 4000®.

More detailed descriptions of the software used for the three data bases are provided in Sections 3.0 through 5.0. Additional information on the software systems used for the CSEI data bases can be obtained from the RBASE 4000® and the LOTUS 1-2-3® User's Manuals. The current version of RBASE 5000® can also be consulted, as this version is compatible with the RBASE 4000® version used to create the CSEI data bases.

2.4 BACKGROUND INFORMATION ON CSEI DATA BASES

The three data bases created to support the conservation assessment tasks of the project are introduced in this section, accompanied by a brief description of their use in the CSEI analysis. In subsequent sections of this report, each data base is presented in greater detail, with examples of the type of information each contains and descriptions of the manner in which it was manipulated and used in the CSEI Assessment Project.

2.4.1 The CSEI Data Bases

The first data base (called INVTRY) was developed to scope the current magnitude of distribution system losses in BPA's Pacific Northwest region. Historical sales and energy requirements data for approximately 170 regional utilities and other direct service customers were received from BPA on magnetic IBM tape. These data, in conjunction with utility identification attributes added by PNL, formed the basis of the first data base. The INVTRY data

® RBASE 5000 is a trademark of MICRORIM, Inc.

base was used to identify historical levels of annual system losses for each BPA customer utility for which matching annual sales (or use) and requirements information were available.

The second and third data bases were created from a voluntary questionnaire sent by PNL to regional utilities to obtain information about the quantity and operating characteristics of components in their distribution systems. The second data base, called QUEST, contains general system operation and loss information obtained from the first portion of the questionnaire. Data that described the important technical specifications and operating characteristics of the key elements in utility distribution systems were obtained in the second portion of the questionnaire and were stored in a third data base (called SYSTEMS). Appendix A contains a copy of the questionnaire that was used. This information was used to help bracket the range of potential loss reduction in the early stages of the project. This third data base contains more extensive technical data on four key distribution system elements: distribution transformers, distribution substation transformers, primary level feeders, and utility-owned transmission lines. The SYSTEMS data base, was used to estimate the number of distribution system components (by size) for the entire region, and to estimate average energy losses of those components.

2.4.2 Use of the CSEI Data Bases

The flexibility and transportability inherent in the RBASE 4000® data base management system allows relations or attributes in any of these three data bases to be exported to other data bases or to other software to facilitate analysis. While each data base had its own particular use in the project, data from all three data bases were used in later stages of the project.

The supplementation, correction, and manipulation of the INVTRY data base provided the information necessary to scope the magnitude and distribution of regional losses experienced by various classes of utilities and to investigate whether sectoral sales could be used to predict utility loss levels. The other two data bases were used primarily to estimate the numbers, current efficiency levels, and loss reduction potentials of the four distribution system components for the region's utilities. These estimates were used to develop a supply curve describing the expected costs and savings of various region-wide

system improvement schemes. Current CSEI analyses of load management approaches were also based in part on these data bases.

3.D THE SALES AND REQUIREMENTS DATA BASE (INVTRY)

This section describes the development of the INVTRY sales and requirements data base. This data base represents an eight-year history of the purchases (and/or the levels of self-generated power for those utilities with their own generating resources) and sales by each utility to five consumer sectors for the years from 1976 to 1983. Once they had been checked and apparent errors corrected, these data were used to estimate system losses for each individual customer and for the region as a whole. For those customers that do not have "sales" [i.e., direct service industries (DSIs) and federal agency customers], losses were estimated using a different approach that is described in Section 3.1.2.

3.1 DATA SOURCES

Average regional electrical losses on the T&D systems of BPA's customers have been estimated by BPA and others for demand forecasts and similar purposes, but comprehensive data on the historical levels and trends of losses for each customer have not been generally available. Although the data needed to estimate losses have existed at BPA in the form of sales and requirements records, these data have not been used previously in a systematic manner to identify individual utility loss patterns or loss recovery potential.

3.1.1 Data Received from BPA

The data provided by BPA were received in the form of four magnetic tapes containing information for the years 1976 through 1982. Sales data for 1983 were also provided when they became available in 1985. The general contents of each tape are described below:

Tape 1--Contains annual sales and number of customers by consumer sector for all BPA customers, including direct service industries (DSIs) and federal customers, for 1976 through 1982. This information was provided to BPA by each customer. Five consumer sectors were represented: domestic, commercial, industrial, irrigation, and "other" (which includes the utility's own usage, municipal uses such as street lighting, and other institutional consumption). The tape files also contained fields with identification information, including

a BPA-assigned customer number, type of utility (municipal, cooperative, public utility district, federal or privately owned), the state in which the customer is located, and the name of its BPA area or district office.

Tape 2--Contains monthly sales, as available, by consumer sector for public utilities in the region (except those located in the BPA Puget Sound Area Office territory) for the period from 1976 through 1983. The data were taken from utility billing records. The actual reporting periods for this data were unknown, and irrigation data were particularly unreliable. These data were not incorporated into the data base.

Tape 3--Contains monthly deliveries by BPA to nongenerating and small public utilities (preference customers) for the period from 1976 through 1983. These data were from BPA billing records, and included the following information: BPA customer number, year, month, maximum peak (kW), billing peak (kW), energy (MWh), and billing in dollars. A FORTRAN program was written to average this information so annual energy requirements for each utility and year could be produced.

Tape 4--Contains monthly requirement data for the investor-owned utilities (IOUs) and the large generating public utilities in the BPA service area. The data were obtained by BPA from the records submitted by the utilities to the Northwest Power Pool, an organization of nineteen utilities and agencies that voluntarily operate their power systems on a coordinated basis. The tape contains the following information: BPA customer number, month, year, number of weeks per month, average power (MW), reading period, peak load, and type of load (firm or nonfirm). The average energy requirements were converted to a value compatible with the requirements of nongenerating utilities by summing and averaging the monthly average megawatts; that result was multiplied by 8760 (the number of hours in a year) to produce requirements in MWh for each year. This tape contained both the requirements of the entire utility system, and the requirements for those portions that were within the BPA service area. Only the latter were used in the INVTRY data base.

1983 Sales Tape--Sales information for 1983 was made available by BPA in the spring of 1985. This data tape provided annual sales information for 121 utilities.

3.1.2 Supplemental Data

BPA has approximately 170 customers. Of that number, 144 are utilities that have retail sales of electricity. The remaining customers are either DSIs or federal agencies (ranging from military installations to Bureau of Reclamation irrigation projects). Although these latter customers constitute approximately 16% of the regional load, little data are available about what portion of the regional loss is attributable to their systems. This information gap was addressed by conducting an informal survey of the 20 DSIs (these industries consumed 14.7% of the regional electrical load in 1982) to determine an average level of electrical loss between the point of bulk power delivery from BPA and its point of use.

The DSI survey data, which contained both estimates and metered losses, indicated that losses for these customers is very low; on the average it is estimated to be only 1.7% of the annual load. Some of the federal entities, which together constitute the remaining group of BPA customers, have loads distributed in a manner similar to that of the utilities (for example, the military bases). Other agencies, such as the Bureau of Reclamation and the Army Corps of Engineers, require power for a single purpose (pumping of irrigation water or dam operation); these customers do not maintain distribution systems. CSEI records on these BPA customers include only their annual requirements, and presently cover only the five-year period from 1979 through 1983. No effort was made to obtain system loss information from these agencies.

3.2 DATA MODIFICATION EFFORTS

Once tape data were transferred to the RBASE 4000® system, several modifications were necessary to facilitate its use in analysis. These modifications are described briefly below.

3.2.1 Customer Identification

Each raw data tape from BPA identified customers using a 3-digit numbering system. Most utility customers had three different numbers (one for each data file or tape). To eliminate confusion and to facilitate the relational

operations of the data base, a 4-letter (alpha) code was assigned to each of the 170 customers. This code is listed in Appendix B and was used in all three data bases.

3.2.2 Error Correction

Three sources of error were possible with the sales and requirement data used for the INVTRY data base. The first two were coding errors made when data were entered on BPA's computer system, and data inaccuracies (errors in the data collected by BPA). Most of these errors were identifiable when anomalous results occurred in preliminary checks. One such check involved summing sales across all consumer sectors and comparing this figure with the amount given for total sales. Another obvious indication of error was when total annual sales exceeded total annual requirements by a significant amount for a given year.

There was some evidence of a third category of possible error that was not addressed. This error is termed the "billing cycle bias," which results because the periods of record for which sales and requirements data are collected do not always coincide. In other words, requirement data may be recorded by calendar weeks or months, while sales are tabulated in 30-day billing periods that may not start at the beginning of the month. These differences can occur because billing periods are often staggered by utilities to make them administratively easier to handle.

To evaluate this error source, time series files were constructed from utility customers' annual sales, requirements, and apparent losses for the 1975 through 1982 period. These files were examined to identify any cyclical variations in losses that would indicate that the billing cycle bias was an important factor in the variation of losses from year to year. While many utilities had loss patterns that showed moderate annual variations (i.e., loss percentages that changed by one or two points) over the eight years, no significant cyclical patterns were apparent. Therefore, while some billing cycle bias is likely to be present in the data, it is assumed that the error introduced by this problem into the gross estimate of losses is small.

3.2.3 Data Merges

In its present form, the INVTRY data base contains information from the tape files, data entered by PNL, and relations (or tables, see Section 2.1) that were the product of relational operations, such as merges or subtractions. These operations are very easily accomplished within RBASE 4000®, and were used for loss reports, for sorting and grouping by certain attributes, and for examining utility clusters. The present size of the data base will allow a moderate amount of additional operations to create new relations. As discussed in Section 2.2, such modifications can be made as long as the number of total attribute (or variable) columns for the whole data base does not exceed 400. This is accomplished by eliminating superfluous relations or storing them in a new data base.

3.3 PRESENT CONTENTS OF INVTRY

The INVTRY data base presently contains four groups of relations. These relations are described below and identified in accompanying tables. In all tables, an 'X' signifies the presence of the attribute (or variable) in the noted table. Refer to Appendix C for a complete explanation of the variables in all three data bases.

3.3.1 Group 1: Identification Relations

The three relations in this group contain identification data for the BPA customers in the CSEI Study. These were used for such activities as cross-referencing in relational operations, for developing mail and phone lists and for storing information on customer contacts. Table 3.1 contains the names and descriptions, data type, formatted field length, and present key designations for attributes in these three relations. The key designation for any attribute can be added or deleted at any time, and is used to facilitate relational operations such as intersects, unions, or subtractions.

3.3.2 Group 2: Original Data Relations

These five relations (listed in Table 3.2) contain data from the tapes in their original form, although FILE3 and ANNGEN data have been converted from monthly to annual requirements.

TABLE 3.1. Identification Relations in INVTRY

Attributes				Relation Names		
Name	Type	Length	Key	ALLID	NAMENUMS	CONTACTS
CODE	TEXT	4 characters	Yes	X	X	X
CUSTNO.1	INTEGER	1 value(s)		X	X	
CUSTNO.2	INTEGER	1 value(s)		X	X	
CUSTNO.3	INTEGER	1 value(s)		X	X	
CUSTNO.4	INTEGER	1 value(s)		X	X	
UTYPE	TEXT	1 characters		X		
NUMBER	INTEGER	1 value(s)		X		
NAME	TEXT	40 characters		X	X	
ADDRESS1	TEXT	40 characters		X		
ADDRESS2	TEXT	40 characters		X		
CITY	TEXT	25 characters		X		
STATE	TEXT	2 characters		X		
ZIPCODE	TEXT	6 characters		X		
CONTACT	TEXT	25 characters				X
TITLE	TEXT	40 characters				X
PHONE	TEXT	12 characters				X
SUBJECT	TEXT	40 characters				X
<u>Current Number of Rows</u>				171	171	184

3.3.3 Group 3: Sales and Requirements Relations

This group consists of four primary relations that contain merged information for each customer. These relations include identifiers, sector data (numbers of consumers and sales by sector), and total annual sales and requirements for 1976 through 1983. Three additional relations hold partial data (e.g., sales or requirements combined with identifiers) that were used for repetitive loss analysis operations. Table 3.3 contains the full description of all seven relations.

TABLE 3.2. Original Data Relations in INVTRY

Attributes				Relation Names					
Name	Type	Length	Key	FILE1	FILE3	FILE4	ANNGEN	SALES83	
CUSTNO.1	INTEGER	1 value(s)		X					X
CUSTNO.2	INTEGER	1 value(s)							X
UTYPE	TEXT	1 characters		X					
STATE	TEXT	2 characters		X					
FERC	TEXT	1 characters		X					
DATATYPE	TEXT	1 characters		X					
OFFICE	TEXT	1 characters		X					
GROUP	TEXT	1 characters		X					
YEAR	TEXT	2 characters		X	X	X	X		X
DOMCUST	INTEGER	1 value(s)		X					X
DOMESTIC	REAL	1 value(s)		X					X
IRRCUST	INTEGER	1 value(s)		X					X
IRRIG	REAL	1 value(s)		X					X
COMCUST	INTEGER	1 value(s)		X					X
COMMERC	REAL	1 value(s)		X					X
INDCUST	INTEGER	1 value(s)		X					X
INDUSTRY	REAL	1 value(s)		X					X
UTHCUST	INTEGER	1 value(s)		X					X
OTHER	REAL	1 value(s)		X					X
TOTCUST	INTEGER	1 value(s)		X					X
SALESMWH	REAL	1 value(s)		X					X
CUSTNO.3	INTEGER	1 value(s)			X				X
REQMWH	REAL	1 value(s)			X		X		
CUSTNO.4	INTEGER	1 value(s)	yes			X	X		X
region	TEXT	8 characters				X	X		
month	INTEGER	1 value(s)				X			
calweeks	INTEGER	1 value(s)				X			
avemwent	REAL	1 value(s)				X			
rpmmonth	INTEGER	1 value(s)				X			
rpday	INTEGER	1 value(s)				X			
hour	INTEGER	1 value(s)				X			
peakmw	REAL	1 value(s)				X			
REQPEAK	REAL	1 value(s)					X		
CODE	TEXT	4 characters							X
NAME	TEXT	40 characters							X
Current Number of Rows				1068	866	2442	225		121

TABLE 3.3. Sales and Requirements Relations

Attributes				Relation Names				
Name	Type	Length	Key	IOUS&R	PUBS&R	PUBS&R83	PREQ83	IOU83
CUSTNO.1	INTEGER	1 value(s)		X	X	X		
CUSTNO.2	INTEGER	1 value(s)		X	X	X		
CUSTNO.3	INTEGER	1 value(s)		X	X	X	X	
CUSTNO.4	INTEGER	1 value(s)	yes	X	X	X		X
REGION	TEXT	8 characters		X				
YEAR	TEXT	2 characters		X	X	X	X	X
REQMWH	REAL	1 value(s)		X	X	X	X	X
CODE	TEXT	4 characters		X	X	X		
NAME	TEXT	40 characters		X	X	X		
UTYPE	TEXT	1 characters		X	X	X		
STATE	TEXT	2 characters		X	X	X		
FERC	TEXT	1 characters		X	X	X		
DATATYPE	TEXT	1 characters		X	X	X		
OFFICE	TEXT	1 characters		X	X	X		
GROUP	TEXT	1 characters		X	X	X		
DOMCUST	INTEGER	1 value(s)		X	X	X		
DOMESTIC	REAL	1 value(s)		X	X	X		
IRRCUST	INTEGER	1 value(s)		X	X	X		
IRRIG	REAL	1 value(s)		X	X	X		
COMCUST	INTEGER	1 value(s)		X	X	X		
COMMERC	REAL	1 value(s)		X	X	X		
INDCUST	INTEGER	1 value(s)		X	X	X		
INDUSTRY	REAL	1 value(s)		X	X	X		
OTHCUST	INTEGER	1 value(s)		X	X	X		
OTHER	REAL	1 value(s)		X	X	X		
TOTCUST	INTEGER	1 value(s)		X	X	X		
SALESMWH	REAL	1 value(s)		X	X	X		
<u>Current Number of Rows</u>				185	912	105	105	20

3.3.4 Group 4: Supplementary Data Relations

Group 4 contains three relations with data collected by PNL to supplement the tape data, which as noted above, lacked certain information on several classes of BPA customers. The relation DSIREQS contains information collected by BPA on the annual requirements for the 20 DSI customers for the years 1976 through 1983. In addition, this relation contains monthly peak requirement data. The relation SECS&R contains data for 16 customers that either purchase their requirements from other regional utilities or generate their own supply, and are therefore not served by BPA. These are primarily small municipal systems, and PNL obtained data on their annual sales and requirements by contacting them directly. For eight of these customers, only sales data were obtainable. The final relation in this group is PFEDS&R, which is a collection of all information available from BPA about distribution of the loads of the six federal agency customers. Table 3.4 lists the contents of these relations.

In addition to sorting utilities by their ownership/generating status, utilities were also categorized by size and sales characteristics. This differentiation was obtained by performing a cluster analysis (described in Appendix D). Eleven clusters were formed in the original analysis. However, it was found that a less refined level of clustering was more useful for statistical purposes. Therefore, the analysis used a cluster of four types of utilities taken from a point closer to the middle of the cluster analysis "trees." Cluster 1 contains small utilities (primarily municipal systems with fewer than 5,000 customers) that do not have significant irrigation loads. Cluster 2 utilities are also small utilities (in terms of their total sales and customers), but that do serve sizable irrigation loads. Cluster 3 contains medium-sized utilities with mixed commercial, industrial, and irrigation loads. Utilities in Cluster 4 are the largest in the region and also serve mixed loads. Most generating utilities fall into this latter category.

TABLE 3.4. Supplementary Data Relations

Attributes				Relation Names		
Name	Type	Length	Key	DSIREQS	SECS&R	PFEDS&R
CODE	TEXT	4 characters		X	X	X
NAME	TEXT	40 characters		X	X	X
YEAR	TEXT	2 characters		X	X	X
REQMWH	REAL	1 value(s)		X	X	X
PEAKMO	TEXT	3 characters		X		
PEAKREQ	REAL	1 value(s)		X		
CUSTNO.1	INTEGER	1 value(s)			X	X
CUSTNO.2	INTEGER	1 value(s)			X	
CUSTNO.3	INTEGER	1 value(s)			X	
CUSTNO.4	INTEGER	1 value(s)			X	
UTYPE	TEXT	1 characters			X	
STATE	TEXT	2 characters			X	X
FERC	TEXT	1 characters			X	
DATATYPE	TEXT	1 characters			X	
OFFICE	TEXT	1 characters			X	
GROUP	TEXT	1 characters			X	
DOMCUST	INTEGER	1 value(s)			X	
DOMESTIC	REAL	1 value(s)			X	X
IRRCUST	INTEGER	1 value(s)			X	
IRRIG	REAL	1 value(s)			X	X
COMCUST	INTEGER	1 value(s)			X	
COMMERC	REAL	1 value(s)			X	X
INDCUST	INTEGER	1 value(s)			X	
INDUSTRY	REAL	1 value(s)			X	X
OTHCUST	INTEGER	1 value(s)			X	
OTHER	REAL	1 value(s)			X	X
TOTCUST	INTEGER	1 value(s)			X	
SALESMWH	REAL	1 value(s)			X	
DELPT	TEXT	20 characters				X
Current Number of Rows				161	122	

3.4 SUMMARY OF INVTRY DATA

The INVTRY data base was used in the CSEI study for a number of analyses, including the initial assessment of system and regional losses by utility and utility type. Some of the more significant results are depicted in the pie charts shown in Figure 3.1.

Figure 3.1 shows the proportion of losses and requirements for 1983 by type of utility. In these tables, IOU is an acronym for investor-owned utilities, GP is a generating public utility, NGP is a nongenerating public utility (i.e., its requirements are fully supplied by BPA or another utility), and DSI denotes direct service industries (primarily aluminum smelters). The category of OTHER consists of the federal agencies supplied by BPA (see Section 3.3.4). This group represented too small a portion of the regional losses to be graphically displayed in the loss pie chart.

These graphs show some interesting aspects of distribution system losses in the BPA region. Both the generating public utilities and investor-owned utilities are responsible for a disproportionate amount of regional losses. This discrepancy is particularly noticeable in the latter group, which required 47.5% of the region's power in 1983, but was responsible for over 60% of the total losses. This situation was not closely analyzed, but the high proportion of losses is probably because these utilities operate extensive transmission facilities that incur losses that are included in this study as "system" losses. Nongenerating utilities and DISs, on the other hand, operate only a very small fraction of the region's transmission system. Power to these utilities is delivered over the BPA-owned transmission grid, and the losses for this part of the regional system were not included in CSEI calculations.

The DSIs show losses that are disproportionately small for a related reason. Because they are typically located very near BPA bulk delivery points, there is no "distribution system," to speak of, for these customers, and thus extremely low distribution system losses occur.

a. Requirement (MWh)

b. Losses (MWh)

FIGURE 3.1. 1983 Requirements and Losses by Customer Type

4.D SURVEY PART 1: THE QUEST DATA BASE

The two remaining data bases were created with information gathered in a survey of utilities conducted in the fall of 1984. This section of the report describes and discusses QUEST, which is the first of these two data bases.

4.1 BACKGROUND INFORMATION

During the fall of 1984, a mailed survey questionnaire was sent to the chief system engineers of BPA's utility customers to request information on the technical and operational characteristics of their distribution systems (see Appendix A). The first portion of the survey was intended to collect general information on utility characteristics and operations that related to system efficiency. This part of the questionnaire was designed to be answered relatively easily by the utility engineers and to not require reference to detailed system records. General information in the following areas was requested:

- requirements information for 1983
- general supply relationships with other utilities
- bulk delivery point power factor information
- estimates of the percent of distribution system losses by component
- estimates of the potential for system loss reductions with efficiency improvements
- average yearly equipment replacement rates and typical costs
- loss studies, work plans, and annual reports as available.

Of the 144 utilities included in the survey, 67 (47%) provided responses to one or more sections of the questionnaire. Table 4.1 provides an indication of the responses to various segments of questionnaire. A "0" indicates that no information was received. The table lists utilities by name and by the alpha code used in the data bases. Headings across the top of the table refer to relations that were created from the data. The clustering system described previously was again found to be helpful in characterizing the types of

TABLE 4.1. Response to Request for Information, by Type of Information and Utility Cluster

Code(a)	Cluster(a)	Name(a)	OREPORTS(b)	OREOS(c)	OSYSCHAR(d)	OLOSS(e)	OEOPREPL(f)	OPARTB(g)	TALLY
MLAP	1	Montana Light and Power	1	1	1	1	1	0	5
RURL	1	Rurley Municipal Distribution System	0	1	1	1	1	0	4
CCAS	1	City of Cascade Locks	1	0	0	1	0	1	3
EMPL	1	Elmhurst Mutual Power and Light	0	1	0	1	0	0	2
LLAP	1	Lakeview Light and Power	0	1	1	0	0	0	2
MCCLP	1	McCleary Light and Power	1	1	0	0	0	0	2
COCO	1	City of Coulee Dam	1	0	0	0	0	0	1
CMON	1	City of Monmouth	1	0	0	0	0	0	1
TOM	1	Town of Milton	0	0	0	0	0	0	0
WORL	1	City of Worley	0	0	0	0	0	0	0
COCE	1	City of Chewelah	0	0	0	0	0	0	0
COED	1	City of Declo	0	0	0	0	0	0	0
CAEB	1	Canby Electric Board	0	0	0	0	0	0	0
EPL	1	Eatonville Power and Light	0	0	0	0	0	0	0
PSPR	1	Puget Sound Power and Light, PT. ROBE	0	0	0	0	0	0	0
CDRA	1	City of Drain	0	0	0	0	0	0	0
TWAT	1	Town of Waterville	0	0	0	0	0	0	0
PENL	1	Penninsula Light Company	0	0	0	0	0	0	0
CWSL	1	Cashmere Water Sewer and Light	0	0	0	0	0	0	0
CSUM	1	City of Sumas	0	0	0	0	0	0	0
PLUM	1	City of Plummer	0	0	0	0	0	0	0
COF	1	City of Fircrest	0	0	0	0	0	0	0
SODA	1	City of Soda Springs	0	0	0	0	0	0	0
ALTP	1	Atlanta Power Company	0	0	0	0	0	0	0
AMLC	1	Alder Mutual Light Company	0	0	0	0	0	0	0
RCL	1	Blaine City Light	0	0	0	0	0	0	0
TOST	1	Town of Stellacoom	0	0	0	0	0	0	0
REU	1	Ruston Electric Utility	0	0	0	0	0	0	0
WESA	1	City of Weiser	0	0	0	0	0	0	0
DUPT	1	Dupont	0	0	0	0	0	0	0
MINI	1	City of Minidoka	0	0	0	0	0	0	0
CASH	1	City of Ashland	0	0	0	0	0	0	0
TANN	1	Tanner Electric	0	0	0	0	0	0	0
PLWC	1	Parkland Light and Water Company	0	0	0	0	0	0	0
Sum Cluster 1 = 40			Percent Cluster 1 Responding to Part 2 = 10.0						
BREA	2	Benton Rural Electrification Assoc.	1	1	1	1	1	1	6
LOST	2	Lost River Electrification Coop.	1	1	1	1	1	1	6
ICLP	2	Idaho County Light and Power Cooperative	1	1	1	1	1	1	6
MEC	2	Midstate Electrification Cooperative	1	1	1	1	1	1	6
VEC	2	Vigilante Electric Cooperative	1	1	1	1	1	1	6
NVEC	2	Nespelem Valley Electric Cooperative	0	1	1	1	1	1	5
VID	2	Vera Irrigation District	1	1	1	1	1	0	5
CPCA	2	Columbia Power Cooperative Assoc.	1	1	1	1	0	1	5
WEC	2	Wasco Electrification Cooperative	0	1	1	1	1	1	5
KEC	2	Kootenai Electrification Cooperative	1	1	1	1	1	0	5
PACP	2	PUD #2 of Pacific County	0	1	1	1	1	1	5

(a) See text.

(b) Identification and loss study information.

(c) 1982 and 1983 requirement by source.

(d) Power factor characteristics.

(e) Utility loss estimate by component.

(f) Equipment replacement information.

(g) Response to technical component questions.

TABLE 4.1. (contd)

Code(a)	Cluster(a)	Name(a)	OREPORTS(b)	OREOS(c)	OSYSCHAR(d)	OLOSS(e)	OEOPREPL(f)	OPARTS(g)	TALLY
LECM	2	Lincoln Electric Cooperative (MONT)	1	1	1	1	1	0	5
RIIRE	2	Rural Electric Company	1	1	1	1	1	0	5
CBFY	2	City of Bonners Ferry	0	1	1	1	1	1	5
CONP	2	Consumers Power, Inc.	12	0	0	1	1	1	4
BLCC	2	Blachly-Lane County Cooperative	0	1	1	1	0	1	4
DEC	2	Douglas Electrification Cooperative	1	0	0	1	1	1	4
OCEC	2	Okanogan County Electric Cooperative	1	1	1	1	0	0	4
HEC	2	Harney Electrification Cooperative	0	1	1	1	0	1	4
GEC	2	Glacier Electric Cooperative	0	1	1	1	0	1	4
EMEC	2	East End Mutual Electrification Coop.	0	1	1	1	1	0	4
MISS	2	Missoula Electric Cooperative	0	1	1	0	1	1	4
CENC	2	Central Electric Cooperative	1	1	1	0	0	1	4
RUPT	2	Rupert	0	1	1	1	1	0	4
LEC	2	Lane Electric Cooperative	1	0	0	0	1	1	3
SSEL	2	South Side Electric Lines	1	0	0	1	1	0	3
RREC	2	Raft River Rural Electric Cooperative	0	1	1	0	0	0	2
CHEY	2	City of Heyburn	1	1	0	0	0	0	2
MEWC	2	Modern Electric Water Company	1	0	0	1	0	0	2
LECM	2	Lincoln Electric Cooperative (WASH.)	0	0	0	0	0	0	0
REC	2	Riverside Electric Company	0	0	0	0	0	0	0
OHOP	2	Ohop Mutual Light Company	0	0	0	0	0	0	0
SREC	2	Salmon River Electric Cooperative	0	0	0	0	0	0	0
CIRO	2	Consolidated Irrigation District	0	0	0	0	0	0	0
CPN	2	CP National	0	0	0	0	0	0	0
PPC	2	Prairie Power Cooperative	0	0	0	0	0	0	0
WOEC	2	West Oregon Electrification Cooperative	0	0	0	0	0	0	0
RCEC	2	Ravalli County Electric Cooperative	0	0	0	0	0	0	0
PPLS	2	Pacific Power and Light--Sandpoint	0	0	0	0	0	0	0
WREC	2	Wells Rural Electric Cooperative	0	0	0	0	0	0	0
CBUN	2	City of Bandon	0	0	0	0	0	0	0
FLEC	2	Flathead Electric Cooperative	0	0	0	0	0	0	0
ULPC	2	Unity Light and Power Company	0	0	0	0	0	0	0
OWC	2	Farmers Electric Company	0	0	0	0	0	0	0
NLI	2	Northern Lights Inc.	0	0	0	0	0	0	0
OWEC	2	Fall River Rural Electrification Coop	0	0	0	0	0	0	0
CALB	2	City of Albion	0	0	0	0	0	0	0
CBEC	2	Columbia Basin Electric Cooperative	0	0	0	0	0	0	0
CPNB	2	CP-National (John Day/Burns)	0	0	0	0	0	0	0
MFLP	2	Milton-Freewater Light and Power	0	0	0	0	0	0	0
COLR	2	Columbia REA	0	0	0	0	0	0	0
HREC	2	Hood River Electrification Cooperative	0	0	0	0	0	0	0
PPLM	2	Pacific Power and Light--Montana	0	0	0	0	0	0	0
SPP	2	Sierra Pacific Power	0	0	0	0	0	0	0
SVEC	2	Surprise Valley Electrification Coop.	0	1	1	1	1	1	5
BIGR	2	Big Bend REA	0	1	1	1	1	1	5
CPC	2	Clearwater Power Company	1	1	1	1	0	1	5

SUM Cluster 2 = 57

Percent Cluster 2 Responding to Part 2 - 37.0

FERP	3	Ferry County PUD	1	1	1	1	1	1	6
UECA	3	Umatilla Electric Cooperative Assoc.	1	1	1	1	1	1	6
LVPL	3	Lower Valley Power and Light	1	1	1	1	0	1	5
RESO	3	Richland Energy Services Department	1	1	1	0	1	1	5
KLIP	3	Klickitat County PUD	0	1	1	0	1	1	4
COM	1	Centralia Municipal Hydro	0	1	1	1	1	1	5
COCH	1	City of Cheney	1	1	1	1	1	0	5

TABLE 4.1. (contd)

Code(a)	Cluster(a)	Name(a)	OREPORTS(b)	OREOS(c)	OSYSCHAR(d)	QLOSS(e)	OEOPREPL(f)	QPARTS(g)	TALLY
COF	1	City of Ellensburg	1	1	1	1	1	0	5
CFOR	1	City of Forrest Grove	0	1	1	1	1	1	5
QPLC	1	Orcas Power and Light Company	1	1	1	0	1	1	5
SE	1	Salem Electric	1	1	1	1	1	0	5
SKAP	3	Skamania County PUD	1	0	0	1	1	0	3
GRTP	3	Grant County PUD	0	1	0	1	0	1	3
TILP	3	Tillamook PUD	1	0	0	1	1	0	3
INPL	3	Inland Power and Light	1	0	0	0	0	1	2
LEWP	3	Lewis County PUD	0	0	0	0	0	0	0
EMEP	3	Emerald PUD	0	0	0	0	0	0	0
WHAP	3	Whatcom County PUD	0	0	0	0	0	0	0
CLAP	3	Clallam County PUD	0	0	0	0	0	0	0
MAPI	3	Mason County PUD #1	0	0	0	0	0	0	0
POCP	3	Pend Oreille County PUD	0	0	0	0	0	0	0
NWCP	3	Northern Wasco County PUD	0	0	0	0	0	0	0
KITP	3	Kittitas County PUD	0	0	0	0	0	0	0
WAHP	3	Wahkiakum County PUD	0	0	0	0	0	0	0
CCEC	3	Coos-Curry Electrification Cooperative	0	0	0	0	0	0	0
CCHP	3	Chelan County PUD	0	0	0	0	0	0	0

Sum Cluster 3 = 20

Percent Cluster 3 Responding to Part 2 = 35.0

SCL	4	Seattle City Light	1	1	1	1	1	1	6
FRAP	4	Franklin County PUD	1	1	1	1	1	1	6
COPA	4	City of Port Angeles	1	1	1	1	1	1	6
DOVP	4	Douglas County PUD	1	1	1	1	1	1	6
PSPL	4	Puget Sound Power and Light	1	1	0	1	1	1	5
SNOP	4	Snohomish PUD	1	1	0	1	1	1	5
OKAN	4	Okanogan County PUD	0	1	1	0	1	1	4
COWP	4	Cowlitz County PUD	1	0	0	1	1	1	4
CLKP	4	Clark County PUD	1	1	0	1	0	1	4
SPUR	4	Springfield Utility Board	1	0	0	1	1	1	4
CITI	4	Citizens Utilities Company	1	1	0	1	1	0	4
RENK	4	Benton County PUD	1	0	0	1	1	1	4
CMCM	4	City of McMinnville	1	0	0	1	1	1	4
PGE	4	Portland General Electric	1	0	0	1	0	1	3
CTAC	4	City of Tacoma	1	0	0	1	1	0	3
CLTP	4	Clatskanie PUD	1	0	0	1	1	0	3
EWEP	4	Eugene Water and Electric Board	0	0	0	0	0	0	0
MPC	4	Montana Power Company	0	0	0	0	0	0	0
MAP3	4	Mason County PUD #3	0	0	0	0	0	0	0
IDFL	4	Idaho Falls Electric Light Department	0	0	0	0	0	0	0
PPLO	4	Pacific Power and Light--U-W-&C	0	0	0	0	0	0	0
GRYP	4	Grays Harbor County PUD	0	0	0	0	0	0	0
IPC	4	Idaho Power Company	0	0	0	0	0	0	0
UP&L	4	Utah Power and Light	0	0	0	0	0	0	0
WWPC	4	Washington Water Power Company	0	0	0	0	0	0	0
CLNP	4	Central Lincoln PUD	0	0	0	0	0	0	0

Sum Cluster 4 = 26

Percent Cluster 4 Responding to Part 2 = 50.0

	REPORTS	REOS	CHAR	LOSS	EQPT	PART B
Sum of Responses by Section	50	53	45	57	50	45
Response by Section as Percent of All Utilities	34.97	37.05	31.47	39.86	34.97	31.47

utilities that responded. The first five headings refer to segments of Part 1 of the questionnaire. The notation "Part 2" refers to responses obtained in the second, technical portion of the questionnaire. A copy of the information request is included as Appendix A to this report. Most of the information on this portion of the questionnaire was entered into the data base in either RBASE 4000® or LOTUS 1-2-3® form. The general information responses from Part 1 are reviewed in the remainder of this section.

4.2 DATA QUALITY

The information collected in Part 1 of the questionnaire was viewed primarily as a general indication of utility concern with system losses and the extent to which their equipment replacement practices were aimed at loss reduction. Much of the information that was obtained on loss allocation was apparently based on opinions of individuals in the utilities surveyed. Therefore, information may be of limited reliability for either definitive loss allocation by component or for estimating the extent that system efficiency improvements are being achieved in the normal course of system maintenance and operations. A comparison of the utilities' responses also indicated that some of the questions may have been misinterpreted by the respondents. However, when used in conjunction with data from the CSEI institutional survey of utilities (Hendrickson and Darwin 1986) this perceptual information helps to illustrate the views that utility staff have of their own systems.

4.3 CONTENTS OF THE QUEST DATA BASE

The information obtained from Part 1 of the survey was coded and entered into eight relations that form the QUEST data base. These relations and their contents are summarized below.

Relation QIDENT--This relation contains the name and title of the utility staff member contacted (usually the chief engineer) and the date of any loss study, loss-reduction work plan, or other related reports that the utility may have prepared. Of the 67 utilities that provided information in this section, 23 (34%) had prepared loss studies for some portion of their systems in recent years. Work plans were prepared by 40 utilities for projects where

efficiencies were improved. Related reports or studies had been conducted by 28 utilities. The fact that only 9 out of 67 utilities indicated that both loss studies and work plans for improvements that addressed those losses were conducted in recent years is open to interpretation; it is possible that this response indicates quite a low level of construction and related activities specifically designed to reduce losses at this time. Reports received in response to this portion of the questionnaire are contained in the CSEI library utility files, which are maintained at PNL.

Relation QREQS--This relation contains 1982 and 1983 data on each utility's requirements, in MWh and by source (BPA, self, other utility); it also contains MWh supplied by the utility to other utilities for those years.

Relation QPODPF--Information was collected on the average, high, and low power factors at the point of delivery for each utility in 1983. The high and low power factors are accompanied by the month of the year in which they occurred. Data for 45 utilities and their points of delivery were obtained and entered in this relation.

Relations QLOSSES and QLOSSEST--Questions concerning the estimated allocation of system losses by component, estimates of loss reduction potential, and any comments about loss reduction efforts are coded in QLOSSES. The relation QLOSSEST contains the distribution of estimated losses by component, and the 1982 sales and losses in MWh. Fifty-five utilities responded to this segment of the questionnaire. Utilities were asked to estimate the contribution to their systems' total losses in six categories: feeders, distribution transformers, secondary feeder systems, transmission/subtransmission lines, substation transformers, and other causes. The losses in this set of relations are slightly different from those used for the study in general, in that utilities were asked to estimate losses as a percentage of sales, rather than of requirements. This definition was used because the pretest showed that many utilities commonly use sales, not requirements, as the basis for assessing their loss levels.

Relation QEQREPL--A final portion of the set of general questions in Part 1 dealt with utility equipment replacement. Information was obtained from 50 utilities on the number of components replaced, features of the

replacements, and approximate costs (both for the component and for the installation). These data were entered into the QUEST data base as text in fixed field format because the data were provided in a variety of forms.

Relations QCOUNT AND QCONTENT--These two relations contain tallies of the utilities that responded to the questionnaire. In QCONTENT, the tally is distributed by the portion of the questionnaire (reports, requirements, power factor characteristics, loss estimates, equipment replacement from Part 1 and component operating characteristics from Part 2).

The relation QCOUNT is simply a listing of all utilities accompanied by a field that indicates whether they responded to the survey.

4.4 HIGHLIGHTS OF QUEST DATA

Some of the more interesting highlights of the information obtained in Part 1 of the questionnaire are summarized in the following tables and figures. Caution should be used before assuming that any trends or other implications of these data are truly representative of Pacific Northwest utilities as a whole. Nevertheless this information is valuable in that it provides the most comprehensive characterization of the regional distribution system yet available.

4.4.1 Estimated Losses by Component

Utilities were asked to estimate the fraction of their systems' total losses contributed by feeders, distribution transformers, secondary feeder systems, transmission/subtransmission lines, substation transformers, and other causes. Figure 4.1 displays a histogram of these estimates for the responding utilities. Most respondents indicated that these allocations were made by "educated guessing." The next survey question requested the respondent estimate the extent to which total system losses could be reduced by replacing existing components with more efficient components that 1) could be economically justified and 2) could be used if economics (rate of return) were not considered. Table 4.2 lists the loss estimates provided on the questionnaire along with the 1982 calculated losses (requirements minus sales as a percentage of sales, utility's estimate). Table 4.2 also lists the utilities' estimates of potential loss reduction through equipment replacement. On average, the

FIGURE 4.1. Utilities' Estimates of Losses

utility engineers that responded to this question felt that loss reductions of 20 to 25% were economically justifiable, but that far greater reductions (50% or more) were technically possible.

The comment section provided some of the most interesting information on current utility practices with regard to system efficiency. Fifty-nine utilities responded to the question, "Are loss reduction measures being systematically installed as part of a regular system improvement plan? If yes, what actions have been taken in 1984 or are planned for 1985?" The distribution of their responses is provided in Table 4.3.

The responses to these questions indicate that a substantial amount of ongoing efficiency improvements are probably being made by a majority of utilities, but it was also clear that many of the component upgrades were typically done as part of a regular replacement schedule, or when costs of losses combined with other problems (e.g., reliability) or system growth justified outright replacement. Whether the response to this question indicates a general

TABLE 4.2. Utilities' Estimates of Loss Reduction Potential

Utility	1982 Loss (Percent) ^(a)	Economically Justifiable Loss Reduction ^(b)	Technically Feasible Loss Reduction ^(b)
Big Bend REA	7.9	6.0	4.5
Blachly-Lane County Coop.	7.9	7.6	7.4
Benton REA	8.6	6.0	4.0
Burley	7.0	4.2	3.5
City of Cascade Locks	6.1	2.5	1.8
Citizens Utility Company	7.5	5.5	4.5
Clark County PUD	7.2	4.0	3.5
Centralia Municipal Hydro	6.3	4.0	2.5
City of Ellensburg	4.7	3.7	2.7
Cowlitz County PUO	1.9	--	--
Clearwater Power Co.	8.4	7.4	6.4
City of Tacoma	7.9	7.4	--
Douglas Elec. Coop.	10.3	9.3	--
East End Mutual Elec. Coop.	7.6	5.6	5.6
Elmhurst Mutual Power and Light	4.8	3.6	2.4
Ferry County PUO	7.9	4.0	2.0
Franklin County PUD	6.5	5.0	3.0
Glacier Elec. Coop.	14.4	8.8	8.5
Idaho County Light and Power	11.6	9.0	7.0
Kootenai Elec. Coop.	9.2	9.2	8.1
Lincoln Elec. Coop. (MT)	11.1	9.2	8.2
Nespelem Valley Elec. Coop.	7.7	7.0	4.0
Orcas Power and Light Co.	13.5	12.0	10.0
Puget Sound Power and Light	8.2	6.0	4.0
Rupert	10.0	5.0	4.0
Salem Electric	5.6	--	4.4
Skamania County PUD	4.5	4.0	4.0
Seattle City Light	7.6	5.0	3.0
Snohomish County PUD	4.6	--	4.0
South Side Elec. Lines	11.0	4.0	2.0
Springfield Utility Board	3.7	3.0	2.0
Surprise Valley Elec. Coop.	9.7	--	4.0
Tillimook County PUD	6.6	5.0	2.5
Vera Irrigation District	5.9	2.9	1.0

(a) Estimated as a percent of sales.

(b) Level to which losses could be reduced, as a percent of sales.

TABLE 4.3. Distribution of Utility Responses: Efficiency Improvements in 1984 and 1985

Utilities Responding to Question	59
Utilities with Systematic Loss-Reduction Efforts	48
Utilities with No Systematic Loss-Reduction Efforts	11

<u>Loss Reduction Measure</u>	<u>Number of Times Mentioned</u>
Reconductoring with Larger Size	34
Replacement with Higher Efficiency Transformer	29
Capacitance Added	14
Voltage Increases	12
Other Feeder System Improvements ^(a)	12
Meter Checking or Replacement Program	6

(a) Includes reconfiguration of feeder system, right-of-way maintenance, adding substations, shortening feeders and secondary lines, installing underground line, and adding phases.

trend among most Pacific Northwest utilities is unclear, because the sample was not statistical and the respondents may have been a self-selected group (i.e., those willing to respond). More information needs to be collected using statistically-appropriate techniques before any conclusions can be reached about voluntary T&D system efficiency improvements made by regional utilities.

4.4.2 Power Factor and Equipment Replacement

Power factor information was requested so a general idea of the amount of reactive power on the regional system at various times of the year could be obtained. Power factor information at specific points of delivery for all BPA full service customers is also available from BPA's Office of Power and Resource Management, where it is used for billing purposes. Table 4.4 shows a summary of the power factor information for 1983 collected by the survey.

Fifty utilities provided information on equipment replacement. The average quantities and costs of each component (feeders, distribution transformer, and substation transformers) stated in the responses varied widely, making it difficult to notice any trends or to identify possible causes of the

TABLE 4.4. Summary of Power Factor by Point of Delivery

<u>Utility Cluster</u>	<u>Average High Power Factor</u>	<u>Month</u>	<u>Average Low Power Factor</u>	<u>Month</u>
1	0.98	January	0.95	August
2	0.99	January	0.96	August
3	0.99	December, January	0.96	August
4	0.99	January	0.93	August

All PODS:

Average High Power Factor	0.99
Most Frequently Stated Month of High Power Factor	January
Average Low Power Factor	0.96
Most Frequently Stated Month of Low Power Factors	August

variation. The overall impression gained from this response is that equipment replacement is taking place at a relatively slow pace at the present time. In view of the rapid growth of many Pacific Northwest utilities during the 1960s and 1970s, the current situation of electricity surpluses, and much slower regional growth, this reduced rate of equipment replacement is not surprising.

5.0 SURVEY PART 2: THE SYSTEMS DATA BASE

The second portion of the 1984 survey sent to BPA utility customers requested detailed technical and operational descriptions of four distribution system components: substation transformers, distribution transformers, primary feeders, and utility-owned transmission/subtransmission lines.

This data base was used primarily to estimate the total regional stock of each of the four components. This information was used in the calculation of component replacement supply curves for the Pacific Northwest, which were developed by Tepel et al. (1986). A description of the SYSTEMS data base and a summary of the derived component stock information are provided in this section.

5.1 CONTENTS OF THE SYSTEMS DATA BASE

The technical component characteristic and operating information data base was originally created by transferring data from questionnaires onto a series of LOTUS 1-2-3® worksheets to facilitate quality assurance procedures. Once data were checked for accuracy and uniformity (i.e., in terms of the units of measurement used), a relation was created in RBASE 4000® for each of the four components of interest. Utility cluster identity was added to all relations; 1983 sales information was also appended where available.

The data required extensive manipulation, sorting, and, in particular, intermediate calculations to prepare them for use in the supply curve analysis. Data in the component relations were therefore transferred back to the Lotus 1-2-3® spreadsheet format at this point. This intermediate phase of data preparation generally involved the same steps for all components:

1. correcting and checking of second-stage data
2. sorting of data rows by cluster, utility, and component size category
3. calculating the total number of components by size category for each utility that responded to the survey
4. eliminating rows that lacked information necessary for calculating component efficiency

5. calculating component efficiency/losses for each row of data
6. calculating weighted averages of efficiency/losses by component size category.

As a result, three categories of data exist in the SYSTEMS data base: 1) the original "raw" data in LOTUS 1-2-3® spreadsheets, 2) the original sorted data in RBASE 4000® component relations, and 3) the manipulated and corrected data in LOTUS 1-2-3® files. In some cases a single final LOTUS 1-2-3® file contains all the corrected information for all sizes of a given component; in others, separate files were prepared for different size categories. Table 5.1 lists the names of the LOTUS 1-2-3® or RBASE 4000® files/rerelations in the latter two categories. The tables are presented in matrix form with an "X" indicating the fields/attributes that each file contains. Description's of the variables (including their units of measurement) appear in Appendix C.

5.2 DATA QUALITY

The data that were received from respondents were not of uniform quality or consistency in several respects, including the units used and the degree to which components were individually described. Use of the data preparation steps described above resolved most, but not all, of the problems regarding data accuracy and consistency. Therefore, the overall quality of the data used for supply curve estimates is reviewed here.

5.2.1 Background

The data requested from utilities on the four components of interest were used in the loss-estimation methodology developed by Westinghouse, Inc. for the Electric Power Research Institute (EPRI 1983). This relatively simple methodology uses a computer program entitled Simplified Calculation of Loss Equations (SCALE). The loss equations in this program were used to characterize the efficiency of the components described by survey data; the equations were also used in the supply curve calculations to determine the incremental energy loss reductions attributable to replacement or upgrading of distribution system components in the Pacific Northwest.

	Number of Rows	Code	Number of Units	Cluster Number	KV	Q Number	Peak	Annual Load	Power Factor	Resistance	Load Loss	No Load Loss	Load Factor	Loss Factor	Losses	Recovery	Sales Information	ID Name	Length	Material	Efficiency	Capacity	QISQR (Loss Scale)
<u>RBASE RELATION</u>																							
QTLNE	463	X	X		X		X	X	X	X								X	X			X	
QLATERAL	455	X			X		X	X		X									X	X			
QOTRAN1	750	X	X	X			X	X			X	X									X	X	
QOVERH4	1151	X	X	X	X		X	X		X								X	X				
QSTRAN2	405	X	X	X			X	X			X	X						X				X	
<u>LOTUS FILE</u>																							
TLCORR	491	X	X	X	X		X	X	X	X								X	X			X	
TLCLOSS	286	X	X	X	X		X	X	X	X			X	X	X			X	X			X	
QOVERH4A	1151	X	X	X	X	X	X	X		X									X				X
QOH4LOSS	500	X		X	X	X	X	X		X			X	X	X				X				
ST-CORR	405	X	X	X			X	X			X	X	X	X	X			X			X	X	
ST-EFF	183	X	X	X			X	X			X	X	X	X	X			X			X	X	
STR4S	12	X	X	X			X	X			X	X	X	X	X	X		X			X	X	
STR4M	31	X	X	X			X	X			X	X	X	X	X	X		X			X	X	
STR4L	62	X	X	X			X	X			X	X	X	X	X	X		X			X	X	
STCS83	37	X	X	X													X						
ST-LOSS	183	X	X	X			X	X			X	X	X	X	X			X			X	X	
DTRAN	750	X	X	X		X	X	X			X	X	X	X	X						X	X	
DT-AVG	750	X	X	X			X	X														X	
DTCORR	385	X	X	X		X	X	X			X	X	X	X				X			X	X	

TABLE 5.1. Matrix of Files and Variables in SYSTEMS Data Base

Although the Westinghouse methodology is considered to be a "simplified" approach, it still requires fairly detailed data about component characteristics. The methodology was developed and tested using data from single utilities that had extensive and precise operational information on components in computerized form (EPRI 1983). There was considerable challenge to applying this methodology (or any other approach requiring detailed component data) to the problem of estimating distribution system loss-reduction potential for an entire region composed of over a hundred utilities of varying sizes. The survey conducted by the CSEI Project staff in 1984 was an exploratory step to gain a better understanding of the degree to which various types of utilities could adequately characterize their distribution system components.

As discussed in Section 1.0, the original project plan called for this survey to be followed by a statistically designed sample survey of regional components. Before this additional survey was conducted, however, BPA made policy decisions that reduced the need for such a detailed effort. Work continued on efforts to estimate supply curves of the T&D system conservation resource, but the approach was modified to use the data available from the preliminary 1984 survey.

5.2.2 Evaluation of 1984 Survey Data

The survey was performed both by mailing questionnaires to utility engineers and by conducting interviews with managers and engineers from a smaller sample. Interviews were conducted with large-, medium-, and small-sized utilities in conjunction with the survey undertaken in the Institutional Assessment Task of the CSEI study (Hendrickson and Darwin 1986). Questionnaires were administered to a total of 144 utilities by one or the other of the approaches described above. The overall response was surprisingly good, considering the time and effort required to provide some of the information that was requested.

The quality of the characterization data varied by component, presumably because of the effort and the quality of records required to complete the questionnaire. Detailed information on distribution transformers (including peak and average load information necessary to estimate losses) was provided primarily by the medium- to large-sized utilities with mixed loads that included irrigation (utilities in Clusters 2, 3 and 4). Utilities in Cluster 1 (small

municipal utilities with no irrigation load) also provided information about the estimated quantity of distribution transformers in their systems, but few usable data regarding operating characteristics were obtained. Of the 750 rows of raw data for distribution transformers that were entered, approximately 385 rows remained after the data were sorted to eliminate rows with missing critical information. However, in the data entry used, each row potentially represents a large number of individual transformers with identical characteristics. Therefore, the base number of transformers (or other components) used for the regression analysis by Tepe1 et al. (1986) was much higher. On average, adequate survey data were available for about 25-30% of the estimated regional stock of distribution transformers.

Adequate substation transformer data, on the other hand, were more uniformly distributed. Utilities in all size/load clusters were represented in the final spreadsheet. Again, a number of rows of data had to be dropped from the original file due to the absence of critical data; 183 rows of complete data remained of the original 405 rows. The "good" data describe, on average, about 25% of the estimated regional stock of substation transformers.

Feeder data were entered as rows that described segments of line varying from 0.5 mile to over 25 miles in length. Although the average distribution factor was requested from the utilities, this information was generally not supplied, so an average was assumed for the purposes of energy loss calculations (Tepe1 et al. 1986). The screening process reduced the number of usable rows of data from 1151 to 500.^(a)

Transmission line data were supplied by about half of the regional utilities that maintain their own lines (transmission/subtransmission lines were defined as lines ranging from 34 kV to 230 kV). Operating characteristics that were used in the loss-reduction and supply-curve calculations relied on the data supplied by the survey. However, the estimate of the total circuit miles at each voltage was derived from Electrical World (1983). Both the current miles estimated for the region and the average operating characteristics of

(a) As was the case for the other components, utilities often provided a single set of operating characteristics that was applicable to a large number of segments of their feeders.

transmission lines appear to be accurate because good utility records are usually available for transmission facilities. The screening process used to obtain adequately characterized line segments resulted in the reduction of the file from 491 to 286 rows. Loss-related characteristics derived from the corrected file are based on approximately 10% of the estimated total regional mileage at various voltages.

5.3 SUMMARY HIGHLIGHTS OF THE SYSTEMS DATA BASE

This section summarizes the component characterization information contained in the SYSTEMS data base. Tables listing these characteristics were developed to assist in the calculation of supply curves (Tepel et al. 1986) and are repeated here to illustrate the results of the data collection, reduction, and manipulation. Other displays, particularly the figures showing distributions and comparisons of components by utility cluster, are presented to show the system characterization capability of the data base.

Figure 5.1 shows a representative portion of a corrected LOTUS 1-2-3® worksheet for transmission lines. Similar worksheets were developed for all components to estimate the average loss-related characteristics that were used to calculate losses of components by size category.

Figures 5.2, 5.3, 5.4, 5.5, and 5.6 show the component size categories that were used in the supply curve analysis, and the distribution of the sample components by those categories (crosshatched bars). The regional stock (stippled bars) was estimated by regressing the number of units of components (from the sample) against known sales and consumer sector data for each utility that provided component quantity information. Ordinary least squares regression was used for this process, and the resulting coefficients were used to predict regional component stocks in the supply curve analysis. In addition to appearing as percentages on Figures 5.2 through 5.5, the estimated total regional stock is listed in Table 5.2 by component and size category.

Operational data for a majority of all sample components indicated that distribution system transformers are generally somewhat underloaded in terms of their installed capacity. Figures 5.7 and 5.8 illustrate the ratio of the actual reported peaks to the installed capacity (peak loading or peak load

LOSSES FOR EACH LINE APPEAR AS REALS (CALC. BY FORMULAS WKS)														
TOTALS AND AVERAGES ARE FORMULAS														
CODE	CL#	ID	KV	#	CKT	CAP	OHMS/MI	MILES	MMH	KVA	PF	LDF	a=	RESIS
													0.85	TIME
													LSF	LENGTH
													LOSSES	
													LOSSES	
WEC	2	D - RB	12.5	1	1	2500	1.120	15.8	11000	2279	1.00	0.351	0.341	17.696
QALC	1	BPA SUB E	25	1	1	2550	0.259	20.0	37000	13300	0.99	0.313	0.130	5.19
QALC	1	EPA SUB O	25	1	1	16900	0.259	12.3	13000	4000	0.99	0.371	0.173	3.1957
DEC	2	DRAIN TO	34.5	1	1	13.7	0.888	14.4	16074	4100	0.96	0.448	0.237	12.7872
DEC	2	AIRPORT 5	34.5	1	1	14044	0.862	1.8	25375	7237	0.96	0.448	0.237	1.56694
DEC	2	DRAIN TO	34.5	1	1	13.7	0.888	4.4	41253	10530	0.96	0.448	0.237	3.9072
DEC	2	PERRY JUN	34.5	1	1	8366	2.240	0.5	1310	1249	0.86	0.163	0.048	1.1424
DEC	2	AIRPORT 5	34.5	1	1	10756	1.410	1.4	31489	6339	0.93	0.367	0.358	1.974
DEC	2	AIRPORT 5	34.5	1	1	17927	0.560	8.3	22587	4032	0.93	0.639	0.444	4.648
DEC	2	ELKTON TO	34.5	1	1	20.4	0.443	13.6	5097	1300	0.92	0.448	0.237	6.032
LEC	2	LYNX HOLL	34.5	1	1	18000	0.607	3.1	2000	700	0.99	0.326	0.139	1.8817
DEC	2	AIRPORT 5	34.5	1	1	14044	0.862	4.8	3077	1991	0.90	0.176	0.033	4.0945
PACP	2	LONG BEAC	34.5	1	1	20000	0.592	14.0	43112	16800	0.98	0.293	0.117	3.288
LEC	2	T25 - CLO	34.5	1	1	14000	1.120	4.3	7000	2200	0.99	0.363	0.167	5.04
DEC	2	BLACKFEST	34.5	1	1	17927	0.560	3.2	42260	15624	0.97	0.309	0.127	1.7732
DEC	2	YONCALL T	34.5	1	1	13.7	0.888	5.5	18152	4630	0.96	0.448	0.237	4.884
DEC	2	AIRPORT 5	34.5	1	1	14044	0.862	2.8	15133	3106	0.88	0.156	0.346	2.4136
BOUP	4	WATERVILL	34.5	1	1	13740	0.888	6.5	19735	6672	0.97	0.338	0.148	5.772
LEC	2	T1 - CRES	34.5	1	1	18000	0.607	1.3	14000	4100	0.99	0.390	0.188	0.7891
LEC	2	EUGENE -	34.5	1	1	18000	0.607	2.9	17000	5600	0.99	0.547	0.154	1.7603
DEC	2	SUTHERLIN	34.5	1	1	20.4	0.443	3.2	18194	2600	0.96	0.448	0.237	1.424
DEC	2	NORTH PHI	34.5	1	1	10756	1.410	1.0	12676	2220	0.97	0.632	0.439	1.41
LEC	2	T25 - T1	34.5	1	1	14000	1.120	1.8	21000	6500	0.99	0.381	0.180	2.016
BREA	2	WAPATO-DE	34.5	1	1	21000	0.552	21.4	42860	7293	0.99	0.671	0.483	11.8123
BIGA	2	SCOOTENEY	34.5	1	1	12000	0.883	13.0	3997	1400	0.98	0.326	0.139	11.505
FERP	3	CURLEW TO	34.5	1	1	17926	0.560	9.0	3206	1305	0.96	0.233	0.144	5.04
BREA	2	RIMROCK	34.5	1	1	11000	1.690	28.5	18322	3120	0.99	0.670	0.493	48.165
LEC	2	CORONA -	34.5	1	1	14000	1.120	1.0	29000	6400	0.98	0.517	0.305	1.12
DEC	2	SANTA RIT	34.5	1	1	13744	0.888	16.1	7437	1365	0.93	0.624	0.424	14.2968
FERP	3	DAY HINES	34.5	1	1	17926	0.560	2.3	7511	1440	0.96	0.393	0.391	1.288
CPC	2	AMATONE	34.5	1	1	-1	0.888	23.1	7209	1693	0.97	0.486	0.274	20.5128
LEC	2	C58 - CUL	34.5	1	1	11000	1.690	7.0	29000	6400	0.98	0.517	0.305	11.33
DEC	2	CEHEX JUN	34.5	1	1	10756	1.410	1.6	17369	3382	0.93	0.586	0.380	2.256
FERP	3	MAUCONDA	34.5	1	1	13743	0.888	14.0	688	216	0.96	0.264	0.167	12.432
FERP	3	SAN POIL	34.5	1	1	17926	0.560	16.0	8562	2700	0.96	0.262	0.166	8.96
DEC	2	CB WATER	34.5	1	1	10756	1.410	4.1	30714	5895	0.94	0.395	0.370	5.781
DEC	2	NORTH PHI	34.5	1	1	10756	1.410	2.0	18038	3675	0.92	0.560	0.351	2.32
DEC	2	CEHEX JUN	34.5	1	1	10756	1.410	0.6	669	293	0.87	0.261	0.097	0.846
DEC	2	YONCALLA	34.5	1	1	10.2	1.374	1.0	17760	4530	0.96	0.448	0.237	1.574
DEC	2	POLE 341	34.5	1	1	13744	0.888	1.4	15123	3106	0.88	0.556	0.346	1.87872
BREA	2	ALFALFA-H	34.5	1	1	22000	0.306	13.9	42860	7293	0.99	0.671	0.483	4.2534
FERP	3	SAN POIL	34.5	1	1	17926	0.560	2.0	20123	5340	0.96	0.430	0.222	1.12
LEC	2	ALVEY - T	34.5	1	1	20000	0.592	5.0	23000	8300	0.99	0.376	0.177	2.96
CPC	2	CEHEX	34.5	1	1	-1	0.888	11.6	3593	797	0.98	0.486	0.274	10.3008
DEC	2	SUTHERLIN	34.5	1	1	20.4	0.443	4.4	7173	1630	0.97	0.448	0.237	1.958
DEC	2	YONCALLA	34.5	1	1	20.4	0.443	6.7	17642	4500	0.96	0.448	0.237	2.9815
DEC	2	DRAIN TO	34.5	1	1	10.2	1.374	4.7	5253	1340	0.97	0.448	0.237	6.4578
LEC	2	WEST 11TH	34.5	1	1	18000	0.607	7.0	12000	3800	0.99	0.360	0.165	4.249
DEC	2	POLE 321	34.5	1	1	13744	0.888	10.5	6568	1521	0.95	0.493	0.280	9.29736

FIGURE 5.1. Portion of Corrected Transmission Line Worksheet with Loss Calculation (sample)

FIGURE 5.2. Distribution of Distribution Transformers by Size Category

FIGURE 5.3. Detail from Figure 5.2 for Distribution Transformers Greater than 75 kVA

FIGURE 5.4. Distribution of Substation Transformers by Size Category

FIGURE 5.5. Distribution of Feeders by Size Category

FIGURE 5.6. Distribution of Transmission Lines (Non-BPA Owned) by Size Category

ratio) for sample transformers. On the average, these transformers experience peaks that are below their installed capacities (i.e., less than 1.0). In contrast, national average peak loadings for most distribution transformer sizes (below 100 kVA) range from 115% to 155% (EPRI 1983). Comparable national averages for substation transformer peak loadings were not found, but the ratio of peak to installed capacity for these units based in the survey is even more startling. Small substation transformers (under 7.5 MVA), which comprise about 66% of the estimated regional stock of all substation transformers, appear to have peak loadings of only a little over 50% of their installed capacity.

Average annual loads in the region are also relatively low, compared to regional peaks. The bar charts shown in Figures 5.9 through 5.12 present a facsimile of load factors by component size category. That is, they show average loads compared to annual peaks for the sample components. These figures indicate that peaks on all components are typically much higher than average

TABLE 5.2. Estimated Number of Components in the BPA Region

Component	Size Category	Size of Sample Component (wtd. avg.) ^(a)	Predicted Quantity
Distribution TX	0-7.5 (kVA)	5 (kVA)	44,664 ^(b)
	7.6-15.0	10	435,204
	15.1-25.0	15	331,274
	25.1-40.0	28	135,557
	40.1-50.0	48	173,401
	50.1-75.0	52	118,531
	75.1-100.0	75	24,656
	100.1-200.0	118	18,454
	200.1-300.0	232	6,384
	300.1-500.0	305	3,501
	>500	1,032	3,019
Substation TX	0-7.5 (MVA)	5.727 (MVA)	789 ^(b)
	7.6-20	11.069	168
	>20	56.023	238
Primary Feeders	0-11.9 (kV)	7.0 (kV)	3,508 ^(c)
	12.0-17.9	12.6	43,219
	18.0-50	24.8	11,933
Transmission	34.5 (kV)	34.5 (kV)	3,603 ^(c)
	69	6.9	4,254
	115	11.5	12,080
	230	23.0	4,161

(a) In the loss calculations, a representative component size was determined by computing a weighted average of the kVA, MVA or kV of all the sample components in a given size category. For example, the weighted average kVA of sample transformers in the 0-7.5 kVA category was 5 kVA; this value was used in the calculation of losses for that group. Characteristics such as load losses were scaled to these average sizes.

(b) Number of transformers in each size group.

(c) Conductor circuit miles.

FIGURE 5.7. Peak Load Ratios of Distribution Transformers (Sample Data)

FIGURE 5.8. Peak Load Ratios of Substation Transformers (Sample Data)

FIGURE 5.9. Comparison of Average Loads to Peak Loads for Substation Transformers, 1984 (Sample Data)

loads for most sizes. National data for distribution transformers indicate that for units under 100 kVA, it is not unusual for load factors to be quite low (0.266 with an average power factor level of 0.925) (EPRI 1983). However, the national average load factor for the full distribution system is about 0.635 (EPRI 1983), while the Pacific Northwest regional average (from the regional peak and requirement data in the INVTRY data base) appears to be below 0.4 for utilities in Clusters 1, 3 and 4 and just above 0.4 for utilities in Cluster 2 (Figure 5.13). Figure 5.13 also shows the component load factors for each of the utility clusters, (from sample data). (In Cluster 1, there were insufficient acceptable data on the peaks and average loads of distribution transformers to calculate load factor.)

Finally, Tables 5.3 through 5.6 present the estimated loss-related characteristics of each component, by size category. These estimates were used to quantify the potential regional conservation from distribution-system efficiency improvements (loss reductions) that can be gained by replacing existing components either with more efficient units (in the case of transformers) or with larger conductors (feeders and transmission lines).

FIGURE 5.10. Comparison of Average Loads to Peak Loads for Distribution Transformers, 1984 (Sample Data)

FIGURE 5.11. Comparison of Average Loads to Peak Load for Feeders, 1984 (Sample Data)

FIGURE 5.12. Comparison of Average Loads (in units of peak) and Peak Loads for Transmission Lines, 1984 (Sample Data)

FIGURE 5.13. Comparison of System and Component Load Factors by Utility Cluster, 1984 (Sample Data)

TABLE 5.3. Distribution Transformers: Categories and Estimated Operating Characteristics of Regional Stock

Nominal Category (a) (kVA)	Average Capacity (b) (kVA)	Log Average Capacity	No Load Loss Existing (c,d) (watts)	Load Loss Existing (c,d) (watts)	No Load Loss Replacement (c,d) (watts)	Load Loss Replacement (c,d) (watts)	Estimated Peak (b) (kVA)	Peak Load Ratio	Estimated Number of Units (e)
7	5	1.6	43	109	30	91	4.7	0.946	44664
15	10	2.3	67	188	47	148	8.6	0.856	435204
25	15	2.7	90	280	64	198	11.9	0.793	331274
40	28	3.3	182	547	119	363	17.6	0.626	135557
50	48	3.9	247	746	154	470	42.4	0.883	173401
75	52	3.9	247	774	158	486	36.9	0.71	118531
100	75	4.3	286	900	182	558	37.1	0.495	24656
200	118	4.8	334	1062	213	547	60.5	0.513	18454
300	232	5.5	406	1300	257	781	112	0.483	6384
500	305	5.7	435	1394	275	836	150.1	0.492	3501
>500 (f)	1032	6.9	565	1821	354	1077	592	0.574	3019

(a) See Table 5.2 for the ranges of each category.

(b) Averages weighted by number of transformers reported in each category.

(c) At peak load ratio=1.00.

(d) Values derived from CH2M-HILL (1981), pp. 45-46.

(e) From regression analysis.

(f) The >500 category includes transformers that have installed capacity exceeding 500 kVA.

TABLE 5.4. Substation Transformers: Categories and Operating Characteristics

Category (kVA)	Average Installed Capacity (kVA) ^(a)	No Load Loss Existing (kW) ^(b)	Load Loss Existing (kW) ^(b)	No Load Loss Replacement (kW) ^(c)	Load Loss Replacement (kW) ^(c)	Average Peak (kVA) ^(b)	Peak Load Ratio ^(d)	Estimated Number of Units ^(e)
<7,500	5,727	10.61	39.0	7.2	25.8	3,038	0.53	789
7,501- 20,000	11,069	15.4	50.4	9.5	31.6	7,084	0.64	168
>20,000	56,023	44.7	176.7	14.8	48.4	47,620	0.85	238

(a) Weighted average installed capacity for each category.

(b) Weighted averages for reported values in size category.

(c) Values for reference transformers (the most efficient sample transformer in a given size category).

(d) Ratio of average peak load to (average) installed capacity.

(e) From regression analysis.

TABLE 5.5a. Primary Feeders: Operating Characteristics of Sample Data^(a)

Average Sample Resistance ^(b)	Length (Circuit Miles) ^(c)	Sum of Calculated Losses (MWh) ^(d)	KLOSS (Constant)
2.57	112	2,172	7.55
0.89	4,257	283,481	74.82
1.38	613	13,248	15.66

TABLE 5.5b. Primary Feeders: Categories and Estimated Operating Characteristics of Regional Stock

Category (kV)	Estimated Average Operating Voltage (kV) ^(e)	Estimated Conductor Size (Existing) ^(f)	Resistance Existing Conductor (ohms/mile) ^(b)	Resistance of Conductor 3 Sizes Larger (ohms/mile) ^(g)	Estimated Length (Circuit Miles) ^(h)
0-11.9	7.0	4 AWG	2.57	1.38 (1.0 AWG)	3,508
12.0-17.9	12.6	2/0 AWG	0.89	0.55 (266.8 Kcmil)	43,219
18.0-50	24.8	1 AWG	1.38	0.72 (3/0 AWG)	11,933

(a) Table 5.5a data were used to compute a constant (KLOSS), which was then used in the actual loss calculations performed with data from Table 5.5b (see Tepel et al. 1986).

(b) Real ACSR resistance (Standard Handbook for Electrical Engineers, 1978) closest to weighted average of feeder resistances reported by utilities.

(c) Sum of reported circuit miles of all sample feeders in each category.

(d) Losses calculated for each feeder/feeder segment.

(e) Weighted average of sample data.

(f) The ACSR conductor size with average sample resistance (see footnote (b) above).

(g) Standard Handbook for Electrical Engineers, (1978); CRC Handbook (1981).

(h) Regional totals estimated by regression.

TABLE 5.6a. Transmission Lines: Operating Characteristics of Sample Data^(a)

Categories (Operating kV)	Average Sample Resistance (ohms/mile) ^(b)	Assumed Conductor ^(c) Size	Length (circuit miles) ^(d)	Sum of Calculated Losses (MWh) ^(e)	KLOSS (constant)
Low (34.5)	0.895	2/0 AWG	461.2	1,902	4.61
Med (69)	0.895	2/0 AWG	806.8	12,836	17.78
HI (115)	0.306	336.4 Kcmil	555.1	39,123	230.37
VHI (230)	0.123	874.5 Kcmil	456.8	65,624	1,167.46

TABLE 5.6b. Transmission Lines: Categories and Estimated Operating Characteristics of Regional Stock

Operating Voltage (kV) ^(f)	Assumed Conductor Size ^(c)	Resistance Existing Conductor ^(b)	Resistance of Conductor 3 Sizes Larger ^(g)	Length (circuit miles) ^(h)
34.5	2/0 AWG	0.895	0.385 (266.8 Kcmil)	4,603
69	2/0 AWG	0.895	0.385 (266.8 Kcmil)	4,254
115	336.4 Kcmil	0.306	0.206 (500 Kcmil)	12,080
230	874.5 Kcmil	0.123	0.104 (1033.5 Kcmil)	4,161

- (a) Table 5.6a data were used to compute a constant (KLOSS), which was then used in the actual loss calculations performed with data from Table 5.6b (see Tepel et al. 1986).
- (b) Real ACSR resistance (Standard Handbook for Electrical Engineers 1978) closest to weighted average of transmission resistances reported by utilities.
- (c) ACSR conductor size with average sample resistance (see footnote b above).
- (d) Sum of reported circuit miles of all sample transmission lines in each category.
- (e) Losses calculated for transmission line segments.
- (f) Standard transmission operating voltages.
- (g) Standard Handbook for Electrical Engineers (1978) CRC Handbook (1981).
- (h) Electrical World (1983).

6.0 CONCLUSIONS

This report has described the development of three data bases for the CSEI Assessment Project, and has provided details on the information contained in each of these data bases. In addition, a number of intermediate summary statistics about loss-related T&D system characteristics have been presented to indicate some of the ways that this information can be used. At this level of analysis, a great deal of insight can be gained as to the strengths and weaknesses of the current regional network of T&D facilities. A still higher level of analysis was used to determine the system's loss recovery potential, and to develop conservation supply curves (Tepel et al. 1986).

These three data bases were essential for estimating the comparative cost-effectiveness of various regional T&D efficiency improvements. However, there are numerous nontechnical problems associated with implementing a regional program to improve distribution system efficiencies by equipment replacement or any other cost-effective strategy. Many of these problems are identified and discussed in the part of the CSEI study on institutional issues (Hendrickson and Darwin 1986). However, there is undoubtedly a potential for loss reduction, just as there is some evidence that system improvements are gradually taking place in the normal course of utility system maintenance and development. Ongoing analyses in the CSEI Assessment Project and other regional and individual utility efforts will no doubt provide more precise system information in the future, as well as a better understanding of how best to achieve efficiency improvements. This initial phase of the CSEI Assessment Project, including the data base development and supply curve analysis, does, however, provide a first step toward identifying and assessing the resource available through loss reductions.

The reliability of such research efforts depends on the accuracy and representativeness of the data upon which they are based. Variations in the quality and volume of data, the number of utilities supplying adequate information, and the proportion of the estimated total regional stock that was represented in the CSEI systems data base make it likely that the loss calculations for transmission lines and substation transformers are more accurate than those

for feeders and distribution transformers. Keeping good records on the first two components appears to be easier for utilities of all sizes, probably because there are fewer of these items in a utility system, because their operating parameters are more closely monitored, and because their replacement or repair may be a major cost to the utility. However, the representativeness of the average loss-related characteristics derived for the supply curve estimation is undoubtedly open to question. The response to the survey could well have been biased toward the utilities having the most interest in system efficiency improvement. Respondents could also have been primarily those utilities with the best records or most available engineering staff. Any of these factors could bias the sample data that were used in this phase of the study.

On the other hand, comparing a number of important T&D characteristics estimated with these data with corresponding parameters from other loss studies indicates that the CSEI data are relatively reliable. The data do not show many outstanding or unreasonable anomalies that run counter to expected characteristics of the region's T&D stock. Sensitivity tests could be developed to bracket the parameters that were used in the supply curve calculations, and to determine the effects of modification of important inputs. However, the level of effort dictated for this phase of the CSEI Assessment Project did not warrant these procedures.

The data base created for the CSEI study is probably unmatched in its comprehensiveness and level of detail for a regional electrical distribution system consisting of a large number of utilities. Developing the data base demonstrated the difficulties associated with adequately characterizing T&D systems at the component level for an entire region. Any future effort to do so with a more supportable sample design will be greatly enhanced as a result of this initial compilation. Using the CSEI data bases significantly improved the accuracy of supply curves that PNL estimated to described the conservation potential represented by T&D system efficiency improvements. Furthermore, the characterization of regional T&D component stocks and the estimations of losses developed in the CSEI assessment have the potential for much broader use in future assessments of T&D system conservation options, plans, and policies.

REFERENCES

- CH2M-Hill. 1981. Distribution System Efficiency Improvement Handbook. DOE/BP/171, produced for the Bonneville Power Administration, Portland, Oregon.
- CRC Handbook of Chemistry and Physics. 62nd Edition, Robert C. Weast and Melvin J. Astle eds., CRC Press, Inc., Boca Raton, Florida.
- Electrical World. 1983. Directory of Electric Utilities. 92nd Edition, McGraw-Hill Book Company, New York, New York.
- EPRI. 1983. Improved Methods for Distribution Loss Evaluation. EL-3261, Electric Power Research Institute, Palo Alto, California.
- Hendrickson, P. L. and R. F. Darwin. 1986. Decision Factors Affecting Transmission and Distribution Efficiency Improvements by Northwest Electric Utilities. PNL-5735, Pacific Northwest Laboratory, Richland, Washington.
- Standard Handbook for Electrical Engineers. 11th Edition, Donald G. Fink and H. Wayne Beaty eds., McGraw-Hill Book Company, New York, New York.
- Tepel, R. C., J. W. Callaway, J. G. DeSteele, W. H. Doggett, A. D. Lee, and Z. T. Taylor. 1986. Customer System Efficiency Improvement Assessment: Supply Curves for Transmission and Distribution Conservation Options. PNL-6076, Pacific Northwest Laboratory, Richland, Washington.

APPENDIX A

REQUEST FOR INFORMATION FORM SENT TO UTILITIES

APPENDIX A

REQUEST FOR INFORMATION FORM SENT TO UTILITIES

The following questionnaire was sent to utilities in the Pacific Northwest region to request information on their distribution system components. Sixty-six utilities responded and provided information in various degrees of specificity.

QUESTIONNAIRE ON SYSTEM CHARACTERISTICS
TRANSMISSION AND DISTRIBUTION EFFICIENCY UPGRADES PROJECT

Customer name: _____
Contact person: _____
Title: _____
Phone: _____

REPORTS:

When was your most recent loss study and/or work plan performed?

Year for loss study: _____ Year for work plan: _____

If possible, would you please provide a copy of the loss study and/or work plan?

Would you please enclose a copy of your annual report?

REQUIREMENTS:

Annual Requirements categorized by source (Total for January-December):

	1982	1983	
From BPA:	_____ MWH	_____ MWH	
Own generation:	_____ MWH	_____ MWH	
Supplied from other	_____ MWH	_____ MWH	
utilities (please name):			

If you provide any power to any other utilities, please list names and amounts supplied for 1982 and 1983. _____

SYSTEM CHARACTERISTICS:

Power factor by delivery point:

Delivery Point Name	Average	Power Factor (1983)	
		High/Month	Low/Month
_____	_____	_____/____	_____/____
_____	_____	_____/____	_____/____
_____	_____	_____/____	_____/____
_____	_____	_____/____	_____/____
_____	_____	_____/____	_____/____

Please attach another page, if needed.

LOSSES:

Estimates of losses (%) by source:

____ Feeders	____ Transmission/subtransmission lines
____ Distribution transformers	____ Bulk power substations (if any)
____ Secondary system	____ Unaccounted for (meters, unexplained, etc.)

How do you allocate these losses by source? (rules of thumb?, measured?, a study?, other?)

To what percentage of total sales could system losses be reduced if all loss components were replaced with higher efficiency components that were economically justified? (estimate %) _____ What percentage of losses would be experienced if all system loss components were replaced by the most efficient components currently available? (estimate %) _____.

Are loss reduction measures being systematically installed as part of a regular system improvement plan? _____ If yes, what measures are being (a) applied in 1984, and (b) planned in 1985?

Have you experienced any trends (increases or decreases) in your percentage losses over the past 5 years? Can you attribute these to any actions on your part (system improvements, etc.) _____

EQUIPMENT REPLACEMENT:

Could you provide typical (or estimated) information on equipment replacement and installation costs for major system components? The last column requests an estimate of the approximate number of these components replaced/purchased per year.

<u>Features (length, size, capacity, efficiency, etc)</u>	<u>Equipment Cost</u>	<u>Installa- tion cost</u>	<u>Units replaced/ added/year</u>
Miles of line: (Overhead and Underground)			
Substation Transformer:			
Distribution Transformer:			
Capacitor:			

PART 2: GENERAL INSTRUCTIONS

The information on the following pages is needed to characterize the various components of your transmission and distribution system for BPA's Customer Systems Efficiency Improvement Study. Please note that we are not requesting information for any part of the transmission and distribution system falling outside of BPA's service area.

As you will note, a separate page is provided for each different component included in this study. If additional room is needed to list any single component, please add additional pages. The first two components (transmission/subtransmission lines and substation transformers) should be itemized individually on the information sheet. For the remaining components, it may be most efficient for you to group the components of a given type in your system, and provide average values. When using average values, please include a brief description of how these values were derived (e.g., estimates, system inventories, studies, etc.). We realize that some information will not be available. Please make your best estimate and put a notation to that effect.

We appreciate your efforts to characterize your T&D systems as accurately as possible. This information will be valuable both for our effort to obtain a good estimate of the recoverable resource that losses represent, and as the basis for an effective and economically optimized loss reduction program by BPA. Please feel free to call Jenifer Callaway (509-376-4744) or Lisa Skumatz (509-376-4661) as questions arise.

Thank you for your help.

..

Instructions: Please provide the following information on all transmission lines within your system (do not include lines owned and operated by BPA)

[illegible]

B. SUBSTATION TRANSFORMER DATA

Instructions: The following information is needed for the transformers in each non-BPA substation in your distribution system. Please fill in the requested data on each type (by rated capacity) of transformer in each of your substations (see example).

<u>Substation Name</u>	<u>Number of transformers (each type)</u>	<u>Capacity (each trans- former type) (kva)</u>	<u>Rated* Load Loss (each Type) (kW)</u>	<u>Rated Nn* Load Loss (each type) (kW)</u>	<u>Average age each type</u>	<u>1983 Peak Load of Transformer (kva)</u>	<u>1983 Annual Load (10³ kWh)</u>

* If this information is not available, please include the name of the manufacturer, the data manufactured, and the serial number of the unit.

C. DISTRIBUTION TRANSFORMERS

Instructions: Please group your distribution transformers by type and rating, and provide the following information for each group.

	<u>Capacity (kVA)</u>	<u>Approximate Number of Units</u>	<u>Average Peak Load (kva)</u>	<u>Efficiency (standard, high, very high) (give percent of each)</u>	<u>Average Annual Load (10³ kW)</u>
RESIDENTIAL					
COMMERCIAL					
INDUSTRIAL					
AGRICULTURAL					

D. OVERHEAD PRIMARY FEEDERS

Instructions: Please provide the following information on the primary feeders in your system. Please list the primary lines individually, where possible.*

IDENTIFICATION (Substation & No. if listed as <u>Individual Lines</u>)	OPERATING VOLTAGE (kV <u>L-L</u>)	Type:	Material	Conductor Size	Annual Load (10 ³ kWh)	Annual Peak Load(kva)	Circuit Miles	Average* Length	Number* of Primaries
		Specify	Specify						
		1=3ØY	1=ACSR						
		2=1ØY	2=Cooper						
		3=2ØD	3=AAAC						
		4=2ØY	4=cw/copper						
		5=Other	5=Other						

(Optional info.- see note below:)

* Large utilities with very extensive primary systems may wish to group primary feeders according to voltage. In this case, please provide the best typical values available, but include the total number of circuit miles and the average length and number of lines in each voltage category. If typical values are used, please so indicate.

4. 8

•

•

OPERATING
VOLTAGE
(kV_{L-L})

Type

Material

Conductor
Size

Typical
Segment
Length

Approximate
Number of
Segments .

Typical
Annual kWh
(per segment)

Typical Peak
Load (kva)
(per segment)

A.11

APPENDIX B

BPA REGION UTILITIES BY CLUSTER

APPENDIX B

BPA REGION UTILITIES BY CLUSTER

NAME	CODE	(a) UTYPE	(b) STATE	(c) CLUSTER
ALDER MUTUAL LIGHT COMPANY	AMLC	3	WA	1
ATLANTA POWER CO.	ALTP	3	ID	1
BLAINE CITY LIGHT	BCL	1	WA	1
BURLEY MUNICIPAL DISTRIBUTION SYSTEM	BURL	1	ID	1
CANBY ELECTRIC BOARD	CAEB	1	OR	1
CASHMERE WATER SEWER AND LIGHT	CWSL	1	WA	1
CENTRALIA MUNICIPAL HYDRO	COC	1	WA	1
CITY OF ASHLAND	CASH	1	OR	1
CITY OF CASCADE LOCKS	CCAS	1	OR	1
CITY OF CHENEY	COCH	1	WA	1
CITY OF CHEWELI	COCE	1	WA	1
CITY OF COULEE DAM	COCU	1	WA	1
CITY OF DECLCO	CDED	1	ID	1
CITY OF DRAIN	CDRA	1	OR	1
CITY OF ELLENSBURG	COE	1	WA	1
CITY OF FIRCHEST	COF	1	WA	1
CITY OF FOREST GROVE	CFOR	1	OR	1
CITY OF MINIDOKA	MINI	1	ID	1
CITY OF MONMOUTH	CMON	1	OR	1
CITY OF PLUMMER	PLUM	1	ID	1
NAME	CODE	UTYPE	STATE	CLUSTER
CITY OF SODA SPRINGS	SOOA	1	ID	1
CITY OF SUMAS	CSUM	1	WA	1
CITY OF WEISER	WESA	1	ID	1
CITY OF WORLEY	WORL	1	ID	1
DUPONT	DUPD	1	WA	1
EATONVILLE POWER AND LIGHT	EPL	1	WA	1
ELMHURST MUTUAL POWER AND LIGHT	EMPL	3	WA	1
LAKEVIEW LIGHT AND POWER	LLAP	3	WA	1
MCCLEARY LIGHT AND POWER	MCLP	1	WA	1
MONTANA LIGHT AND POWER	MLAP	3	MT	1
ORCAS POWER AND LIGHT COMPANY	OPLC	3	WA	1
PARKLAND LIGHT AND WATER COMPANY	PLWC	3	WA	1
PENINSULA LIGHT COMPANY	PENL	3	WA	1
RUSTON ELECTRIC UTILITY	REU	1	WA	1
SALEM ELECTRIC	SE	3	OR	1
TAMMER ELECTRIC	TAMM	3	WA	1
TOWN OF MILTON	TOM	1	WA	1
TOWN OF STELLACOOM	TOST	1	WA	1
TOWN OF WATERVILLE	TWAT	1	WA	1
BENTON RURAL ELECTRIFICATION ASSOCIATION	BREA	1	WA	2
NAME	CODE	UTYPE	STATE	CLUSTER
ZIG BEND REA	BIGR	3	WA	2
BLACHLY-LANE COUNTY COOPERATIVE	BLCC	3	OR	2
CENTRAL ELECTRIC COOPERATIVE	CENC	3	OR	2
CITY OF ALBION	CALE	1	ID	2
CITY OF BENDON	CBUN	1	OR	2
CITY OF BONNERS FERRY	CBFY	1	ID	2

CITY OF HEYBURN	CHEY	1	ID	1
CLEARWATER POWER COMPANY	CPC	3	ID	1
COLUMBIA BASIN ELECTRIC COOPERATIVE	CBEC	3	OR	1
COLUMBIA POWER COOPERATIVE ASSOCIATION	CPCA	3	OR	1
COLUMBIA REA	COLR	3	WA	1
DOUGLAS ELECTRIFICATION COOPERATIVE	DEC	3	OR	1
EAST END MUTUAL ELECTRIFICATION COOP	EMEC	3	ID	1
FALL RIVER RURAL ELECTRIFICATION COOP	QVEC	3	ID	1
FARMERS ELECTRIC COMPANY	QVC	3	ID	1
FLATHEAD ELECTRIC COOP	FLEC	3	MT	1
GLACIER ELECTRIC COOP	GEC	3	MT	1
HARNEY ELECTRIFICATION COOPERATIVE	HEC	3	OR	1
HOOD RIVER ELECTRIFICATION COOPERATIVE	HREC	3	OR	1
IDAMO COUNTY LIGHT & POWER COOP. ASSOC.	ICLP	3	ID	1
NAME	CODE	UTYPE	STATE	CLUSTER

KOOTENAI ELECTRIFICATION COOPERATIVE	KEC	3	ID	1
LAME ELECTRIC COOPERATIVE	LEC	3	OR	1
LINCOLN ELECTRIC COOPERATIVE (MT)	LECM	3	MT	1
LINCOLN ELECTRIC COOPERATIVE (WASH.)	LECW	3	WA	1
LOST RIVER ELECTRIFICATION COOPERATIVE	LOST	3	ID	1
MIDSTATE ELECTRIFICATION COOPERATIVE	MEC	3	OR	1
MILTON-FREEWATER LIGHT AND POWER	MFLP	1	OR	1
MISSOULA ELECTRIC COOP	MISS	3	MT	1
MODERN ELECTRIC WATER COMPANY	MEWC	3	WA	1
NESPELEM VALLEY ELECTRIC COOPERATIVE	NVEC	3	WA	1
NORTHERN LIGHTS INC.	NLI	3	ID	1
OHOP MUTUAL LIGHT COMPANY	OHOP	3	WA	1
OXANOGAN COUNTY ELECTRIC COOPERATIVE	OCEC	3	WA	1
PRAIRIE POWER COOPERATIVE	PPC	3	ID	1
PUD #1 OF PACIFIC COUNTY	PACP	1	WA	1
RAFT RIVER RURAL ELECTRIC COOPERATIVE	RREC	3	ID	1
RAVALLI COUNTY ELECTRIC COOP	RCEC	3	MT	1
RIVERSIDE ELECTRIC COMPANY	REC	3	ID	1
RUPERT	RUPT	1	ID	1
RURAL ELECTRIC COMPANY	RURE	3	ID	1
NAME	CODE	UTYPE	STATE	CLUSTER

SALMON RIVER ELECTRIC COOPERATIVE	SREC	3	ID	1
SIERRA PACIFIC POWER	SPP	3	NV	1
SOUTH SIDE ELECTRIC LINES	SSEL	3	ID	1
SURPRISE VALLEY ELECTRIFICATION CORP	SVEC	3	CA	1
UNITY LIGHT AND POWER COMPANY	ULPC	3	ID	1
VERA IRRIGATION DISTRICT	VID	1	WA	1
VIGILANTE ELEC. COOP	VEC	3	MT	1
WASCO ELECTRIFICATION COOPERATIVE	WEC	3	OR	1
WELLS RURAL ELECTRIC COOP	WREC	3	NV	1
WEST. OREGON ELECTRIFICATION COOPERATIVE	WOEC	3	OR	1
CHELAM COUNTY PUD	CCHE	1	WA	1
CITY OF MCMINNVILLE	CMCM	1	OR	1
CLALLAM COUNTY PUD	CLAP	1	WA	1
CONSUMERS POWER, INC.	CONP	3	OR	1
COOS-CURRY ELECTRIFICATION COOPERATIVE	CCOC	3	OR	1
EMERALD PUD	EMEP	1	OR	1
FERRY COUNTY PUD	FERP	1	WA	1
INLAND POWER AND LIGHT	INPL	3	WA	1
KITITAS COUNTY PUD	KITP	1	WA	1
Klickitat County PUD	KLIP	1	WA	1
NAME	CODE	UTYPE	STATE	CLUSTER

ALCOA--REMATCHER	ALCOA	6	VA	-0-
ALCOA--VANCOVER	ALCOA	6	VA	-0-
ALCOA--ADCO	ALCOA	6	VA	-0-
WASHINGTON WATER POWER COMPANY	WAPC	5	WA	4
UTAH POWER AND LIGHT	UTEL	3	UT	4
SPRINGFIELD UTILITY BOARD	SPUB	1	OR	4
SMOKMISH PUB	SMOP	2	WA	4
SEATTLE CITY LIGHT	SECL	1	WA	4
POCKET SOUND POWER & LIGHT	PSEL	3	WA	4
PORTLAND GENERAL ELECTRIC	PGE	5	OR	4
PACIFIC POWER AND LIGHT--SANDPOINT	PPLS	5	ID	4
PACIFIC POWER AND LIGHT--O-A-IC	PPLD	5	OR	4
PACIFIC POWER AND LIGHT--MONTANA	PPLM	5	OR	4
OXANOGAN COUNTY PUB	OXAN	2	WA	4
MONTANA POWER COMPANY	MPC	5	MT	4
MASON COUNTY PUB #1	MAP1	2	WA	4
IDAHO POWER COMPANY	IPC	5	ID	4
IDAHO FALLS ELECTRIC LIGHT DEPARTMENT	IDEL	1	ID	4
CHAS HARBOR COUNTY PUB	CHCP	2	WA	4
CHAMT COUNTY PUB	CHCP	2	WA	4
FRANKLIN COUNTY PUB	FRAP	2	WA	4
LEWIS COUNTY PUB	LEWP	2	WA	3
LOWER VALLEY POWER AND LIGHT	LVPL	3	WA	3
MASON COUNTY PUB #1	MAP1	2	WA	3
NORTHERN WASCO COUNTY PUB	NWCP	2	OR	3
PEND OREILLE COUNTY PUB	POCP	2	WA	3
RICHLAND ENERGY SERVICES DEPARTMENT	RESD	1	WA	3
SKAMANIA COUNTY PUB	SKAP	2	WA	3
TILLAMOOK PUB	TILP	2	OR	3
UMATILLA ELECTRIC COOPERATIVE ASSOC.	UECA	3	OR	3
VAHIALEUM COUNTY PUB	VAHP	2	WA	3
SECTOR COUNTY PUB	SEMP	2	WA	4
CENTRAL LINCOLN PUB	CLMP	2	OR	4
CITIZENS UTILITY CO.	CITI	1	ID	4
CITY OF PORT ANGELES	COFA	1	WA	4
CITY OF TACOMA	CTAC	1	WA	4
CLALLAM COUNTY PUB	CLCP	2	WA	4
CLATSOP COUNTY PUB	CLCP	2	OR	4
COVIL COUNTY PUB	COVP	2	WA	4
DOUGLAS COUNTY PUB	DOCP	2	WA	4
EUGENE WATER AND ELECTRIC BOARD	EVER	1	OR	4
ALCOA--REMATCHER	ALCOA	6	VA	-0-
ALCOA--VANCOVER	ALCOA	6	VA	-0-
ALCOA--ADCO	ALCOA	6	VA	-0-
WASHINGTON WATER POWER COMPANY	WAPC	5	WA	4
UTAH POWER AND LIGHT	UTEL	3	UT	4
SPRINGFIELD UTILITY BOARD	SPUB	1	OR	4
SMOKMISH PUB	SMOP	2	WA	4
SEATTLE CITY LIGHT	SECL	1	WA	4
POCKET SOUND POWER & LIGHT	PSEL	3	WA	4
PORTLAND GENERAL ELECTRIC	PGE	5	OR	4
PACIFIC POWER AND LIGHT--SANDPOINT	PPLS	5	ID	4
PACIFIC POWER AND LIGHT--O-A-IC	PPLD	5	OR	4
PACIFIC POWER AND LIGHT--MONTANA	PPLM	5	OR	4
OXANOGAN COUNTY PUB	OXAN	2	WA	4
MONTANA POWER COMPANY	MPC	5	MT	4
MASON COUNTY PUB #1	MAP1	2	WA	4
IDAHO POWER COMPANY	IPC	5	ID	4
IDAHO FALLS ELECTRIC LIGHT DEPARTMENT	IDEL	1	ID	4
CHAS HARBOR COUNTY PUB	CHCP	2	WA	4
CHAMT COUNTY PUB	CHCP	2	WA	4
FRANKLIN COUNTY PUB	FRAP	2	WA	4
LEWIS COUNTY PUB	LEWP	2	WA	3
LOWER VALLEY POWER AND LIGHT	LVPL	3	WA	3
MASON COUNTY PUB #1	MAP1	2	WA	3
NORTHERN WASCO COUNTY PUB	NWCP	2	OR	3
PEND OREILLE COUNTY PUB	POCP	2	WA	3
RICHLAND ENERGY SERVICES DEPARTMENT	RESD	1	WA	3
SKAMANIA COUNTY PUB	SKAP	2	WA	3
TILLAMOOK PUB	TILP	2	OR	3
UMATILLA ELECTRIC COOPERATIVE ASSOC.	UECA	3	OR	3
VAHIALEUM COUNTY PUB	VAHP	2	WA	3
SECTOR COUNTY PUB	SEMP	2	WA	4
CENTRAL LINCOLN PUB	CLMP	2	OR	4
CITIZENS UTILITY CO.	CITI	1	ID	4
CITY OF PORT ANGELES	COFA	1	WA	4
CITY OF TACOMA	CTAC	1	WA	4
CLALLAM COUNTY PUB	CLCP	2	WA	4
CLATSOP COUNTY PUB	CLCP	2	OR	4
COVIL COUNTY PUB	COVP	2	WA	4
DOUGLAS COUNTY PUB	DOCP	2	WA	4
EUGENE WATER AND ELECTRIC BOARD	EVER	1	OR	4

MARTIN MARIETTA ALUMINUM--GOLDENDALE NAME	MMAC CODE	4 UTYPE	WA STATE	-0- CLUSTER
MARTIN MARIETTA--THE DALLES	MMAD	4	OR	-0-
OREGON METALURGICAL CORPORATION	OMC	4	OR	-0-
PACIFIC CARBIDE AND ALLOYS	PCA	4	OR	-0-
PEMOWALT CORPORATION	PC	4	OR	-0-
PORT TOWNSEND PAPER CORPORATION	CZ	4	OR	-0-
PUGET SOUND POWER AND LIGHT, PT. ROBERTS	PSPH	5	WA	-0-
REYNOLDS METALS COMPANY--LONGVIEW	RMCL	4	WA	-0-
REYNOLDS METALS COMPANY--TROUTDALE	RMCT	4	OR	-0-
USN, PSN SHIPYARD, USN COMPLEX USN RADIO	USN	4	WA	-0-
WHATCOM COUNTY PUB	WMAP	2	WA	-0-

- (a) Type of utility: 1 = municipal; 2 = public utility district; 3 = cooperative or other public; 4 = federal; 5 = privately owned; 6 = direct service industry.
- (b) "State" refers to the state in which the greatest portion of a utility's service area lies, and/or the state in which its corporate headquarters are located.
- (c) See Appendix D for explanation of cluster. A "0" indicates that the customer was not included in the 4-category clustering used for estimation of the regional stock of distribution system components.

APPENDIX C

NAMES OF VARIABLES OR ATTRIBUTES USED IN DATA BASES

APPENDIX C

NAMES OF VARIABLES OR ATTRIBUTES USED IN DATA BASES

I. INVTRY DATA BASE

ADDRESS1, ADDRESS2	Utility mailing address
ALLID	Comprehensive utility identification information
ANNGEN	Annual requirements file for NW Power Pool (generating) customers, MW, 1978 to 1983
avemwent	Average annual megawatts, required power
calweeks	Number of weeks in requirement reporting period
CITY	Location of utility headquarters
CODE	Four letter code used for utility identification
COMCUST	Number of commercial users served annually by utility
COMMERC	Annual sales to commercial users by a utility
CONTACT	Name of utility or organization representative contacted by CSEI staff
CUSTNO.1	Customer (utility) number assigned to BPA in annual sales files
CUSTNO.2	Customer number assigned by BPA in monthly sales files
CUSTNO.3	Customer number assigned by BPA to utilities in FILE3 (annual requirements, full service customers)
CUSTNO.4	Customer number assigned by BPA to utilities in FILE4 (energy requirements of generating utilities)
DATATYPE	Boolean value (1,2) used to identify a row of data as number of consumers or sales (by sector)
DELPT	BPA power delivery point
DOMCUST	Number of domestic users served annually by utility

DSIREQS	Annual requirements for direct service industries, MWh, 1978-1984
DOMESTIC	Annual sales to domestic users by a utility
FEDS&R	Annual deliveries to federal customers by delivery points
FERC	Federal Energy Regulatory Commission utility category
FILE1	Corrected annual sales file for BPA customers, MWh, 1978-1983
FILE3	Corrected annual requirements file for BPA preference customers, MWh, 1978 to 1983
FILE4	Corrected annual requirements file for NW Power Pool Customers, MWh, 1978 to 1983
GROUP	East or West group, BPA
hour	Hour at which peak daily demand occurred
INDCUST	Number of industrial users served annually by a utility
INDUSTRY	Annual sales to industrial users by a utility
IOU83	NW Power Pool customers requirements data file, 1983
IOUS&R	Combined sales and requirements file for NW Power Pool customers, by consumer sector, 1978 to 1983
IRRCUST	Number of irrigation users served annually by a utility
IRRIG	Annual sales by MWh to irrigation customers
month	Month in which requirement was measured (integer 1-12)
NAME	Utility name
NAMENUMS	Utility names with BPA sales and requirements ID numbers
NUMBER	Tabulation of utility codes by cluster number
OFFICE	BPA area office to which a utility is assigned
OTHCUST	Number of unclassified users served annually by a utility
OTHER	Annual sales to unclassified users by a utility

peakmo	Month in which highest peak requirement by a direct service industry (DSI) customer occurred
peakmw	Peak requirement, in megawatts
peakreq	Peak requirement of a DSI customer in a given year, in megawatt hours
PHONE	Utility phone number
PREQ83	Preference customers requirements data file, 1983
PUBS&R	Combined sales and requirements file for preference customers by consumer sector, 1978 to 1983
PUBS&R83	Same as PUBS&R except for 1983 only
region	Boolean value for utility requirements data to indicate purchases for services areas within or outside BPA regions
REQMWH	Total annual requirement of a utility, in megawatt hours
REQPEAK	Peak requirement in megawatt hours, generating utilities
rpday, rpmonth	Day and month in which peak requirement (megawatts) was received for generating utilities
SALESMWH	Total annual sales of a utility, in megawatt hours
SALES83	1983 sales by consumer sector, all BPA customers
SECS&R	Annual sales and requirements by consumer sector for secondary customers (nongenerating utilities that purchase power from other PBA customers), 1978 to 1983
STATE	Two letter code to identify state in which utility operates
SUBJECT	Text field describing purpose of utility or organizations contact by CSEI staff
TITLE	Organizational title of person contacted by CSEI staff
TOTCUST	Total number of users (all sectors) served annually by a utility
UTYPE	Type of utility: 1 = municipal; 2 = cooperative; 3 = public utility district; 4 = federal, 5 = investor-owned utility; 6 = direct service industry

YEAR Year for which data in row are recorded (76 = 1976,
77 = 1977, etc.)

ZIPCODE Zipcode of utility headquarters

II. QUEST DATA BASE

LOSTPCT Total system loss as estimated by utility

QALLOCBY Basis of utility estimate of loss allocation by system
component

QCONTENT Tally of responses by portion of the survey

QCOUNT Tally of utilities that responded to the survey

QEQUIREPL Utility equipment replacement information from survey

QLOSSBP% Percent of estimated losses attributed to bulk power
system

QLOSSOTS Percent of estimated losses attributed to distribution
transformers

QLOSSES Utility's estimate of the allocation of system losses by
component

QLOSSEST Subset of QLOSSES with annual sales and requirements
from CSEI sales and requirements files

QLOSSF% Percent of estimated losses attributed to primary
feeders

QLOSSSS% Percent of estimated losses attributed to secondary
feeders

QLOSSUN% Percent of estimated losses attributed to unknown source

QLOST/S% Percent of estimated losses attributed to substation
transformers

QLRCOM Comment by utility on recently installed or planned loss
reduction measures (text)

QPODPF Utility's estimate of average power factor at point of
delivery (POD)

QTRNDCOM Comment by utility on expected system loss trends (text)

The following attributes contain boolean values to indicate the receipt of information on a given portion of the survey questionnaire. The attributes also represent categories of subattributes, not listed here, that hold coded or verbatim information from portion of the questionnaire indicated by the attribute name.

QEQPREPL	Equipment replacement practices and/or plans
QLOSS	Estimates of system loss by component
QPARTB	Component characterization information on Part B of questionnaire
QREPORTS	Annual business reports
QREQS	Utility-reported annual requirements in MWH and source 1982 and 1983
QSYSCHR	Power factor information

III. SYSTEMS DATA BASE

Annual Load	Annual energy handled by a component, usually megawatt-hours
Capacity	Either the nameplate rating, or the generally assumed safe, maximum continuous power handling ability of a device, usually kilovolt-amperes
Code	Four letter code for utility (text)
Cluster Number	Integer between 1 and 4 that indicates the utility cluster of each customer (see Appendix C)
DT-AVG	File of transformers classified by size category, average operating characteristics, and efficiencies (LOTUS file)
DTCORR	Lotus file of QDTRAN, with apparent errors corrected (LOTUS file)
DTRAN	Original unedited file of distribution transformer data from survey (LOTUS file)
Efficiency	The ratio of the power output of a component to the power input
ID Name	Utility-assigned name to a distribution system component
KV	Operating voltage, kilovolts

Length	Conductor length, circuit miles
Load Factor	The average loading of a component in per units of peak loading
Losses	The energy dissipated by a distribution system component, usually expressed in kilowatt-hours
Loss Factor	The average loss of a component in per units of peak loss
Load Loss	The copper or winding losses in a transformer, watts or kilowatts
Material	Conductor material
No Load Loss	The iron or core losses in a transformer, watts or kilowatts
Number of Units	Item count
Peak	Peak loading, usually kilovolt-amperes
Power Factor	Ratio of apparent power to active power
Q Number	Integer for utility identification in SYSTEMS
QDTRAN1	Edited file of distribution transformer information (RBASE relation)
QISQR (Loss Scale)	A relative loss measure used in analysis, unitless
QLATERAL	Secondary feeder information from the survey (RBASE relation)
QOVERH4	Edited file of primary feeder information (RBASE relation)
QOVERH4A	Lotus file of RBase file of same name (LOTUS file)
QSTRAN2	Edited file of substation transformer information (RBASE relation)
QTLINE	Transmission line information from the technical portion of the survey (RBASE relation)
Recovery	The estimated energy that would be saved by a given action, usually in average annual megawatts
Resistance	Ratio of voltage to current, ohms/mile

ST-CORR	Lotus file of QSTRAN2 with apparent errors corrected (LOTUS file)
STCS83	ST-CORR file combined with 1983 customer sales information (LOTUS file)
ST-EFF	Same as ST-CORR with estimated transformer efficiencies (LOTUS file)
ST-LOSS	File with estimated losses for each reported substation transformer
STR4L	Subset of ST-EFF, large size transformers (LOTUS file)
STR4M	Subset of ST-EFF, medium size transformers (LOTUS file)
STR4S	Subset of ST-EFF (category labeled "small") (LOTUS file)
TLCLOSS	Estimated loss per circuit mile of sample transmission lines (LOTUS file)
TLCORR	Transmission line operating characteristics, standardized (LOTUS file)

APPENDIX D

CLUSTER ANALYSIS

APPENDIX D

CLUSTER ANALYSIS

INTRODUCTION

There are 170 customers within the BPA service area covering all or part of seven states. Most of these customers are utilities that purchase power from BPA. The utilities range in size from large investor owned companies with over 1 million residential customers to very small municipal and cooperative systems serving less than 500 customers. In order to reduce the variation in distribution system characteristics that results from this diversity, similar utilities were grouped into clusters. One hundred and forty seven BPA customers^(a) were grouped into strata based on cluster analysis of the customer sector (domestic, irrigation, commercial, industrial and other) sales data, utility type (municipal, PUD, cooperative, IOU, and federal), and magnitude of total sales. The clustering program used, called CLUSTER, was developed by Marshall and Romesburg at Utah State University. The basic data for each utility were the MWh sold in each of the five consumer sectors: domestic, irrigation, commercial, industrial, and other. Thus, each utility was represented by a vector of five observations, and the measure of dissimilarity between utilities was the Euclidean distance in the 5-dimensional space. The clustering algorithm used was an unweighted pair group method based on average distance between current clusters (referred to as UPGMA in the literature).

Preliminary analysis of the data revealed that the observations for each customer sector were highly skewed, with half of the observations being less than 1% of the maximum for each customer sector. In order to avoid standardizing (levelizing) with arithmetic averages that did not represent the centers of the distributions, the data were transformed by taking their natural (base e) logarithm, which produced a more normal (Gaussian) distribution. A standard

(a) Individual sales records were not available for the remaining 23 customers, which are federal agencies and small utilities that purchase power from other BPA customers.

normal distribution was then developed from the "ln" transformed data by subtracting the mean and dividing by the standard deviation, which produced data for clustering that were on about the same scale as standard normal deviates.

The clustering algorithm defined 9 clusters with 5 to 59 members (utilities) each. These 9 clusters were reorganized to account for utility types (municipal, PUD, cooperative, IOU, and federal). The original clusters reflected the size (total MWh sales for 1982) of the utilities, and this was maintained in the reorganization into strata.

Figure D.1 provides an indication of the face validity of the defined strata. These "boxplots" summarize the distribution of the total MWh for the utilities included in each stratum. The "box" contains 50% of the observations, with a plus sign marking the median. The "whiskers" reach out to include "close" observations. An observation moderately separated from the "whiskers" is marked with an asterisk and is called "out" and a more separated observation is called "far out" and marked with an "O". These terms have precise definitions in terms of the spread, or the distance between the upper and lower quartiles (called "hinges"). The upper whisker extends to the last observation falling within the upper hinge +1.5 (spread), an observation between the upper hinge +1.5 (spread) and upper hinge +3.0 (spread) is "out," and a point beyond this is "far out." Similar definitions hold at the lower end of the boxplot.

The Unclassified Stratum is a catch-all stratum that includes the two smallest utilities (Atlanta and Minidoka) and one of the largest (Seattle). It is composed of the late-joiners in the clustering and so includes the "unusual" utilities. The boxplot in Figure D.1 reflects this diversity. The other strata group utilities based on the cluster analysis and the logical analysis of the utility types. Three of the strata (5, 6 and 9,) have mixed utility types. There is some overlap in the boxplots, but they do add to the face validity of the stratification, and to the names assigned to the strata. The strata appear to strike a good balance between the customer sectors served, the type of utility ownership, and the overall size of the utility.

FIGURE D.1. Boxplots for Strata

Table D.1 organizes the strata by percentage of total MWh sold. Since Seattle accounts for most (92.7%) of the total MWh for Stratum 0, it is separated out, ranking tenth among all groups. The 3D utilities (20.4%) of the first six rank groups account for only 2.4% of the total MWh. By itself, Seattle sells almost as much electricity as the 95 utilities in the first eight rank groups. The six High Commercial Utilities (Stratum 6 and rank group 11) have total sales twice as large as Seattle's. BPA's direct service customers used about the same amount of electricity as the 10 Large Municipal and PUD utilities. Finally, the five Large IOUs account for more than one-third (38%) of the total, equivalent to the total usage of the 139 utilities excluding BPA and Seattle.

TABLE D.1. Strata Ordered by Total GWh Sold

Rank	Total GWh	Stratum	% of MWh	% of Utilities	N	Stratum	CUM N	CUM MWh %	CUM % 1
1	239	12	0.2	1.4	2	USIIS	2	0.2	1.4
2	254	10	0.2	2.0	3	Small IOU	5	0.4	3.4
3	392	3	0.3	4.1	6	MUNI, IRG	11	0.7	7.5
4	398	7	0.3	4.1	6	Other PUD	17	1.0	11.6
5	627	0 Other	0.5	3.4	5	Unclassified	22	1.5	15.0
6	1,144	2	0.9	5.4	8	COCP, No IRG	30	2.4	20.4
7	1,308	1	1.0	17.7	26	MUNI, No. IRG	56	3.4	38.1
8	4,056	4	3.1	26.5	39	COOP, IRG	95	6.5	64.6
9	5,696	5	4.3	11.6	17	Mixed, Med.	112	10.8	75.2
10	7,918	0 Seattle	6.0	0.7	1	Seattle	113	16.8	75.9
11	16,060	6	12.1	8.2	12	High Commercial	125	28.9	85.1
12	21,401	9	16.2	6.8	10	Large MUNI + PUD	135	45.1	91.9
13	21,871	8	16.5	4.8	7	BPA	142	61.6	96.7
14	51,016	11	38.5	3.4	5	Large IOU	147	100.1 ^a	100.1 ^a
TOTAL 132,400			100.1 ^(a)	100.1 ^(a)					

(a) Column totals do not add exactly to 100% due to rounding.

The stratification provides a logical organization of the utilities into groups for characterizing "similar" utilities. The method of stratification was based on sales to customer sectors and utility ownership, so that "similarity" is defined in terms of these characteristics, which have some face validity as indicators of similar energy loss patterns. But energy loss is a function of the hardware (i.e., lines and transformers) in each utility's distribution system. A major goal of the stratification is to reduce the scope of the data collection effort by reducing the number of utilities for which detailed hardware inventory data are collected. Under the reasonable assumption that energy losses are roughly proportional to sales, the larger utilities will have the largest losses.

The cluster analysis was based on an order-preserving transformation of the MWh sales to customer sectors. This transformation preserved the size of the utility as an important factor, and the consideration of type of utility ownership in the definition of the final stratification brought in another factor that could influence loss control policy (if not actual losses). This is not the only approach that could have been used. It was chosen because this approach appeared to provide the best hope for defining strata that would be least sensitive to errors in the data and most accurate for MWh loss estimation, given the data available. Other variables considered were: kWh divided by number of customers, number of customers, and percentage of total sales in each sector. The cluster analysis was done for the percentage of total sales in each sector data resulting in (again) 9 clusters with 2 to 46 utilities per cluster. Since percentages of a total are interdependent (e.g., if the domestic sector accounts for 75% of the total MWh, no other sector can account for more than 25%), these clusters did discriminate more exactly in terms of customer sector mix than the transformed MWh data. Both clusterings had BPA direct service customers and the two U.S. Interior Indian Services customers (USIIS) well separated from the other utilities, and utilities with no, or very low, sales in a particular sector grouped together. An example of a major difference was that the five large IOUs constituted a distinct cluster in the MWh clustering but were buried among the cluster with 46 utilities in the percentage based approach.

Valid loss data for the regression analysis were available for 117 of the 147 utilities used in the cluster analysis. Four strata from Figure D.1 were not included in the regression analysis. The seven BPA groups, Stratum 8, of direct service industries are planned for special handling as separate stratum, along with Whatcom PUD (Utility Code 482), from the Unclassified Stratum 0. The three Small IOUs, Stratum 10, and the two USIIS, Stratum 12, have no loss data. The Unclassified Stratum, 0, had two utilities with no loss data; Seattle and Idaho Falls were moved to Stratum 11 to join the large IOUs; and Minidoka, a small utility with a large (16.7%) loss, was removed from the analysis. The remaining 16 utilities with no loss data were distributed among the original strata. These revised strata, including only the 116 utilities with loss data, did not have enough utilities for stratum-by-stratum regression analysis so they were aggregated into four groups, as defined in Figure D.2. Figure D.3 shows the boxplots of $\ln(\text{MWh Total})$ for the four groups which were used in the supply curve analysis.

The variable

$$\text{TINDEX} = \text{M2} = (\text{Circuit Miles}/\text{N Customers}) (\% \text{ Self-Generation})$$

was also used in developing the estimation equations. Two other indicators of extent of transmission involvement were also used:

$$\text{M1} = \ln(\text{Circuit Miles})$$

and

$$\text{M3} = \ln[(\text{Circuit Miles} \times \% \text{ Self-Generation})/100]$$

The full statistical model fitted to these data was

$$\begin{aligned} \ln(L) = & a + b_1 \text{M3} + b_2 \text{LDM} + b_3 \text{LIRG} + b_4 \text{LCOM} \\ & + b_5 \text{LIND} + b_6 \text{LOTRE} + e \end{aligned} \quad (\text{D.1})$$

FIGURE D.2. Boxplots for the 117 Utilities with Loss Data, by Adjusted Strata

FIGURE D.3. Boxplots for Four Groups of Aggregated Strata

where M3 is the third transmission index defined above (when a utility had no data on self-generation, M3 was set to zero),

L_{DOM}, ..., L_{TOR} are the natural logarithms of the MWh sales to the five customer sectors

a , b_1 , ..., b_6 are the regression coefficients to be estimated by minimizing the sum of squares of e , the residual from the fit

$\ln(L)$ is the natural logarithm of the utility's loss

The system loss, L , was calculated as the difference between the GWh required from the BPA grid (plus self-generation) and the total GWh sold (or for the utility's own use) by the utility as reported by the utility.

This model (Equation D.1) was fitted to all of the 117 utilities with loss data and to each of the four groups separately. All of the 16 utilities with self-generation data were in Group 4. The results are given in Table D.2.

The procedure used was to fit the full model, determine which coefficients were statistically different from zero, remove their carrier (independent)

TABLE D.2. Summary of Fits of $\ln(\text{Loss, GWh})$ to $\ln(\text{Sector Sales})$ and M3

Group	N		Estimated Coefficients							Adj. R^2	sd(Resid)	df
			a	M3	LDM	LTRG	LDM	LIND	LOTR			
ALL	117	Coeff.	-6.656	0.12206	0.70898	0.07030	0.10465	0.03389	-	91.5	0.5377	111
		t	-8.66	3.96	8.18	5.92	1.52	2.48	(0.91)	91.5	0.5385	110
1.1	26	Coeff.	-7.972	*	0.87031	*	-	-	-	78.7	0.6086	24
		t	-8.56		9.67		(0.65)	(0.21)	(0.71)	77.0	0.6329	21
1.2	26	Coeff.	-2.575	*		*				0.90549	81.9	24
		t	-7.37							10.65	0.5627	20
2	43	Coeff.	-6.540	*	0.63923	0.14408	-	0.6652	-	86.9	0.3679	39
		t	-9.56		8.90	5.67	(0.66)	3.93	(1.10)	87.0	0.3669	37
3	21	Coeff.	-8.662	*	0.9435	0.13801	-	-	-0.11594	79.0	0.4173	17
		t	-5.17		5.43	3.82	(1.46)	(-0.52)	-2.03	79.2	0.4151	15
4	27	Coeff.	-5.416	0.18208	0.7219	-	-	-	-	85.4	0.6085	24
		t	-3.83	4.41	6.53	(1.24)	(-1.47)	(0.11)	(-0.24)	86.1	0.5938	20

Notes

- * means all data were zero for this variable in this group
- means the variable was not statistically significant in the fit to the full model
- t the values in the t row are the Student's t statistic for the coefficient above it. If there is a dash above it, then it is parenthesized to indicate that is the t-value from the full model. A coefficient was judged "non-significant" if its t-value was in the interval ± 1.5 , which includes about 85% of the expected values of t when the true coefficient is zero. The R^2 and sd(Resid) in the t-row are the for the full model.

variable and rerun the regression. (The MINITAB® statistical software package was used to do the analyses.) As noted at the bottom of Table D.2, the critical t-value used for judging significance was ± 1.5 , which is about the 85th, two-sided percentile of the t-distribution.

Only the LOTR carrier in the fit of the full model to all 117 utilities was judged to produce a nonsignificant contribution to the fit (t-value of -0.81). Its removal had no effect on the adjusted R^2 , which is approximately the percentage of total variability in $\ln(\text{Loss})$ accounted for by the fit. The "sd(Resid)" column is the standard deviation of the residuals, [e in the model of Equation D.1]. The smaller "sd(Resid)" is, the more precise the fit. The last column "df" has the degrees of freedom associated with "sd(Resid)" appropriate for the t-tests. Since the carriers are

intercorrelated and multicollinear, interpreting relative magnitudes of coefficients as being indicative of relative "importance" of the carrier variables can be highly misleading.

Two equations are summarized for Group 1. The second is recommended for use since it provides a slightly better fit (based on the R^2 and $sd(\text{Resid})$ statistics). For the carrier variable, the first equation used the natural logarithm of the MWh sold to domestic customers and the second used the natural logarithm of the total GWh sold.

Groups 2 and 3 have LDOM and LIRG as significant carriers, with LIN contributing in Group 2 and LOTR in Group 3. Group 4 is the only group with transmission data (for 16 of the 27 utilities; 4 of the 16 had M3 of zero). This carrier, M3, is significant, along with LDOM in the full model.

It will be noted in Table D.2 that the adjusted R^2 is smaller for the group regression than for the regression using all 117 data points from the utilities.^(a) Despite this, it can be shown that the group fits will provide better precision of estimation when applied to utilities that satisfy the group definitions.

Percentage Loss

A similar set of estimation equations was developed for estimating the percentage loss from the transmission index normalized by number of customers (M2), and the percentage of total sales sold in each customer sector. This model is expressed as

$$\begin{aligned} \%L = & a + b_1 M2 + b_2 PDOM + b_3 PIRG + b_4 PCDM \\ & + b_5 (PIND \text{ or } POTR) + e \end{aligned} \quad (D.2)$$

(a) The adjustment in the "Adj. R^2 " is for the number of carriers as well as the number of data points, so that comparisons for different data sets and restricted models are more meaningful.

where $M2 = (\text{Circuit Miles}/N \text{ Customers}) \times (\% \text{ Self-Generation})$

PDOM, ..., POTR are the percentages of total sales to each customer sector

$\%L = 100(\text{GWh Required} - \text{GWh Sold})/\text{GWh Required}.$

The coefficients ($a, B_1, \dots, B_5$) and the residual (e) were as defined for Equation (D.1). Since the percentages are colinear, either POTR or PIND was removed so that the full model had only 6 carriers, including the vector of ones for the intercept.

The results are given in Table D.3. The same "Notes" as for Table D.2 apply, except that t-values are usually not given for a full model, since any of the five percentage-in-sector carriers could be removed to define a full model. The results are not as good, in terms of R^2 , as the results for the $\ln(\text{MWh})$ data (summarized in Table D.3). The best overall fit has an R^2 of 27.4% compared with 91.5% for the fit of $\ln(\text{Loss})$ for the 117 utilities. The

TABLE D.3. Summary of Fits of Percent Loss to Percent of Sale in Customer Sector and $(\text{CMI} \times \% \text{ S.G.})/\text{NCUST}$

Group	N		a	M2	PDOM	PIRG	PCOM	PIND	POTR	Adj. R^2	sq(Resid)
ALL	117	Coeff.	2.720	4.0606	0.06564	0.08591	-	-	-	27.37	3.118
		t	2.53	5.34	3.77	4.56	(0.24)	[0.37]	(-0.31)	26.17	3.143 ^b
1	26	Coeff.	-	*	0.0766	*	-	-	0.1132	9.04 ^a	3.189
		t			6.11				1.86		
2	43	Coeff.	9.29	*	-	-	0.08371	-0.04740	-0.8484	12.41	2.877
		t	11.41				1.43	-1.63	-2.39		
3	21	Coeff.	9.38	*	-	-	-	-0.08718	-0.4361	20.96	2.896
		t	7.27					-1.94	-1.92		
4	27	Coeff.	2.939	4.4134	0.06407	-	-	-	-	58.62	2.686
		t	1.67	6.22	1.61	(1.03)	(-0.51)	-	(0.74)	55.97	2.771

Notes

- The R^2 is for the fit with an intercept since R^2 is not defined for the no intercept case. (The intercept was -0.051 with a t-value of -0.02.)
- The statistics for the full model are for the fit eliminating PIND, except for the t-value for PIND which was for the fit omitting POTR.

best fit is for Group 4, with an R^2 of 58.6%. But the residuals from this fit have a strong linear relationship with % Loss, for the 22 loss values less than 10%, indicating that the relatively high R^2 is spurious as an indicator of the degree of fit.

DISTRIBUTION

<u>No. of</u> <u>Copies</u>		<u>No. of</u> <u>Copies</u>	
<u>OFFSITE</u>		66	<u>Pacific Northwest Laboratory</u>
30	W. M. Warwick MS/KES Bonneville Power Administration P.O. Box 3621 Portland, OR 97208		W. B. Ashton J. W. Callaway (40) C. A. Counts R. F. Darwin J. G. DeSteeze (5) W. H. Doggett J. E. Englin C. A. Geffen P. L. Hendrickson J. W. Johnston M. S. Klan A. D. Lee R. J. Nesse R. G. Rivera T. J. Secrest R. C. Tepel Publishing Coordination MH (2) Technical Information (5)
30	DOE Technical Information Center		
<u>ONSITE</u>			
	<u>DOE Richland Operations Office</u> J. J. Sutey/D. R. Segna		