PNL--7378

DE91 001292

SYSTEM DEMAND-SIDE MANAGEMENT: REGIONAL RESULTS

J. E. Englin
R. D. Sands
J. G. De Steese
S. J. Marsh

May 1990

Prepared for
the 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

MASTER

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

SUMMARY

To improve the Bonneville Power Administration's (Bonneville's) ability to analyze the value and impacts of demand-side programs, Pacific Northwest Laboratory (PNL) developed and implemented the System Demand-Side Management (SDSM) model, a microcomputer-based model of the Pacific Northwest Public Power system. This document outlines the development and application of the SDSM model, which is an hourly model. Hourly analysis makes it possible to examine the change in marginal revenues and marginal costs that accrue from the movement of energy consumption from daytime to nighttime. It also allows a more insightful analysis of programs such as water heater control in the context of a hydroelectric-based generation system.

The SDSM model simulates electricity consumption on an average day for each month, for both a Base Case and a Demand-Side Program Case, over the years 1989 to 2010. The model covers all aggregated public utilities in the Pacific Northwest.

Five demand-side management programs were selected to be analyzed: electric thermal storage (ETS), water heater control (WH), and Model Conservation Standards (MCS) in the residential sector; efficient commercial lighting (CL) in the commercial sector; and conservation voltage reduction (CVR) in the transmission and distribution system. These programs cover a broad range of sectors and give a broad overview of an hourly analysis of load-shaping issues such as load shifting and peak reduction. Also, the California Energy Commission (CEC) tests were implemented to help assess the economic impact of the programs on participants, the utility, ratepayers, and society at large.

In general the energy results were consistent with prior expectations. There were no energy impacts in the ETS and WH programs. The MCS, CVR, and CL programs showed significant energy savings, with MCS savings showing the most seasonality. One of the striking results was that the WH program generated a new, higher peak because of the program's payback late in the morning. ETS used just as much energy as regular forced air; however, its ability to shift the load into the nighttime hours results in a consistent peak reduction.

All of the programs had sizable impacts on the costs and revenues of Bonneville. The largest single program impact was from CVR. Because of the broad efficiency improvements implied by the CVR program, considerable savings occurred; marginal revenue impacts of over $600 million were predicted for the program. MCS, CL, and WH all had revenue impacts ranging from $150 to $200 million. Of the five programs, only MCS and CVR had positive CEC Total Resource Cost Test results (societal cost test). The rest of the programs, while saving energy and/or peak cost, did not meet the Total Resource Cost Test. The CVR program had net benefits of $375 million. The MCS program had net benefits of $127 million.

CONTENTS

SUMMARY v

1.0 INTRODUCTION 1.1

1.1 BACKGROUND 1.1

1.2 STUDY OBJECTIVES AND OVERVIEW 1.2

1.3 ORGANIZATION OF REPORT 1.3

2.0 SYSTEM DEMAND-SIDE MANAGEMENT MODEL AND METHODOLOGY 2.1

2.1 OVERVIEW OF THE SDSM MODEL 2.1

2.2 END-USE MODULE STRUCTURE 2.3

2.3 SUMMARY MODULE 2.5

2.4 FINANCIAL MODULE 2.5

2.5 MODEL VERIFICATION 2.7

3.0 BASE-CASE MODEL 3.1

3.1 SECTORAL INPUTS 3.1

3.1.1 Residential Sector 3.1

3.1.2 Commercial Sector 3.2

3.1.3 Industrial Sector 3.2

3.1.4 Aluminum Direct Service Industries (DSIs) Sector . . . 3.2

3.1.5 Agricultural Sector 3.3

3.1.6 Street Lighting Sector 3.3

3.2 SYSTEM CALIBRATION 3.3

3.3 VERIFICATION 3.4

4.0 DEMAND-SIDE MANAGEMENT ANALYSIS 4.1

4.1 PROGRAM SELECTION 4.1

4.2 PROGRAM PENETRATION AND COST DATA 4.2

4.3 ELECTRIC THERMAL STORAGE PROGRAM 4.3

4.4 WATER HEATER CONTROL PROGRAM 4.4

4.5 MODEL CONSERVATION STANDARDS PROGRAM 4.5

4.6 COMMERCIAL LIGHTING PROGRAM 4.6

4.7 CONSERVATION VOLTAGE REDUCTION PROGRAM 4.6

5.0 RESULTS FOR PROGRAMS ANALYZED 5.1

5.1 DEMAND-SIDE MANAGEMENT ENERGY RESULTS 5.1

5.2 DEMAND-SIDE MANAGEMENT PEAK RESULTS 5.1

5.3 DEMAND-SIDE MANAGEMENT ECONOMIC RESULTS 5.2

5.3.1 Bonneville Economic Results 5.2

5.3.2 Utility Impacts 5.3

5.3.3 California Energy Commission (CEC) Tests 5.4

5.4 CONCLUSION 5.5

6.0 SENSITIVITY ANALYSES 6.1

6.1 SENSITIVITY ASSUMPTIONS 6.1

6.2 HIGH-GROWTH CASE CALIBRATION 6.1

6.3 SENSITIVITY RESULTS 6.2

6.3.1 Peaking and Energy Results 6.2

6.3.2 Economic Results 6.4

6.3 CONCLUSION 6.7

7.0 CONCLUSIONS 7.1

8.0 REFERENCES 8.1

APPENDIX A - SIMULATED LOAD SHAPES COMPARED WITH AVERAGE HISTORICAL SYSTEM LOAD SHAPES A.1

APPENDIX B - PENETRATION SCHEDULES FOR FIVE SYSTEM DEMAND-SIDE MANAGEMENT PROGRAMS B.1

APPENDIX C - PEAK REDUCTION POTENTIAL FOR CONSERVATION VOLTAGE

REDUCTION IN THE BONNEVILLE SERVICE AREA C.1

1.0 INTRODUCTION

This report presents the results of a study prepared for Bonneville Power Administration (Bonneville) by the Pacific Northwest Laboratory (PNL).[a] For this study, PNL developed and implemented a microcomputer-based model of the Pacific Northwest Public Power system. In this chapter, a context for the study is provided, its objectives and methodology are briefly described, and the report's organization is given.

1.1 BACKGROUND

Demand-side management (DSM) has become an important part of utility planning. In the Northwest it has received less attention because the hydro system is generally thought to be energy constrained rather than capacity constrained. The large hydro component of Bonneville's generating capacity gives the Northwest resource portfolio unique operating characteristics. The analysis in this study provides some additional insights into the interaction of DSM programs and the Northwest generation portfolio.

The load-following abilities of the hydroelectric generation provide an unusual backdrop for an hourly analysis of DSM programs. PNL staff developed and applied the System Demand-Side Management Model (SDSM) of the Northwest's public power system to reflect these circumstances. SDSM models an average day by hour in each month of the year. Because of its hourly focus, it is able to differentiate daytime and nighttime savings, winter and summer program savings, and the value of programs that save energy (peak) when marginal cost is high from the value of programs that save energy when marginal cost is low.

The SDSM model was developed to enhance Bonneville's ability to analyze the value and impacts of demand side programs. Despite the hydroelectric system, Bonneville faces the same load shaping issues as other utilities, such as valley filling, peak shaving, and night time return. Hourly models of

---

(a) Pacific Northwest Laboratory is operated for the U.S. Department of Energy by Battelle Memorial Institute.

system demand are well suited to address the impacts of demand side programs on load shaping problems.

This study uses seasonally and hourly values to determine the relative value of five sample DSM programs. To properly evaluate a DSM program, the full range of its impacts must be examined. Without a careful examination of the costs, benefits, and their redistribution effects, policy positions are difficult to defend.

This analysis is consistent with the outputs and assumptions of other analyses performed by Bonneville, including load forecasts, energy assumptions, and some program penetration assumptions. The goal of SDSM is to gain insights into the effects of programs by examining the hourly impacts, rather than simply considering annual energy.

The ability of an hourly model such as SDSM to account for diurnal and seasonal variations in program impacts allows a program's financial impact to be more precisely calculated. By disaggregating to an hourly and monthly level, the model can account for changes in revenues and for changes in marginal system cost on a month by month level.

1.2 STUDY OBJECTIVES AND METHODOLOGY

The study develops a consistent model of the public power system in the Pacific Northwest; and using the SDSM model, the study forecasts hourly energy usage over the next 20 years. Five demand-side management scenarios are examined in this study: electric thermal storage (ETS), water heater control (WH), and Model Conservation Standards (MCS) in the residential sector; efficient commercial lighting (CL) in the commercial sector; and conservation voltage reduction (CVR) in the transmission and distribution system. These programs cover a broad range of sectors and give a broad overview of an hourly analysis of load shape issues such as load shifting and peak reduction.

By evaluating the model under different DSM scenarios, we can assess the implications of these scenarios for Bonneville. These implications are examined in several dimensions. One dimension involves a classic energy/peak analysis. A second dimension examines the effect on Bonneville revenues and

costs. The third looks at the relative impact of these programs on generating and non-generating public utilities. Finally, the California Energy Commission (CEC) tests are implemented to help assess the impact of the tests on participants, the utility, ratepayers, and society at large. These tests assess the economic impact of DSM on these groups.

1.3 ORGANIZATION OF REPORT

This report consists of eight chapters and three appendixes. In Chapter 2, the general underlying technical relationships and the outputs of the SDSM model are briefly discussed. Chapter 2 also describes the software used for the analysis and the data required for each module in the SDSM model. Chapter 3 presents the Base Case (the public power system in the absence of any new programs), describes the sources of the data used in this analysis, and discusses the model calibration process. Chapter 4 describes the programs analyzed in this study. It first explains how the five programs were chosen, then explains the assumptions that were made about penetration and costs associated with each program, and finally describes the programs in detail.

Chapter 5 presents the analytical results--energy, peak, and financial--from applying SDSM to each program in a medium-growth, full technical performance scenario. The financial results include impacts on marginal costs and benefits to Bonneville, changes in the retail utility bills for generators and non-generators, and an application of the four California Energy Commission (CEC) tests. Chapter 6 examines the sensitivity of the results presented in Chapter 5 to the high-load growth scenario and to a reduced measure performance scenario. These results provide some sense of the robustness of the programs. Chapter 7 summarizes the conclusions of the study, and Chapter 8 contains the list of references.

Appendix A shows in graphical form the simulated load shapes compared with average historical system load shapes. Appendix B shows the penetration schedules for the five SDSM programs, and Appendix C discusses CVR peak reduction potential in the Bonneville Service Area.

2.0 SYSTEM DEMAND-SIDE MANAGEMENT MODEL AND METHODOLOGY

The System Demand-Side Management (SDSM) model is an hourly model. Hourly analysis makes it possible to examine the changes in marginal revenues that accrue from the movement of energy consumption from daytime to nighttime. It also allows a more insightful analysis of programs such as water heater control in the context of a hydroelectric-based generation system.

This chapter provides background on the SDSM model. A detailed discussion of the equations and mechanics of the model is contained in System Demand-Side Management: Software Tool Description.[a] The background information is presented in the same order that information flows through the model: the end-use module first, then the summary module, and finally the financial module.

2.1 OVERVIEW OF THE SDSM MODEL

The SDSM model simulates electricity consumption on an average day for each month, for both a Base Case and a Demand-Side Program Case, over the years 1989 to 2010. The model covers all aggregated public utilities in the Pacific Northwest. The model is written in Javelin,[b] a personal computer modeling package especially well suited to time series data. Running the model requires a copy of Javelin an IBM AT or compatible personal computer and, because of the SDSM model's expanded memory, large data storage requirements.

The SDSM model's Base Case is set up to follow and use data developed from conventional Bonneville section work. The Base Case contains six sectors: residential, commercial, industrial, aluminum service industries, agricultural, and street lighting sectors. The Base Case is calculated by

---

(a) Sands, R. D., and J. E. Englin. 1990. Letter report to Bonneville, Portland, Oregon.

(b) Javelin is a registered trademark of Javelin Corporation, Waltham, Massachusetts.

summing the end uses into sector totals and then aggregating the sector totals to find the system load.

The Demand-Side Program Case is found by adjusting the Base Case to account for the changes induced by a program affecting a single end use. The calculation involves subtracting (or adding) the impact of the program on the end use from the system loads for each hour. The analysis examines the effect of each program in isolation, requiring a separate analysis for each program.

SDSM contains three types of modules: end-use modules, summary modules, and financial modules. Each end-use module requires enough information to simulate load shapes by month, for both a Base Case and a Demand-Side Program Case. The summary module aggregates across end uses and compares the Base Case with the conservation programs analyzed in this study (described in Chapter 4) with one summary module per demand-side program. The financial module then performs a cost-benefit analysis, with one financial module per demand-side program.

Total system load can be broken down into any number of end uses, which are simulated separately in end-use modules. For the Base Case in this study, the end uses are defined as follows, with one module per end use:

- residential
  - space heat
  - water heat
  - other
- commercial
  - lighting
  - other
- industrial
  - pulp and paper
  - lumber
  - metals

- chemicals
- food
- other

- aluminum direct service industries
- agricultural
- street lighting.

Each end-use module requires information on load shapes, energy consumption, number of units, saturation rates, and penetration curves for demand-side programs. Four types of equipment are simulated over the 20 years: original equipment, replacement equipment for the Base Case, new equipment for the Base Case, and demand-side program equipment. The Demand-Side Program Case is constructed by allowing demand-side program equipment to replace other equipment at a rate specified by demand-side program penetration curves.

Once the end uses have been simulated for the Base Case and the Demand-Side Program Case, output from all end-use modules is consolidated into a summary module. The financial module then uses output from the summary module for a cost-benefit analysis.

2.2 END-USE MODULE STRUCTURE

Almost all of the nonfinancial data are entered into end-use modules. There is one module, or Javelin template, per end use. This module keeps track of the quantities of four types of equipment from 1989 through 2010. Each type of equipment has an associated load shape for each calendar month, and total energy demand by end use is calculated by multiplying equipment counts by their load shapes and summing across equipment types.

Load shapes for each type of equipment are scaled so that they match monthly and annual energy control totals. This allows end-use modules to be calibrated to forecasts of annual electricity consumption. The four types of equipment are:

Base Case:	existing equipment replacement equipment new equipment
Demand-Side Program Case:	demand-side program equipment

Two scenarios are constructed in the end-use module: a Base Case and a Demand-Side Program Case. Output for each scenario consists of hourly electricity consumption on an average day for each month from 1989 through 2010. Both cases are simulated separately, with all four equipment types entering into the Demand-Side Program Case where demand-side program equipment replaces other equipment types over time. In a retrofit program, existing equipment would be replaced. New standards for appliance efficiency would impact replacement equipment and new equipment.

Using three different equipment types provides the flexibility to simulate a realistic Base Case. Even without any demand-side program in place, existing equipment will wear out and be replaced with equipment that is at least as energy-efficient. An effective demand-side program will improve even further on standard replacement equipment.

Each end-use module starts out with annual counts of buildings, both total buildings and new buildings, from which the number of existing buildings can be calculated. An equipment replacement curve, based on equipment lifetime, is applied to existing buildings to determine how many buildings will require equipment replacement. For example, the equipment replacement curve determines how many water heaters will be replaced each year in existing homes. For each year, there are now three categories of buildings: 1) buildings that still use the original equipment, 2) old buildings that must replace worn-out equipment, and 3) new buildings that require new equipment.

Next, saturation rates, or market shares of electricity, are applied to the three categories of buildings. For example, the saturation rate for replacement water heaters determines what fraction will be electric. If supporting data are available, three different saturation rates for the three different equipment types may be entered. This provides equipment counts, by year, of the three types of electricity-consuming base-case equipment. The

Base Case is then constructed by multiplying equipment counts by load shapes and summing across equipment types.

A Demand-Side Program Case is constructed by keeping track of demand-side program equipment over time. Penetration rates for a demand-side program determine how quickly base-case equipment is replaced with demand-side program equipment. The model allows for two types of penetration rates, one for retrofit programs and one for programs impacting new and replacement equipment.

2.3 SUMMARY MODULE

The summary module is the simplest of the three modules. The summary module aggregates the end-use modules according to sector and tracks the energy, peak, and shape of each sector as well as the total load shape.

Each demand-side program has its own summary module. This module contains system base-case information, identical across all the programs, and the effect of the particular program on the Base Case. From a computational perspective, the only change needed to examine a different program is to add or subtract the effects of a different program end-use module.

2.4 FINANCIAL MODULE

The financial module performs four functions. First, the program cost information is entered into the model. Second, the module performs annual energy calculations that are directly comparable to other Bonneville forecasting models. Third, the module calculates the California Energy Commission (CEC) tests, estimating program impacts on the energy and demand charge of the generating and non-generating public utilities in the region [CEC and California Public Utility Commission (CPUC) 1987].

The financial model also calculates energy numbers that are commensurate with other Bonneville planning models, for example, system average megawatts (AMW) by average day, by month, and by year, and estimates of the sustained peak by month and by year.

To calculate the CEC tests (or financial results), the module requires the following cost information:

- incentive levels per participant
- administrative costs per participant
- avoided participant costs per participant
- participant out-of-pocket costs
- maintenance costs per unit
- measure cost ($/unit)
- discount rate.

The four CEC tests were designed to indicate the impact of the program on each of the interested parties. The interested parties in a utility demand-side program are the participants, the utility ratepayer, the shareholders of the utility (the utility itself serves as proxy for its shareholders), and society (which cares primarily about minimizing total resources).

The tests are designed with a conventional thermal utility in mind, which creates some conceptual difficulty in directly applying the tests to Bonneville programs. A further difficulty in applying the CEC tests to this model is that the CEC tests are designed to be applied to a closed system. This model does not dictate how Bonneville is to distribute the revenue from out-of-region sales. Some assumptions about the distribution of the benefits received from a program need to be made. For this study, we assumed that any revenue that accrues from the program will eventually flow back to program participants.

The financial module also examines the impacts of the program on the demand and energy portions of the generating and non-generating utility bills. This is based on the percentage of the hourly load that accrued to the generators and non-generators by hour for each month of the year during

and 1986.[a] (The calculation multiplies the percentage, by hour, times the simulated system load for each month and year of the forecast.)

Finally, the financial module calculates the present value of changes in Bonneville system costs and revenues. The changes in costs are calculated under two scenarios. One is if the transmission and distribution system is considered binding. Clearly, the instantaneous generating capacity of the hydro system in the Northwest is greater than the transmission and distribution system can handle. This version of the marginal costs also uses the concept of a single hour peak as the measure of peak. It is closest to the traditional thermal utility approach to valuing marginal costs.

A second measure of marginal cost is provided through the use of a sustained peak. This approach ignores any added costs that would accrue to the transmission and distribution system and focuses on the average megawatts required during the peak 15-hour period. In this case the marginal cost is the cost of energy (the same as the constrained case), with the energy cost including a daytime adder. This is the same as the sustained peak marginal cost. The marginal revenues are calculated the same in either circumstance. They include the additional revenue Bonneville could receive from sales to the highest bidder of the power freed up by the program.

2.5 MODEL VERIFICATION

Each of the three module templates was subject to verification of the underlying model relationships and logic. The level and focus of the model verification and quality assurance varied according to the function and degree of computational difficulty associated with each module.

The most straightforward of the modules was the end use module. Since the module only carries forward load data, no logical testing is required.

(a) If, for example, the generating utilities used 60% of the load at 8:00 am on an average day in January, the simulated system load is multiplied by 0.60 at 8:00 am for each January in the forecast. Because the utility behavior in 1985 and 1986 is expected to apply to the years forecasted, these numbers provide a measure of the changed incentives to generators and non-generators under the program.

The focus of the quality assurance procedures is to be certain that the data and variable names are consistent across the modules and line up with the names in summary module.

The summary module contains both new data and information imported from the end use module. Model verification consisted of two major procedures. The first was to verify that, on a month by month basis, the SDSM energy and peak results matched the results found using the PLM model of energy. The second module verification procedure was to check the logical consistency of the underlying code by checking sub-sections of the calculations in another software package. Together these two strategies assured that the software programming used in the model conforms with expectations.

The final module is the financial module. This module was verified in two ways. One was to assure that the interface between the financial module and the summary module was correct data entries were checked one by one for a random subset. Secondly, the software programming was verified on an output by output basis using other software. Verifiaction ofd the outputs using another software package assures that the programming logic is as expected.

3.0 BASE-CASE MODEL

The Base-Case models the public power system is the absence of any new programs. The Base Case provides predicted system loads by hour for each month of the year over twenty years. This chapter describes the inputs required to generate a Base-Case analysis, the calibration of the Base Case, and the verification of the Base-Case simulations and calibration through comparison with historical system load shapes.

3.1 SECTORAL INPUTS

In the Base Case the sectors are modeled as end-use energy demand by hour for an average day in each month of the year. Summing across end uses creates the simulated system load shape for each of the twenty years covered by the Base Case. Each end-use module requires inputs on the number of buildings, market share of electricity, average load shapes for each month, annual energy consumption per appliance, and the breakdown of annual energy into monthly energy consumption.

The 1989 long-term Bonneville forecast of annual energy consumption provides many of these inputs. Data from Bonneville's End-Use Load and Consumer Assessment Program (ELCAP) provides residential and commercial load shapes; load shapes for other sectors are taken from the Hourly Electric Load Model (HELM). Input data were obtained from the following sections at Bonneville: the Residential/Commercial Section of Power Forecasting (RPCB), the Utility Load Section of Power Forecasting (RPCD), and the End-Use Research Section of the Assessment/Evaluation Branch (RPEE). Data inputs for each sector are summarized below.

3.1.1 Residential Sector

Control totals for annual energy consumption by end use are taken from the medium-case forecast for public utilities obtained from RPCB. Control totals are expressed in average megawatts for each end-use by year. The forecast provides annual energy consumption, numbers of households, and saturation rates for electric appliances.

ELCAP provided hourly electricity consumption data by end use for several hundred residences in the Pacific Northwest. Separate load shapes were constructed for each calendar month by averaging hourly electricity consumption across households and days in the month. Monthly energy consumption shares are inputs required by the end-use module. The ELCAP data are also used to construct the breakdown of annual energy consumption into monthly energy consumption shares.

3.1.2 Commercial Sector

The medium-case commercial sector forecast provided annual energy control totals by end use. Forecasts of commercial electricity consumption are based on floor space, not numbers of buildings. For the SDSM model, a "building" is defined as 10,000 square feet of floor space. The commercial sector is modeled with two end uses, Lighting and Other, which are assumed to cover 100% of the floor space.

As in the residential sector, load shapes were derived from ELCAP data. ELCAP was able to provide shapes for five building types: offices, retail, grocery, restaurant, and warehouses. In order to be used in the SDSM model, these commercial sector building types were weighted and aggregated to derive a representative commercial building. This representative commercial building was then used in the SDSM model.

3.1.3 Industrial Sector

Six industrial groups are modeled in the SDSM model: Pulp and Paper, Lumber, Metals, Chemicals, Food, and Other. Control totals for annual energy consumption were taken from the medium-case industrial forecast. Industrial forecasts reported by Standard Industry Code (SIC) industry group were aggregated into these six industry groups for each of the six end-use modules. Because no particular customer number is reported for each industrial group, each industry is modeled as one large aggregate customer. Load shapes used in SDSM were taken from the HELM.

3.1.4 Aluminum Direct Service Industries (DSIs) Sector

Control totals for annual DSI energy consumption were taken from the medium-growth forecast. Load shapes were obtained by averaging daily load

shapes from HELM across days in a month. RPCD provided the monthly shares of annual energy.

3.1.5 Agricultural Sector

Agricultural sector forecasted loads came from the medium-growth forecast for public utilities. The number of units or customers was obtained from RPEE's End-Use Research Section. The load shapes from the HELM model were modified in the winter months. The absence of loads from November through February in the HELM shapes was not substantiated by fiscal and operating data. The monthly share breakdown was based on fiscal and operating data.

3.1.6 Street Lighting Sector

Annual energy forecasts for Street Lighting came from RPCD's Utility Load Section and the load shapes came from the HELM model. The daily shapes were averaged by hour into average monthly shapes. The monthly share breakdown came from fiscal and operating data.

3.2 SYSTEM CALIBRATION

The SDSM model is not capable of simulating energy consumption in the same way as the long-term residential forecasting model. In particular, price elasticities are not included in SDSM. The SDSM model simply calibrates to annual energy in the beginning and ending years of the long-term forecast.

Base-case calibration is accomplished by adjusting energy consumption for the three types of base-case equipment, which are inputs to the model. In 1989, the starting year, energy consumption for original equipment in the Base Case is adjusted to match the forecast. To match the ending year forecast, in 2010, energy consumption for new and replacement equipment is adjusted.

All of the end-use modules were calibrated to both the beginning and ending years of the long-term forecast. The residential forecast used for SDSM does not include Model Conservation Standards (MCS) homes but does assume that new or current-practice homes will be more efficient than existing homes. Conservation savings for the MCS program are relative to current-practice homes. A separate set of end-use modules was calibrated to the high-growth forecast to examine the sensitivity of conservation savings to load growth.

The end-use modules were set up so that much of the data found in a medium-growth forecast could be entered directly. This was especially true of the following annual time series from the residential forecast: total households, new households, saturation rate for existing equipment, saturation rate for new equipment in existing households, and saturation rate for new equipment in new households.

3.3 VERIFICATION

The SDSM model starts with annual energy consumption for each type of equipment in the Base Case. Annual energy is then broken down into monthly energy, based on monthly consumption data from ELCAP or HELM. Dividing by the number of days in each month provides energy for an average day by end use. Daily energy is then broken down into hourly consumption using the ELCAP or HELM load shapes. Multiplying the load shapes by equipment counts and summing across end uses provide a simulated system load shape for an average day during each of the twelve months.

The quality of the Base-Case simulations and calibration is assessed by comparing it with historical system load shapes. Simulated system load shapes from 1989, the first year in the SDSM model, were compared with average historical system load shapes from 1985 and 1986. This comparison was done for all twelve months. Appendix A provides a graphical comparison of historical and modeled system shapes.

After all of the end-use modules were completed, annual energy totals were again checked against the 1989 Bonneville forecast. Variables were added to the end-use modules to sum energy consumption across months, providing annual energy totals. Annual energy, in megawatt-hours, was then converted to average megawatts for a direct comparison with the forecast. The totals match because of SDSM's calibration for residential and commercial end-uses in 1989 and 2010, the beginning and ending years of the SDSM simulation. Other sectors are modeled with less detail, allowing for calibration to energy totals for all years.

4.0 DEMAND-SIDE MANAGEMENT ANALYSIS

This chapter presents information about the conservation programs analyzed in this study, including the rationale behind the selection of the programs and cost and the program penetration information. Each program is then discussed separately in detail.

4.1 PROGRAM SELECTION

Because a major goal of this study was to provide a broad test of the application of the SDSM model and methodology to varying data quality and institutional wisdom about DSM programs, a key issue in the study design was selecting the programs to be analyzed. Three criteria were applied in selecting these programs:

- The programs should span the main customer sectors that Bonneville serves. By spanning several sectors, a variety of Bonneville analytical sections could contribute to the project. This also provided a test of the impact of programs in different sectors on Bonneville system loads over the next twenty years.

- New programs not under active development at Bonneville should be included, as well as existing programs.

- Load-shaping issues should be addressed. By looking at programs that affected system loads in dramatically different ways, the study could examine the relative impact of different strategies to shaping the Northwest's public system.

Four primary sectors of load were considered for programmatic analysis: residential, commercial, industrial, and agricultural. The residential sector was chosen because it will play a major role in load growth in the Pacific Northwest over the next twenty years and residential data are readily available. Three programs were selected that affect residential sector load: Model Conservation Standards (MCS), water heater control (WH), and electric thermal storage (ETS). Although the commercial sector has also been well studied across the country, the results of many of these programs are not applicable to conditions in the Pacific Northwest region and others would clearly be impractical here. Only commercial lighting (CL) was considered suitable. This type of program has been studied around the country and in the

Northwest. Industrial programs proved to be elusive: sufficient detailed information was not available about costs, penetration schedules, and load-shape impacts to construct a credible program. As a result, no industrial program is analyzed. The agricultural sector was not included in this study because it has been the recent subject of careful analysis by Bonneville. Finally, conservation voltage reduction (CVR) was chosen because it allows Bonneville to enhance the efficiency of the system itself rather than attempting to influence the end-use demands of particular sectors. Because CVR enhances the efficiency of the entire system, it covers all sectors.

The MCS is an extremely well-studied program; several of the other programs are less understood in the Northwest. Applying a CVR program to the Pacific Northwest power system has been the subject of several studies, as has CL. ETS has been examined in other parts of the country and has been considered as a program to defer transmission and distribution construction, but has not been the subject of a region-wide study. A similar discussion applies to WH programs.

The programs are designed to address a wide range of load-shaping issues. MCS addresses basic energy saving and winter peaking concerns. CVR saves energy all year. ETS shifts load from the daytime to the evening, filling the nighttime valley and reducing peak. The WH program is a peak reduction program that can operate all year. The CL program is basically an energy reduction program but also provides some peak savings.

4.2 PROGRAM PENETRATION AND COST DATA

Once the programs were selected, the program design issues had to be addressed, including the rate of penetration and program costs. The degree to which the programs penetrate the respective "populations" varies considerably. MCS and CVR achieve very high penetration rates because they are either code or entirely under Bonneville control. Other programs are not likely to achieve such high penetration rates. The penetration schedules associated with each program are shown in Appendix B.

Table 4.1 shows the costs associated with implementing each program. The table shows the cost per participant or control point for each of the programs

TABLE 4.1. Program Costs ($ per participant)

	ETS	WH	MCS
Incentive	100	25	1609
Installation	0	0	0
Measure	2400	150	0
Administration	5	0	0
Maintenance	0	0	0

except for the CVR and CL programs. The CVR covers the entire system at a cost of $12 million per year for 10 years. CL is on a per-square-foot basis. The costs are defined as cost per average 10,000 square foot commercial building. CL incentive costs are $3,168; a $20 administrative cost is assumed. The t ble shows the ETS program to be the most expensive on a per-point basis. MCS follows closely behind, with WH easily the least expensive.

4.3 ELECTRIC THERMAL STORAGE PROGRAM

The ETS programs store heat generated during the evening and release that heat during the day by heating bricks or crushed rock at night and simply circulating air over the hot bricks or rock during the day. ETS programs can have dramatic effects on the pattern of heating load used by residential customers. However, they may create new, higher peaks early in the morning or late at night if too many customers join a program. In the United States, ETS has enjoyed good customer acceptance in the Northeast and the Midwest [Electric Power Research Institute (EPRI) 1987, p. 53]. ETS has been widely used in Europe. In general it is a well-understood program.

Heat storage systems allow consumers to have heat on demand but consume electricity to charge the storage system, which can only be used during a predetermined time period. The heat is stored in the rocks or bricks by heating coils that have capacities between 14 and 30 kilowatts (kW) and storage capacities between 90 and 200 kilowatt-hours (kWh). The load for the fan required to circulate the heat is about 0.17 kW. Standard heating charging periods are about 8 hours; the timing of the charging cycle is up to

the utility. No consumer benefits or costs are associated with the timing of the recharge.

End-use load shapes are based on an engineering adjustment to ELCAP load shapes. The engineering adjustment assumes that the total daily heating load of the residence will not change under a ceramic heater program. The ceramic heater program will even out the load throughout the nighttime hours, but will be essentially zero during the day. The only load will be the fan used to circulated air over the hot bricks. Figure 4.1[a] compares the average base and ETS typical residential load shape.

4.4 WATER HEATER CONTROL PROGRAM

WH programs directly control residential water heaters either by installing a timer on the water heater or by using radio command. Normally, water heaters are controlled either by complete shutoff or by cycling during peak morning periods. The peak period control results in a need to pay back the energy later in the morning. As a result, system peak is reduced in the early morning but, when the full system load is flat in the morning, the payback can result in a new higher peak later in the morning.

WH programs have been widely applied throughout the United States. One Northwest program is currently under way in the Milton-Freewater Public Utility District (PUD). WH is well understood and (relatively) widely practiced (EPRI 1987, p. A-57).

WH measures are widely used throughout the country as a way for a utility to control loads that are spiked in the morning and are truly deferable for many customers. The typical reduction in peak demand achieved from control of water heaters is 1 kW. Deferred savings has been reported to range from 0.3 kW to 1.6 kW per controlled water heater.

The controlled water heater end-use load shapes used in this analysis are based on an engineering adjustment to ELCAP data. The loads are

---

(a) All figures referred to in this chapter are shown at the end of the chapter.

controlled between 6:00 am and 9:00 am and are paid back between 9:00 am to 12:00 pm. Figure 4.2 compares the load shapes associated with the average base and WH cases.

4.5 MODEL CONSERVATION STANDARDS PROGRAM

The residential MCS constitute an energy-efficiency code for new residential construction. The philosophy behind the improvement in energy efficiency is that residential construction will be a lost resource in the future without energy-efficient construction. Bonneville has an extensive MCS program and actively encourages its adoption through the Northwest Energy Code program. This analysis assumes that the code will be adopted on a region-wide basis by 1992.

While the MCS program has undergone considerable shifts and changes since its introduction, its basic intent and construction and material requirements have not. The code requires improved energy efficiency in windows, doors, and insulation. In addition, the code emphasizes different construction techniques that make the house "tighter," improving the energy efficiency of the home.

Because MCS is a code rather than a technology, its technical description is not clear cut. A variety of methods can be used to meet the MCS. A second confounding factor is that the specifics of the MCS differ by climate zone. This makes definition of the precise technical aspects of the MCS code beyond the scope of this chapter. The key ingredient is that achieving the MCS means achieving a particular level of energy efficiency. The average annual energy savings the code is expected to achieve across the three climate zones is 2476 kWh per residence built to the code.

In most analyses the adjustment to the Base-Case end-use load curves is based upon an engineering calculation. In this analysis the end-use load shapes are based on actual metered data: subset of the ELCAP project meters homes built to the MCS, the Base-Case houses are based on the non-MCS ELCAP homes. Figure 4.3 compares average base and MCS space heating loads for a typical residence.

4.6 COMMERCIAL LIGHTING PROGRAM

Increasing the efficiency of CL is source of both peak and energy reduction. The basic premise of the program is that much of the existing CL is not energy-efficient. In most retail stores the CL load is between 25% and 30% of total building load. The program consists of increasing the energy efficiency of the CL as the lighting is replaced due to natural failure. Energy-efficient CL is well understood and is part of many demand-side programs around the country.

Several approaches to CL are available. The most straightforward is a simple replacement of existing bulbs with more efficient bulbs during the normal replacement cycle. A general sense of the energy used by commercial buildings is that an average office building will use 1.57 watts per square foot (W/ft^2) and a restaurant will use 1.62 W/ft^2. The energy-efficient lighting will reduce this energy consumption by 12%.

The precise reduction of the building load depends on the type of commercial building. Without splitting the commercial sector into each of its sub-building types, precise estimates of the technical potential of the energy savings are not possible. This study uses an average commercial square foot, which is built up from approximate counts of the different types of commercial buildings in the Pacific Northwest using the Pacific Northwest Nonresidential Energy Survey (Baker 1986). End-use load shapes are based on an engineering adjustment to ELCAP load shapes. The engineering adjustment assumes that the pattern of total daily lighting will not change under the program. The change in the load comes through the change in the energy used by the lighting. Figure 4.4 compares the average base and CL load shapes for a typical commercial building.

4.7 CONSERVATION VOLTAGE REDUCTION PROGRAM

One option for reducing system energy and demand is to improve the system itself. CVR is one technique that could be applied to produce savings in all distribution systems in the Bonneville service area. An analysis of the potential savings for the Bonneville system is reported in Assessment of Conservation Voltage Reduction Applicable in the BPA Service Region (De Steese

1987). This report is the basis of the present analysis to estimate the regional effect of using CVR as a peak reduction measure.

Most appliances are sensitive to the voltage level of electric service coming into a building. Residential service is required to be in a range of 114 to 126 volts, or within 5% of 120 volts. If the voltage serving a residence is reduced, many of the appliances will consume less energy. Resistive loads, such as lights and heating elements, will experience more than a proportional decrease in power. However, some of the decrease will be offset over time because the appliance will stay on longer. This is particularly true of electric resistance space heating systems.

A CVR program imposes a narrower band, from 114 volts to 120 volts, on the voltage serving appliances. Each appliance still operates on a voltage in the allowable range, but the average voltage serving all appliances is lower. Table 4.2 shows estimates of the percentage reduction in power, by sector, for a voltage reduction of 2.85%, the percentage reduction used by De Steese (1987). The values in Table 4.2 were used to scale the base load shapes used in the SDSM analysis by a fixed percentage reduction throughout the day.

Estimates for each sector are based on an average percentage response of demand, or power, to a 1% reduction in voltage. The rate of response, or elasticity, for each sector is actually a linear approximation to the sum of many nonlinear processes. Appliances respond very differently to voltage reductions, requiring separate elasticities for each sector. The percentage change in voltage and an elasticity are all that are needed to estimate percentage changes in demand due to CVR.

Appendix C provides more detail on the percentage of voltage reduction that could be achieved through various CVR programs. The appendix also provides estimated costs for each of the programs. Section C.5 describes how the response to a change in voltage, or elasticity, can vary across appliances.

TABLE 4.2. Percentage Effect on Hourly Load Shapes for 2.85% Average CVR Applications

End-Use Load	CVR Hourly Demand Reduction (%)
Average Residential Sector Energy	2.2
Average Commercial Sector Energy	2.8
Average Industrial Sector Energy	1.2
Average Agricultural Sector Energy	(a)

(a) Literature lumps Agriculture with Industrial Sector. The percentages could be considered to range between 1.2% for the Industrial Sector and 2.9% for the Motor-Operated Equipment.

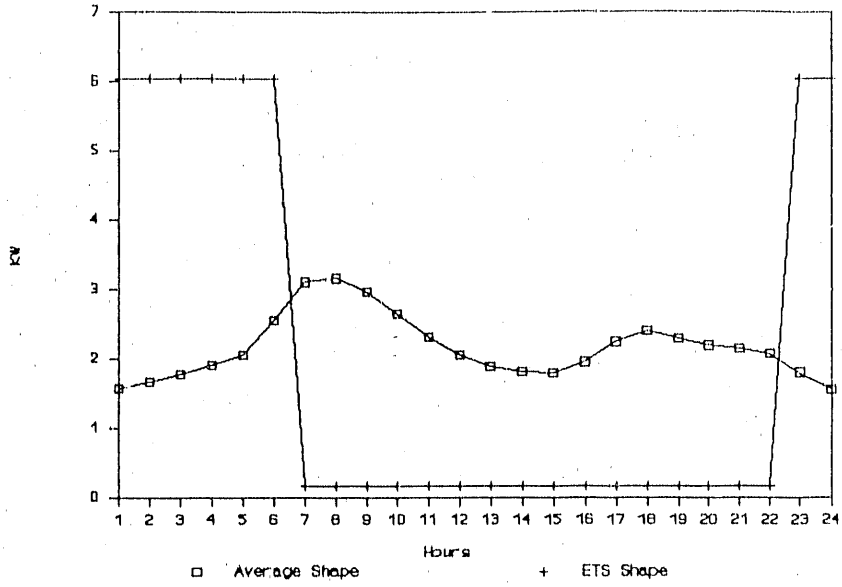

FIGURE 4.1. Average Base and ETS Daily Shape for a Typical Residence

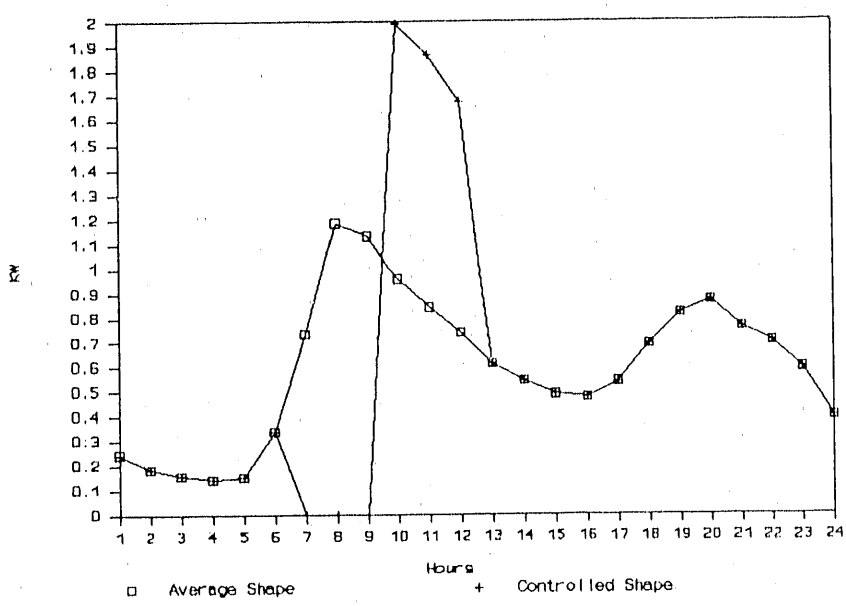

FIGURE 4.2. Average Base and WH Daily Shape for a Typical Residence

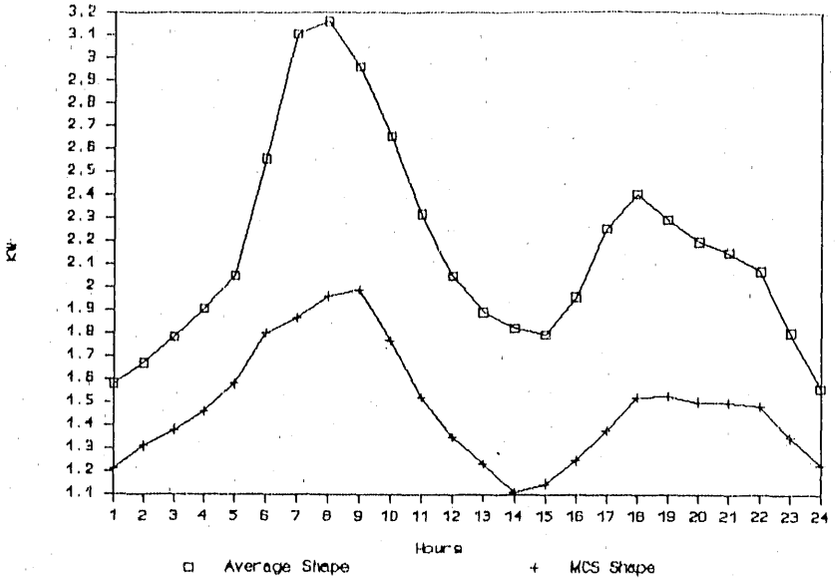

FIGURE 4.3. Average Base and MCS Daily Shape for a Typical Residence

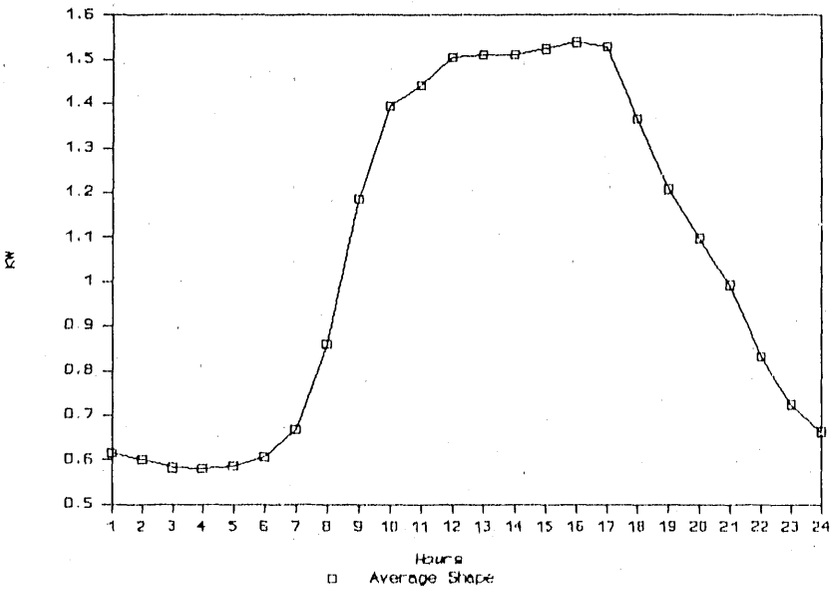

FIGURE 4.4. Average Base and CL Daily Shape for a Typical Commercial Residence

5.0 RESULTS FOR PROGRAMS ANALYZED

This chapter reports the impacts of the five DSM programs analyzed in this study on the public power system. First, the peaking and the energy results of the analysis are discussed. The remaining sections are devoted to the financial results: the Bonneville financial impacts, the retail utility impacts, and the CEC tests.

5.1 DEMAND-SIDE MANAGEMENT ENERGY RESULTS

The ETS and WH programs were designed to have no energy impacts. Energy was shifted between hours within each day, resulting in no change to total energy consumption over a month or year. The other three programs resulted in energy savings. Energy savings by season--measured in average megawatts (AMW)--for CL, MCS, and CVR are shown in Figures 5.1 through 5.3, respectively.[a]. Energy savings from residential MCS are concentrated in the winter months because of the Northwest system characteristics. Savings from the CL program are spread out fairly evenly throughout the year. The CVR program had the highest overall energy savings, at 168 AMW, with a seasonal pattern roughly proportional to that of total system load.

5.2 DEMAND-SIDE MANAGEMENT PEAK RESULTS

Peak savings are generally higher than the corresponding average energy savings for four of the five demand-side programs. Peak savings are measured in megawatts at the hour of system peak and are therefore coincident peak savings. Coincident peak savings for ETS, WH, CL, MCS, and CVR are shown in Figures 5.4 through 5.8, respectively.

ETS reduces winter system peaks, even without any overall energy savings. The WH program peak impacts differ from other programs. With controlled water heaters in the region, the hour and magnitude of system peak can be changed. If the system peak is changed, then peak savings from WH are negative. If the

---

(a) All figures referred to in this chapter are shown at the end of the chapter.

time of system peak is not changed, then savings are positive. Peak savings for WH were positive during some months and negative during others, especially in the summer. The negative savings in the summer result from the payback causing a higher later system peak.

5.3 DEMAND-SIDE MANAGEMENT ECONOMIC RESULTS

The DSM economic results value the changes in energy and capacity generated by the programs. Three dimensions of the results are reported here: the impact of the programs on the revenues and costs of the Bonneville system, the distribution of the results across the generating and non-generating retail utilities in the Northwest, and the calculation of the conventional CEC tests of the relative value to different participants. These results yield some insight into the distribution of the benefits of the programs.

5.3.1 Bonneville Economic Results

Two economic impacts on Bonneville from this program are assessed: marginal revenue and marginal cost. Marginal revenue is evaluated under a single set of assumptions, while marginal cost is evaluated under two sets of alternative assumptions: 1) when transmission and distribution are constrained and 2) when the transmission and distribution are not constrained.

Table 5.1 shows the present value of the marginal costs and marginal revenues to Bonneville by program. The difference in marginal costs between the transmission and distribution constrained case and the unconstrained case are small for each of the programs except WH. This difference reflects the relative precision of the WH program. WH is aimed at a particular hour, the system peak, rather than across a broad spectrum of hours. In the constrained case the WH savings reduces system marginal cost by an additional $28 million. Aside from this case, little difference exists between the two methods of valuing changes in marginal cost.

As Table 5.1 indicates, the programs differ greatly in the scale of their effects. CVR is the dominant program with respect to reduction in marginal cost and increases in potential marginal revenue. The present value of the

Table 5.1. Bonneville Economic Results (millions of dollars)

	Reductions in Unconstrained Costs	Reductions in Costs	Increases in Revenue
ETS	32	26	73
WH	44	16	130
CL	143	147	169
MCS	127	133	186
CVR	530	527	642

increased marginal revenue is forecasted to be better than one-half billion dollars. The other programs all fall into the 100 to 200 million dollar range.

5.3.2 Utility Impacts

The generators, non-generators and the DSIs constitute the bulk of the public power system's customers. The present value of the impact in millions of dollars of the five programs on both generating and non-generating utilities is shown in Table 5.2. Because the ETS and WH programs have no net energy impact, the utilities energy payments to Bonneville are not affected. However, the demand charge is reduced. In general, the reduction in payments seen by Priority Firm rates is modest. The greatest reduction by a large margin is an $18.8 million reduction of non-generators demand charges under CVR. Non-generators benefit more from additional reductions in demand charges

Table 5.2. Retail Utility Impacts (millions of dollars)

	Energy Charge		Demand Charge	
	Generator	Non-Generator	Generator	Non-Generator
ETS	0.0	0.0	-0.7	-1.4
WH	0.0	0.0	-1.7	-3.8
CL	-0.8	-2.3	-0.3	-0.7
MCS	-0.5	-1.4	-0.5	-1.0
CVR	-6.8	-7.8	-3.7	-8.8

than do the generators because most generators already manage their generation to reduce their Bonneville demand charges. Our analysis assumes that the behavior of the utilities does not change regardless of program activities.

5.3.3 California Energy Commission (CEC) Tests

Another perspective on the programs can be found by applying the four CEC tests. The CEC tests are designed to reflect a variety of perspectives on program benefit and costs (CEC and CPUC 1987). The tests are simple or net present values using similar variables in their calculation. The distinguishing features of each test are as follows:

- The Participant Test is the only test that includes as a benefit the reduction in energy bills (rather than rates) of program participants.
- The Ratepayer Impact Measure (RIM) Test considers increases in rates to be a negative outcome regardless of the impact of the program on participant bills or social well being.
- The Total Resource Cost Test, or societal cost test, includes all the costs and benefits for both the utility and participants. According to the CEC, it counts as costs both utility program costs and participant out-of-pocket costs.
- The Utility Cost Test is identical to the Total Resource Cost Test except that participant costs and benefits are excluded.

These tests are useful tools for screening and ranking potential resources. Table 5.3 shows the resulting present values in millions of dollars.

Table 5.3. California Energy Commission Tests (millions of dollars)

	Participant	Ratepayer	Utility	Total Resource
ETS	46	38	-143	-28
WH	-20	-65	-151	-24
CL	244	-169	134	-113
MCS	545	-427	-411	127
CVR	156	156	523	373

Only one program, CVR, is found to beneficial to everyone under the CEC tests. The CVR program pays large dividends from all perspectives. Both CVR and MCS are valuable from a total resource, or social, perspective. Interestingly, the net benefits of CVR are nearly triple the MCS benefits. The Total Resource Cost Test is the one that would typically be applied by a public agency. The Participant Test is positive for all the programs except WH. Because the increases in marginal revenues are very large ($73 to $640 million), these results are likely to flow from the assumption that additional marginal revenues are eventually returned to the participants in the form of reduced rates and that participants receive the incentive payments. The only program that is not favorable to any group is the WH program.

5.4 CONCLUSION

In general the energy results were consistent with prior expectations. There were no energy impacts in the ETS and WH programs. The MCS, CVR, and CL programs showed significant energy savings, with MCS savings showing the most seasonality. One of the striking results was that the WH program generated a new, higher peak because of the program's payback late in the morning. ETS used just as much energy as regular forced air; however, its ability to shift the load into the nighttime hours results in a consistent peak reduction.

All of the programs had sizable impacts on the costs and revenues of Bonneville. The largest single program impact was from CVR. Because of the broad efficiency improvements implied by the CVR program, considerable savings occurred; marginal revenue impacts of over $600 million were predicted for the program. MCS, CL, and WH all had revenue impacts ranging from $150 to $200 million. Of the five programs, only MCS and CVR had positive CEC Total Resource Cost Test results. The rest of the programs, while saving energy and/or peak cost, did not meet the Total Resource Cost Test. The CVR program had net benefits of $375 million. The MCS program had net benefits of $127 million. All of the programs demonstrated the generating utilities ability to reduce demand charges. The size of these impacts were fairly small, generally running in the $2 to $3 million range.

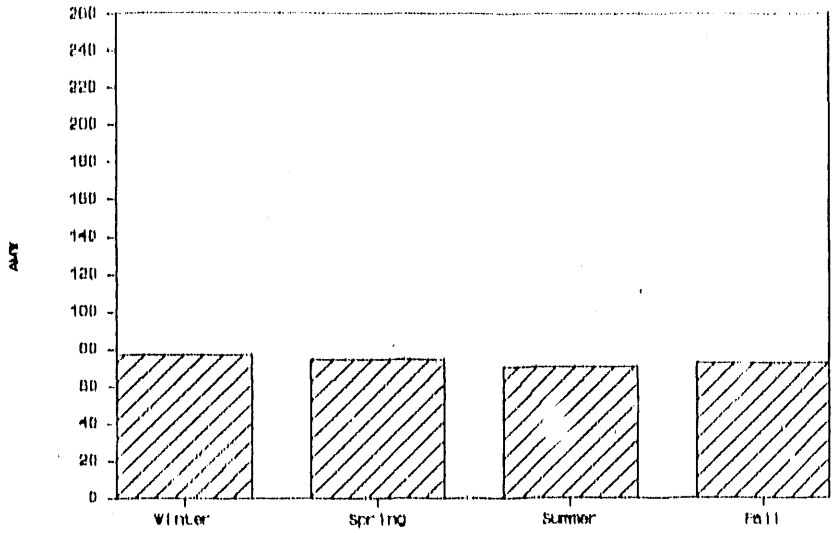

FIGURE 5.1. CL Energy Savings by Season (2010)

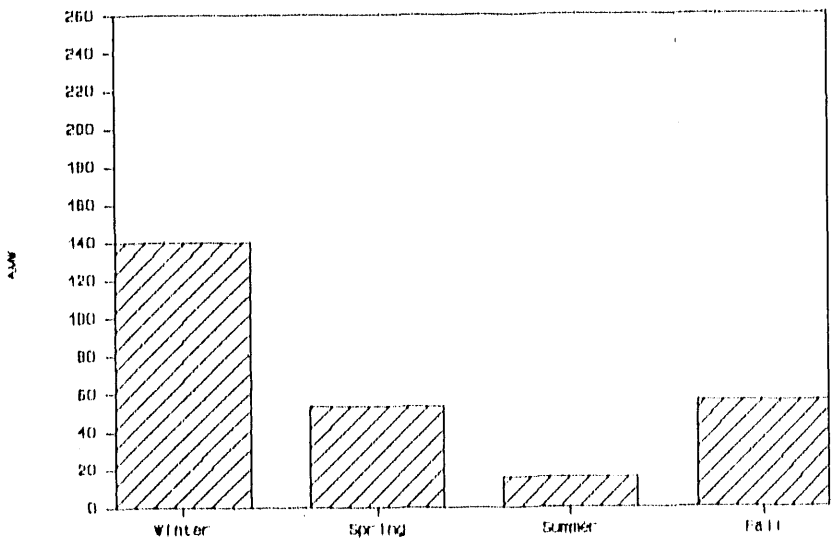

FIGURE 5.2. MCS Energy Savings by Season (2010)

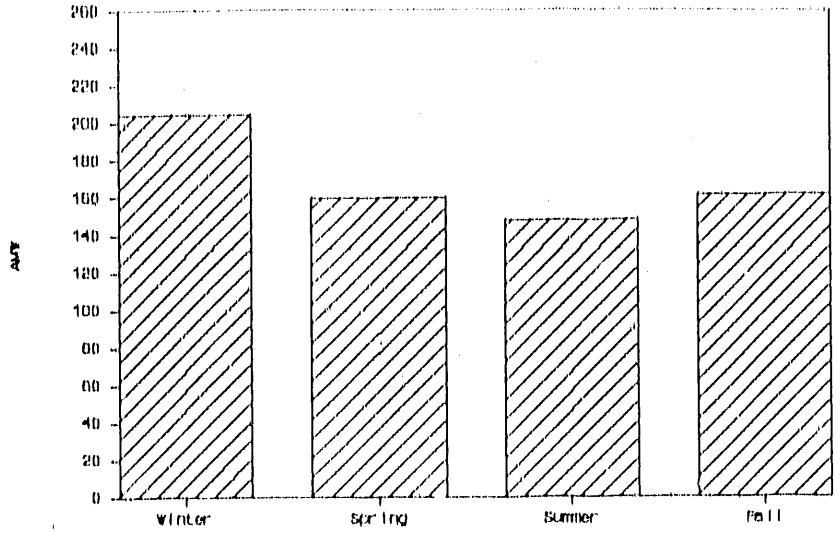

FIGURE 5.3. CVR Energy Savings by Season (2010)

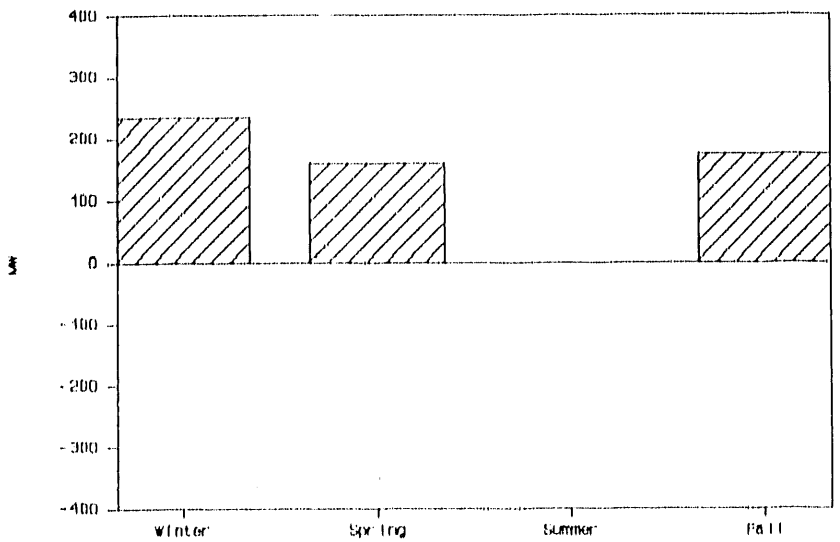

FIGURE 5.4. ETS Peak Effects by Season (2010)

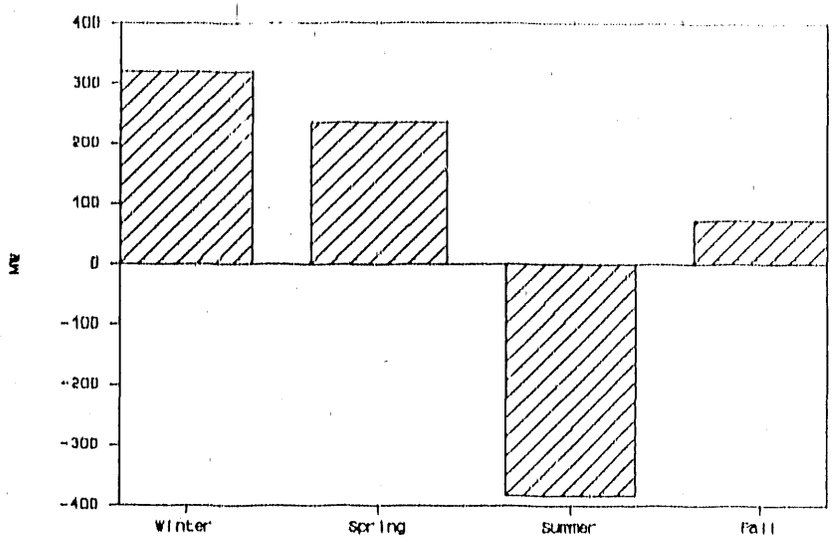

FIGURE 5.5. WH Peak Effects by Season (2010)

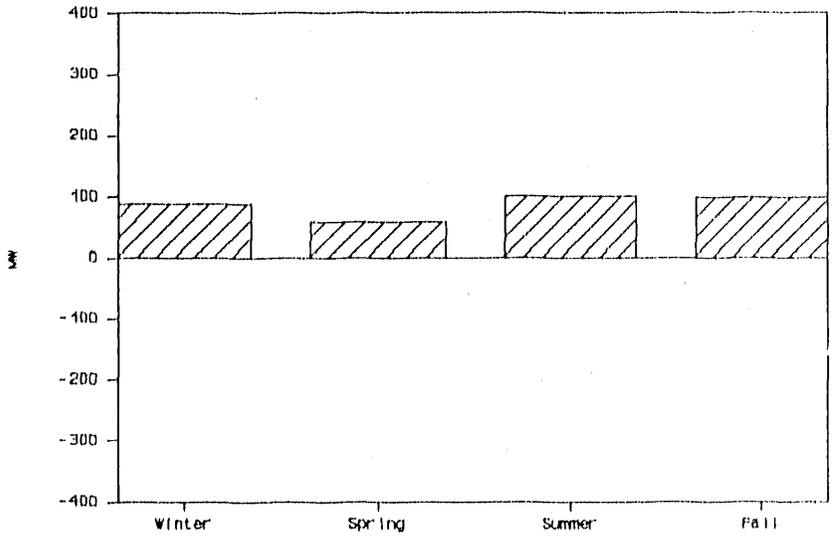

FIGURE 5.6. CL Peak Effects by Season (2010)

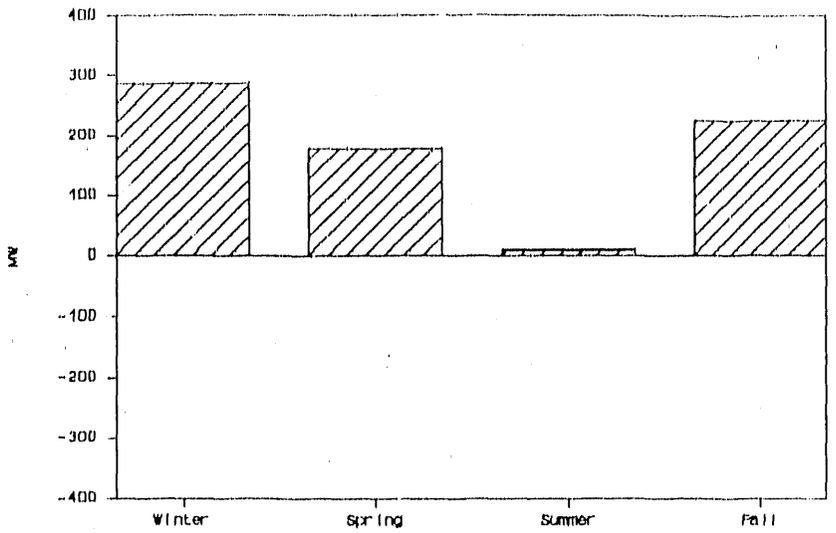

FIGURE 5.7. MCS Peak Effects by Season (2010)

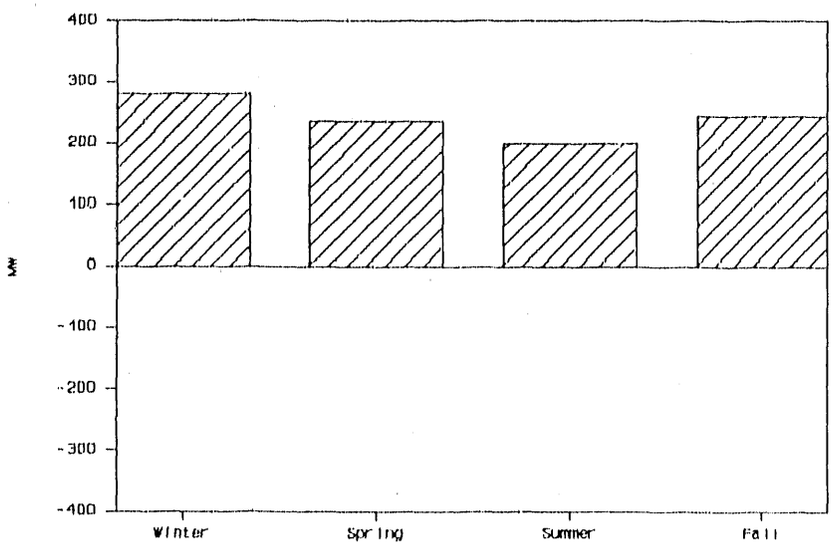

FIGURE 5.8. CVR Peak Effects by Season (2010)

6.0 SENSITIVITY ANALYSES

The results presented in Chapter 5 are based on several assumptions. Two key assumptions are the rate of load growth (medium growth) and the efficiency of each conservation measure (full technical performance). In this chapter, the sensitivity of the overall results to these assumptions are evaluated by varying the rate of growth and measure performance.

6.1 SENSITIVITY ASSUMPTIONS

The sensitivity analyses focused on two cases of concerns to utility planners: when load growth exceeds what has been predicted as likely and when programs do not function to the level of the predictions. The first corresponds to the high-growth load case in this set of sensitivity runs. Our performance degradation case entails reducing the expected savings associated with a program by 25%. Assessing the performance of the program under extreme growth conditions helps reveal the degree to which these programs can function as insurance against unforseen load growth. A program that functions especially well under high-load growth has additional value that is not measured by the standard cost-benefit calculus. In the same vein, a program that is of positive value even if it functions below expected performance is also a better bet.

Only three of the five programs assessed in the Base Case were examined: CL, MCS, and CVR. Each performed reasonably well in the Base Case. This analysis assesses how well the programs perform under less-than-predicted conditions. WH and ETS were not examined because they have no energy savings associated with them.

6.2 HIGH-GROWTH CASE CALIBRATION

The high-growth case was calibrated in exactly the same way as the medium-growth case (Base Case). Bonneville provided the 1989 high-growth forecast in the same format as the medium forecast. All end uses were calibrated to match annual energy in at least 1989 and 2010, the beginning and ending years of the SDSM simulation. Sectors that did not have a specific

demand-side program, such as the industrial sector, were modeled in a simple enough way so that all years could be calibrated to annual energy. As in the medium-growth case, calibration was obtained by adjusting energy consumption of existing and new equipment in the Base Case.

6.3 SENSITIVITY RESULTS

Our sensitivity results reflect changes in either measure performance or the rate of growth of the regions demand for electricity. Program parameters are held constant across the Base Case and the sensitivities analyses. This allows direct comparison of the results. In the high-growth scenario, the model is applied to the Bonneville high-growth case. The other set of sensitivity analyses are based on the medium-growth case, but with measure performance reduced by 25%. The sources of data are the same as those for the Base Case (described in Section 3.1). The following subsections report the energy, peak and financial results of the model.

6.3.1 Peaking and Energy Results

Seasonal energy results are summarized in Table 6.1 for the Base Case (medium-growth) and two sensitivity cases (measure performance and high-growth). Sensitivity analysis was performed only on the CL, MCS, and CVR programs. As expected, all three programs showed a decrease in savings for the measure performance analysis, and an increase in savings for the high-growth case. The MCS program in the high-growth case shows a dramatic increase in savings relative to the Base Case and to all other programs. In the high-growth case, most of the increase in residential electricity consumption is due to new households, providing more potential MCS homes. MCS energy savings for the medium-growth and high-growth cases are plotted in Figure 6.1.[a]

MCS energy savings show a very steep drop in the measure performance case because of the way in which the 25% drop in measure performance was defined. The 25% decrease in savings was measured relative to the average existing home

---

(a) All figures referred to in this chapter are shown at the end of the chapter.

TABLE 6.1. Seasonal Energy Savings in 2010 (average megawatts)

Medium-Load Growth	Winter	Spring	Summer	Fall
ETS	0	0	0	0
WH	0	0	0	0
CL	77	74	70	72
MCS	140	53	16	56
CVR	204	159	148	161
Measure Performance				
CL	59	57	53	55
MCS	47	18	5	19
CVR	153	120	111	121
High-Load Growth				
CL	81	78	73	75
MCS	422	161	48	169
CVR	278	216	200	219

in the Northwest. This brought MCS performance down to where it was only marginally better than current-practice homes. Therefore, savings from residential MCS were not much greater than in the Base Case.

Peak savings are displayed for all programs by season in Table 6.2. During the winter, peak savings are larger than the corresponding energy savings for all programs and for all sensitivity cases. Peak savings are well behaved in the winter and shoulder months, decreasing in the measure performance sensitivity case, and increasing in the high-growth case. Peak savings for MCS homes became very large in the high-growth case and are plotted in Figure 6.2.

TABLE 6.2. Seasonal Peak Savings in 2010 (megawatts)

Medium-Load Growth	Winter	Spring	Summer	Fall
ETS	234	160	0	175
WH	320	236	-384	73
CL	87	58	101	98
MCS	285	179	8	225
CVR	281	235	201	243
Measure Performance				
CL	66	44	77	75
MCS	156	121	-11	131
CVR	211	177	150	183
High Load Growth				
CL	91	60	105	102
MCS	775	497	46	599
CVR	381	319	272	329

6.3.2 Economic Results

The same financial results as the Base Case are used in the sensitivity analysis. The basis for the calculations is identical: direct comparison between the Base Case and appropriate sensitivity results. Table 6.3 presents the Bonneville financial impacts.

Both measure performance and high growth are reported in the table. As in the Base Case, CVR generates the most additional revenue and reduces marginal costs the most. If expected MCS performance is degraded to 75% of the performance currently expected, reductions in marginal costs fall dramatically. Base results show an unconstrained marginal cost of $127 million; the present value of reduced measure performance costs is only $50

TABLE 6.3. Bonneville Financial Results (present value in millions of dollars)

Measure Performance	Unconstrained Marginal Costs	T&D Constrained Marginal Costs	Marginal Revenue
CL	109	111	129
MCS	50	40	76
CVR	398	396	482
High-Load Growth			
CL	219	207	173
MCS	561	558	541
CVR	813	789	681

million, a reduction in benefits of over 60%. In contrast, CVR reductions in marginal cost are only 25%, from $530 to $398 million.

CL falls about 30% if measure performance is reduced. The transmission and distribution constrained costs behave very similarly. Marginal revenue calculations also show the non-linear effects of different program performance. MCS reductions in marginal revenue from the Base Case is also about 60%. CVR is about 25% as well. In the context of reduced Bonneville costs or increased revenues, benefits from the CVR program are less vulnerable to over-optimistic technical assumptions than are the MCS benefits.

High-load growth is another scenario of considerable interest. These results reinforce the interpretation of MCS as a program with benefits that vary considerably with the baseline assumptions. The marginal cost reduction under the unconstrained scenario for MCS is nearly 450% greater than under the medium-growth case. Revenue under the high-growth case has a dramatic effect for MCS as well, with an increase of about 300% over the Base Case. CVR and CL also gain value under a high load growth scenario. High-growth CVR and CL cost reductions are around 150% of the Base-Case change in cost. In very sharp contrast CVR increases 6% and CL only 2%.

Table 6.4 shows the relative impact on the retail utilities of the programs if performance is degraded or if a high-growth scenario is realized. The basic effects on the retail utilities is very similar to the medium growth Base Case. The scale of the numbers is very close under either scenario or the Base Case. The relative impact of the programs on the generators or non-generators is relatively invariant to measure performance or high-load growth.

The final sensitivity analysis looked at the CEC test calculations, shown in Table 6.5. The CL program did not meet the Total Resource Cost Test under either sensitivity case. MCS and CVR met the Total Resource Cost Test under both scenarios. Under degraded measure performance, the benefits are about one-third that of the Base Case for both the MCS and CVR.

High-load growth scenarios show considerable programmatic benefits. For MCS the Total Resource Cost Test indicates net benefits of over one-half billion dollars. For CVR the benefits are over three-quarters of a billion dollars. A distinction between the programs can be seen in the Utility Test. Because the utility (in this case Bonneville) is paying the incentives (along with ratepayers), they show a net loss on their balance sheet. If the incentives reflected social gains more evenly, these costs would more than

TABLE 6.4. Retail Utility Impacts (millions of dollars)

Measure Performance	Energy Charge		Demand Charge	
	Generator	Non-Generator	Generator	Non-Generator
CL	-0.6	-1.7	-0.2	-0.5
MCS	-0.1	-0.4	-0.2	-0.5
CVR	-5.1	-5.8	-2.8	-14.1
High-Load Growth				
CL	-0.8	-2.3	-0.3	-0.7
MCS	-1.5	-4.1	-1.3	-2.8
CVR	-2.6	-7.3	-1.5	-2.6

TABLE 6.5. California Energy Commission Tests (millions of dollars)

Measure Performance	Participant	Ratepayer	Utility	Total Resource
CL	233	-180	98	-137
MCS	513	-458	-463	46
CVR	117	117	392	281
High-Load Growth				
CL	245	-305	-202	-54
MCS	873	-902	-314	561
CVR	-87	-87	876	811

offset the reductions in cost accruing to MCS. CVR, on the other hand, involves no incentives and so the cost accruing to the utility is smaller than MCS.

6.3 CONCLUSION

The most striking energy result is the increase in savings, in both peak and energy, due to residential MCS in the high-growth case. These savings show the importance of the residential sector to the regional high-growth scenario. Other energy results were fairly predictable. The energy savings from CVR roughly follows the pattern of regional system load growth.

The financial results provide additional insights. CL is fairly constant under all scenarios examined. CVR programs are also quite steady. The system changes and their value are nearly proportional to measure performance and load growth. On the other hand, MCS varies widely in the financial analysis. The net benefits grow quickly as the regional load growth increases. Both CVR and MCS have positive CEC Total Resource Cost Test results, meaning that they are worth more than their cost under either scenario (as well as under the Base Case). The result that CVR and MCS are programs with net positive benefits is robust to the scenarios in this study.

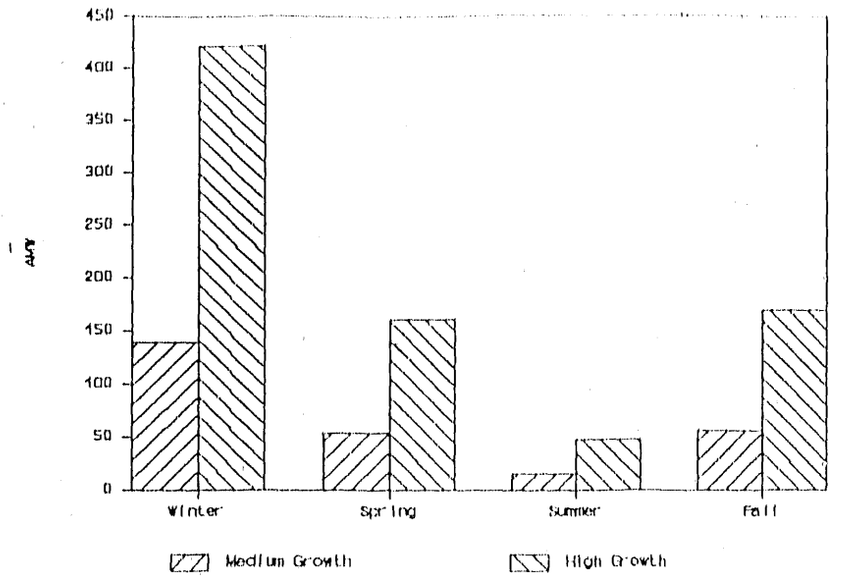

FIGURE 6.1. MCS Energy Savings by Season (2010)

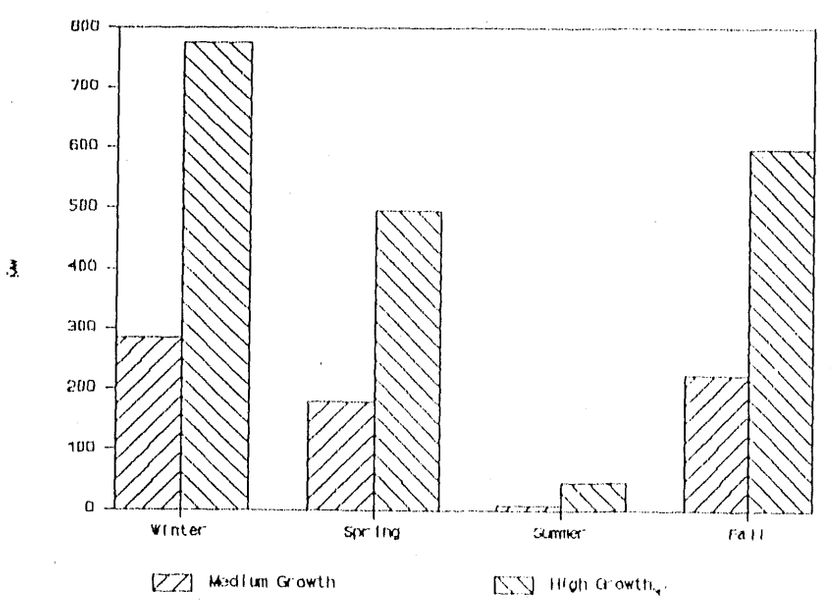

FIGURE 6.2. MCS Peak Savings by Season (2010)

7.0 CONCLUSIONS

The public power system in the Pacific Northwest is relatively unique. The load-following abilities of the hydroelectric generation provide an unusual backdrop for an hourly analysis of DSM programs. The SDSM model of the Northwest's public power system is programmed to reflect these circumstances.

This model was developed to enhance Bonneville's ability to analyze the value and impacts of demand-side programs. Despite the hydroelectric system, Bonneville faces the same load-shaping issues as other utilities. Among these issues are valley filling, peak shaving, and night time return. Hourly models of system demand are well suited to address the impacts of demand-side programs on load-shaping problems.

The SDSM model also fits within the framework of other Bonneville models. The forecasts built into the model are consistent with the Bonneville energy forecast. As a result, the annual energy outputs of the SDSM model is comparable with other Bonneville models. The unique aspect of the model is its ability to disaggregate the effects of programs by month and by hour. This attribute of the model lets it use monthly marginal cost and monthly marginal revenue numbers in its economic calculations. As a result, the seasonal, peak, and energy effects of programs can be isolated from one another.

Developing data to support an hourly analysis of any power system is problematic. Balancing detail and aggregation is as much an art as it is a science. An hourly energy analysis requires precise information about sectoral energy consumption. At the same time the sectors must be aggregated to a high enough level to be analytically tractable. Finally, hourly level data are expensive to obtain and process. These constraints put considerable demands on Bonneville and the modelers. The data are of higher resolution than annual models of consumption. The higher level resolution makes the data development more difficult.

Data development should take into account the sectors that are targets of DSM programs. These sectors require special care to ensure that the DSM

programs can be carefully examined within the framework of the model. Other sectors are simply placeholders to ensure that the model properly accounts for the total system load. If no industrial sector DSM program is anticipated, there is no need to develop a detailed hourly profile of different parts of the industrial sector. A total industrial contribution to system load may be sufficient. The analytic resources saved are best spent developing sectors that are potential candidates for DSM programs.

Program design is a key issue. The design of any particular program is nearly always hypothetical. In rare circumstances the program is one that has already been implemented and therefore well understood. Three key components affect the perceived effectiveness of a program. One is the penetration schedule. With few exceptions, the faster the program is predicted to be adopted, the better and more effective the program will be predicted to be. The second key aspect is the technical performance of the measure. Engineering calculations can provide a good estimate of the impact of the program. However, inaccurate predictions of measure performance can have a large impact on predicted measure performance. Finally, the expected rate of growth of the system can play an important role. If the measure addresses a sector of the system that is expected to be growing at a rapid rate, the measure can be especially effective.

The economic calculations provided by the model provide two perspectives. One may be characterized as the "Bonneville as a utility" perspective. The other perspective considers Bonneville's broader interregional role.

The CEC tests capture the former perspective. The CEC tests provide the results of programs when Bonneville is treated a conventional thermally based utility. Using these results allows the programs to be put into perspective with how the programs would be valued if they were a run by a private utility. However, as result of this they need to be interpreted with care. For example, public utility commissions are generally reluctant to allow programmatic benefits to accrue to non-ratepayers. The CEC results reflect these distributional biases. The closest CEC test to a conventional Bonneville analysis is probably the Total Resource Test. This test measures the value of the program to society (ignoring environmental costs). For most programs the

CEC tests are indicative; they need to be part of an overall evaluation of the program.

The second perspective of the model on the program is captured by the cost and revenue calculations. These calculations explicitly incorporate Bonneville's important interregional role. The changes in marginal costs incorporate the diurnal and monthly differentials in cost. The marginal revenue calculations include the opportunity to sell excess firm power outside of traditional Priority Firm avenues. Other opportunities include sales to private utilities, sales to the southwest, and sales to California.

8.0 REFERENCES

Baker, M. 1986. Pacific Northwest Nonresidential Energy Survey. DOE/BP-13795-12, Bonneville Power Administration, Portland, Oregon.

California Energy Commission (CEC) and California Public Utility Commission (CPUC). 1987. Economic Analysis of Demand-Side Management Programs. Standard Manual P400-87-006, Sacramento, California.

De Steese, J. G. 1987. Assessment of Conservation Voltage Reduction Applicable in the BPA Service Region. DOE/BP-14031-1, U.S. Department of Energy, Washington, D.C.

Electric Power Research Institute (EPRI). 1987. DSM Technology Alternatives. EM-5457, Palo Alto, California.

Englin, J. E., J. G. DeSteese, R. W. Schultz, and M. A. Kellogg. 1989. Peak Load Management: Potential Options. PNL-7173, Pacific Northwest Laboratory, Richland, Washington.

Kirshner, D., and P. Giorsetto. 1984. "Statistical Tests of Energy Savings Due to Voltage Reduction." IEEE Transactions on Power Apparatus and Systems, Vol. PAS-103, No. 6, pp. 1205-1210.

Moe, R. J., B. J. Harrer, M. A. Kellogg, A. J. Lyke, K. L. Imhoff, and Z. T. Fisher. 1986. The Electric Savings of New Technologies. PNL-5665, Pacific Northwest Laboratory, Richland, Washington.

APPENDIX A

SIMULATED LOAD SHAPES COMPARED WITH AVERAGE HISTORICAL SYSTEM LOAD SHAPES

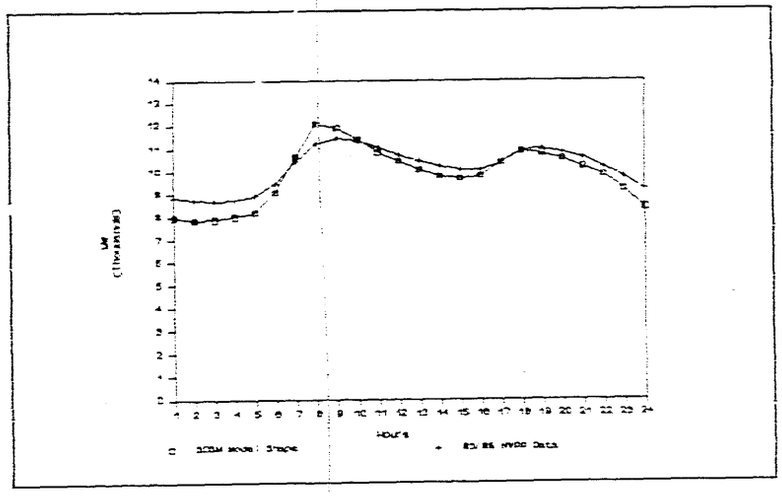

Figure A.1. Comparison of 1985/86 NWPP Data and SDSM Model Base Shape January Average Weekday

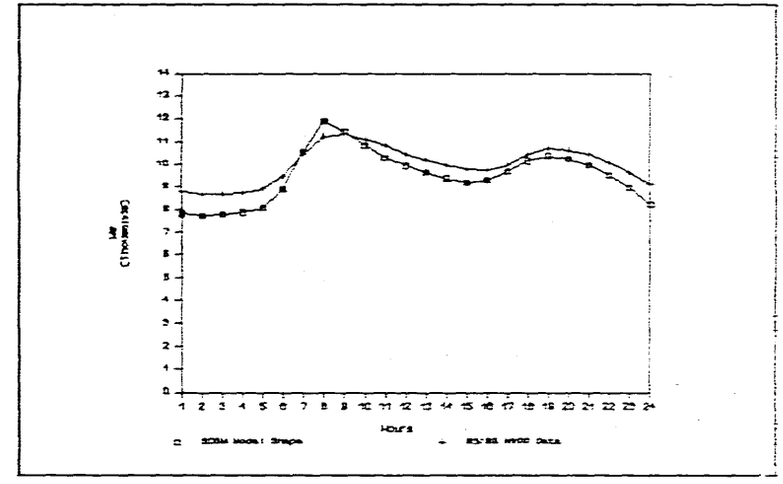

Figure A.2. Comparison of 1985/86 NWPP Data and SDSM Model Base Shape February Average Weekday

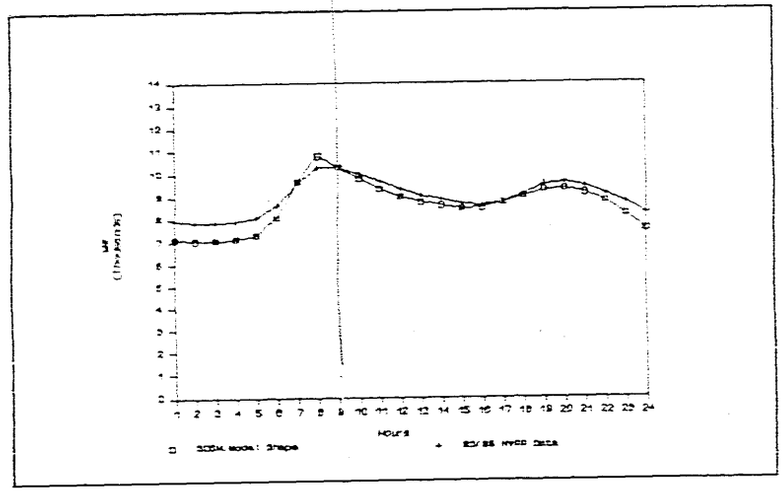

Figure A.3. Comparison of 1985/86 NWPP Data and SDSM Model Base Shape March Average Weekday

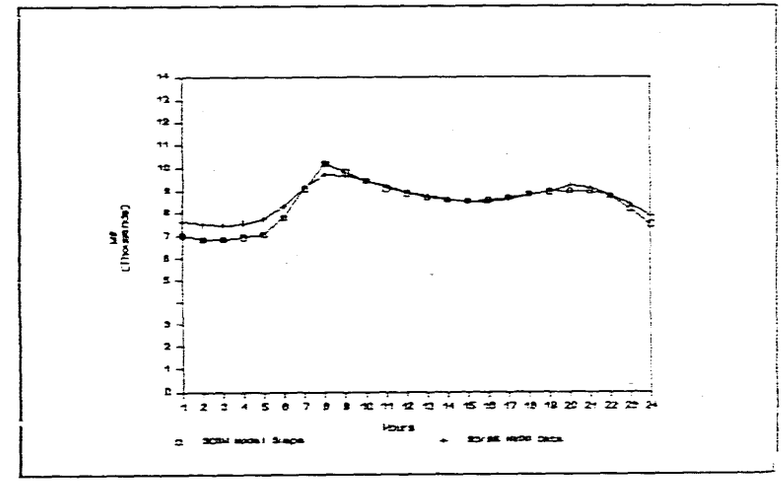

Figure A.4. Comparison of 1985/86 NWPP Data and SDSM Model Base Shape April Average Weekday

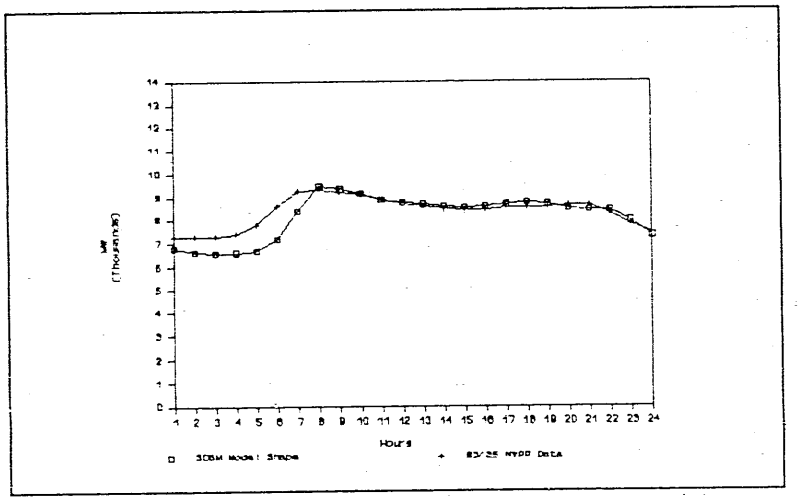

Figure A.5. Comparison of 1985/86 NWPP Data and SDSM Model Base Shape May Average Weekday

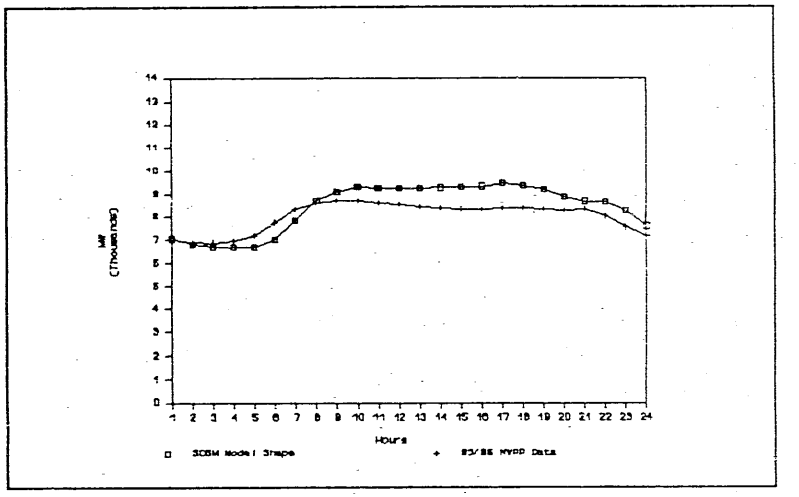

Figure A.6. Comparison of 1985/86 NWPP Data and SDSM Model Base Shape June Average Weekday

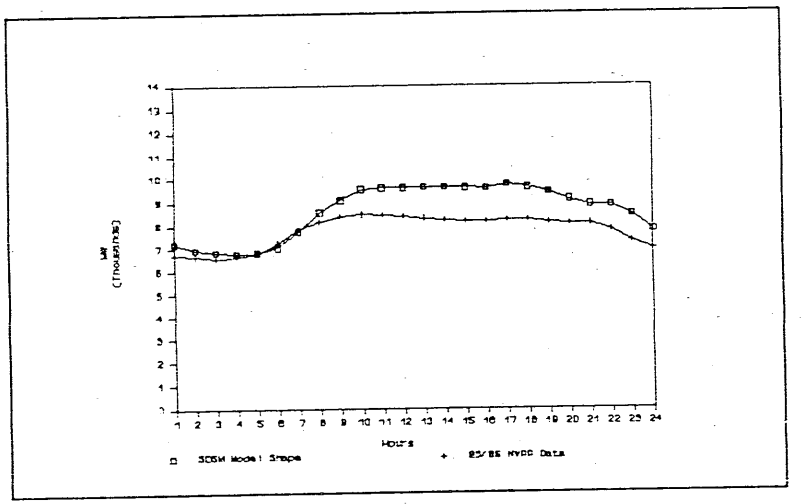

Figure A.7. Comparison of 1985/86 NWPP Data and SDSM Model Base Shape July Average Weekday

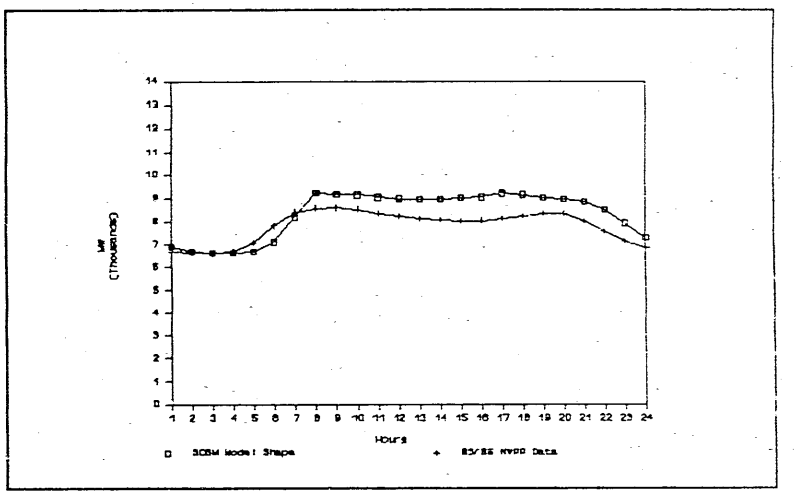

Figure A.8. Comparison of 1985/86 NWPP Dat and SDSM Model Base Shape August Average Weekday

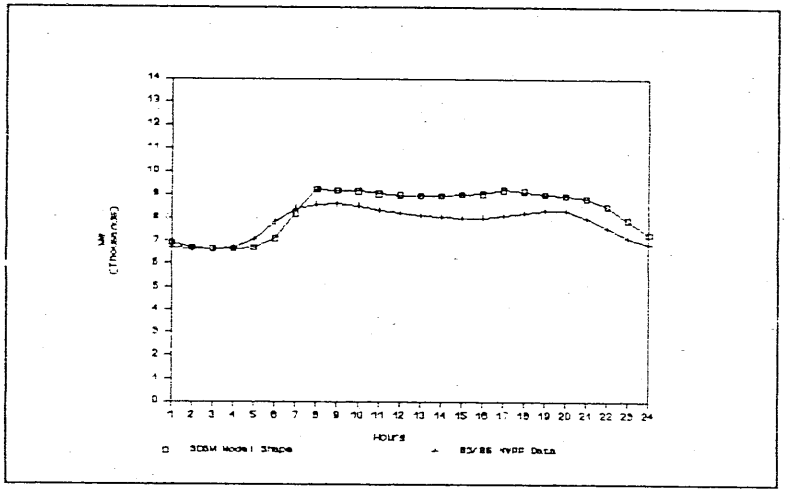

Figure A.9. Comparison of 1985/86 NWPP Data and SDSM Model Base Shape September Average Weekday

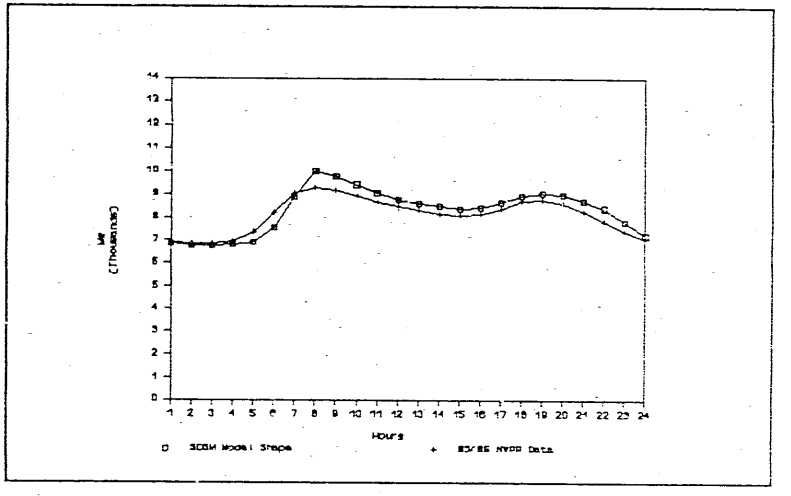

Figure A.10. Comparison of 1985/86 NWPP Data and SDSM Model Base Shape October Average Weekday

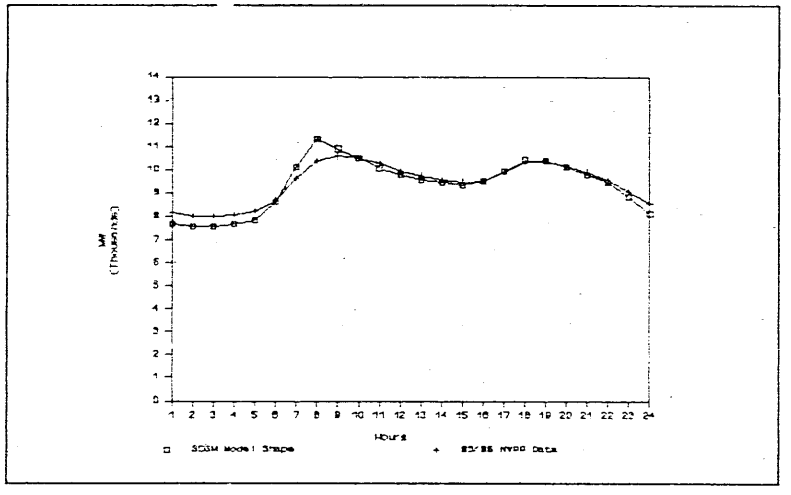

Figure A.11. Comparison of 1985/86 NWPP Data and SDSM Model Base Shape November Average Weekday

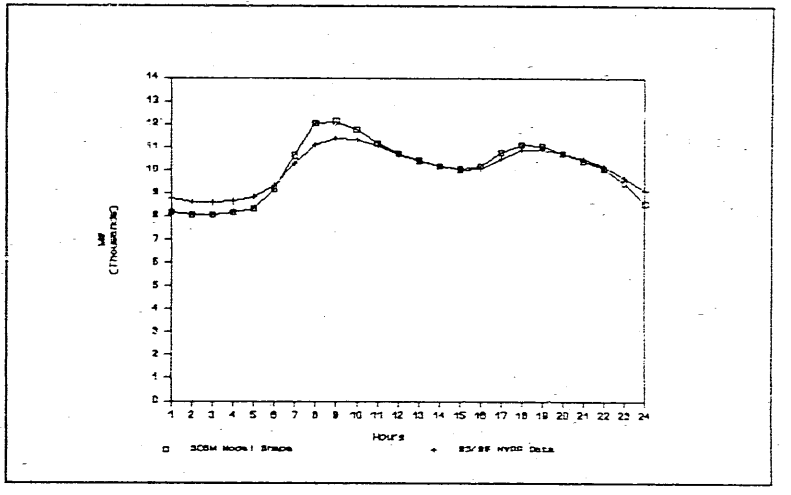

Figure A.12. Comparison of 1985/86 NWPP Data and SDSM Model Base Shape December Average Weekday

APPENDIX B

PENETRATION SCHEDULES FOR FIVE SYSTEM DEMAND-SIDE MANAGEMENT PROGRAMS

APPENDIX B

PENETRATION SCHEDULES FOR FIVE SYSTEM DEMAND-SIDE MANAGEMENT PROGRAMS

Table B.1 provides the program penetration schedules used in the each of the program analyses described in this report. Two schedules are reported for each program except Model Conservation Standards (MCS). The first, Retro, is the penetration of the program in the retrofit market. The second, New, is the penetration of the program in the new market. Because MCS is a code for new houses, only the new market penetration is reported. There are no retrofit MCS houses.

TABLE B.1. Program Penetration Schedules

	ETS		WH		CL		MCS	CVR
	Retro	New	Retro	New	Retro	New	New	All
1990	.005	.005	.007	.007	.086	.086	.40	.10
1991	.01	.01	.014	.014	.171	.171	.65	.20
1992	.02	.02	.021	.021	.257	.257	.85	.30
1993	.03	.03	.028	.028	.343	.343	.85	.40
1994	.04	.04	.035	.035	.429	.429	.85	.50
1995	.05	.05	.042	.042	.514	.514	.85	60
1996	.06	.06	.049	.049	.600	.600	.85	.70
1997	.06	.07	.056	.056	.600	.600	.85	.80
1998	.06	.08	.063	.063	.600	.600	.85	1.00
1999	.06	.09	.070	.070	.600	.600	.85	1.00
2000	.06	.10	.077	.077	.600	.600	.85	1.00
2001	.06	.10	.085	.085	.600	.600	.85	1.00
2002	.06	.10	.085	.085	.600	.600	.85	1.00
2003	.06	.10	.085	.085	.600	.600	.85	1.00
2004	.06	.10	.085	.085	.600	.600	.85	1.00
2005	.06	.10	.085	.085	.600	.600	.85	1.00
2006	.06	.10	.085	.085	.600	.600	.85	1.00
2007	.06	.10	.085	.085	.600	.600	.85	1.00
2008	.06	.10	.085	.085	.600	.600	.85	1.00
2009	.06	.10	.085	.085	.600	.600	.85	1.00
2010	.06	.10	.085	.085	.600	.600	.85	1.00

APPENDIX C

PEAK REDUCTION POTENTIAL FOR CONSERVATION VOLTAGE REDUCTION IN THE BONNEVILLE SERVICE AREA

APPENDIX C

PEAK REDUCTION POTENTIAL FOR CONSERVATION VOLTAGE REDUCTION IN THE BONNEVILLE SERVICE AREA

In 1987, Pacific Northwest Laboratory (PNL) estimated the energy savings resulting from a hypothetical application of conservation voltage reduction (CVR) to all distribution systems in the Bonneville service area. This work, reported in Assessment of Conservation Voltage Reduction Applicable in the BPA Service Region (De Steese 1987), is the basis of the present analysis to estimate the regional effect of using CVR as a peak reduction measure.

C.1 COMPLEXITY OF CVR ASSESSMENT

The biggest problem to be addressed in assessing CVR value is that essentially each feeder on each system is amenable to a different and locally constrained level of CVR implementation. Constraints include the feeder length, load density and consumer sectors served. De Steese (1987) defined some 27 CVR implementation measures and assigned a cost to accommodate the variability of these conditions in the Northwest. These measures are listed in Table C.1 together with the average voltage reduction achievable, cost per circuit, and the percentage of circuits amenable to the application of each CVR measure.

C.2 ESTIMATING METHODOLOGY

Energy savings estimates, developed in De Steese's (1987) conservation study, were based on a number of statistically derived estimates, including the number of feeders in a length class, the percentage of feeders in each class that require a given measure to apply CVR, and the average voltage reduction achieved. Account was taken of the load distribution by consumer class in each feeder category. The resulting energy conservation was estimated by considering the average effectiveness of CVR in reducing the energy demand of each consumer class.

C.3 AVERAGE VOLTAGE REDUCTION

The foregoing work provides a reasonable basis for the System Demand-Side Management (SDSM) analysis. First, the conservation analysis provides a basis for estimating the average voltage reduction achievable with a regional CVR program. CVR produces an energy and demand reduction effect that can be scaled from the average voltage reduction achieved (most literature on the subject expresses the effect in units of percentage energy or demand reduction per percentage of voltage reduction).

In De Steese (1987), energy savings for a region-wide application of a fixed 2.5% voltage reduction were computed to illustrate the relative end-use energy savings by consumer class. By scaling from the resources, 151 to 233 average megawatts (AMW), estimated for this fixed CVR percentage to the resources, 170 to 268 AMW, indicated by the supply curve synthesized from CVR effects in each feeder class, it may be concluded that an average region-wide voltage reduction of 2.85% produces the economic conservation resource. This is defined as the resource achievable at a cost of up to 5 cents/kWh according to criteria established by the Northwest Power Planning Council. In the SDSM analysis, the assumption is made that the cost of CVR measures that produce conservation costing more than 5 cents/kWh would not be included in a CVR program directed at peak reduction.

C.4 DEMAND REDUCTION PER UNIT VOLTAGE REDUCTION

While the literature describes CVR effects on individual appliances in extensive detail, only a few data available relate CVR value to the load shapes under consideration in the SDSM analysis. Many references to CVR experience show conflicting results and reach different conclusions about the effectiveness of CVR. In this analysis, a high degree of reliance is placed on the work of Kirshner and Giorsetto (1984), who performed regression analysis on results of eight CVR field tests. Their conclusions that each 1% reduction in voltage produces an average energy savings of 0.76%, 0.99% and 0.41% in the residential, commercial and industrial class loads, respectively, are the basis for estimating CVR effects on load shapes in the SDSM analysis.

TABLE C.1. CVR Implementation Costs: Distribution

Circuits Less Than Three Miles in Length:

Option	Voltage Circuits (%)	Reduction (%)	Cost/Circuit
Reregulation 5% Lower and LDC	12.7	5.7	$150
Reregulation 5% Lower	14.0	5.0	$150
LDC	31.3	2.4	$150
Reregulation 1.2% Lower	17.6	1.2	$150
Balance Feeders, LDC, and 5% Reduction	0.8	5.7	$390
Balance Feeders and 5% Reduction	0.7	5.0	$390
Balance Feeders and LDC	1.9	2.4	$390
Balance Feeders and 1.2% Reduction	1.1	1.2	$390
Capacitor Addition	9.0	2.5	$24,800
Regulator Addition	8.0	3.2	$8,010
Capacitors and Regulators	2.9	3.2	$32,000

Circuits from 3 to 12 Miles in Length:

Option	Circuits (%)	Reduction (%)	Voltage Cost/Circuit
Reregulation	8.0	2.0	$150
Regulator Addition	14.1	2.0	$8,010
Regulator and Capacitor Addition	11.1	2.0	$27,800

TABLE C.1. (Cont.) CVR Implementation Costs:

Circuits from 3 to 12 Miles in Length (contd):

Capacitor Addition	13.1	2.0	$47,600
Reinsulate	3.2	2.0	$106,000
Reconductor	5.0	2.0	$324,000
Combination	12.7	2.4	$126,000
Reregulation and LDC	4.0	4.4	$150
Regulator Addition, Reduction	6.9	4.4	$8,010
Regulator and Capacitor Addition	5.4	4.4	$27.800
Capacitor Addition	6.4	4.4	$47,800
Reinsulation	1.6	4.4	$106,000
Reconductor	2.4	4.4	$324,000
Combination	6.3	4.6	$126,000

Circuits Greater than 12 Miles in Length:

Option	Voltage Circuits (%)	Reduction (%)	Cost/Circuit
Reinsulate	43.5	2.5	$486,000
Combination	56.5	2.5	$703,000

Several reports suggest that CVR is more effective in reducing peak load than in producing energy savings. However, Kirshner and Giorsetto (1984) claim that both effects, on average, are similar. The percentage load reductions indicated in Table C.2 are based on values for energy conservation. If circumstances permit load reduction to exceed energy conservation, the peak load reductions estimated in this analysis will therefore tend to be conservative (i.e., underestimate the peak reduction value of CVR).

C.5 CVR EFFECT ON LOAD SHAPES

Table C.2 shows the effect of CVR on the demand of several end-use loads. The demand reduction for each load type is estimated by multiplying the response to voltage reduction (% demand reduction/% average voltage reduction) by 2.85, the average voltage reduction achievable, as described above.

TABLE C.2. Percentage Effect on Hourly Load Shapes for 2.85% Average CVR Application

End-Use Load	CVR Hourly Demand Reduction (%)	
Space Heating	0[a]	5.6[b]
Cooking	5.6	
Incandescent Lights	5.6	
Fluorescent Lights	4.3	
High-Pressure Lamps	5.6	
Motor-Operated Equipment	2.8	
Distribution Line Loss	0.3	
Average Residential Sector Energy	2.2	
Average Commercial Sector Energy	2.8	
Average Industrial Sector Energy	1.2	
Average Agricultural Sector Energy	(c)	

(a) In period of nonextreme weather with thermostat control < 1 hour.
(b) In periods of extremely cold weather with thermostat cycles > 1 hour.
(c) Literature lumps Agriculture with Industrial Sector. The percentage could be considered to range between 1.2% for the Industrial Sector and 2.8% for Motor-operated Equipment.

The values of the CVR demand reduction shown in Table C.2 modify the baseload shapes considered in the SDSM analysis by the indicated fixed percentage reduction throughout the day. CVR generally requires no payback, with the exception of thermostatically controlled resistive loads that deliver a constant amount of energy to a process.

With CVR, the demand of such loads is reduced but they stay on longer in each cycle. The CVR effect on the space heating load shape therefore should be distinguished according to severity of the weather. On an average day, when space heating might cycle on and off at a frequency less than 1 hour, the effect of CVR on the load shape is negligible because the hourly load shape essentially shows a demand based on average energy consumed each hour. Even if the heating cycle is a few percentages longer because of CVR, the hourly demand will not change as long as cycling occurs at less than an hourly frequency. However, in extremely cold weather conditions, space heating systems can operate continuously in a effort to keep up with energy lost to the ambient. In this case, the effect of CVR in reducing the demand of the end use would be indicated by a reduction in the hourly load shape.

In Table C.2, the regressions of Kirshner and Giorsetto (1984) included the effect of CVR on agricultural loads as part of the industrial sector. The PNL conservation study (De Steese 1987) estimated a very small conservation resource (5 AMW) from applying CVR to agriculture. However, in the SDSM analysis of agricultural load shapes, the peak reduction effect of CVR can be estimated by applying load-shape reductions ranging from 1.2% to 2.8%. This corresponds, at one extreme, to assigning the conservative industrial average effect to agriculture. At the other end of the range, agriculture could be considered to achieve the effect of a primarily motor-operated system.

C.6 COST BASIS AND PENETRATION RATE OF A REGION-WIDE CVR PROGRAM

The supply curves generated by the PNL conservation study were based on the estimated costs of 27 CVR measures applied to appropriate feeder classes in the region. The capital cost, energy savings and cost/kWh are shown in Table C.3 for each measure considered. The bounds of the energy savings columns reflect the range of different levels of CVR effectiveness as a conservation resource.

From Table C.3, the total cost for CVR measures producing energy savings up to 5 cents/kWh ranges from $181 million (lower bound) to $198 million (upper bound). It is reasonable to assume that any implementation of such a

TABLE C.3. Cost, Energy Savings and Resource Value of 27 CVR Measures Applicable in the Bonneville Service Area

Option	Proportion of Total Lines	Proportion of Lines in Each Size Range	Cost ($)	Energy Savings (MW) Lower Bound	Energy Savings (MW) Intermediate	Energy Savings (MW) Upper Bound	Cost (¢/kWh) Lower Bound	Cost (¢/kWh) Intermediate	Cost (¢/kWh) Upper Bound
1	0.50	0.127	95,701	21.0	26.3	33.4	0.00260	0.00211	0.001672
2	0.50	0.140	105,503	27.3	32.9	41.9	0.00224	0.00180	0.001400
3	0.50	0.313	236,009	25.6	31.0	39.5	0.00530	0.00431	0.003403
4	0.50	0.170	132,700	7.1	9.1	11.1	0.01002	0.00053	0.000900
5	0.50	0.000	16,004	1.6	1.9	2.4	0.00504	0.00405	0.003013
6	0.50	0.007	13,723	1.2	1.5	1.0	0.00000	0.00561	0.004347
7	0.50	0.019	37,249	1.6	1.9	2.4	0.01390	0.01122	0.009060
8	0.50	0.011	21,506	0.5	0.6	0.7	0.02015	0.02219	0.010112
9	0.50	0.090	11,219,074	7.7	9.5	11.0	0.05350	0.00005	0.552000
10	0.50	0.000	3,222,790	8.6	10.6	13.3	0.21700	0.17044	0.141340
11	0.50	0.029	4,701,954	3.1	3.9	4.0	0.09000	0.72223	0.570537
12	0.39	0.000	41,749	3.8	4.7	5.0	0.00040	0.00510	0.004100
13	0.39	0.131	21,094,100	6.2	7.7	9.5	2.05201	1.03014	1.320020
14	0.39	0.141	3,931,270	6.6	8.3	10.3	0.34560	0.27500	0.223353
15	0.39	0.111	10,753,913	5.2	6.5	8.1	1.20002	0.95035	0.770105
16	0.39	0.032	17,310,303	1.5	1.9	2.3	5.70720	5.35200	4.334955
17	0.39	0.050	31,311,770	2.4	2.9	3.5	7.70197	6.19457	5.010004
18	0.39	0.127	55,072,327	7.2	8.9	11.1	4.51971	3.02072	2.925000
19	0.39	0.040	20,070	4.2	5.1	6.4	0.00291	0.00239	0.001900
20	0.39	0.004	10,632,005	6.7	8.1	10.2	0.92000	0.70311	0.504054
21	0.39	0.009	1,923,010	7.2	8.8	11.0	0.15575	0.12007	0.101514
22	0.39	0.054	5,231,033	5.5	6.9	8.5	0.54123	0.44503	0.352741
23	0.39	0.010	8,050,191	1.7	2.0	2.5	3.02305	2.40570	1.970242
24	0.39	0.024	15,029,050	2.5	3.0	3.8	3.49045	2.37007	2.200000
25	0.39	0.003	27,049,050	6.9	8.3	10.5	2.34450	1.03150	1.520592
26	0.06	0.463	94,949,210	3.3	4.1	5.1	10.7340	13.4499	10.03929
27	0.06	0.505	170,310,202	4.3	5.3	6.5	24.1950	19.4473	15.07201

CVR program would likely take more than 1 year but possibly not more than 10 years to complete. For the purpose of the SDSM analysis, a 10-year CVR implementation strategy would require to expenditure of $18 million to $20 million per year.

C.7 REFERENCES

De Steese, J. G. 1987. Assessment of Conservation Voltage Reduction Applicable in the BPA Service Region. DOE/BP-14031-1, U.S. Department of Energy, Washington, D.C.

Kirshner, D., and P. Giorsetto. 1984. "Statistical Tests of Energy Savings Due to Voltage Reduction." IEEE Transactions on Power Apparatus and Systems, Vol. PAS-103, No. 6, pp. 1205-1210.

END

DATE FILMED

11 / 08 / 90