DIVIDER

STATE OF NORTH DAKOTA
INFORMATION TECHNOLOGY DEPARTMENT
SFN 2053 (4-2002)

DESCRIPTION

PU-05-531
Montana-Dakota Utilities Co , a Division of MDU Re
Integrated Resource Plan
Biennial Report 05
Filed 9/15/2005 Closed 9/15/2005

ORIGINAL

MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc

400 North Fourth Street
Bismarck, ND 58501
(701) 222-7900

September 15, 2005

Executive Secretary
North Dakota Public Service
Commission
State Capitol Building
Bismarck, ND 58505

Re: Case No. PU-399-91-689
Integrated Resource Plan
Biennial Filing

Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc., herewith submits ten (10) copies of its biennial report for its Electric Integrated Resource Plan in accordance with the Amended Order issued March 11, 1992 in Case No. PU-399-91-689.

Please acknowledge receipt by stamping or initialing the duplicate copy of this letter attached hereto and returning the same in the enclosed self-addressed, stamped envelope.

Sincerely,

Donald R Ball

Donald R. Ball
Assistant Vice President -
Regulatory Affairs

Enclosure

C. Comm.
Legal
PUD (5)

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Integrated Resource Plan filed under Case No
PU-05-531
by Montana-Dakota Utilities Co a Division of MDU Res
09/15/2005

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Integrated Resource Plan

by Montana-Dakota Utilities Co a Division of MDU Res
09/15/2005 CC Comm Legal PUD (4) Mike

HARD COPY OF INTEGRATED RESOURCE PLAN ON CD DISC

DOCKET SEQUENCE NO. ______

EXHIBIT ______

CASE NO. PU-05-531

ON FILE IN

STATE ARCHIVES

CONTROL NUMBER: 80051

2005
Integrated Resource Plan

Submitted to the
North Dakota Public Service Commission
September 15, 2005

Montana-Dakota Utilities Co.
2005 Integrated Resource Plan

Submitted to the
North Dakota Public Service Commission

SEPTEMBER 15, 2005

MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc

EXECUTIVE SUMMARY

Montana-Dakota Utilities Co. (Montana-Dakota) began formal Integrated Resource Planning (IRP) in 1987 as a result of an order by the North Dakota Public Service Commission.

The 2005 IRP process and product (report and appendices) were enhanced with the participation of Montana-Dakota's IRP Public Advisory Group (PAG) and discussions with PSC Staff regarding a change in focus from pure least-cost planning to a broader resource planning perspective. The PAG has been an invaluable tool within the IRP process since 1994. The 2005 advisory group was established at the beginning of the 2005 planning cycle and provided Montana-Dakota with input from a nonutility perspective throughout the 2005 IRP process.

As shown graphically in Figure E-1, the IRP process at Montana-Dakota encompasses three main areas: load forecasting, demand-side analysis, and supply-side resource plan. A summary of the study results for each of these areas is provided.

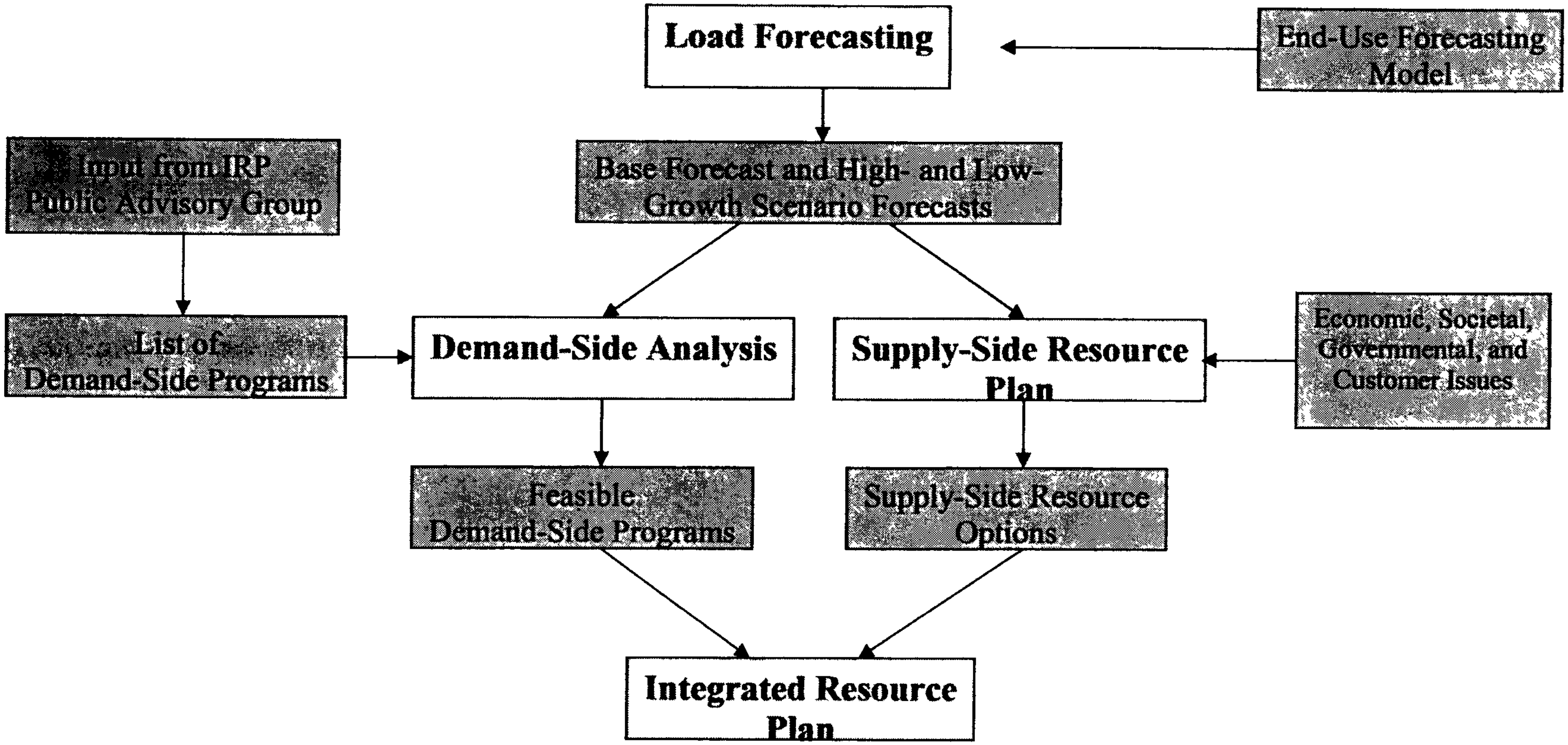
The load forecasting activities employ an end-use forecasting method to predict the customers' future demand for electricity. The long-term forecast is an estimate of energy requirements and peak demand and is a representation of the customers' energy usage pattern in the future. The results for the base forecast show that, during the 2005-2024 time period, the average growth rate for the projected summer peak demand is 1.0 percent, while the annual energy is expected to increase at 0.9 percent annually. Based on these results and a 15 percent reserve capacity obligation, with its existing resources, Montana-Dakota will incur a capacity deficit in 2007.

To address the load forecast uncertainty, high-growth and low-growth scenario forecasts were developed. The high-growth scenario assumed an average growth rate of 4.4 percent per year during the 20-year forecast horizon, and the low-growth scenario assumed an average growth rate of 0.5 percent per year during the same time period. These forecasts, together with the base forecast, were used as the basis for the determination of Montana-Dakota's Integrated Resource Plan.

The demand-side analysis is an evaluation process to determine the potentially feasible demand-side management (DSM) programs applicable to Montana-Dakota's system. This DSM evaluation is performed on a list of residential and commercial programs selected through a joint effort between Montana-Dakota and the PAG. Based on the demand-side analysis in Section 3, a

FIGURE E-1

MONTANA-DAKOTA UTILITIES CO.
INTEGRATED RESOURCE PLANNING PROCESS



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package of four DSM programs was chosen to provide the best fit and the most cost-effective programs for Montana-Dakota. Those four programs are:

1. ENERGY STAR® Partnership
2. Promote electric heat (in North Dakota only)
3. Promote high efficiency residential central air conditioning
4. Promote commercial lighting T-8 retrofit

The four programs will provide an estimated demand reduction of 6.5 MW at a cost of approximately $100/kW.

In Section 4 of this report, Montana-Dakota proposes a supply-side resource plan which relies on the traditional IRP approach of "least cost" but also considers other important factors which are not captured in a strict least-cost analysis. The resulting plan considers economic, societal, governmental, and customer issues resulting in a "best cost" supply-side resource plan. The plan calls for a future coal-fired baseload unit and "bridge power" resources to meet customer demand from the time the Antelope Valley Unit No. 2 (AVS II) power purchase agreement expires to the time the baseload unit comes on-line.

For the future baseload units, Montana-Dakota is actively pursuing the following four options with other utilities or partners:

- A 175 MW coal plant near Gascoyne, North Dakota to be on-line in 2010,
- Part ownership of a 600 MW coal plant addition at the existing Big Stone plant near Big Stone, South Dakota to be on-line in 2011,
- Part ownership of a 600-1200 MW coal project being considered for construction in one of five locations in the upper Midwest to be on-line in 2012 or later (The Resource Coalition), and
- Purchase of power from other utilities or from the energy market.

At the time of this IRP filing, Montana-Dakota's supply-side resource plan still faces uncertainties. First, the decision on which baseload option is the most beneficial for Montana-Dakota's customers will most likely not be made until the third quarter of 2006. Second, although a contract has been signed for the purchase of summer peaking capacity for the bridge power, the final transmission arrangements are not yet in place. Montana-Dakota and the seller will secure the confirmed firm transmission service to deliver power from the seller's system to Montana-Dakota's customer load.

For the purpose of this IRP, Montana-Dakota assumes its supply-side resource plan consists of:

2006 – 25 MW of Summer peaking capacity from NorthPoint Energy (existing contract)
2007 – 85 MW of Summer peaking capacity from Northern States Power Company (NSP)
2008 – 90 MW of Summer peaking capacity from NSP
2009 – 95 MW of Summer peaking capacity from NSP
2010 – 100 MW of Summer peaking capacity from NSP
2011 – 116 MW of Big Stone II

Based on the selection of the demand-side programs and the above assumptions for the supply-side resource plan, Montana-Dakota's projected loads and proposed resources for the next ten years (2006-2015) as determined by this integrated resource plan are summarized in Table E-1.

TABLE E-1

MONTANA-DAKOTA UTILITIES CO.
INTEGRATED RESOURCE PLAN SUMMARY

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Load Forecast		Demand-Side Adjustments			Total Forecast		Supply-Side Additions		Accredited	Reserve	Reserve
YEAR	MW	GWh	DSM Implement.*	MW	GWh	MW	GWh	Installation	MW	Cap. (MW)	Cap. (MW)	Margin (%)
2006	478 2	2,406 6	High-efficiency A/C, High-efficiency lighting,	-1.396	6.9	476 8	2,413 5	NorthPoint peaking cap	25 0	569.8	93 0	19 5%
2007	483 4	2,440 4	& Electric heat	-2 792	13.9	480.6	2,454.3	AVS II expiration & NSP peaking cap	-66 4 85 0	563 4	82 8	17.2%
2008	488 6	2,474 2		-4 188	20 8	484.4	2,495.0	NSP peaking cap	90 0	568 4	84 0	17 3%
2009	493 8	2,509 6		-5 327	11 3	488.5	2,520 9	NSP peaking cap	95 0	573.4	84 9	17 4%
2010	499 0	2,536 4		-6 466	1 9	492 5	2,538 3	NSP peaking cap	100 0	578 4	85 9	17 4%
2011	504 2	2,558 9		-6 466	1 9	497.7	2,560 8	Big Stone II	116 0	594 4	96 7	19 4%
2012	509 4	2,580 6		-6 466	1.9	502.9	2,582 5			594 4	91.5	18 2%
2013	514 6	2,601 3		-6.466	1.9	508 1	2,603 2			594 4	86.3	17 0%
2014	519 8	2,618 5		-6 466	1.9	513 3	2,620 4			594 4	81 1	15 8%
2015	525 0	2,635 6		-6 466	1 9	518 5	2,637.5			594 4	75 9	14 6%

* Indicates the first year the DSM programs are implemented. Their MW and GWh impacts will take 3 or 5 years to reach maximum customer potentials.

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SECTION 1

INTRODUCTION

1.1 PURPOSE OF STUDY

Montana-Dakota Utilities Co. (Montana-Dakota) began formal Integrated Resource Planning (IRP) in 1987 as a result of an order by the North Dakota Public Service Commission.

Montana-Dakota operates an integrated electric system in the states of North Dakota, South Dakota, and Montana. Montana-Dakota forecasts its load and plans and operates its generation and transmission system to meet the requirements of its customers on an integrated system basis. The results of this plan for the integrated system will direct Montana-Dakota's management decisions and action plans and will provide guidance for future resource acquisitions by the company.

1.2 REPORT OVERVIEW

The IRP process currently implemented at Montana-Dakota encompasses three main areas: load forecasting, demand-side analysis, and supply-side resource plan. The following is an overview of those activities:

1. Load forecasting. Presented in Section 2, the load forecasting activities include the development of a base load forecast and the high-growth and low-growth scenario forecasts. These forecasts are used as the basis for the determination of Montana-Dakota's IRP.

2. Demand-side analysis. The demand-side analysis described in Section 3 is an evaluation process to determine the potentially feasible demand-side management programs applicable to Montana-Dakota's system. This DSM evaluation is performed on a list of programs developed with input from the IRP Public Advisory Group (PAG).

3. Supply-side resource plan. Section 4 presents Montana-Dakota's proposed supply-side resource plan.

Section 5 provides a nontechnical summary of Montana-Dakota's projected forecast and proposed resource options as a result of this IRP.

Section 6 provides the two-year action plan for the period September 2005 through August 2007. The action plan shows how Montana-Dakota intends to implement this IRP over the next two years.

Section 7 describes the role and the workings of Montana-Dakota's IRP PAG. A list of the PAG participants and a list of the PAG meetings are also included.

Finally, Appendices A through E contain the supporting data for the load forecasting activities. Appendices F through H include output summaries from the demand-side analysis and document input data and assumptions for the studied residential and commercial DSM programs. Appendix I shows the calculations of the levelized fixed charge rates which were used in various analyses of this IRP.

SECTION 2

LOAD FORECASTING

Load forecasting is a crucial step in the integrated resource planning process. A load forecast provides information on the customers' expected future demand, which is the basis of the resource requirements. For Montana-Dakota's Integrated System, the objective is to perform a long-range (20-year) forecast which is not only an estimate of energy and demand that will be required but also a representation of the customers' energy usage patterns in the future. This is accomplished through the use of an end-use forecasting model. The results will be used throughout this study: from the demand-side analysis (Section 3) to the supply-side analysis (Section 4) to the integration analysis (Section 5).

2.1 FORECAST OVERVIEW AND DATA SOURCES

2.1.1 Forecast Overview

An end-use forecasting model was used to develop a long-range (20-year) electric load forecast for Montana-Dakota's Integrated System, which comprises its service territories in Montana, North Dakota, and South Dakota. The most basic end-use forecasting models are simple accounting statements which enumerate the end-uses and add the electricity use for each end-use from its components:

Energy Use by End-Use = Number of Users in End-Use
x Energy Use per End-Use

State-of-the-art end-use models are far from simple. The complexity enters at the stage of developing estimates of data inputs, which requires most of the effort in end-use forecasting. There are numerous variables, many of which require judgment and forecasting assumptions.

The software used in the development of Montana-Dakota's end-use forecast is SHAPES II, an integrated forecasting model from NewEnergy Associates, a Siemens Company of Atlanta, Georgia. The end-use forecasting methodology is described in Section 2.2 and the forecasting procedure associated with SHAPES II is detailed in Section 2.3. The next section (Section 2.4) presents the electric sales forecast results. From the sales forecast (Section 2.4.1), the total system load in terms of energy requirements and seasonal peak demands are calculated (Section 2.4.2). Finally, to address the uncertainty in the load forecast, forecasts reflecting temperatures that correspond to higher confidence levels as well as high-growth and low-growth scenario forecasts are developed (Section 2.4.3).

2.1.2 Data Sources

At the time this study was begun (April 2004), the most recent year for which a complete set of weather, energy use curves, and monthly sales by sector was available was 2003. This year was used for residential model calibration as discussed in Section 2.3.1.5.

The data used in the development of the forecast that are available in-house include Montana-Dakota's load research data, residential energy use surveys and rate projections, as well as historical sales, energy, demand, and number of customers. In addition to these data sources, most of the economic and demographic data used in the study are obtained from Woods & Poole Economics, Inc. by county. The Woods & Poole data are apportioned and adjusted to represent the data for the Montana-Dakota service territory. Other data sources used include the National Oceanic and Atmospheric Administration (NOAA), Edison Electric Institute (EEI), Association of Home Appliance Manufacturers (AHAM), Gas Appliance Manufacturers Association (GAMA), Association of Edison Illuminating Companies (AEIC), United Power Association's compilation of residential appliance information, U.S. Census Data, and others.

The Integrated System of Montana-Dakota consists of the counties listed in Table 2-1, which are located in eastern Montana, north central South Dakota, and the western and central portion of North Dakota.

Table 2-1

Counties by State in Montana-Dakota's Integrated System

Montana	South Dakota	North Dakota	
Custer	Campbell	Adams	Logan
Daniels	Corson	Bowman	McIntosh
Dawson	Edmunds	Burke	McKenzie
Fallon	Faulk	Burleigh	Mercer
Prairie	Harding	Dickey	Morton
Richland	McPherson	Divide	Mountrail
Roosevelt	Perkins	Dunn	Oliver
Rosebud	Potter	Emmons	Renville
Sheridan	Walworth	Golden Valley	Slope
Wibaux		Grant	Stark
		Hettinger	Williams
		Kidder	

Montana-Dakota also provides electric service to a small part of Brown county of South Dakota. However, since Brown county includes the town of Aberdeen which is not served by Montana-Dakota but which comprises the majority of the population for the county, including Brown county in the database would reflect too much of the economic activity that occurs in Aberdeen.

Historical data used in the development of the forecasts are included in Appendix A. Tables A-1 through A-4 list annual sales by customer class for Montana, North Dakota, South Dakota, and the Integrated System for the years 1966-2003, respectively. Table A-5 lists the seasonal peaks and load factors of the Integrated System for the years 1960-2003. Table A-6 lists demand by state at the time of the system peak for the summer and winter seasons. Appendix B contains information on the forecasts of exogenous variables and Appendix C contains additional input data required by SHAPES II.

2.2 END-USE FORECASTING METHODOLOGY

The Integrated System forecast is disaggregated into five end-use sectors:

1. Residential sector.

2. Small Commercial and Industrial (SC&I) sector. This sector consists of those commercial and industrial customers whose peak demand averages less than 50 kilowatts a month over a year's time.

3. Large Commercial and Industrial (LC&I) sector. This sector consists of those commercial and industrial customers whose peak demand averages more than 50 kilowatts a month over a year's time.

4. Street Lighting. This sector consists of energy for public street and highway lighting.

5. Miscellaneous sector. This sector includes energy for sales to other public authorities, interdepartmental sales, and company use.

SHAPES II is used to forecast sales for the three primary customer categories: residential, SC&I, and LC&I, while sales for the miscellaneous sector and street lighting are forecasted exogenously and then input to SHAPES II where the forecasted annual sales are allocated to the 8760 hours of each year. Within each sector, hourly demand and monthly and annual energy were modeled as described below.

Before the general methodology for each of the five end-use sectors is described, several SHAPES II features that are common to the three primary customer categories can be explained. First, for each end-use within each customer class, a price adjustment factor is computed using an electricity price forecast, price elasticities, and price elasticity weights to capture the change in electricity consumption as a result of changes in the real price of electricity. Price elasticities capture the customers' short- and long-term reactions to the changes in the price of electricity while price elasticity weights are used to provide a smooth transition from the short-term to the long-term effect of price changes. Second, the days of the week are categorized by day type to reflect the way that hourly demand of an end-use varies by time of day and type of day. Day type is a group of days of the week which have similar patterns of demand for electricity. Analysis of Montana-Dakota load data resulted in four day types: Day Type 1 = Monday; Day Type 2 = Tuesday through Friday; Day Type 3 = Saturday; Day Type 4 = Sunday and holidays such as Independence Day and Christmas. Third, in addition to being a function of time of day and day type, hourly demand of a temperature-insensitive end-use was assumed to vary by month (to capture seasonal variation) and hourly demand of a temperature-sensitive end-use was assumed to vary with the temperature. Finally, various use patterns are input to SHAPES II to define hourly demand as a function of time of day, day type, and month or temperature.

2.2.1 Residential Sector Model

In the residential sector model, hourly demand is first forecasted and energy is computed by summing demand over time. The basic equation is that the hourly demand for each type of appliance is the product of the number of appliances, the connected load, and the probability that the appliance is in use at a given hour:

$$DEMAND^a{}_h = NAP^a \times CL^a \times USE^a{}_h$$

where:

a = appliance type
h = hour
DEMAND = demand for appliance type a at hour h
NAP = number of appliances of type a
CL = connected load for appliance type a
USE = the probability appliance a is in use at a given hour

Then energy consumption by type of appliance is the sum of the hourly demand over time:

$$ENERGY^a = \sum_h DEMAND^a{}_h$$

An exogenous household forecast from Woods & Poole was input directly to SHAPES II. SHAPES II then applies a customer-to-household ratio to the household forecast to arrive at a customer forecast. The customer forecast is then broken down by dwelling type. The number of appliances (NAP) is computed by multiplying the number of customers by the appliance saturation rate by dwelling type. An appliance saturation rate is the percentage of customers who have and use the appliance.

The price adjustment factors described earlier that are calculated for each appliance in the residential sector are applied to the connected loads (CL). Also, appliance efficiency trends are used to account for changes in appliance efficiencies over time.

Usage (USE) is determined by use patterns for each appliance. The temperature-sensitive appliances considered in the model include room air conditioners, central air conditioners, and space heating. The temperature-insensitive appliances include ranges, frost-free refrigerators, standard refrigerators, frost-free freezers, standard freezers, dishwashers, washers, dryers, water heaters, microwave ovens, color televisions, black and white televisions, and lights. All other energy-using equipment such as personal computers and water beds are not individually modeled but are accounted for through the use of miscellaneous end-use appliance percentages.

2.2.2 Small C&I Sector Model

The SC&I sector model forecasts energy and demand using the opposite approach; that is, annual energy is forecasted first and then allocated to monthly energy and hourly demand.

The SC&I sector model is essentially econometric in nature. It relies on a regression analysis of historical energy intensity (kWh per unit of economic activity), as well as an exogenous forecast of that economic activity, to predict annual energy consumption. Employment is the most common measure of economic activity used, primarily because employment data are readily available. Therefore, energy intensity is computed in terms of kWh per employee. The regression analysis is performed on a monthly basis using heating and cooling degree days and time for the independent variables and energy intensity (kWh per employee) as the dependent variable.

For each customer category, SHAPES II forecasts annual energy for three end-uses: baseload, cooling, and heating. Use patterns for these three end-uses are input to the model to allocate annual energy to monthly energy and then hourly demand. Baseload is the temperature-insensitive component, while demand for heating and cooling varies with temperature. SHAPES II applies the price adjustment factor calculated for each end-use to the baseload, heating, and cooling forecasts to arrive at the annual energy forecast.

In this study, the entire SC&I sector for the Integrated System was modeled as one customer category.

2.2.3 Large C&I Sector Model

The LC&I sector model is similar to the SC&I model in that it generates an annual energy forecast based on regression analyses of historical energy intensity (kWh per employee). However, these regression analyses are run on an annual basis and the LC&I sector is treated as temperature-insensitive.

Like the SC&I sector, the LC&I sector forecast begins with an annual forecast of energy which is allocated to monthly energy and hourly demand.

In this study, five LC&I categories or end-uses were identified for the Integrated System and modeled individually: Tesoro (formerly Amoco) Refinery sales, Westmoreland (formerly Knife River) Coal Mining sales, Oil Field sales, Sabin Metals sales, and General LC&I sales (sales to all other LC&I customers). Input use patterns are required for each customer category. For the General LC&I sales, SHAPES II applies the price adjustment factor calculated to the product of energy intensity and employment to arrive at the annual energy forecast.

2.2.4 Street Lighting Sector Model

Electric sales for the street lighting sector were forecasted exogenously based on the results of a time trend analysis of actual 1989-2003 sales and were then input to SHAPES II. Within SHAPES II, a street lighting use pattern was used to allocate the sales to hourly demand. The street lighting use pattern was determined based on sunrise and sunset times for Bismarck and the assumption that street lights go on 15 minutes after sunset and off 15 minutes before sunrise.

2.2.5 Miscellaneous Sector Model

With SHAPES II, the miscellaneous sector can be forecasted by using the specified extent (in percent) to which monthly energy and hourly demand patterns resemble the patterns of consumption in other sectors. In this study, the electric sales for interdepartmental were input to SHAPES II based on the results of time trend analyses of actual 1989-2003 sales, sales to other public authorities were based on the results of time trend analyses of actual 1994-2003 sales, and company use was held constant for the next twenty years at the 2003 level. The LC&I use pattern was used to allocate the annual energy for the miscellaneous sector to each hour of the year.

2.3 SHAPES II FORECASTING PROCEDURE

As mentioned in Section 2.1.1, most of the effort in end-use forecasting involves developing estimation procedures for data inputs to the model and estimating data values. In the forthcoming discussion, Sections 2.3.1 through 2.3.3 present the forecasting procedure used for the residential, SC&I, and LC&I sectors, respectively. Next, the typical meteorological year (TMY) data, which defines a temperature profile assumed for future years in the SHAPES II simulations, is discussed in Section 2.3.4.

There are two data estimation activities that are common to all three sectors: residential, SC&I, and LC&I. First, the electricity prices for these sectors were projected based on the historical and current prices as well as rate projections provided by Montana-Dakota's Financial Reporting & Planning and Regulatory Affairs Departments. The rate projections were based on Montana-Dakota's financial plan for 2004 to 2013 which was developed in late 2003. The residential prices were adjusted to real prices in 1996 dollars using the personal consumption expenditure deflator (Appendix B-1) while the SC&I and LC&I prices were adjusted to real prices in 2000 dollars using the GDP deflator (Appendix B-2) before being input to SHAPES II. The electricity price data are shown in Appendix B-3. Second, the price elasticity weights modeled were the same for all end-uses in the three sectors. These weights, shown in Appendix C-5, are SHAPES II default values and are a series of weights describing an S-curve over a 12-year period.

2.3.1 Residential Sector Forecast

The end-use forecast for the residential sector includes estimating data for six areas: (1) number of households, (2) number of residential customers, (3) appliance saturation rates by dwelling type, (4) appliance price elasticities, (5) appliance connected loads and appliance efficiencies, and (6) appliance use patterns.

2.3.1.1 Number of Households

A household forecast is the primary driver for the residential sector. An exogenous household forecast for the counties within which Montana-Dakota provides electric utility service was obtained from Woods & Poole and was input directly to SHAPES II.

2.3.1.2 Number of Residential Customers

The historical and projected number of households for the Integrated System is included in Appendix B-4. The forecast of the number of residential customers was arrived at by adjusting the number of households by the customer-to-household ratio. This ratio was calculated to account for the difference between the number of households and the number of actual customers in the service territory. Residential customer numbers were held constant beginning in 2018 to reflect the assumption that the Territorial Integrity Act will remain in effect diminishing the company's opportunity to add new residential customers.

The resulting forecast of the number of residential customers and households is plotted in Figure 2-1. As shown in Figure 2-1 and Appendix B-4, the number of residential customers was projected to grow at approximately 0.2 percent per year during 2004-2014.

2.3.1.3 Appliance Saturation Rates by Dwelling Type

SHAPES II forecasts the number of appliances by dwelling type based on saturation rates exogenously specified for each year. The appliance stock by dwelling type is calculated by applying the appliance saturation rate for each year to the number of residential customers by dwelling type.

The number of residential customers by dwelling type was specified for single-family, multi-family, and mobile home residences. These data are available from the *Residential Energy Use Surveys* usually conducted biennially by Montana-Dakota's Marketing Department. Using information from the most recent survey conducted in 2004, a mix of 81.3 percent, 12.1 percent, and 6.6 percent for single family, multi-family, and mobile home residences, respectively, was used for the entire forecast period.

The *2004 Residential Energy Use Survey* was also used as the primary data source for the appliance saturation rates by dwelling type. An examination of past survey data indicated there are several appliances whose historical saturations show a definite and consistent trend. Those appliances are microwaves, color televisions, black and white televisions, central air conditioning, and room air conditioning. Historical appliance saturation trends from the survey data were used to estimate saturations for the year 2024 for these appliances. The lighting saturation was changed to reflect increasing lighting connected load (the number of light bulbs is increasing). The saturations for all other appliances were held constant at the levels indicated in the *2004 Residential Energy Use Survey* for the entire forecast period. The historical and projected appliance saturations are shown in Appendix C-1.

Montana-Dakota Integrated System
Residential Households and Customers

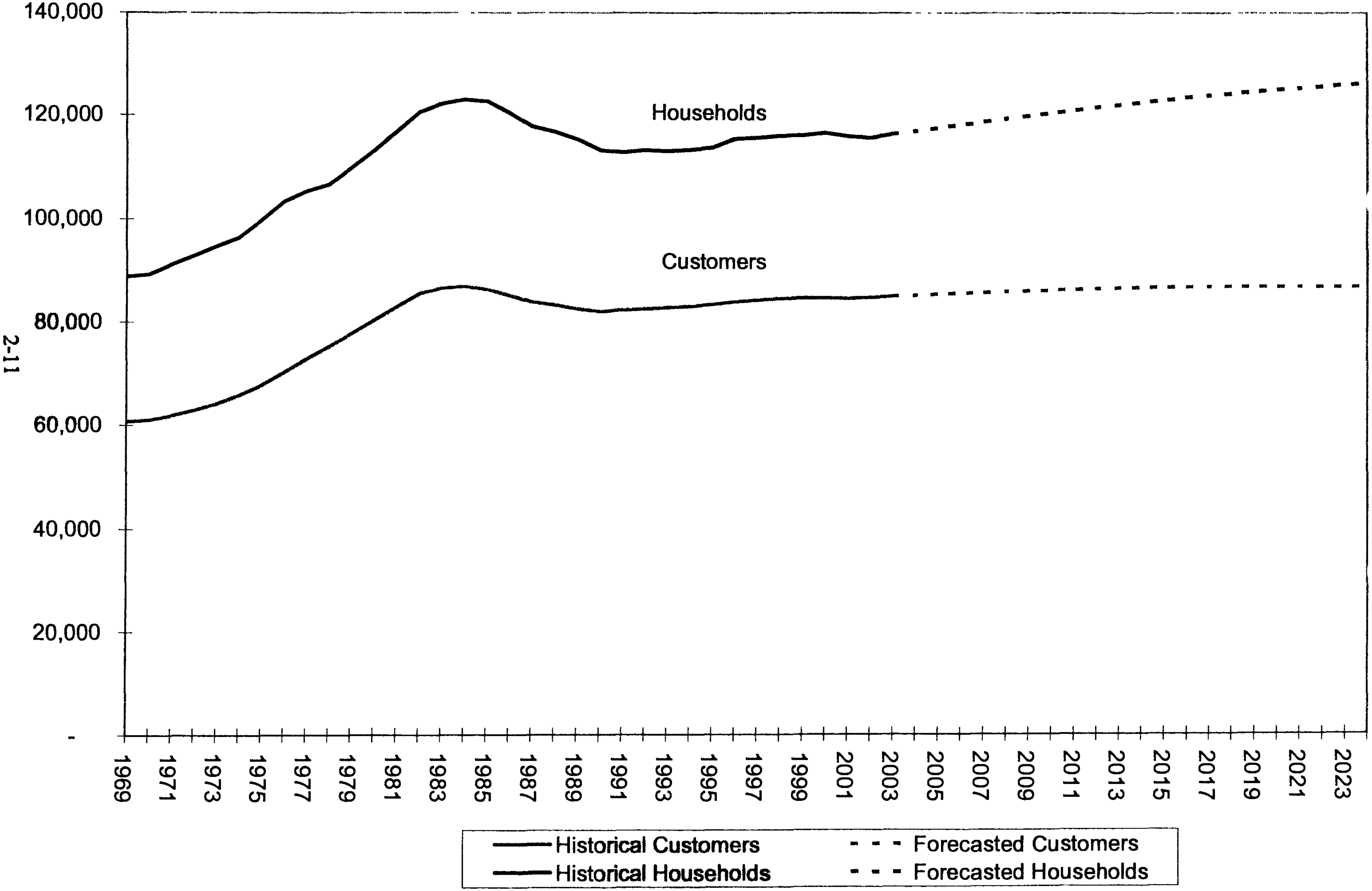


Figure 2-1

For the miscellaneous appliances (e.g.; personal computers and water beds), annual energy was estimated as two percent of the total energy forecast for the temperature-sensitive and eight percent of temperature-insensitive appliances. These values were selected based on operating experience.

2.3.1.4 Appliance Price Elasticities

The appliance price elasticities were modeled based on SHAPES II default values which were developed for the New England Power Pool after the SHAPES II developers reviewed a broad range of studies on the subject of residential appliance elasticities. However, when the SHAPES II default values were used, Montana-Dakota's residential customers' usage increased at unacceptably high rates from year to year. This was caused in part by the declining real electricity prices that have existed since 1984 and that are projected for most of the forecast horizon. After numerous trial runs, the elasticities were set at one-half the default values to produce reasonable results. At this level, the elasticities still fall well within the range of price elasticities that are known to exist in the utility industry. As shown in Appendix C-2, price elasticities were modeled for each type of appliance but they were assumed to be the same for all dwelling types.

2.3.1.5 Appliance Connected Loads and Efficiencies

The connected loads are the *average* demand in watts for each appliance type. These connected loads, in conjunction with appliance efficiency trends, use patterns, and temperature profiles, are used to determine annual appliance energy usage. However, without conducting expensive end-use metering load research programs, utilities do not actually know the appliance energy usage of a typical or average customer. Therefore, estimates are commonly used.

Typical appliance energy usage information is available from a number of sources such as the Association of Home Appliance Manufacturers (AHAM), Edison Electric Institute (EEI), and other publications and reports on those few utilities who have conducted end-use studies. The difficulty in estimating connected loads stems from the fact that values from the various sources vary considerably, in some cases as much as 200 percent. In addition, for each appliance type, there are numerous makes, models, and appliance ages whose electricity consumption differs. Even the electricity consumption for units of the same make and model is different, depending on their number of years in use, mechanical conditions, and how they are used.

Using the information available, initial appliance annual usage was established and then through the calibration process adjustments were made to arrive at reasonable estimates for appliance annual usage for Montana-Dakota's customers. This was accomplished by making adjustments to the initial connected loads during model calibration.

Calibration was performed based on actual monthly 2003 sales and weather. The hourly temperatures for Bismarck in 2003 that were used for this calibration process are plotted in Appendix E. Adjustments to the connected loads were made so that the SHAPES II generated monthly sales are as close as possible to the actual monthly sales for the shoulder or baseload months such as May and September when there are minimal heating and cooling loads. Similarly, adjustments were made based on monthly sales for the winter peak months of January and December and the summer peak months of July and August. The process continued until the input connected loads produced target results for the baseload, winter peak, and summer peak months, and results for all other months were acceptably close to actuals. The calibrated connected loads and the resulting annual energy usage are shown in Appendix C-3.

Appliance efficiency trends were used to account for changes in appliance efficiency over time. As shown in Appendix C-4, the appliance efficiencies are expressed as a fraction of the connected loads estimated for 2003. These trends are used to modify the appliance average connected loads and therefore the appliance energy use. In order to model appliance efficiency trends in the forecast, appliance efficiencies were developed using information available from AHAM, EEI, and the National Appliance Energy Conservation Act of 1987 (NAECA).

The NAECA sets performance standards that prescribed a minimum level of energy efficiency or a maximum quantity of energy use for certain appliances. As a result, appliance manufacturers are improving and changing their appliance designs so that less energy is used in order to comply with the Act. As the overall mix of appliances in customers homes changes to models that are more efficient, the annual energy usage of certain appliances will decrease. Since the appliance connected loads input to the model are set based on calibration for 2003, the 2003 appliance mix -- that is, appliance age, size, model and efficiency -- already reflects efficiencies. Since the life expectancy of many appliances approaches 20 years, efficiencies were developed based on the assumption that in 20 years all appliances would attain the currently designed energy usage.

SHAPES II uses the efficiency multipliers shown in Appendix C-4 as follows. In 2003, all appliance efficiencies are at the 100 percent level corresponding to the connected loads determined by the calibration process. The other efficiency multipliers are input in the year shown and then through linear interpolation SHAPES II calculates the efficiency multipliers for the years in-between and uses these multipliers to reduce the appliance connected loads and therefore the appliance annual energy usage.

In Appendix C-4, several efficiency multipliers are set to one. These conservative values were justified based on a number of reasons. First, for electric ranges/ovens, clothes dryers, microwaves, and space heating, the National Appliance Energy Conservation Act mandated no reductions because these appliances or energy uses are already efficient. Also, for uses such as electric space heating and water heating which use a resistant heating coil, little improvement in efficiency can be made. Second, the only NAECA mandate for dishwashers is an option to dry without heat after January 1, 1988. The only mandate for washing machines is that after January 1, 1988 all models must have cold rinse cycles but may have a heated water rinse option. It is not known exactly how the mandates on dishwashers and washing machines should be reflected in their efficiencies. Finally, given the technology age that we live in, new options are being added to many of our home appliances which drive energy usage up and offset some of the gains in efficiencies. For example, ice making features are being added to refrigerators, ranges come with self-cleaning or continuous cleaning options, the size of TV screens is increasing and TVs have stereo sound, light fixtures are being replaced with ceiling fan/light fixture combinations, single bulb fixtures are being replaced with multi-bulb fixtures, and so on.

2.3.1.6 Appliance Use Patterns

The use patterns for all temperature-insensitive appliances such as refrigerators, dishwashers, and water heaters were data from the Load Research Committee of the Association of Edison Illuminating Companies. These use patterns were furnished with the SHAPES II model by NewEnergy Associates. The data represent residential customers' energy usage nationwide. At the present time, Montana-Dakota is unable to produce the use patterns for temperature-insensitive appliances that are specifically applicable to the Integrated System service territory.

The use patterns for all temperature-sensitive appliances (i.e., air-conditioning and heating) were compiled using Montana-Dakota's in-house load research data. Load research for the Integrated System has been undertaken by Montana-Dakota since 1977. The load research samples currently in place on the Integrated System are designed to gather usage information for residential customers' whole house load. In such programs, special recorders are installed at the sites of representative samples of customers. The recorders measure the customers' total usage at 15-minute intervals and recorded data are stored on computers for subsequent statistical analyses and reporting applications. The procedure used to develop use patterns for the temperature-sensitive appliances is as follows:

All available demand data from Montana-Dakota's residential load research sample for 1994 were compiled on an hourly basis and corresponding hourly temperature data were identified. Average demand by temperature range, day type, and hour was then computed. Demand at each hour of the day versus temperature was plotted for each day type. The baseload portion of the load was identified on each plot and then linear regression analyses were run to interpolate and extrapolate hourly demand as a function of temperature. This procedure was repeated for each hour of each day type. A more complete explanation of the process is included for the Small C&I sector in Section 2.3.2.2.

2.3.2 Small C&I Sector Forecast

The SC&I sector consists of those commercial and industrial customers whose peak demand averages less than 50 kilowatts a month over a year's time. The end-use forecast for the SC&I sector includes estimating data for five areas: (1) SC&I employment forecast, (2) heating, cooling, and baseload use patterns, (3) SC&I price elasticities, (4) heating and cooling degree days and saturations, and (5) SC&I energy intensity.

2.3.2.1 Small C&I Employment Forecast

The forecast of the number of individuals employed by customers in the SC&I sector was based on Woods & Poole employment data for all industries with the exception of mining and farming. Mining employment was not included because mining industry sales are forecasted separately within the LC&I sector with both coal mining and oil field sales being forecasted individually. Since farms are usually served by the rural electric cooperatives, the employment for farming reflects employment generally not in Montana-Dakota's service territory. As a result, the employment numbers used in the development of the SC&I sector includes employment data for agricultural services; construction; manufacturing; transportation, communications, and public utilities; wholesale trade; retail trade; finance, insurance, and real estate; services; federal civilian; federal military; and state and local government.

Historical employment numbers from 1969 to 2001 are provided by Woods & Poole. These historical numbers are from the U.S. Department of Commerce, Bureau of

Economic Analysis. Woods & Poole then estimates the historical employment for 2002 and 2003 and projects the employment for the forecasted period 2004-2024.

Employment for the counties in Montana-Dakota's service territory is projected by Woods & Poole to grow 1.0 percent per year for the next 20 years.

Actual growth in employment for 1991-2001 was 1.7 percent per year while ten year historical growth in SC&I sales was 1.3 percent. The SC&I sector sales forecast resulting from the 1.0 percent growth in employment as projected by Woods & Poole was 0.4 percent per year for the next ten years. Since employment growth for the last ten years was significantly higher than what is now projected by Woods & Poole for the next ten years, and because SC&I sales growth is expected to be more than 0.4 percent per year, it was decided that growth in employment for the sector would be allowed to increase at historical levels (1.7 percent per year) for the next ten years and at 1.0 percent per year thereafter. Employment as forecasted by Woods & Poole and the revised employment forecast as well as historical employment are shown on Figure 2-2. The data for SC&I employment are included in Appendix C-6.

2.3.2.2 Heating, Cooling, and Baseload Use Patterns

For the SC&I sector, SHAPES II forecasts energy and demand for three end-uses: baseload, cooling, and heating. The use patterns for these end-uses were developed from load research data for the Integrated System for calendar year 1994. The procedure used to develop the SC&I use patterns is described below.

The customer average demand from load research data was tabulated on an hourly basis for the entire year. Actual temperature data were correspondingly identified. The

Montana-Dakota Integrated System

Historical & Forecasted Employment

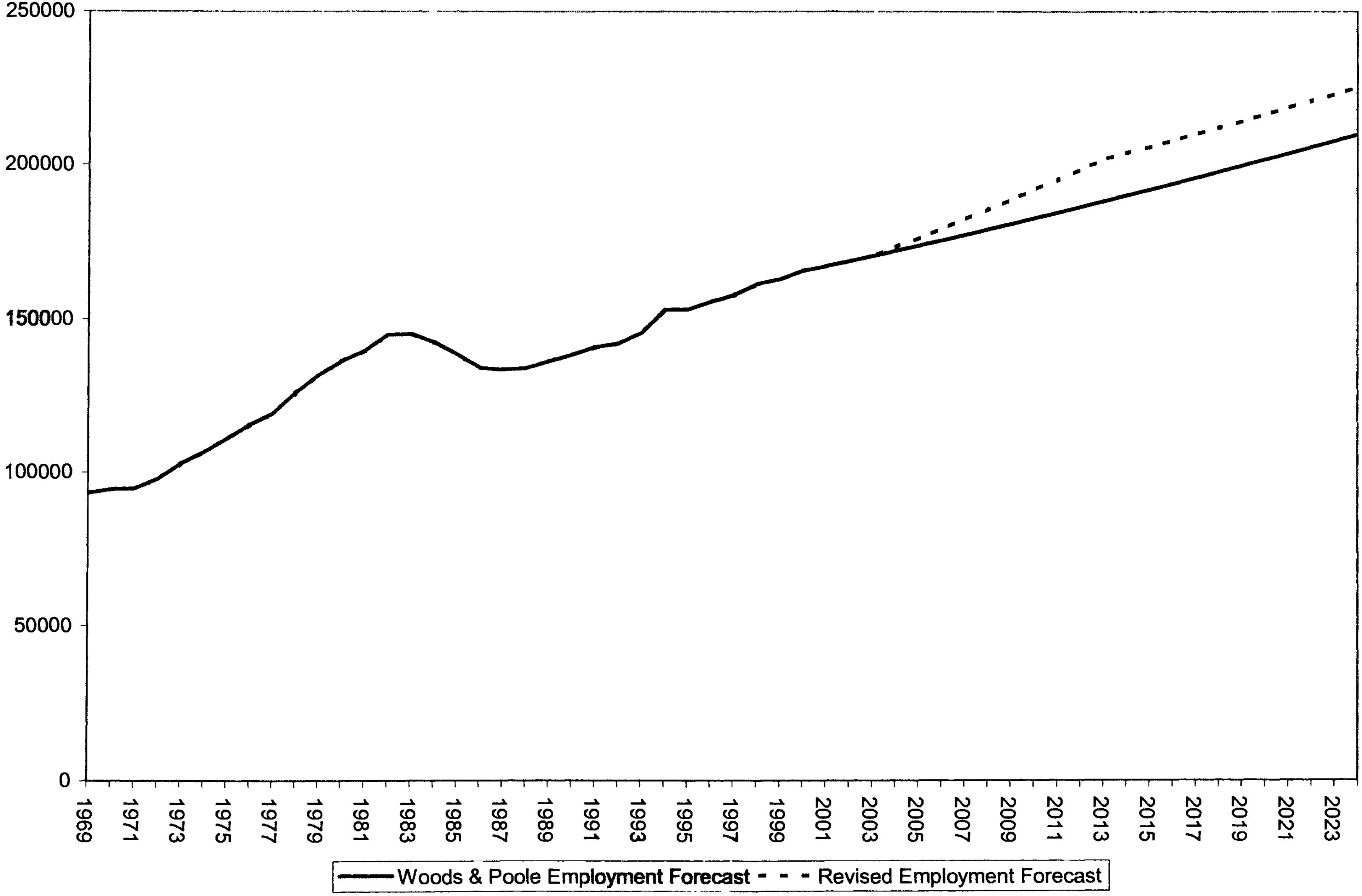


Figure 2-2

data were then divided into day types and the average demand by temperature index, day type, and hour was computed. A temperature index represents a three-degree temperature range such that index 1 represents the temperature range from -27 to -25°F, index 10 represents the temperature range from 0 to 2°F, ..., and index 45 represents the temperatures above 102°F. Hourly demand versus temperature range was plotted for each hour of each day type. As a result, 96 graphs (24 hours x 4 day types = 96) were plotted, one of which is shown in Figure 2-3. Please note that the unit on the vertical axis is decawatt (1 decawatt = 10 watts), while the horizontal axis represents the temperature index.

The next step was to manually identify the baseload, heating and cooling portions on each plot. For example, in Figure 2-3, the observations between A and B were identified as the baseload portion, or "deadband" region. The observations to the left of A were identified as the heating portion. The observations to the right of B were identified as the cooling portion. The temperature-insensitive demand was then computed as the average of the demands within the "deadband" region. For the heating and cooling end-uses, linear regression analyses were run to interpolate and extrapolate the hourly demand as a function of temperature. The resulting hourly demands for heating and cooling for the hour in Figure 2-3 are shown in Figure 2-4. This step was repeated for each hour of each day type and another 96 plots were generated as the result of 192 regression analyses.

2.3.2.3 Small C&I Price Elasticities

For the SC&I sector, the short-term elasticity was set to -0.050 and the long-term to -0.100. These values were selected because they produced acceptable growth rates for SC&I sales as well as the fact that they fell within the lower range of price elasticities that were available to us from a number of studies, one of which was a 1976 study conducted by the National Economic Research Association.

Commercial Demand in kilowatts vs. Temperature Range -- File: plot.data.94/res.d
Day type = 1   Hour = 03

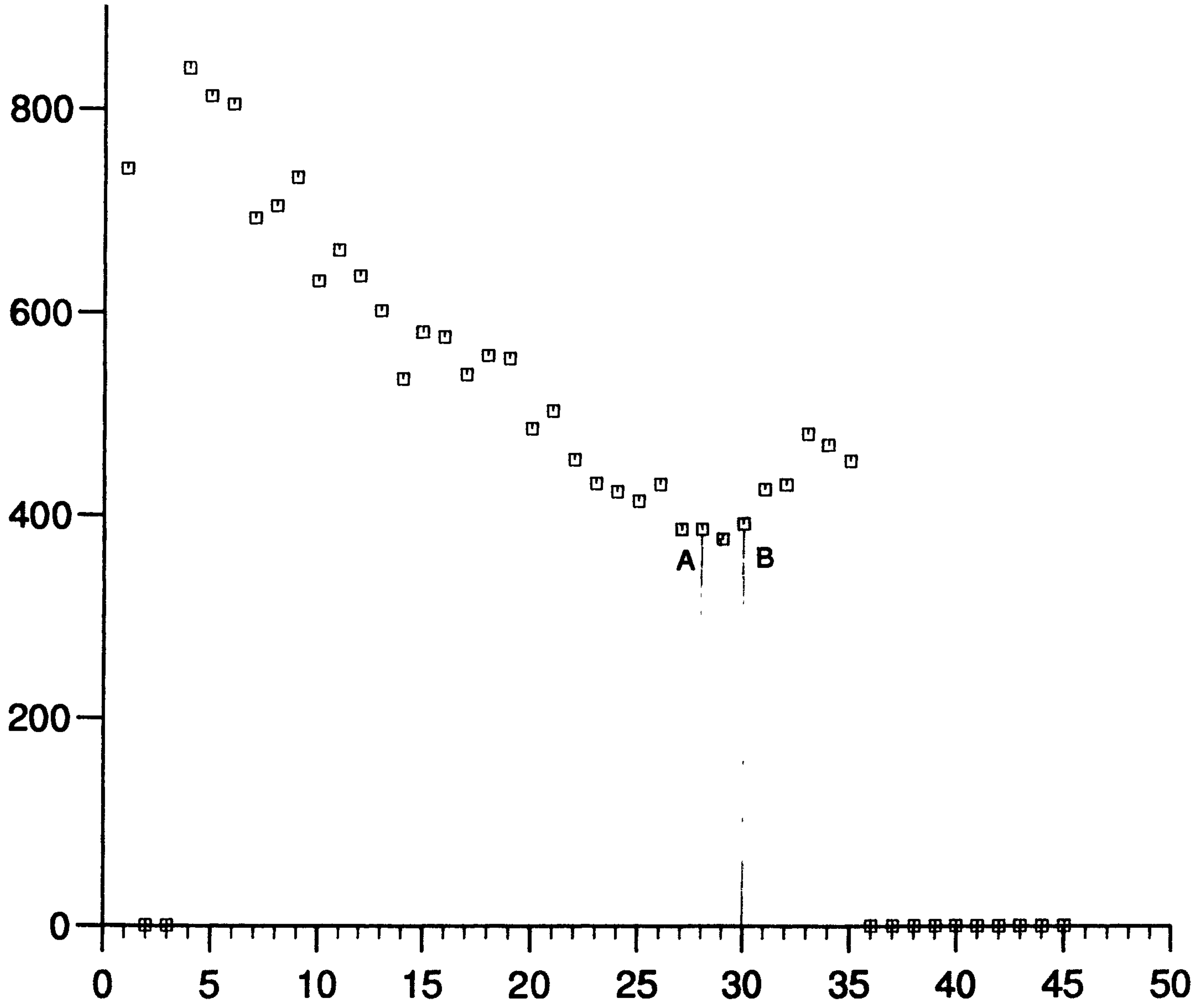


Figure 2-3

Smoothed Commercial Demand in kW vs. Temperature Range -- File: plot.data.94/res
Day type = 1   Hour = 03

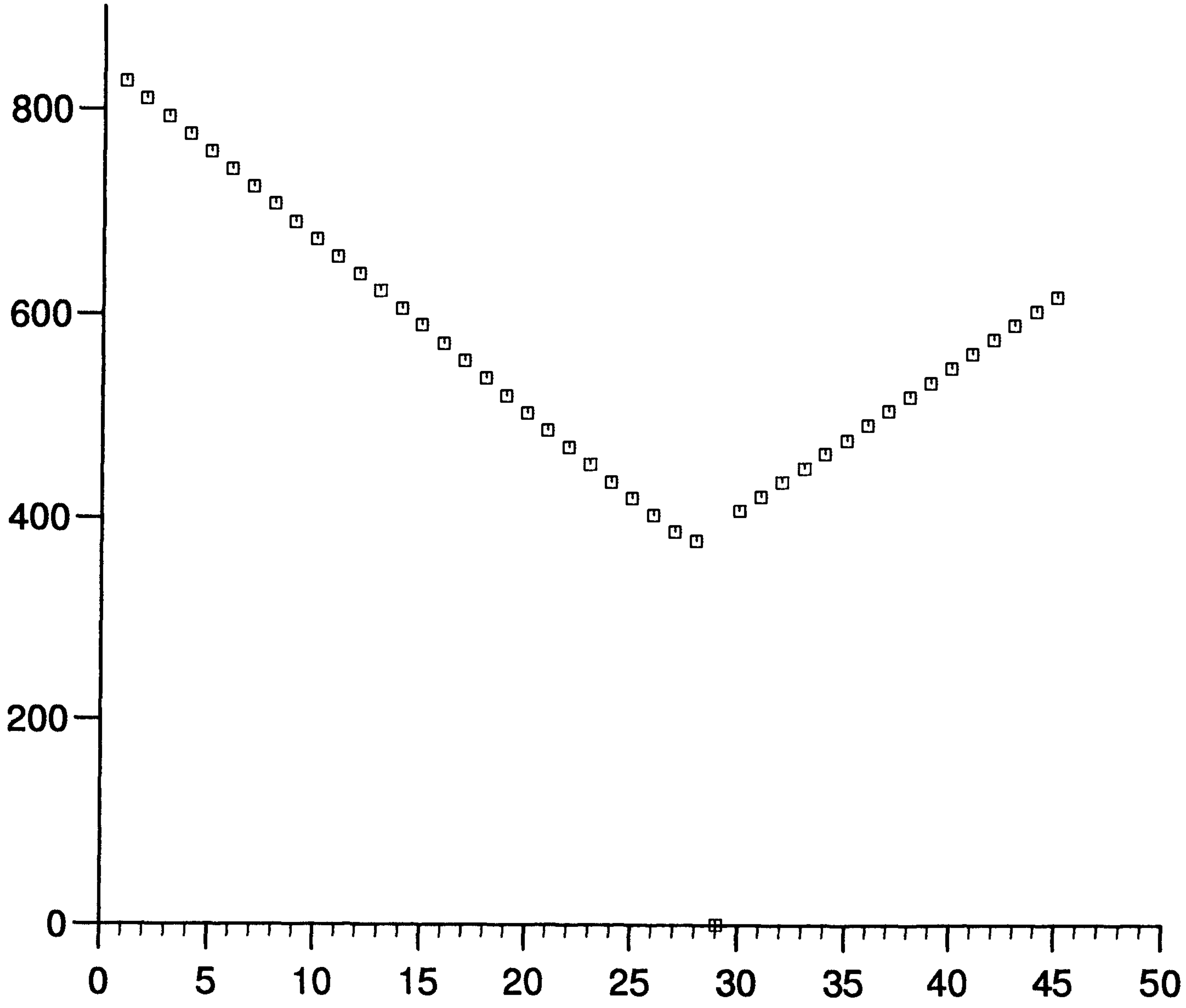


Figure 2-4

2.3.2.4 Heating and Cooling Degree Days and Saturations

Annual heating and cooling degree days are the primary drivers for the heating and cooling components of the SC&I energy intensity estimate (Section 2.3.2.5 below). Historical heating and cooling degree days were calculated from the hourly weather data obtained from the National Oceanic and Atmospheric Administration (NOAA) for Bismarck. Since electric sales were predicted with the assumption that future years would have "normal" weather, the projected annual heating and cooling degree days used in the model were simply the "normal" degree days, which are defined by NOAA as the 30-year average for three decades 1971-2000. The "normal" heating and cooling degree days for Bismarck are 8802 and 471, respectively.

Since not all the SC&I customers are electrically cooled and heated, cooling and heating saturation rates are used to represent the fraction of SC&I customers who are. The cooling saturation rate used was 47.5 percent and the electric heating saturation rate 6.6 percent. These values were the results of a 1989 survey of 116 of Montana-Dakota's Integrated System commercial customers which is the most current data available.

2.3.2.5 Small C&I Energy Intensity

Small C&I energy intensity (kWh per employee) was estimated on a monthly basis using heating and cooling degree days and employment data. The SC&I energy intensity model was developed from monthly historical data for the time period 1991-2003, as described below.

The regression analysis results provided the constants to satisfy the equation:

$$EI = A1 + (B1 * M) + (ALPHAC * COOL) + (ALPHAH * HEAT)$$

where:

M = month: 1,2, ..., 156 (156 months of historical data)
EI' = monthly energy intensity
A1 = baseload intercept coefficient
B1 = baseload time trend coefficient
ALPHAC= cooling coefficient
COOL = product of the cooling saturation and cooling degree days
ALPHAH = heating coefficient
HEAT = product of the heating saturation and heating degree days

The first step was to calculate the energy intensity for each month of the historical period by dividing monthly sales by the number of SC&I employees (EI=SALES/EMPLOYEES). The calculated values became the dependent variable in the next step -- regression analysis using the product of cooling degree days and the cooling saturation rate, the product of heating degree days and the heating saturation rate, and time in months as the independent variables. The resulting energy intensity coefficients are listed in Table 2-2 and were the result of the regression on 156 months of history for the time period 1991-2003.

Table 2-2

Small C&I Energy Intensity Coefficients

Variable	Value	Variable Description
A1	180.455	Baseload intercept coefficient
B1	-0.084	Baseload time trend coefficient
ALPHAC	0.387	Cooling coefficient
ALPHAH	0.310	Heating coefficient

2.3.3 Large C&I Sector Forecast

The LC&I sector consists of those commercial and industrial customers whose peak demand averages more than 50 kilowatts a month over a year's time. Within the LC&I sector, five end-uses are forecasted individually: Tesoro Refinery sales, Westmoreland Coal Mining sales, Oil Field sales, Sabin Metals sales and General LC&I sales which includes sales to all other LC&I customers. The forecast for the General LC&I category is forecasted within SHAPES II while the forecasts for the other four end-uses are forecasted exogenously and then input to SHAPES II. The sales forecasts for each of the end-uses is shown in Table 2-3 and graphed on Figure 2-5.

2.3.3.1 General Large C&I Sector Forecast

The end-use forecast for the General LC&I sector includes estimating data for four areas: (1) LC&I employment forecast, (2) LC&I use patterns, (3) LC&I price elasticities, and (4) LC&I energy intensity.

Large C&I Employment Forecast

The number of individuals employed by customers in the LC&I sector was projected based on Woods & Poole employment data for all industries with the exception of mining and farming as explained in Section 2.3.2.1. The data for LC&I employment are included in Appendix C-7.

Large C&I Use Patterns

Use patterns are input to SHAPES II for each of the five LC&I categories or end-uses:

1. General LC&I - Developed from load research data for the Integrated System for January 1994 to December 1994.
2. Tesoro Refinery – Hourly data available for January 2003 to December 2003 from Montana-Dakota's Energy Management System (EMS).
3. Westmoreland Coal Mining - Hourly data available for January 2003 to December 2003 from Montana-Dakota's EMS.
4. Oil Field - Hourly data available for January 2003 to December 2003 from Montana-Dakota's EMS.
5. Sabin Metals – Estimated for the former Dakota Catalyst based on information provided by Dakota Catalyst and now used for Sabin Metals.

HISTORICAL AND FORECASTED ANNUAL SALES BY LC&I END-USE
INTEGRATED SYSTEM

	GENERAL LC&I 1/		TESORO REFINERY 2/		WESTMORELAND COAL 3/		ENCORE ACQUISITION 4/		OTHER OIL FIELD 5/		SABIN METALS 6/		TOTAL LC&I	
YEAR	SALES(MWh)	%GROWTH	SALES(MWh)	%GROWTH	SALES(MWh)	%GROWTH	SALES(MWh)	%GROWTH	SALES(MWh)	%GROWTH	SALES(MWh)	%GROWTH	SALES(MWh)	%GROWTH
1993	463,455		37,035		30,844		112,887		29,442		4,971		678,634	
1994	479,259	3 41%	38,670	4 41%	33,333	8 07%	107,671	-4 62%	30,265	2 80%	18,009	262 28%	707,207	4 21%
1995	492,683	2 80%	35,515	-8 16%	30,613	-8 16%	100,620	-6 55%	30,207	-0 19%	14,148	-21 44%	703,786	-0 48%
1996	508,989	3 31%	36,206	1 95%	28,052	-8 37%	102,508	1 88%	28,159	-6 78%	16,587	17 24%	720,501	2 38%
1997	532,895	4 70%	41,807	15 47%	24,484	-12 72%	99,132	-3 29%	24,818	-11 86%	5,671	-65 81%	728,807	1 15%
1998	540,627	1 45%	40,444	-3 26%	28,047	14 55%	99,203	0 07%	24,915	0 39%	-		733,236	0 61%
1999	560,751	3 72%	43,424	7 37%	30,069	7 21%	99,887	0 69%	30,637	22 97%	-		764,768	4 30%
2000	581,857	3 76%	38,375	-11 63%	26,816	-10 82%	109,618	9 74%	42,539	38 85%	350		799,555	4 55%
2001	595,601	2 36%	44,744	16 60%	27,993	4 39%	118,215	7 84%	42,218	-0 75%	4,478	1179 43%	833,249	4 21%
2002	607,360	1 97%	42,022	-6 08%	28,091	0 35%	139,392	17 91%	43,529	3 11%	6,507	45 31%	866,901	4 04%
2003	615,084	1 27%	38,669	-7 98%	27,362	-2 60%	164,191	17 79%	53,153	22 11%	7,401	13 74%	905,860	4 49%
2004	625,667	1 72%	49,443	27 86%	28,000	2 33%	164,484	0 18%	51,854	-2 44%	9,198	24 28%	928,646	2 52%
2005	639,134	2 15%	51,222	3 60%	28,000	0 00%	176,718	7 44%	63,712	22 87%	9,198	0 00%	967,984	4 24%
2006	661,067	3 43%	53,000	3 47%	28,000	0 00%	188,964	6 93%	64,402	1 08%	12,498	35 88%	1,007,931	4 13%
2007	670,812	1 47%	54,779	3 36%	28,000	0 00%	201,224	6 49%	65,093	1 07%	12,498	0 00%	1,032,406	2 43%
2008	681,756	1 63%	56,557	3 25%	28,000	0 00%	213,497	6 10%	65,784	1 06%	12,498	0 00%	1,058,092	2 49%
2009	693,899	1 78%	58,335	3 14%	28,000	0 00%	225,783	5 75%	66,477	1 05%	12,498	0 00%	1,084,992	2 54%
2010	705,250	1 64%	60,114	3 05%	28,000	0 00%	227,083	0 58%	67,170	1 04%	17,097	36 80%	1,104,714	1 82%
2011	716,688	1 62%	61,892	2 96%	28,000	0 00%	228,396	0 58%	67,035	-0 20%	18,017	5 38%	1,120,028	1 39%
2012	727,749	1 54%	63,671	2 87%	28,000	0 00%	229,724	0 58%	66,900	-0 20%	18,937	5 11%	1,134,981	1 34%
2013	738,365	1 46%	65,449	2 79%	28,000	0 00%	231,065	0 58%	66,766	-0 20%	19,856	4 85%	1,149,501	1 28%
2014	748,875	1 42%	67,228	2 72%	28,000	0 00%	232,420	0 59%	66,633	-0 20%	20,776	4 63%	1,163,932	1 26%
2015	759,694	1 44%	69,006	2 64%	28,000	0 00%	233,790	0 59%	66,500	-0 20%	21,236	2 21%	1,178,226	1 23%
2016	770,864	1 47%	70,784	2 58%	28,000	0 00%	235,174	0 59%	66,369	-0 20%	21,236	0 00%	1,192,427	1 21%
2017	782,515	1 51%	72,563	2 51%	28,000	0 00%	236,572	0 59%	66,239	-0 20%	21,236	0 00%	1,207,125	1 23%
2018	794,160	1 49%	74,341	2 45%	28,000	0 00%	237,986	0 60%	66,109	-0 20%	21,236	0 00%	1,221,832	1 22%
2019	805,984	1 49%	76,120	2 39%	28,000	0 00%	239,414	0 60%	65,980	-0 20%	21,236	0 00%	1,236,734	1 22%
2020	817,692	1 45%	77,898	2 34%	28,000	0 00%	240,857	0 60%	65,852	-0 19%	21,236	0 00%	1,251,535	1 20%
2021	829,527	1 45%	79,677	2 28%	28,000	0 00%	242,315	0 61%	65,725	-0 19%	21,236	0 00%	1,266,480	1 19%
2022	841,391	1 43%	81,455	2 23%	28,000	0 00%	243,789	0 61%	65,599	-0 19%	21,236	0 00%	1,281,470	1 18%
2023	853,369	1 42%	83,233	2 18%	28,000	0 00%	245,278	0 61%	65,473	-0 19%	21,236	0 00%	1,296,589	1 18%
2024	865,402	1 41%	85,012	2 14%	28,000	0 00%	246,783	0 61%	65,349	-0 19%	21,236	0 00%	1,311,782	1 17%
1993-2003 AVG YEARLY GROWTH (10 YRS HIST)		3 00%		1 28%		-1 30%		3 26%		6 04%		-		2 78%
1998-2003 AVG YEARLY GROWTH (5 YRS HIST)		2 63%		-0 48%		-0 81%		10 82%		14 81%		-		4 30%
2004-2009 AVG YEARLY GROWTH (5 YEARS)		2 09%		3 36%		0 00%		6 54%		5 09%		-		3 16%
2004-2014 AVG YEARLY GROWTH (10 YEARS)		1 81%		3 12%		0 00%		3 52%		2 54%		-		2 28%
2004-2024 AVG YEARLY GROWTH (20 YEARS)		1 64%		2 75%		0 00%		2 05%		1 16%		-		1 74%

1/ GENERAL LARGE COMMERCIAL & INDUSTRIAL FORECAST WAS CALCULATED BY SHAPES BASED ON A REGRESSION OF 94-03 ENERGY INTENSITY
2/ TESORO REFINERY SALES ARE BASED ON A LINEAR REGRESSION OF 81-03 SALES
3/ WESTMORELAND COAL IS HELD CONSTANT AT 2002 ACTUAL LEVELS
4/ ENCORE ACQUISITION SALES FORECAST IS BASED ON AN EXPONENTIAL CURVE FIT THROUGH 94-03 SALES
5/ OTHER OIL FIELDS SALES FORECAST IS BASED ON AN EXPONENTIAL CURVE FIT THROUGH SALES AT EACH OIL FIELD INDIVIDUALLY (OUTLOOK, POPLAR, AND ALL OTHER MT OIL FIELD SALES)
6/ SABIN METALS HAS OPERATED AT ABOUT 3 5 MW WITH A 30% LOAD FACTOR BUT THEY EXPECT TO INCREASE THEIR FURNACE LOAD FACTOR IN 2006 AND ADD ANOTHER ARC FURNACE IN 2010

Table 2-3

Montana-Dakota Integrated System
Historical and Forecasted Sales by LC&I Customer

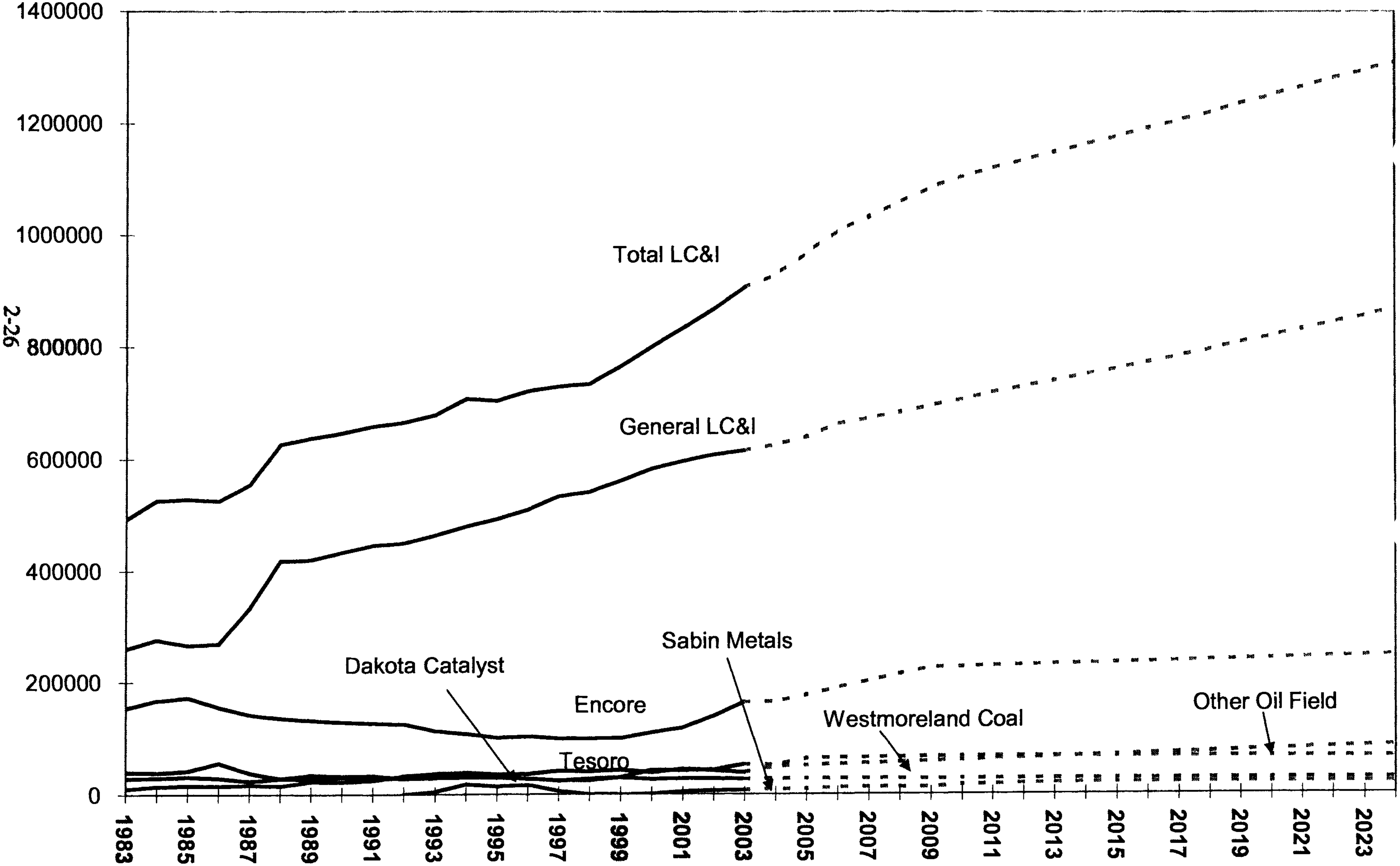


Figure 2-5

Large C&I Price Elasticities

The General LC&I short-term elasticity was set to -0.150 and the long-term to -0.300. These values were selected because they produced acceptable growth rates for General LC&I sales as well as the fact that they fell within the range of price elasticities that were available to us from a number of studies, one of which was a 1976 study conducted by the National Economic Research Association.

Large C&I Energy Intensity

To estimate the General LC&I energy intensity, historical sales, Woods & Poole employment data, and energy intensity for the time period of 1981 to 2003 were analyzed and linear regression analyses on sales and energy intensity were run. It was noted that employment declined each year in the time period of 1984 to 1987 but increased from 1988 to 2003 as shown in Appendix C-6. It was also noted that historical sales for the sector changed somewhat erratically until 1988 while sales for the time period 1988 to 2003 grew quite evenly from year to year.

Further analysis indicated that regression on energy intensity, based on the time period of 1994-2003 was the best fitting of all those for 1988 through 1998 while also producing a reasonable sales forecast for the General LC&I sector, and therefore, that is what was used in the model. The resulting regression equation was:

$$\text{Energy Intensity} = 2.639938 + (0.030539 \times \text{year})$$

2.3.3.2 Tesoro Refinery Sales

The sales forecast for the Tesoro Refinery is based on a linear regression of 1981 to 2003 actual sales and is input to SHAPES II where a use pattern for the Tesoro Refinery is used to allocate the sales to the hours of the year.

2.3.3.3 Westmoreland Coal Mining Sales

The sales forecast for Westmoreland Coal for the year 2004 is based on 2 percent growth from actual 1999 sales at all mines excluding Gascoyne and is thereafter held flat. Gascoyne mine sales are excluded from the total Westmoreland Coal sales because of the expiration of the Big Stone Plant contract on July 1, 1995. The sales forecast is input to SHAPES II where the Westmoreland use pattern is used to allocate the sales to the hours of the year.

2.3.3.4 Oil Field Sales

Oil field sales are made up of three Montana oil fields: the Cedar Creek Anticline near Baker, the Outlook oil field, and the Poplar oil field. Sales at the Cedar Creek Anticline are further broken down into sales to Encore Acquisition and all other sales at the Cedar Creek Anticline. Sales to Encore Acquisition account for about 76 percent of all oil field sales. The oil fields sales forecast is based on exponential curve regressions for each of the four oil field customers individually.

The forecast for Encore Acquisition in the Cedar Creek Anticline was based on an exponential curve fit through 1994 to 2003 historical sales excluding new load added in 2000-2003. Total load associated with new growth experienced during the 2000-2003 time period due to the installation of new equipment and changes in operations was added to the forecast beginning in 2004. Additional load of 11,000 MWh was also added each year from 2005-2009 for expected increases in Encore's conventional drilling operations.

Sales in the Cedar Creek Anticline that are not to Encore Acquisition are called Other MT Oil Field sales. This forecast was based on an exponential curve through 1987 to 2003 sales excluding new load that was added by Burlington Resources in 1999, 2000, and 2003. New load of 27,000 MWh was then added back in to the forecast in 2004 to reflect the increased load experienced by Burlington Resources. Additional load of

8,700 MWh in 2005 and 1,000 MWh for each year 2006-2009 for new wells to be added by Burlington Resources was also added to the other MT Oil Field sales forecast.

The forecast for the Poplar oil field was developed from an exponential curve through 1986 to 2003 sales, while the forecast for the Outlook oil field was based on an exponential curve through 1996 to 2003 sales.

Historical and forecasted sales for each of the four oil field customers individually are shown on Figure 2-6. Sales to the oil fields in total have generally declined each year from 1986 to 1997. New equipment was added by Encore and Burlington Resources causing sales to increase in 1999 through 2003. Sales are expected to increase rather significantly through 2009 due to new projects that are underway or expected to be in place over the next five years. Because of the uncertainty beyond that point, sales are projected to increase at the rate experienced historically excluding the extraordinary load growth that was added in that time period. The oil field sales forecast is input to SHAPES II where the oil field use pattern is used to allocate the sales to the hours of the year.

2.3.3.5 Sabin Metals Sales

Sabin Metals began production in Williston, ND in mid-2001. The Montana-Dakota Marketing Department estimates the load at Sabin Metals to be approximately 3.5 MW with a 30 percent load factor. Sabin Metals expects to operate at this level through 2005. An increase in the load factor of the arc furnace at Sabin Metals is expected to increase sales approximately 3,300 MWh per year beginning in 2006. It is also expected that an additional arc furnace will be added in 2010 with about a 50 percent load factor and that furnace will ramp up to about a 95 percent load factor by the year 2015. These changes are reflected in the Sabin Metals forecast. The sales forecast is input to SHAPES II where an estimated use pattern is used to allocate the sales to the hours of the year.

Montana-Dakota Integrated System

Historical and Forecasted Montana Oil Field Customers Sales

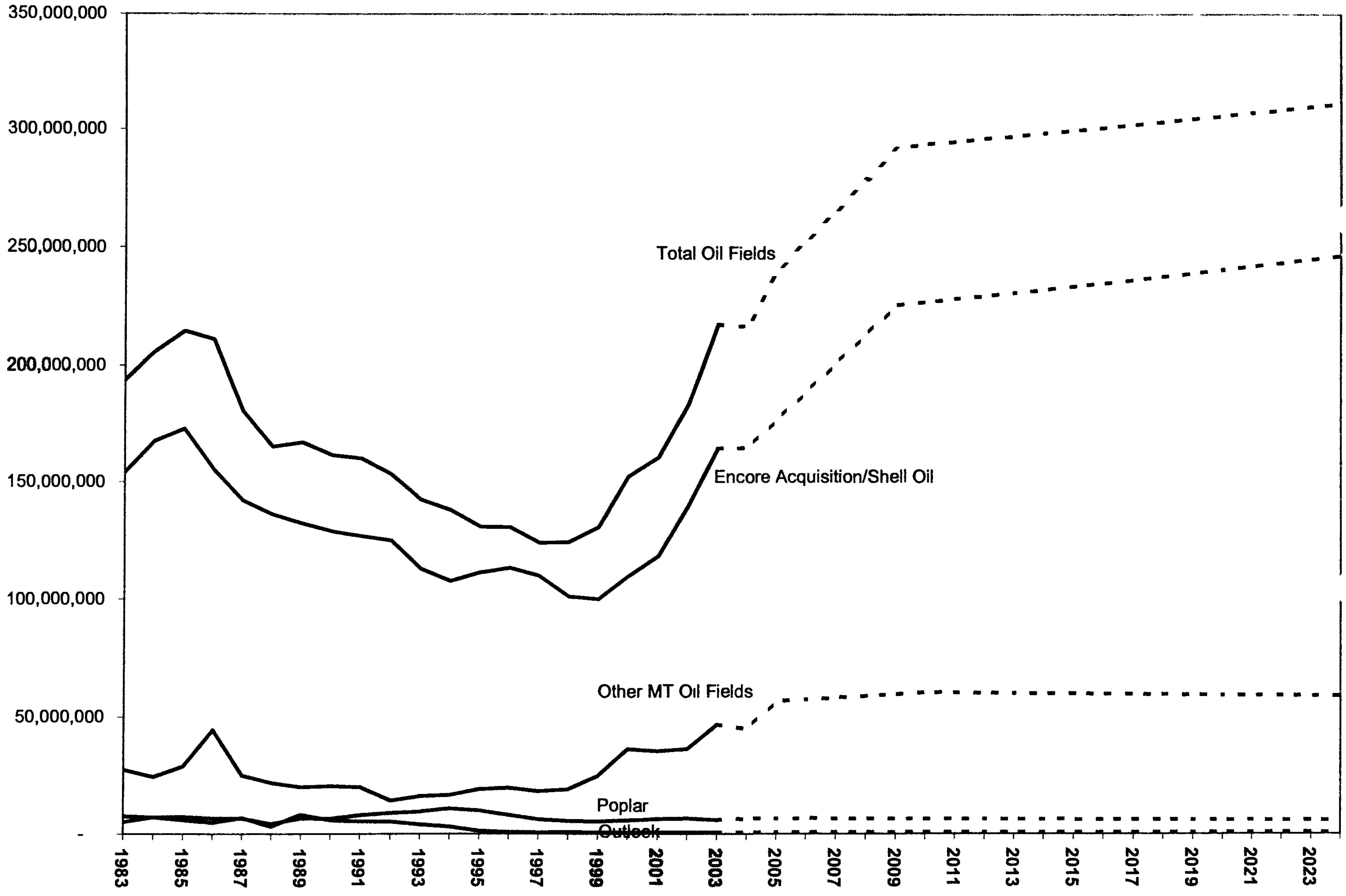


Figure 2-6

2.3.4 Temperature Profile and Typical Meteorological Year Data

The typical meteorological year (TMY) data define a temperature profile to be assumed for future years of the SHAPES II simulations. The temperature profile, which consists of hourly temperatures for an entire year, is used to calculate the demand for the temperature-sensitive end uses, such as the cooling and heating components of the SC&I sector (Section 2.3.2.2), and the temperature-sensitive appliances in the residential sector (Section 2.3.1.6).

Historical weather data are generally available from the National Climatic Data Center of the National Oceanic and Atmospheric Administration (NOAA) for a limited number of weather stations in Montana-Dakota's service area in the form of Surface Airways Hourly TD-3280 Data. The problem encountered in the forecast procedure is how to determine a representative temperature profile for the Montana-Dakota service area of more than 168,000 square miles. This problem consists of the selection of the location where the temperatures were measured and the time period for which data are to be used.

An attempt to solve the location problem is to formulate a weighted average of the temperatures at three major load centers: Bismarck, North Dakota; Miles City, Montana; and Williston, North Dakota. This effort does not lead to an acceptable result because the Miles City and Williston temperatures are not complete. Several years of data were missing, and in many of the years that data are available, they were only partially available; months of data are missing, or data are provided for only part of the day. Because of this situation, Bismarck temperatures, which are available for 1948 through 2003, are the remaining choice for TMY data.

The remaining question is which part of the available historical data should be used? In previous load forecasts, the concept of a "typical" year was explored. With that concept, the total cooling degree days for the summer months and total heating degree days for the winter months were calculated. The "typical" year selected would be the one with the total cooling and heating degree days nearest the "normal" values defined by NOAA. For the present study, we decided to use the typical meteorological year provided by NOAA as the future temperature profile. From the weather data for Bismarck from the 1960s, 1970s, and 1980s, for each of the twelve calendar months, NOAA identifies a typical meteorological month based on four measures: (1) dry bulb temperature (normal temperature referred to in this report), (2) dew point temperature, (3) wind velocity, and (4) global solar radiation on horizontal surface. (See Typical Meteorological Year User's Manual TD-9734). From operating experience, it is known that all four measures used in the selection affect electric consumption. As a result, the composition of the Bismarck typical meteorological year is as follows:

January	1988	July	1964
February	1974	August	1986
March	1968	September	1988
April	1985	October	1968
May	1969	November	1967
June	1972	December	1967

The hourly Bismarck temperatures for those months are plotted in Appendix D.

2.4 FORECAST RESULTS

2.4.1 ANNUAL SALES FORECASTS BY SECTOR

After the residential model was calibrated, the SHAPES II simulations were run using the normal cooling and heating degree days, and the Bismarck TMY data to produce the sales forecast. This section discusses the electric sales forecast produced by SHAPES II.

The electric sales forecast for the residential sector is shown in Figure 2-7. The residential sales are projected to increase at 0.2 percent per year during the ten year period

Montana-Dakota Integrated System
Historical and Forecasted Residential Sales

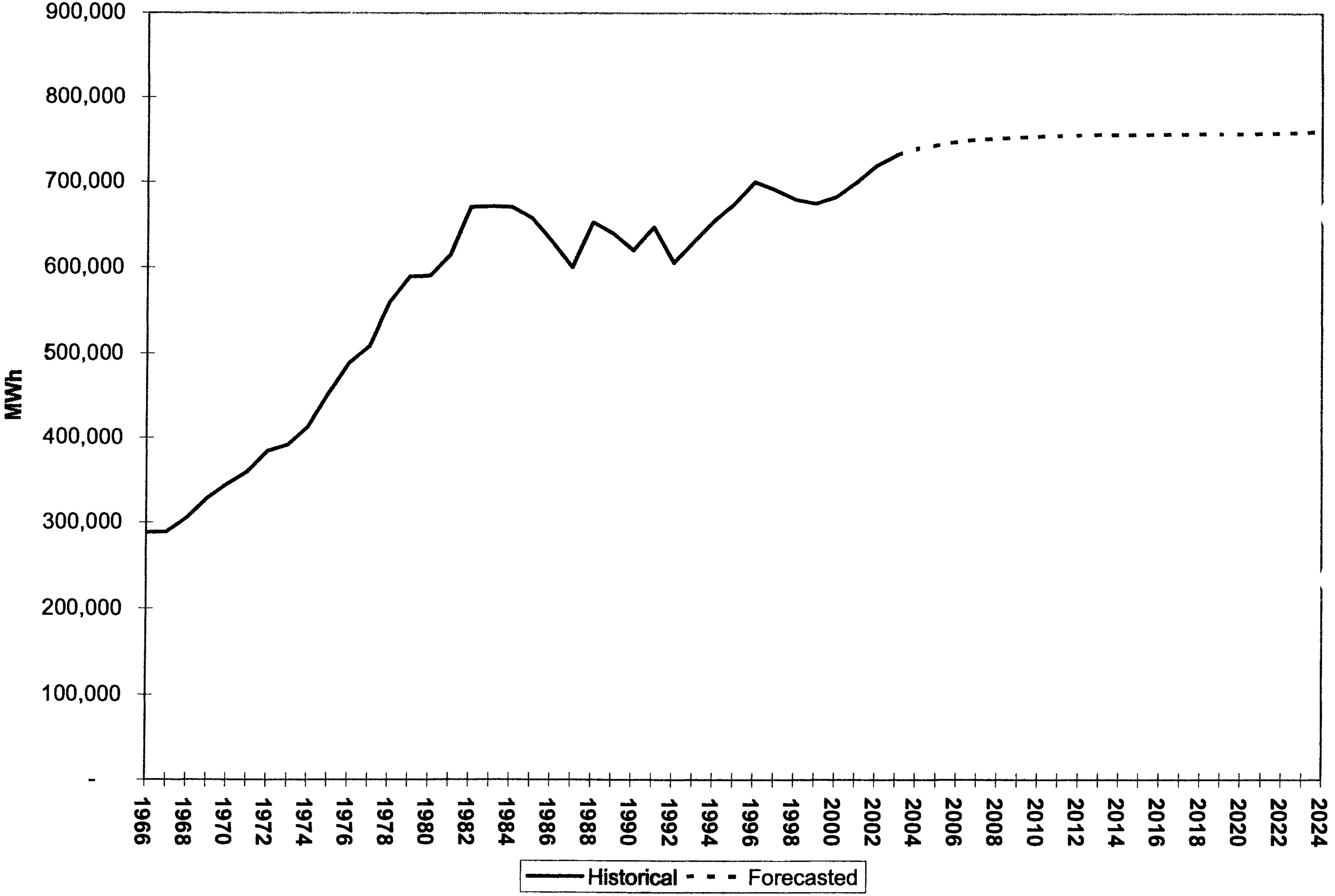


Figure 2-7

2004-2014. This projected increase compares to an average growth of 1.1 percent per year for 1993-2003, and 1.7 percent per year for 1998-2003. Historical and forecasted residential sales, customers, and annual use per customer are given on Table 2-4.

The electric sales forecast for the SC&I sector is shown in Figure 2-8. The SC&I sales are forecasted to increase 1.0 percent during the period 2004-2014. This increase compares to an average growth of 1.3 percent per year for 1993-2003, and 1.1percent per year for 1998-2003.

The electric sales forecast for the LC&I sector is shown in Figure 2-9. The LC&I sales for the class as a whole are projected to increase at 2.3 percent per year during the period 2004-2014. This compares to 2.8 percent growth per year for 1993-2003, and 4.3 percent per year for 1998-2003.

The electric forecast for street lighting sales is shown in Figure 2-10. Street lighting sales are projected to grow very slowly at an average of 0.1 percent per year for the next 20 years which is about the same growth that was experienced historically from 1993-2003.

The electric sales forecast for the miscellaneous sector (sales to other public authorities, interdepartmental sales, and company use) is shown in Figure 2-11. Sales for the sector are forecasted to remain almost flat for the next 20 years. The growth for the historical ten year period 1993-2003 averaged about -0.2 percent per year while growth for the period 1998-2003 was -0.5 percent.

Finally, Table 2-5 captures the numerical results of the end-use forecast and gives the total electric sales forecast, which is plotted in Figure 2-12. The sales forecasts for street lighting and for miscellaneous sales shown in the table were obtained with the time trend method, as discussed in Section 2.2.4 and 2.2.5. The total sales forecast increases at an average of 1.3 percent per year for the next ten years and 1.0 percent per year for the next 20 years.

Table 2-4

MONTANA-DAKOTA UTILITIES CO.
HISTORICAL AND FORECASTED
RESIDENTIAL SALES, CUSTOMERS, AND USE PER CUSTOMER
INTEGRATED SYSTEM

YEAR	SALES (MWh)	%GROWTH	AVG CUSTS	CUST NO INC/(DEC)	AVG USE PER CUST (kWh/YR)	
1993	630,108		83,038		7,588	
1994	654,760	3.91%	83,242	204	7,866	
1995	675,493	3.17%	83,639	397	8,076	
1996	700,642	3 72%	84,153	514	8,326	
1997	691,325	-1 33%	84,510	357	8,180	
1998	680,290	-1 60%	84,833	323	8,019	
1999	675,658	-0.68%	84,935	102	7,955	*/
2000	683,435	1.15%	84,914	-21	8,049	
2001	700,552	2.50%	84,866	-48	8,255	
2002	720,346	2 83%	85,012	146	8,473	
2003	733,030	1 76%	85,278	266	8,596	
2004	740,872	1.07%	85,453	175	8,670	
2005	745,522	0.63%	85,663	210	8,703	
2006	749,555	0.54%	85,818	155	8,734	
2007	752,130	0.34%	86,014	196	8,744	
2008	753,264	0 15%	86,181	167	8,740	
2009	754,691	0 19%	86,328	147	8,742	
2010	755,450	0.10%	86,464	136	8,737	
2011	756,585	0.15%	86,606	142	8,736	
2012	757,422	0 11%	86,745	139	8,732	
2013	757,782	0.05%	86,880	135	8,722	
2014	757,906	0.02%	86,969	89	8,715	
2015	758,194	0.04%	87,072	103	8,708	
2016	758,437	0.03%	87,140	68	8,704	
2017	758,603	0.02%	87,195	55	8,700	
2018	758,757	0 02%	87,224	29	8,699	
2019	758,846	0.01%	87,224	0	8,700	
2020	759,070	0.03%	87,224	0	8,703	
2021	759,527	0.06%	87,224	0	8,708	
2022	760,179	0.09%	87,224	0	8,715	
2023	761,030	0 11%	87,224	0	8,725	
2024	761,958	0.12%	87,224	0	8,736	

	SALES	CUSTS
1993-2003 AVG YEARLY GROWTH (10 YRS HIST)	1 07%	0.26%
1998-2003 AVG YEARLY GROWTH (5 YRS HIST)	1 70%	0.08%
2004-2009 AVG YEARLY GROWTH (5 YEARS)	0.37%	0.20%
2004-2014 AVG YEARLY GROWTH (10 YEARS)	0.23%	0.18%
2004-2024 AVG YEARLY GROWTH (20 YEARS)	0 14%	0 10%

*/ AVG CUSTS and AVG USE PER CUST for 1999 are only estimates. Due to the installation of a new CIS in 1999, actual customer numbers are not available.

Montana-Dakota Integrated System
Historical and Forecasted SC&I Sales

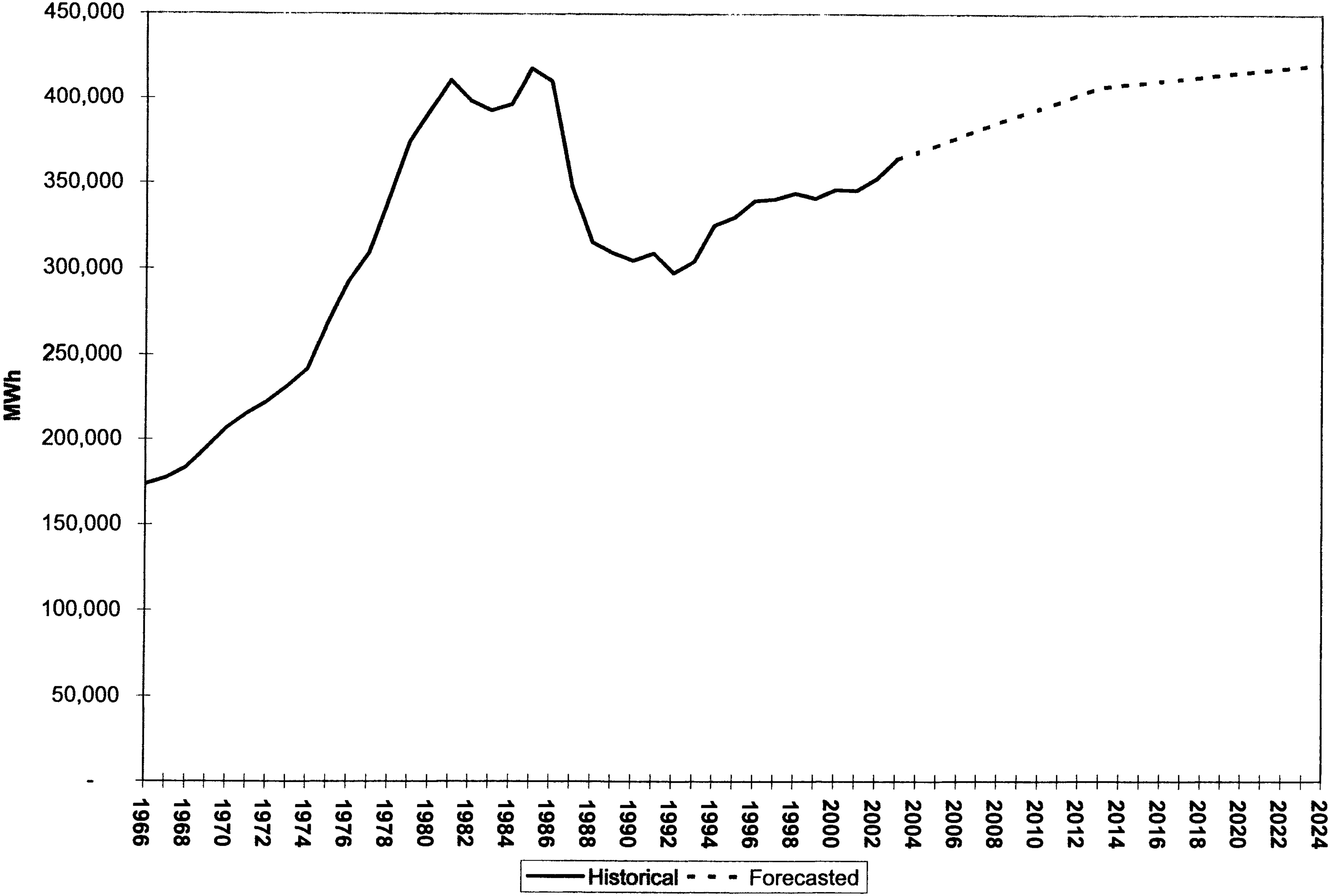


Figure 2-8

Montana-Dakota Integrated System
Historical and Forecasted LC&I Sales

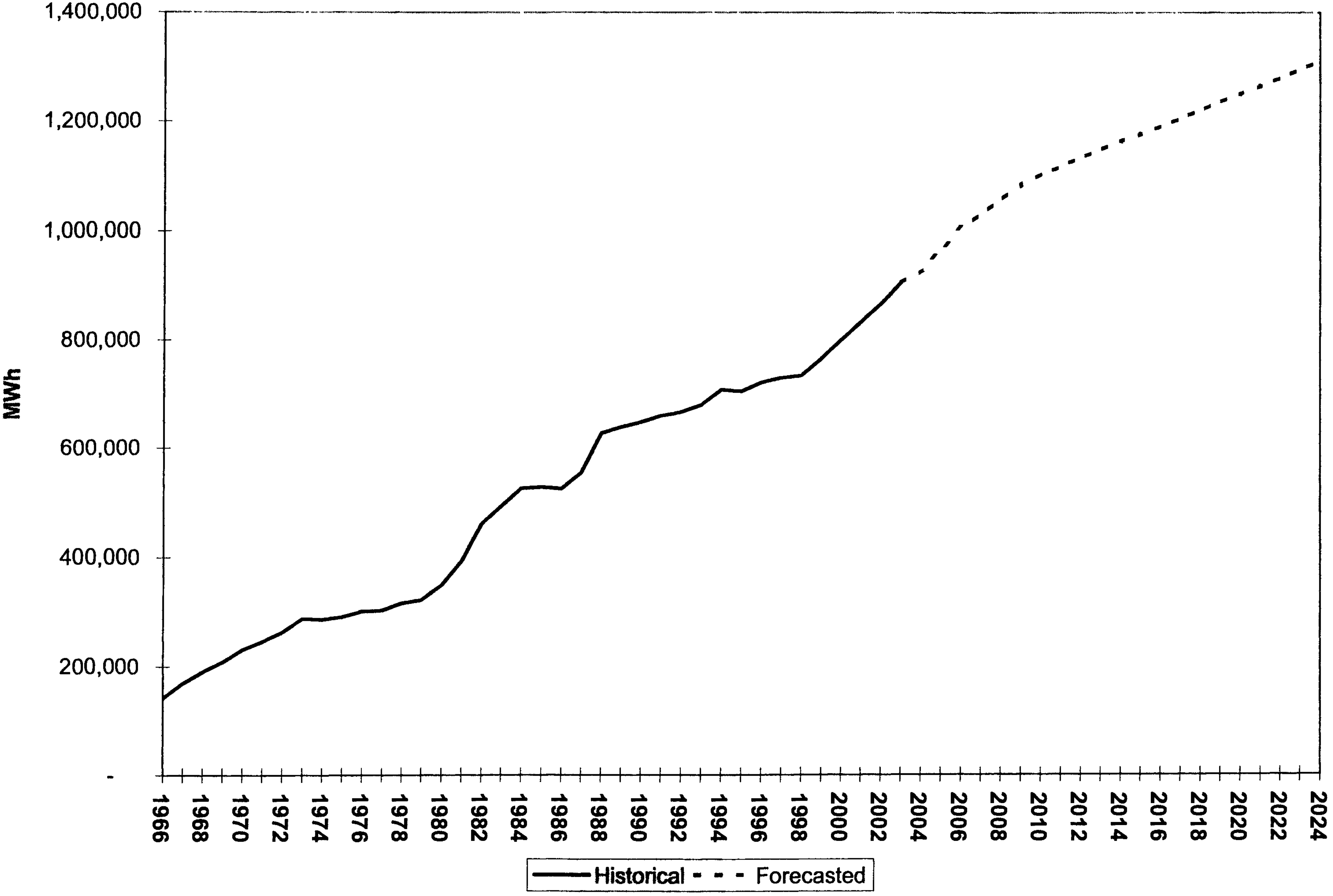


Figure 2-9

Montana-Dakota Integrated System
Historical and Forecasted Street Lighting Sales

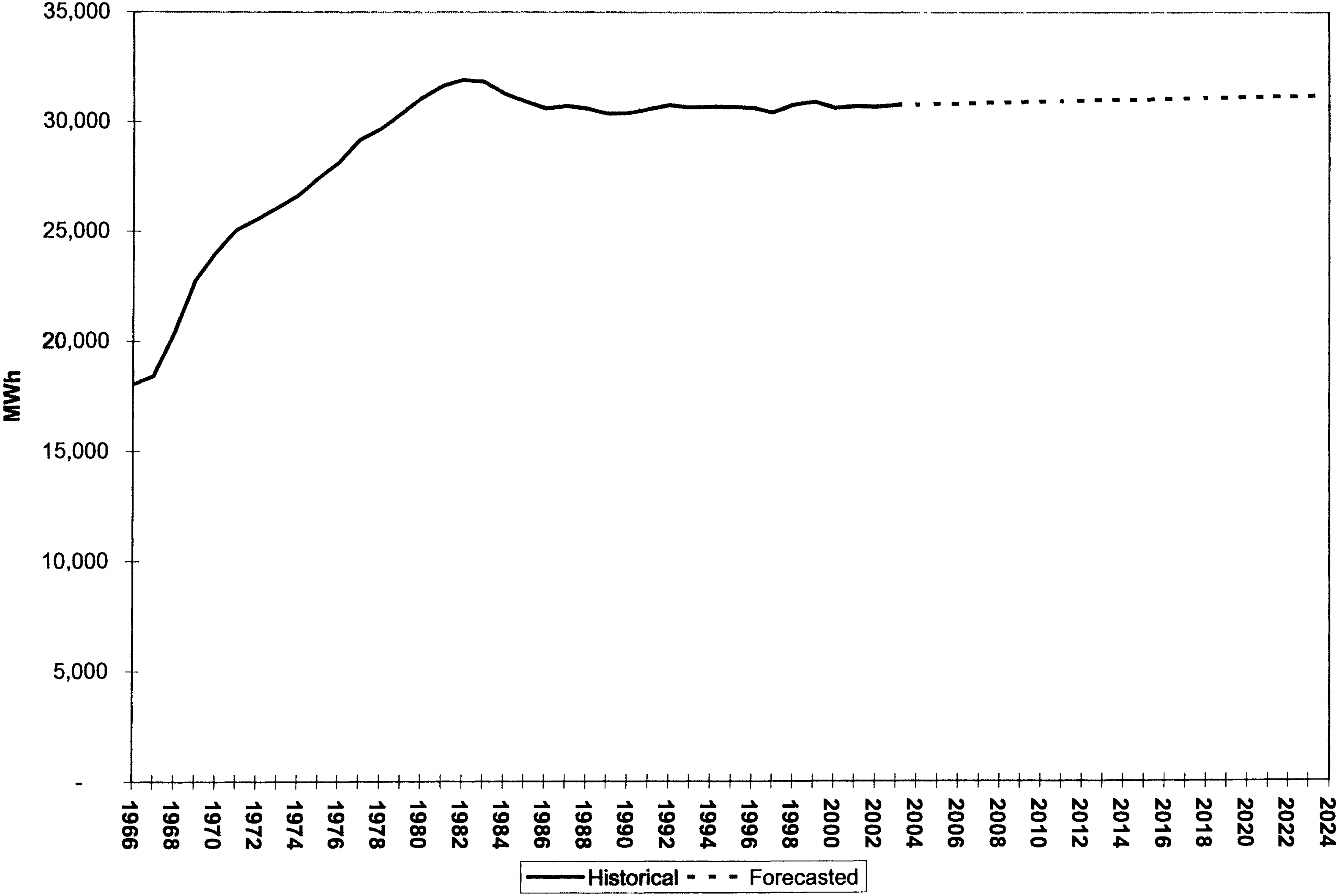


Figure 2-10

Montana-Dakota Integrated System
Historical and Forecasted Miscellaneous Sales

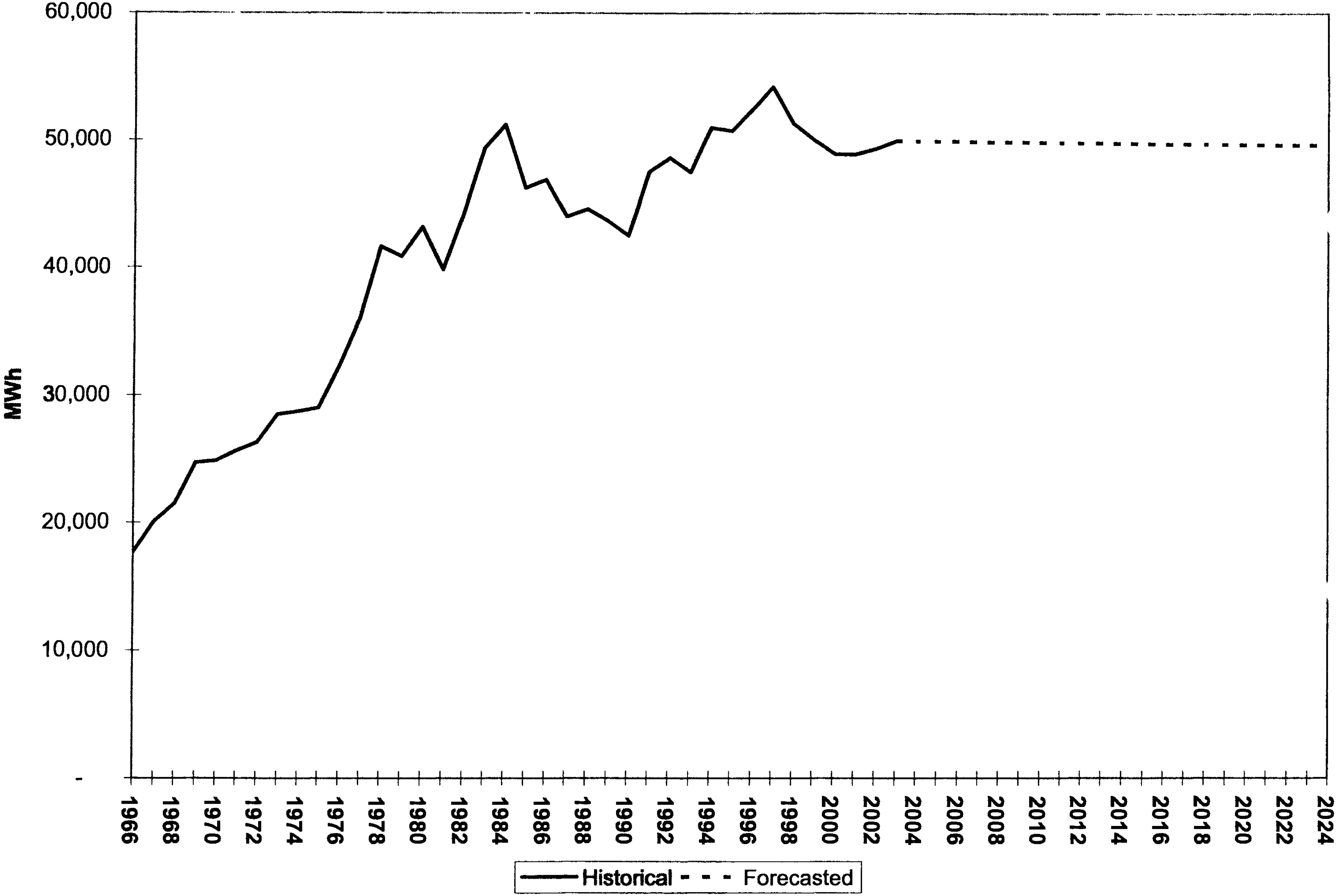


Figure 2-11

MONTANA-DAKOTA UTILITIES CO.
HISTORICAL AND FORECASTED ANNUAL SALES BY SECTOR
INTEGRATED SYSTEM

	RESIDENTIAL		SMALL C&I		LARGE C&I		STREET LTG		MISCELLANEOUS		TOTAL SALES		TOTAL ENERGY REQUIREMENTS	
YEAR	SALES(MWh)	%GROWTH	SALES(MWh)	%GROWTH	SALES(MWh)	%GROWTH	SALES(MWh)	%GROWTH	SALES(MWh)	%GROWTH	SALES(MWh)	%GROWTH	MWh	%GROWTH
1993	630,108		304,809		678,634		30,715		47,505		1,691,771		1,870,268	
1994	654,760	3 91%	325,785	6 88%	707,207	4 21%	30,755	0 13%	51,019	7 40%	1,769,526	4 60%	1,934,561	3 44%
1995	675,493	3 17%	330,770	1 53%	703,787	-0 48%	30,744	-0 04%	50,777	-0 47%	1,791,571	1 25%	1,952,872	0 95%
1996	700,642	3 72%	340,545	2 96%	720,501	2 37%	30,708	-0 12%	52,469	3 33%	1,844,865	2 97%	2,014,830	3 17%
1997	691,325	-1 33%	341,525	0 29%	728,808	1 15%	30,492	-0 70%	54,256	3 41%	1,846,406	0 08%	2,005,195	-0 48%
1998	680,290	-1 60%	345,012	1 02%	733,236	0 61%	30,848	1 17%	51,342	-5 37%	1,840,728	-0 31%	2,007,534	0 12%
1999	675,658	-0 68%	341,967	-0 88%	764,768	4 30%	30,980	0 43%	50,072	-2 47%	1,863,445	1 23%	1,996,647	-0 54%
2000	683,435	1 15%	347,350	1 57%	799,555	4 55%	30,718	-0 85%	48,958	-2 22%	1,910,016	2 50%	2,077,579	4
2001	700,552	2 50%	346,870	-0 14%	833,248	4 21%	30,792	0 24%	48,931	-0 06%	1,960,393	2 64%	2,104,119	1 [illegible]
2002	720,346	2 83%	353,778	1 99%	866,901	4 04%	30,778	-0 05%	49,387	0 93%	2,021,190	3 10%	2,158,431	2 58%
2003	733,030	1 76%	365,259	3 25%	905,860	4 49%	30,857	0 26%	50,013	1 27%	2,085,019	3 16%	2,226,531	3 16%
2004	740,872	1 07%	369,310	1 11%	928,646	2 52%	30,879	0 07%	49,999	-0 03%	2,119,706	1 66%	2,301,026	3 35%
2005	745,522	0 63%	373,897	1 24%	967,984	4 24%	30,901	0 07%	49,986	-0 03%	2,168,290	2 29%	2,353,766	2 29%
2006	749,555	0 54%	378,566	1 25%	1,007,931	4 13%	30,922	0 07%	49,973	-0 03%	2,216,947	2 24%	2,406,585	2 24%
2007	752,130	0 34%	382,700	1 09%	1,032,406	2 43%	30,944	0 07%	49,960	-0 03%	2,248,140	1 41%	2,440,446	1 41%
2008	753,264	0 15%	386,963	1 11%	1,058,092	2 49%	30,966	0 07%	49,946	-0 03%	2,279,231	1 38%	2,474,196	1 38%
2009	754,691	0 19%	391,277	1 11%	1,084,992	2 54%	30,988	0 07%	49,933	-0 03%	2,311,881	1 43%	2,509,639	1 43%
2010	755,450	0 10%	395,458	1 07%	1,104,714	1 82%	31,009	0 07%	49,920	-0 03%	2,336,551	1 07%	2,536,420	1 07%
2011	756,585	0 15%	399,700	1 07%	1,120,028	1 39%	31,031	0 07%	49,907	-0 03%	2,357,251	0 89%	2,558,890	0 89%
2012	757,422	0 11%	403,916	1 05%	1,134,981	1 34%	31,053	0 07%	49,893	-0 03%	2,377,265	0 85%	2,580,616	0 85%
2013	757,782	0 05%	408,076	1 03%	1,149,501	1 28%	31,075	0 07%	49,880	-0 03%	2,396,314	0 80%	2,601,295	0 80%
2014	757,906	0 02%	409,329	0 31%	1,163,932	1 26%	31,096	0 07%	49,867	-0 03%	2,412,130	0 66%	2,618,464	0 66%
2015	758,194	0 04%	410,564	0 30%	1,178,226	1 23%	31,118	0 07%	49,853	-0 03%	2,427,955	0 66%	2,635,642	0 66%
2016	758,437	0 03%	411,803	0 30%	1,192,427	1 21%	31,140	0 07%	49,840	-0 03%	2,443,647	0 65%	2,652,677	0 65%
2017	758,603	0 02%	413,053	0 30%	1,207,125	1 23%	31,162	0 07%	49,827	-0 03%	2,459,770	0 66%	2,670,179	0 66%
2018	758,757	0 02%	414,285	0 30%	1,221,832	1 22%	31,183	0 07%	49,814	-0 03%	2,475,871	0 65%	2,687,657	0 65%
2019	758,846	0 01%	415,512	0 30%	1,236,734	1 22%	31,205	0 07%	49,800	-0 03%	2,492,097	0 66%	2,705,271	0 66%
2020	759,070	0 03%	416,722	0 29%	1,251,535	1 20%	31,227	0 07%	49,787	-0 03%	2,508,341	0 65%	2,722,904	0
2021	759,527	0 06%	417,918	0 29%	1,266,480	1 19%	31,249	0 07%	49,774	-0 03%	2,524,948	0 66%	2,740,932	0 [illegible]
2022	760,179	0 09%	419,104	0 28%	1,281,470	1 18%	31,271	0 07%	49,761	-0 03%	2,541,785	0 67%	2,759,209	0 67%
2023	761,030	0 11%	420,267	0 28%	1,296,589	1 18%	31,292	0 07%	49,747	-0 03%	2,558,925	0 67%	2,777,815	0 67%
2024	761,958	0 12%	421,419	0 27%	1,311,782	1 17%	31,314	0 07%	49,734	-0 03%	2,576,207	0 68%	2,796,576	0 68%
1993-2003 AVG YEARLY GROWTH (10 YRS HIST)		1 07%		1 30%		2 78%		0 04%		-0 18%		1 77%		1 46%
1998-2003 AVG YEARLY GROWTH (5 YRS HIST)		1 70%		1 11%		4 30%		-0 05%		-0 49%		2 58%		2 21%
2004-2009 AVG YEARLY GROWTH (5 YEARS)		0 37%		1 16%		3 16%		0 07%		-0 03%		1 75%		1 75%
2004-2014 AVG YEARLY GROWTH (10 YEARS)		0 23%		1 03%		2 28%		0 07%		-0 03%		1 30%		1 30%
2004-2024 AVG YEARLY GROWTH (20 YEARS)		0 14%		0 66%		1 74%		0 07%		-0 03%		0 98%		0 98%

Table 2-5

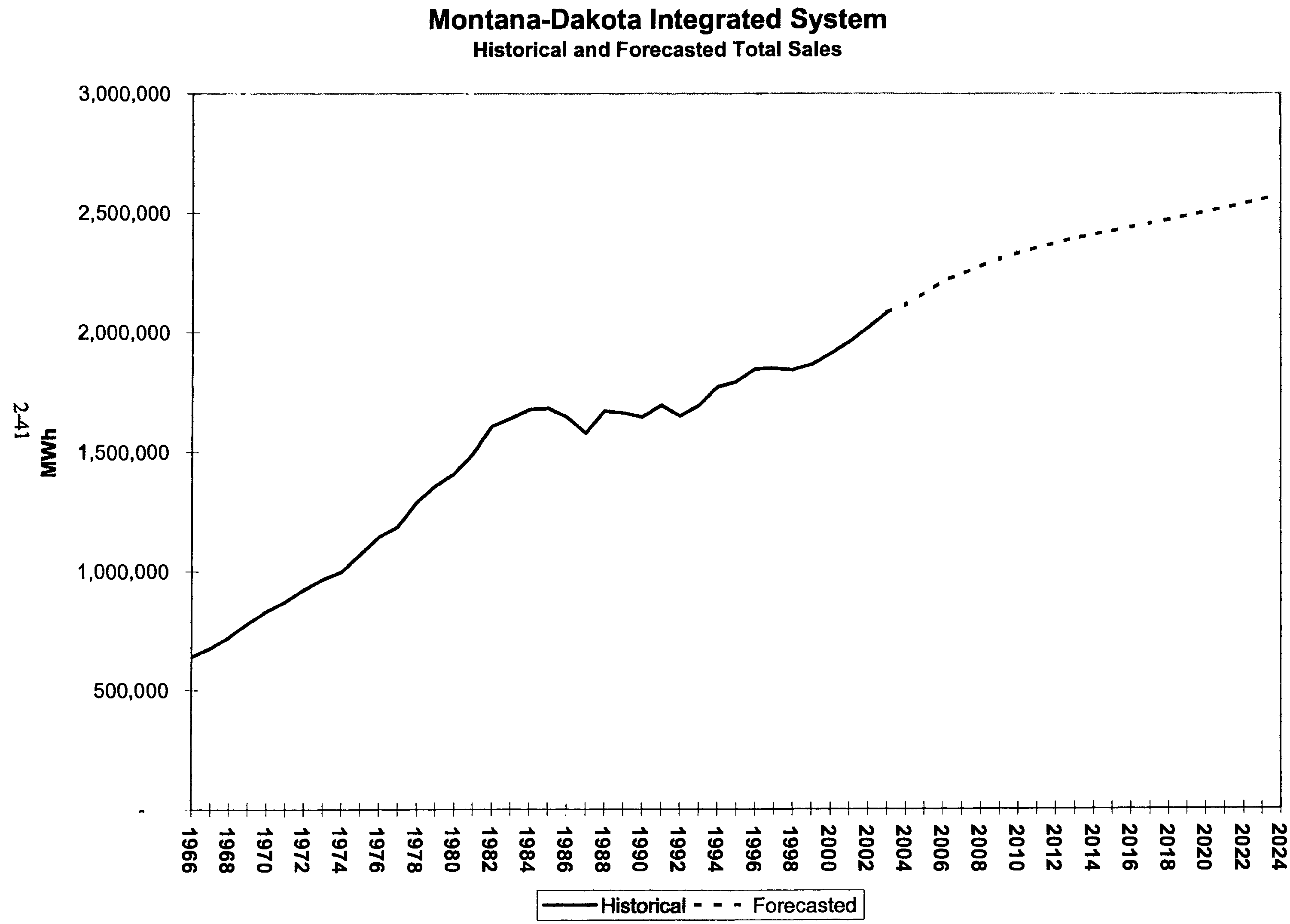

Montana-Dakota Integrated System
Historical and Forecasted Total Sales
MWh
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
-
1966
1968
1970
1972
1974
1976
1978
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
Historical
Forecasted

Figure 2-12

2.4.2 TOTAL SYSTEM LOAD FORECAST

SHAPES II produces hourly demands for the entire forecast period (2004-2024). These demands represent the end-use load at the customer level and do not include the system losses.

A FORTRAN program was developed by Montana-Dakota to calculate the system hourly losses from the data given by SHAPES II. This algorithm assumes that, at each hour during the year in consideration, the total system load consists of three components: (1) end-use load given by SHAPES II as chronological demand, (2) transformer no-load losses, which are assumed to be constant throughout the year, and (3) I^2R-loss component, which is assumed to be proportional to the square of the end-use load at that hour.

The transformer no-load losses can be calculated based on the actual transformer total KVA capacity connected to Montana-Dakota's system and estimated no-load losses per KVA (watt/KVA) for different classes of transformers. The total system losses (MWh) can be calculated based on the percentage of the annual energy losses, which is defined as:

$$\frac{\text{Total system losses (MWh)}}{\text{Total system load (MWh)}} * 100$$

in which the total system load consists of the end-use load at the customer level and the total system losses.

Thus, the I^2R-loss component of the total annual energy can be computed. Once this component is known, it can be allocated to each hour of the year, assuming that it is proportional to the square of the end-use demand at that hour.

Historically, the percentages of the annual energy losses varied from year to year, as shown in Table 2-6. The average value for the past ten years is 7.88 percent. Using this value for all future years, the total system hourly loads are calculated for each year during the study period.

Table 2-6

Percentages of Annual Energy Losses

Year	Percent
2003	6.1
2002	5.3
2001	8.3
2000	8.2
1999	8.3
1998	8.6
1997	8.6
1996	8.6
1995	8.7
1994	8.1
Average	7.88

As a result of the above loss calculation procedure, the total Integrated System projected demand and energy are shown in Table 2-7, and plotted in Figures 2-13 and 2-14. For normal years, summer peak is predicted to occur in July and winter peak in December of the year.

2.4.3 FORECAST UNCERTAINTY

The projected demand and energy produced by the SHAPES II model and the loss calculation procedure as described above produce a forecast based solely on the information inputted into the model. These results, however, are only estimates and are subject to error.

The presence of forecasting errors or chance variations is a fact of life; forecasting is a process permeated with uncertainty. For purposes of Integrated Resource Planning, a single forecast does not allow the analysis of risk and uncertainty associated with the input assumptions. Robust resource decisions cannot be made unless uncertainty is

Table 2-7

MONTANA-DAKOTA UTILITIES CO.
HISTORICAL AND FORECASTED ENERGY AND DEMAND
INTEGRATED SYSTEM

	TOTAL ENERGY REQUIREMENTS		SUMMER PEAK - MW				WINTER PEAK */	
YEAR	MWh	%GROWTH	INTERRUPTIBLE LOADS NOT INTERRUPTED	INTRPT LOADS	INTERRUPTIBLE LOADS INTERRUPTED	% CHG	MW	%GROWTH
1993	1,870,268				350.3		332.7	
1994	1,934,561	3.44%			369.8	5.57%	322 6	-3.04%
1995	1,952,872	0.95%			412.7	11 60%	348 7	8.09%
1996	2,014,830	3 17%			393.3	-4.70%	343.1	-1.61%
1997	2,005,195	-0 48%			404.6	2 87%	332.8	-3.00%
1998	2,007,534	0 12%			402 5	-0 52%	354 2	6.43%
1999	1,996,647	-0.54%			420 6	4 50%	342.4	-3.33%
2000	2,077,579	4 05%			432 3	2 78%	353 9	3 36%
2001	2,104,119	1.28%			453.0	4 79%	328.9	-7 06%
2002	2,158,431	2.58%			458.8	1 28%	343.5	4.44%
2003	2,226,531	3.16%			470.5	2 55%	367.7	7.05%
2004	2,301,026	3 35%	467.3	1.5	465 8	-1 00%	383.7	4.35%
2005	2,353,766	2.29%	472 5	1 5	471 0	1.12%	388 0	1.11%
2006	2,406,585	2.24%	479 7	1 5	478.2	1 53%	393.7	1 48%
2007	2,440,446	1 41%	484 9	1 5	483 4	1 09%	398 0	1 08%
2008	2,474,196	1 38%	490.1	1.5	488.6	1 08%	402 2	1.07%
2009	2,509,639	1 43%	495.3	1.5	493 8	1.06%	406 5	1.06%
2010	2,536,420	1 07%	500 5	1.5	499 0	1.05%	410 8	1 05%
2011	2,558,890	0.89%	505 7	1 5	504 2	1.04%	415 0	1 04%
2012	2,580,616	0 85%	510 9	1.5	509.4	1 03%	419 3	1.03%
2013	2,601,295	0 80%	516 1	1.5	514 6	1 02%	423.5	1 02%
2014	2,618,464	0.66%	521 3	1 5	519 8	1.01%	427.8	1 01%
2015	2,635,642	0.66%	526.5	1 5	525.0	1 00%	432.0	1.00%
2016	2,652,677	0.65%	531.7	1 5	530 2	0 99%	436.3	0 99%
2017	2,670,179	0 66%	536 9	1 5	535.4	0 98%	440.6	0.98%
2018	2,687,657	0.65%	542 1	1 5	540 6	0 97%	444.8	0 97%
2019	2,705,271	0 66%	547 3	1.5	545 8	0.96%	449 1	0.96%
2020	2,722,904	0 65%	552 5	1 5	551 0	0.95%	453.3	0.95%
2021	2,740,932	0 66%	557 7	1 5	556 2	0.94%	457.6	0 94%
2022	2,759,209	0.67%	562.9	1 5	561 4	0.93%	461 9	0 93%
2023	2,777,815	0 67%	568 1	1 5	566.6	0.93%	466 1	0.92%
2024	2,796,576	0 68%	573.3	1 5	571.8	0 92%	470 4	0.91%

*/ Winter Peak is for Nov-Dec of current year and Jan-Apr of following year.

Montana-Dakota Integrated System

Summer and Winter Season Peak Demand

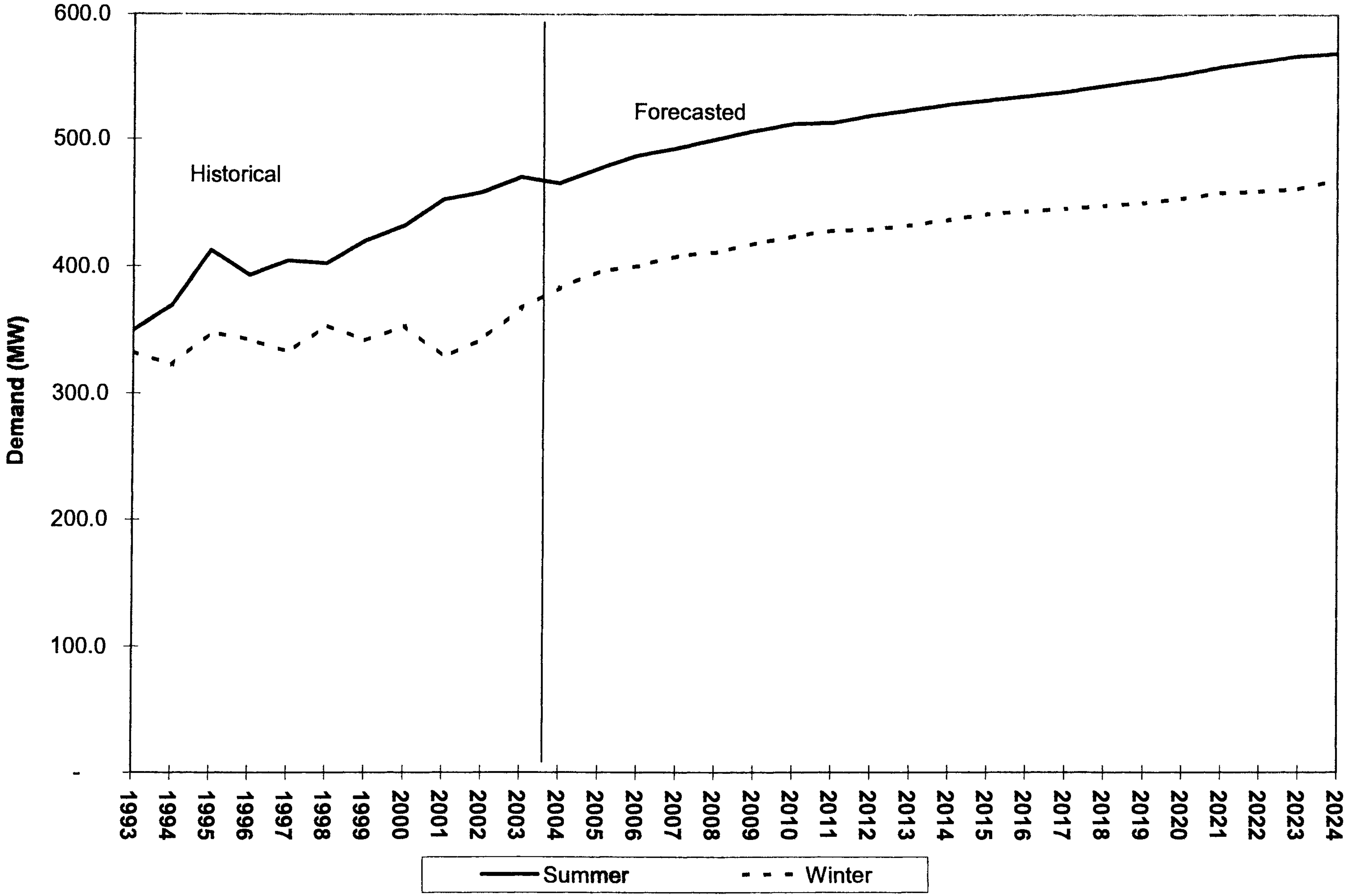


Figure 2-13

Montana-Dakota Integrated System
Historical and Forecasted Sales and Energy

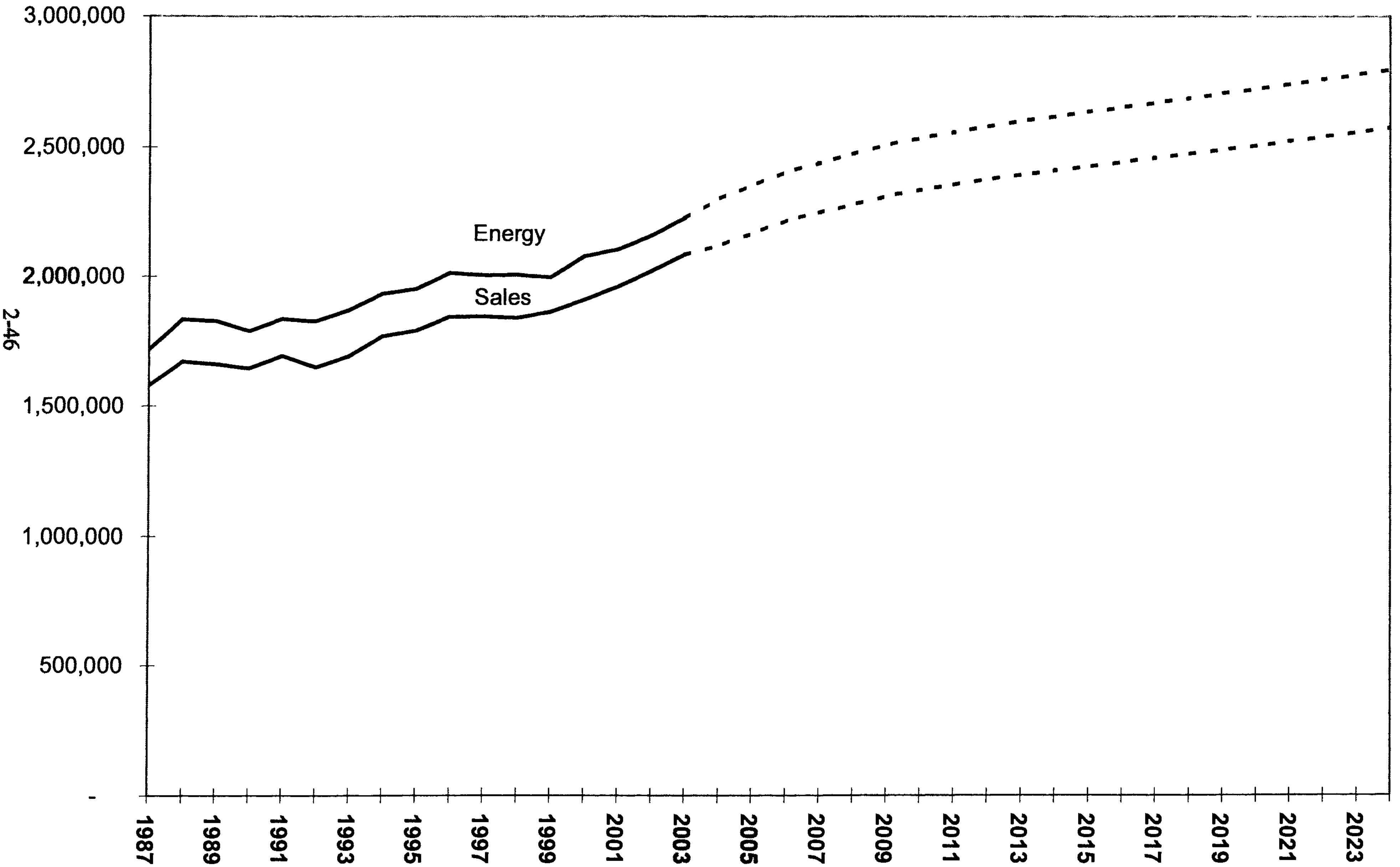


Figure 2-14

considered. That uncertainty is dealt with by developing forecasts reflecting temperatures that correspond to higher confidence levels as well as high-growth and low-growth scenarios for forecasts. Alternate temperature and confidence level forecasts are explained in Section 2.4.3.1. High-growth and low-growth scenarios for forecasts are discussed in Section 2.4.3.2.

2.4.3.1 Alternate Temperature and Confidence Level Forecasts

The forecast of summer peak demand shown in Table 2-7 reflects average temperature conditions of approximately 98 degrees F which is the weighted average temperature at the time of system peak for the last ten years (1994-2003). The weighted average temperatures reflect a weighting of temperatures at Bismarck (70 percent Miles City (15 percent), and Williston (15 percent). Using temperatures weighted in this way for these three locations has been tested and proven in the company's short-term demand forecasts as well as in other analyses.

The forecast shown in Table 2-7 and the forecasts that have been published historically were developed assuming ten-year average temperatures at the time of system peak. However, there are some shortcomings associated with this methodology. First, with an average temperature forecast, by definition actual peak demands would have approximately a 50 percent probability of being lower than the forecast values and a 50 percent probability of exceeding forecast values (50/50 forecast). Second, there is an appearance that demand is underforecasted when the actual temperature at the time of system peak exceeds the ten-year average temperature. Therefore, in 2004 a study was performed to establish a confidence or risk level on which the long-term demand forecast would be based. The results will help the company to weigh risks and costs when determining a resource plan for the coming years.

As part of the 2004 study, a trend analysis of the company's historical July and August demand and corresponding temperatures at times when the temperatures equaled or exceeded 85 degrees F indicated that a peak demand of approximately 465 MW would have occurred if the weighted temperature at peak was 98 degrees F. The analysis also indicated that each one degree increase in temperature at the time of peak would result in an increase of approximately 5 MW in peak demand.

In the 2004 study, further statistical analysis of temperatures at the time of system peak for the years 1984 through 2004 (prior to 1984 the company was a winter peaking utility) provided the results shown in Table 2-8.

Table 2-8

Temperature Probability at Peak and Effect on Peak Demand

Probability (%)	Weighted Temperature (°F)	Approximate Increase in Peak Demand (MW)
50.0	96.8	0.0
60.0	98.0	6.0
75.0	99.4	13.0
80.0	100.1	16.5
85.0	100.9	20.5
90.0	101.9	25.5
95.0	103.3	32.5

As Table 2-8 shows, with a weighted average temperature of 98 degrees F at the time of peak, there is a 60 percent probability that the temperature at peak would be lower than 98 degrees F and a 40 percent probability that temperatures at peak would be higher than 98 degrees F. This is called the 60/40 forecast and is the forecast shown in Table 2-7. A second peak demand forecast has been developed called the 85/15 forecast or high temperature conditions forecast. The 85/15 forecast reflects the peak demand at temperatures of 101 degrees F; there is an 85 percent probability that actual temperatures at peak would be lower than 101 degrees F and a 15 percent probability that actual temperatures at peak would be higher than 101 degrees F. This reflects higher than normal temperatures at the time of peak as is shown in Table 2-8.

After considering all aspects of this study, it was decided to provide two forecasts: a forecast to reflect ten-year average temperatures at the time of system peak (60/40 forecast) and a forecast to reflect a scenario with higher temperatures at the time of system peak and correspondingly higher confidence (85/15 forecast). This higher confidence level forecast would provide a peak demand forecast that represents a probability of 85 percent that the actual peak demand would not exceed the forecast value and a 15 percent probability that the actual peak demand would be higher than the forecast value. Table 2-9 summarizes the results of the 60/40 probability and 85/15 probability forecasts.

2.4.3.2 High-Growth and Low-Growth Scenario Forecasts

Another approach used to deal with forecast uncertainty in this study was to simulate high-growth and low-growth scenarios which represent the extreme economic conditions that may occur. These high-growth and low-growth scenario forecasts were developed as follows.

Historical total energy was analyzed in order to find a period of time during which unusually high growth was experienced and a period of time during which unusually low growth was experienced. Based on the historical sales data shown in Figure 2-15 and Appendix A-7, the average growth rate that occurred from 1977 to 1985 was used as the high-growth rate and the average growth rate that occurred from 1985 to 1993 was used as the low-growth rate. Both periods consist of eight years of history.

As a result, for the high-growth scenario, an average growth rate of 4.4 percent per year was assumed to occur during the 20-year forecast horizon. For the low-growth scenario, an average growth rate of 0.5 percent per year was assumed to occur during the 20-year forecast horizon. Demand for each scenario was arrived at by applying the load factors calculated from the SHAPES II generated base forecast to the high-growth and low-growth scenario forecasted energy. The results are shown in Figures 2-16 and 2-17 and listed in Table 2-10.

Table 2-9

Montana-Dakota Utilities Co.
Integrated System
Alternate Summer Peak Demand Forecast Comparison

Year	Base Forecast (98.0 degrees F) 60/40 Forecast (MW)	Growth Rate (%)	Alternate Forecast (100.9 degrees F) 85/15 Forecast (MW)
2004	465.8		480 3
2005	471 0	1 12%	485 7
2006	478.2	1.53%	493 1
2007	483.4	1 09%	498.4
2008	488 6	1 08%	503 8
2009	493.8	1.06%	509 2
2010	499.0	1.05%	514.5
2011	504 2	1.04%	519.9
2012	509 4	1.03%	525.3
2013	514 6	1.02%	530.6
2014	519.8	1.01%	536.0
2015	525 0	1 00%	541 3
2016	530.2	0 99%	546 7
2017	535 4	0.98%	552.1
2018	540.6	0 97%	557 4
2019	545.8	0 96%	562 8
2020	551 0	0 95%	568.2
2021	556.2	0.94%	573 5
2022	561 4	0.93%	578 9
2023	566 6	0.93%	584 2
2024	571.8	0.92%	589.6

Growth rates are assumed to be the same for both scenarios

Montana-Dakota Integrated System
Total Energy Requirements

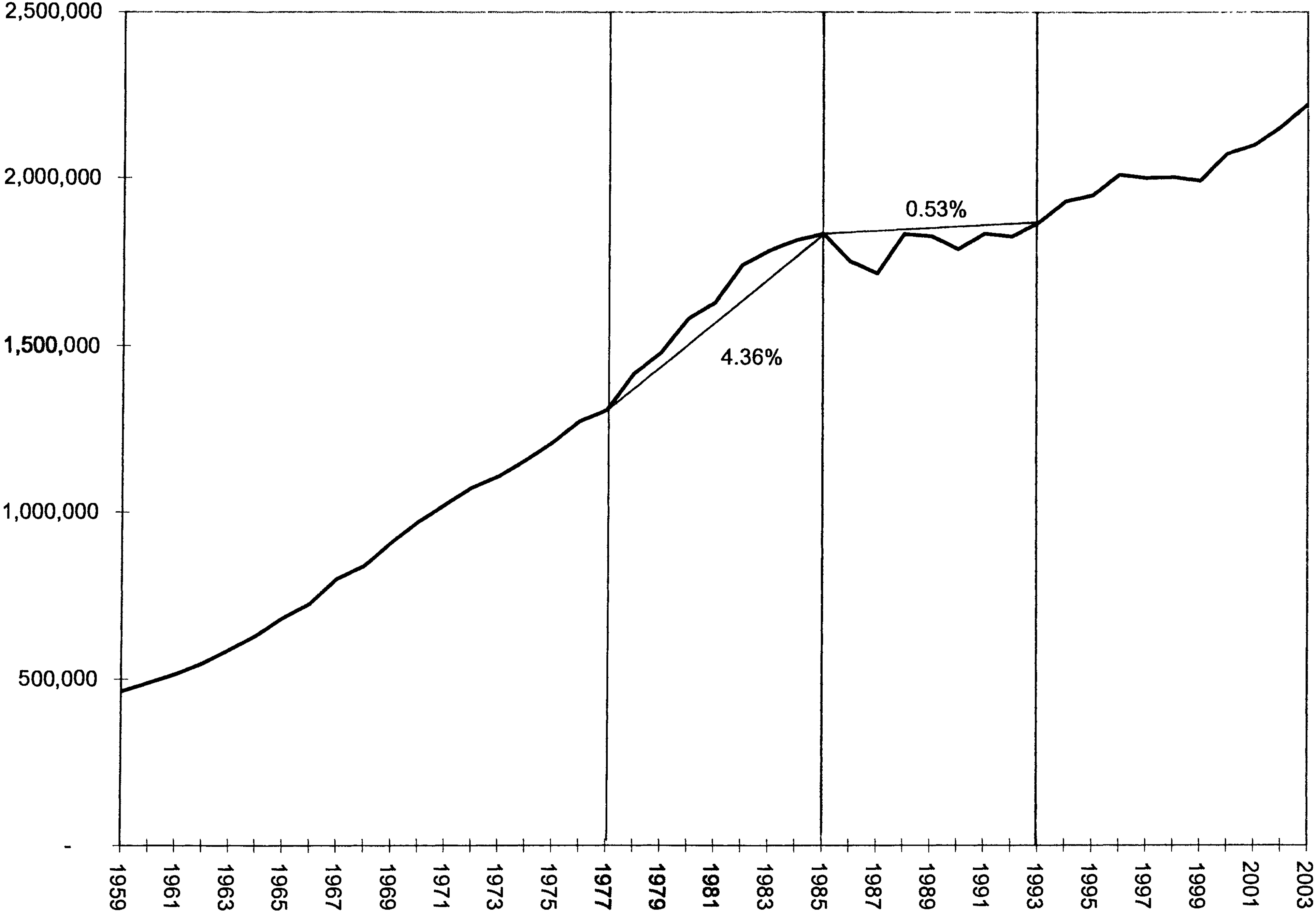


Figure 2-15

Montana-Dakota Integrated System

High-Growth and Low-Growth Scenarios - Energy

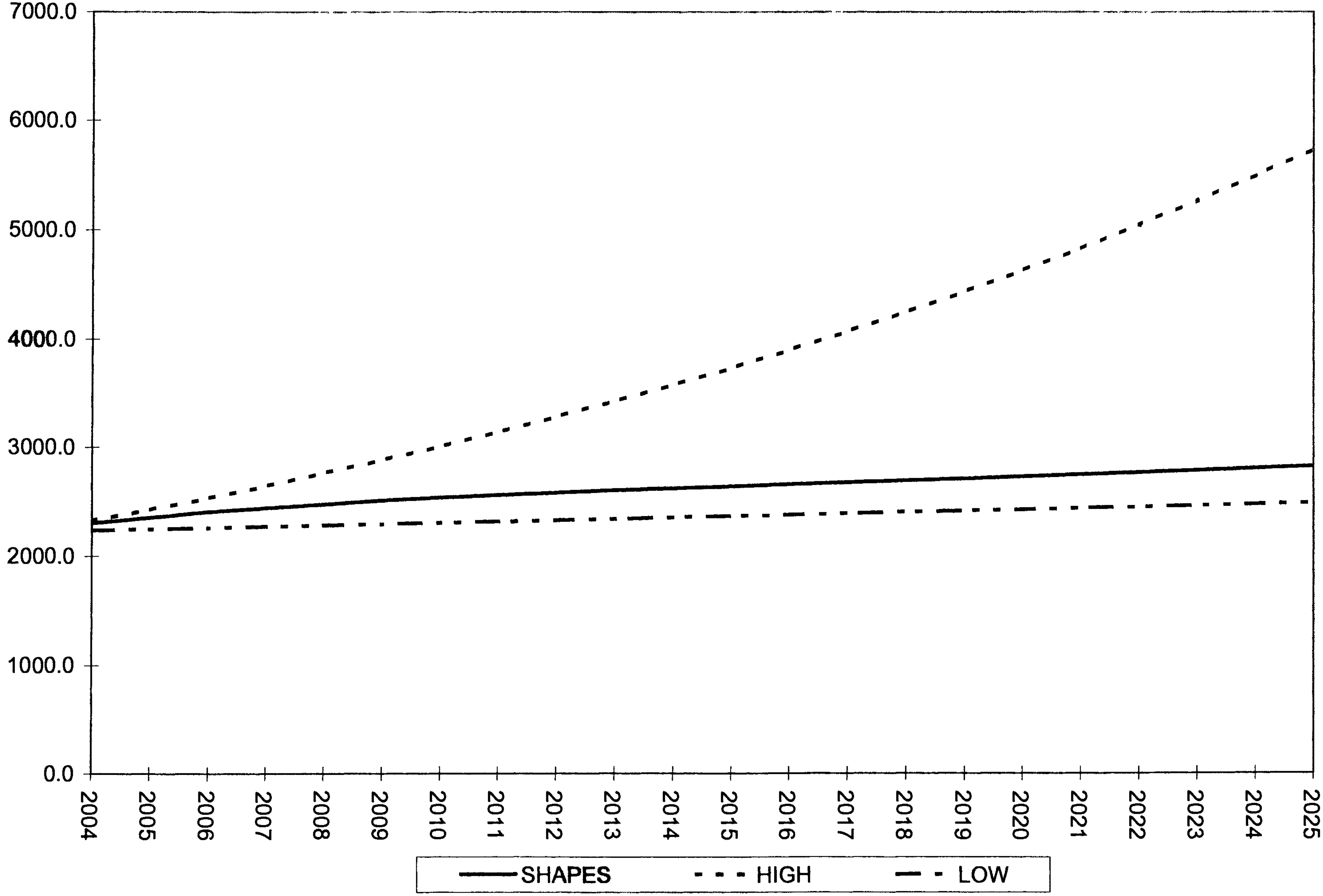


Figure 2-16

Montana-Dakota Integrated System
High-Growth and Low-Growth Scenarios - Demand

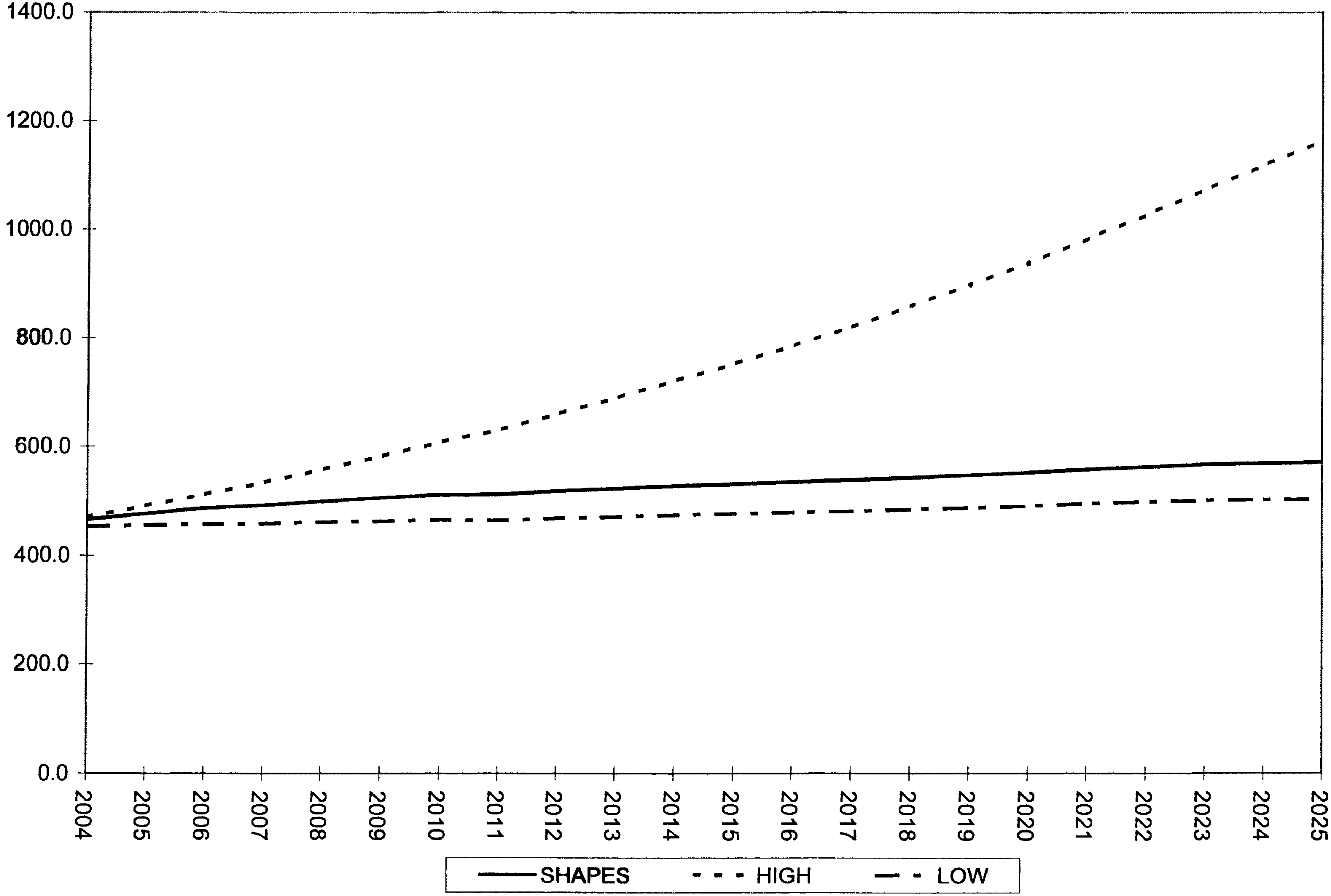


Figure 2-17

Table 2-10

**HIGH-GROWTH AND LOW-GROWTH SCENARIOS
TOTAL ANNUAL ENERGY (GWh) AND
SUMMER PEAK DEMAND (MW)**

	ENERGY			DEMAND		
	SHAPES	HIGH 1/	LOW 2/	SHAPES	HIGH	LOW
2004	2301.0	2324.5	2237.6	465.8	470.6	453.0
2005	2353.8	2426.7	2248.8	477.2	492.0	455.9
2006	2406.6	2533.5	2260.1	487.6	513.3	457.9
2007	2440.4	2645.0	2271.4	493.3	534.7	459.1
2008	2474.2	2761.4	2282.7	500.1	558.1	461.4
2009	2509.6	2882.9	2294.1	507.0	582.4	463.5
2010	2536.4	3009.7	2305.6	512.7	608.4	466.0
2011	2558.9	3142.1	2317.1	513.6	630.7	465.1
2012	2580.6	3280.4	2328.7	519.4	660.3	468.7
2013	2601.3	3424.7	2340.4	524.0	689.9	471.4
2014	2618.5	3575.4	2352.1	528.6	721.8	474.8
2015	2635.6	3732.7	2363.8	532.0	753.5	477.1
2016	2652.7	3897.0	2375.6	535.4	786.5	479.5
2017	2670.2	4068.5	2387.5	538.8	820.9	481.8
2018	2687.7	4247.5	2399.5	543.5	858.9	485.2
2019	2705.3	4434.4	2411.5	548.1	898.4	488.6
2020	2722.9	4629.5	2423.5	552.7	939.7	491.9
2021	2740.9	4833.2	2435.6	558.5	984.8	496.3
2022	2759.2	5045.8	2447.8	563.1	1029.8	499.6
2023	2777.8	5267.8	2460.1	567.7	1076.6	502.8
2024	2796.6	5499.6	2472.4	569.8	1120.5	503.7
2025	2815.5	5741.6	2484.7	571.9	1166.3	504.7

1/ HIGH FORECAST ASSUMES 4.4% GROWTH PER YEAR (ACTUAL 77-85 GROWTH).
2/ LOW FORECAST ASSUMES 0.5% GROWTH PER YEAR (ACTUAL 85-93 GROWTH).

2.5 FUTURE LOAD FORECASTS

Montana-Dakota has used SHAPES II, an end-use forecasting model, as its forecasting tool since 1988. Prior to 1988, econometric and time-series methods of forecasting were used. However, in 1987, the North Dakota Public Service Commission's Order in Case No. 10,799 required Montana-Dakota to file long range least-cost plans in which the demand forecast would "...identify at least three possible demand scenarios using end-use and econometric analysis."

End-use forecasting has several strengths:

- End-use forecasting focuses on components of electricity use (end-use) and, therefore, location of forecasting errors can be traced.
- End-use forecasts potentially provide a good structure for analyzing the impacts of demand-side management programs.
- End-use forecasts may be easier to explain and to be understood.

There are also several weaknesses inherent in end-use forecasting:

- End-use forecasts are very data intensive.
- The data assembly required to drive end-use forecasts is very time consuming, costly, and difficult.
- The individual components of an end-use forecast (e.g., appliance saturations, connected loads and efficiencies and price elasticities) are difficult to forecast, especially for the long term.
- The SHAPES II forecasting model is no longer supported by the vendor.
- While end-use forecasting was very popular and widely used for some time, most utilities in North American no longer use end-use forecasting models.

Beginning in 2006, Montana-Dakota will be returning to the econometric model as its forecasting tool. An econometric model is a set of equations that expresses electricity use as a function of underlying factors such as income, price of electricity, and weather.

The strengths of econometric forecasting models include:

- Econometric models explicitly measure the effects of underlying causes of trends and patterns.
- Econometrics provide statistical evaluation of forecast uncertainty.
- Econometric models combine with economic and demographic information.
- Econometric models can be readily re-estimated.

SECTION 3

DEMAND-SIDE ANALYSIS

3.1 METHODOLOGY

3.1.1 DEFINITION

The phrase *Demand-Side Management (DSM)* is defined by the Electric Power Research Institute (EPRI) as:

> The planning and implementation of those utility activities designed to influence customer use of electricity in ways that will produce desired changes in the utility's load shape -- i.e., changes in the pattern and magnitude of a utility load.

This definition includes programs such as load management, new uses of electricity, strategic conservation, electrification, and adjustments in market share. In order for an activity to be included under this definition of DSM, it must result from direct intervention on the part of the utility. Thus, customers deciding on their own to install high-efficiency air conditioning would not fall under DSM, while a utility-sponsored information or incentive program designed to accomplish the same goal would.

Because DSM encompasses much more than conservation and load management, demand-side management alternatives warrant consideration by all electric utilities regardless of their current capacity and peak load situation.

3.1.2 POTENTIAL DSM PROGRAMS

Given this definition of DSM, Montana-Dakota looked for programs that would be best suited to the company's load shape in order to get the results when needed. In the past, Montana-Dakota has evaluated a multitude of potential programs that would have an effect on a customer's electric usage. In this study, Montana-Dakota has pared down the list to include a total of 12 residential programs and seven commercial programs (listed in Tables 3-1 and 3-2). These programs were selected through a joint effort between Montana-Dakota and the IRP Public Advisory Group.

TABLE 3-1
POTENTIAL DEMAND-SIDE MANAGEMENT PROGRAMS
RESIDENTIAL CUSTOMER SECTOR

<u>Quantitative Analysis</u>

1. Promote ENERGY STAR® clothes washers – to electric water heating customers

2. Promote ENERGY STAR® dish washers – to electric water heating customers

3. Promote ENERGY STAR® refrigerators

4. Promote ENERGY STAR® freezers

5. Promote high-efficiency air conditioning – to customers replacing their current central air conditioner.

6. Promote central air conditioner cycling

7. Promote recycling program for old refrigerators ("Refrigerator Round-Up")

8. Promote geo-thermal heat pumps

9. Promote uncontrolled electric space heating – to customers switching from an alternate fuel

<u>Qualitative Analysis</u>

10. Become an ENERGY STAR® Partner

11. Provide on-line home energy audits

12. Provide proper air conditioner sizing training seminars

TABLE 3-2
POTENTIAL DEMAND-SIDE MANAGEMENT PROGRAMS
COMMERCIAL CUSTOMER SECTOR

Quantitative Analysis

1. Promote high-efficiency air conditioning equipment – to customers replacing their current air conditioner

3. Promote high-efficiency lighting – T-8 retrofit

4. Promote LED exit sign lighting

5. Promote central air conditioning cycling

Qualitative Analysis

6. Provide building energy audits

7. Continue to promote load management rates (as filed)

3.1.3 BENEFIT-COST COMPARISON

For the considered demand-side programs, a benefit/cost analysis involved a feasibility study using an Excel Spreadsheet-based model (Montana-Dakota DSM Model) based on a model used to evaluate natural gas programs, as modified to fit Montana-Dakota's electric program analysis.

The evaluation tool requires utility-specific input on generation costs, DSM program costs, electric rates, program load impacts, participation rates and other pertinent data. Participation rates for each program were estimated based upon a combination of primary and secondary research for the various programs. The process of selecting participation rates is addressed in more detail later in the report.

The basic function of the evaluation tool is to compare the results of a DSM program with the *status quo*. In the *status quo*, customers use energy in a given pattern and pay a given set of prices for this energy. DSM programs are designed to change energy use patterns and, perhaps, energy prices. The evaluation tool compares the situation for the customer and the utility for these two conditions to predict the impacts of a DSM program.

The calculations involved in making this comparison are conceptually straightforward. This process is best explained by considering the utility and customer benefit calculations separately.

<u>Customer Benefit Calculations</u>

The net benefit for the customer is the cost for the customer with the DSM program less the cost for the customer in the *status quo*. If the net benefit is negative, the customer is better off with the DSM program. The cost is a present value of the annual costs over the years in the analysis horizon. The present value uses the customer discount rate and assumes the cash flows occur at the end of the year. The cost to the customer is the sum of five cost categories:

Cost to Customer = Electric Bill + Non-electric Fuel Bill + Investment Cost + O&M Cost + Other Costs

The electric bill consists of four components:

Electric Bill = Fixed Charge + Energy Charges + Demand Charges - Incentive

Utility Benefit Calculations

The net benefit for the utility is the cost with the DSM program in place less the cost in the *status quo*. A negative net benefit indicates that the utility has reduced its costs. The cost is a present value of the annual costs over the years in the analysis horizon, assuming the cash flows occur at the end of the year. The annual costs are discounted at the utility discount rate. The annual cost is the sum of four components:

Annual Utility Cost = Cost of Energy Sold - Revenue - (Annual Capacity Credit x Demand Reductions) + DSM Program Cost

Revenue for electricity sold is the energy sales times the price plus revenue received from the demand charge. The energy charge and demand charge are determined from the retail rate schedule.

The difference between utility peak demand with the DSM program and the *status quo* is the demand reduction. The benefit of the demand reduction is calculated by using the annual capacity credit, or capacity avoided cost. The avoided cost for this study is the cost of a combustion turbine at $74.46/kW-Year. The avoided cost is escalated at a rate of 2.15% percent per year for this life of the program evaluation. Program cost for the utility includes investment, administrative, and incentive costs.

Benefit-Cost Comparison

The DSM Model's benefit-cost comparison provides an indication of the program benefits and costs and its impact on the electric system. The programs were evaluated against four different cost-effectiveness tests: *Participant Test*, *Utility Test*, *Ratepayer Test* and *Societal Benefit Test*.

The *Participant Test* considers the economic impact of a program on the participating customers. The *Utility Test* considers the impact on the utility without consideration of revenue requirements. The *Ratepayer Test* includes all of the quantifiable benefits and costs of a given program and its impact on all ratepayers. The *Societal Benefit Test* measures the net costs of a management program based on its total costs, including both the participant's and the utility's costs as well as including environmental externalities and excluding tax credit benefits.

In determining whether a program is beneficial, Montana-Dakota relies on the resulting benefit/cost ratios for the *Ratepayer Test* and *Societal Benefit Test.* A benefit-cost ratio greater than one for the Ratepayer Test indicates the program will reduce overall rates, while a ratio less than one implies the program will cause rates to increase. A benefit-cost ratio greater than one for the Societal Benefit Test indicates the program will reduce costs to society, while a ratio less than one implies that the program will increase costs to society.

3.2 DATA ASSUMPTIONS

Prior to program evaluation, a review of all assumptions used in the model was performed.

3.2.1 POWER SUPPLIER ASSUMPTIONS

A utility discount rate of 7.34 percent was used for the analysis. This discount rate is the weighted average cost of capital, computed based on the capital structure and associated interest rates forecasted for the long-range planning of resource needs for Montana-Dakota. See Appendix I for the calculation of the weighted average cost of capital.

The annual transmission and distribution losses represent an average of the losses that have occurred on Montana-Dakota's system. A value of 7.88 percent was used for residential and commercial program evaluations and was calculated based on the following formula:

$$\% \text{ Losses} = \frac{\text{Total System Losses}}{\text{Total System Load}} * 100$$

(Total system load is made up of electric sales to the end user and total system losses that occur.)

For the benefit-cost comparison, Montana-Dakota's DSM Model calculates the energy cost on a seasonal basis using the seasonal retail rates. The model also calculates the benefit of demand reduction based on the avoided cost of installing a combustion turbine at a cost of $74.46/kW-Year and escalated at a rate of 2.15 percent per year.

3.2.2 PROGRAM ASSUMPTIONS

A review of all program assumptions was made prior to the demand-side evaluation. Updates were made to technology cost data and were based on information obtained from ENERGY STAR®, Department of Energy, United Power Association's Appliance Report June 1992, Western Area Power Administration's *DSM Pocket Guidebook* and various energy industry partners.

To provide documentation of the underlying demand-side resource program designs and evaluation criteria, cost information and other assumptions that are particular to the studied programs are given in the program data sheets in Appendix G.

All DSM programs were designed to show the economic feasibility of retrofit applications. It was felt that programs designed to retrofit existing equipment would better represent Montana-Dakota's marketing potential.

<u>Determination of Incentive and Market Penetration</u>

To establish incentive and customer participation levels for the various potential demand-side programs, Montana-Dakota used a combination of primary and secondary research data. Two primary research sources used were studies conducted by Xenergy, Inc. Xenergy was Montana-Dakota's consultant for its first IRP, which was filed with the North Dakota Public Service Commission in October 1989. The Xenergy studies are:

- *The Relationship between Incentive Levels and Penetration in the Commercial Sector*, which provides the effect incentives have on penetration (or customer participation) in the commercial sector, and

- *The Residential DSM Attitudinal Survey*, which is a study of residential customer attitudes and the effect incentives have on residential customer choice.

The compilation of the information gleaned from the above sources normally served as a basis for determining incentive and customer participation levels. These levels were then adjusted by using past experience gained from the implementation of the programs offered by Montana-Dakota. The company kept detailed records on the programs that were offered. In addition, whenever applicable, the incentive and customer participation levels were determined or adjusted by using the information obtained from Montana-Dakota's own-research data.

Montana-Dakota has conducted other research regarding the demand-side programs. First, a detailed energy use survey is administered every two years to a statistically valid sample of the company's customer base. The latest survey, *The 2004 Residential Energy Survey*, was conducted in the spring of 2004. Among other results, the survey helps to identify conservation measures used by customers, saturation levels of appliances, and trends in customer energy purchase decisions.

Second, Montana-Dakota sponsored a research study of its Wyoming electric customers in 1994 to determine their attitudes toward demand-side programs. That study assessed the customer willingness to participate in 25 specific demand-side programs at four different incentive levels.

3.3 ANALYSIS PROCEDURE

Qualitative Evaluation

As noted earlier, five programs were selected to be evaluated on a qualitative basis. These evaluations were performed based on secondary research. Due to the nature of these five programs, it is difficult to determine the number of customers who would change their energy usage pattern as a result of offering these programs. Therefore, Montana-Dakota has recognized the significance of offering these programs from a consumer education standpoint and the programs merited a qualitative evaluation. Appendix F contains the qualitative analysis for each of the respective programs.

For those programs that were evaluated on a qualitative analysis basis, their economic and implementation feasibility was determined through group discussion and consensus of the IRP Demand-Side Project Team.

Quantitative Evaluation

Montana-Dakota's DSM Model was used as the evaluation tool for the remaining 13 programs. As a result of the DSM analysis, a benefit/cost summary together with a description of the program assumptions for each of the studied programs is included in Appendices G & H. The analysis shown in these appendices was conducted with the assumption that a specific number of customers would participate in the program and all program costs (i.e. operating, incentive, administrative & advertising) would be incurred by the utility. The cost incurred by each participant would be the cost of the equipment less the incentive.

For those programs that were studied analytically with the DSM Model, their economic feasibility was determined by their benefit/cost ratios for the Ratepayer Impact test and the Societal Benefit test. If both ratios were greater than one for a particular program, it is considered feasible and will be further evaluated for implementation.

Montana-Dakota's DSM Model does not, however, account for increased revenue resulting in the promotion of a load shifting program such as Electric Heat Promotion (considered for implementation in North Dakota), therefore this analysis results in a zero benefit for the ratepayer and society, although this program does benefit both the ratepayer and society. The program is considered feasible.

3.4 DSM ANALYSIS RESULTS

This section presents the quantitative DSM analysis results for the residential and commercial programs. These results are summarized in Table 3-3. Their detailed analysis is provided in Appendix H.

3.4.1 RESIDENTIAL PROGRAMS (QUANTITATIVE ANALYSIS)

1. Promote ENERGY STAR® clothes washers (with electric water heating):

   A maximum potential of 1,588 customers was assumed for this program over a three-year time period. The administrative costs were assumed to be $9/customer with a $30/unit incentive.

Table 3-3
DSM Analysis Summary
All Programs

DSM #	DSM Program	Analysis Method	Customer Segment	Program Objective	Program Start Date	Utility B/C Ratio	Rate Payer B/C Ratio	Societal B/C Ratio	Partic B/C Ratio
	Programs Evaluated Qualitatively								
1	Energy Star Partner - Per ES Plan	Qualitative	R	PS	2006	NA	NA	NA	NA
2	Commercial Energy Audits (Contract)	Qualitative	CI	PS	2006	NA	NA	NA	NA
3	Continue Load Management Rates (As Filed)	Qualitative	RCI	PS					
	- TOD Rate 31	Qualitative	CI	PS/LS	2006	NA	NA	NA	NA
	- Demand Reponse Rate 39 (38)	Qualitative	CI	PS	2006	NA	NA	NA	NA
	- Seasonal Rates	Qualitative	RCI	PS/LS	2006	NA	NA	NA	NA
4	Home Energy Audits (Self Audit)	Qualitative	R	PS	2006	NA	NA	NA	NA
5	Proper A/C Sizing Training Seminars	Qualitative	R	PS	2006	NA	NA	NA	NA
	Programs Evaluated Quantitatively								
	Promote Energy Star Appliances								
1	- Clothes Washers - Electric Water Heating	Quantitative	R	PS	2006	0.62	1.55	0.63	1.79
2	- Dish Washers - Elec Water Heating	Quantitative	R	PS	2006	0.28	0.46	0.31	1.51
3	- Refrigerators	Quantitative	R	PS	2006	1.25	2.05	1.19	1.43
4	- Freezers	Quantitative	R	PS	2006	1.04	1.47	0.9	1 14
5	High Efficiency A/C Residential	Quantitative	R	PS	2006	2.27	4.4	1.28	1.01
6	High Efficiency A/C Commercial	Quantitative	CI	PS	2006	2.73	3.41	1.26	1.27
7	Residential A/C Cycling	Quantitative	R	PS	2006	1.82	1.98	2.37	INF
8	Refrigerator Round-Up	Quantitative	R	PS	2006	1.68	4.83	8.84	INF
9	Residential Geo-Heat Pump	Quantitative	R	PS / LS	2006	1.06	0.66	0.26	1.83
10	Electric Heat Incentives / Promotion	Quantitative	RCI	LS	2006	6.02	0	0	2.75
11	Commercial Lighting T-8 Retrofit	Quantitative	CI	PS	2006	6 12	12.82	3.27	6.89
12	Commercial Lighting - LED Exit	Quantitative	CI	PS	2006	1.1	2.75	0.94	2.2
13	Commercial A/C Cycling	Quantitative	CI	PS	2006	1.91	1.97	2.63	INF

PS = Peak Shaving *LS = Load Shifting* *C= Commercial* *R= Residential* *I = Industrial*

2. Promote ENERGY STAR® dish washers (with electric water heating):

   A maximum potential of 966 customers was assumed for this program over a three-year time period. The administrative costs were assumed to be $16/customer with a $10/unit incentive.

3. Promote ENERGY STAR® refrigerators:

   A maximum potential of 1,714 customers was assumed for this program over a three-year time period. The administrative costs were assumed to be $9/customer with a $10/unit incentive.

4. Promote ENERGY STAR® freezers:

   A maximum potential of 1,320 customers was assumed for this program over a three-year time period. The administrative costs were assumed to be $11/customer with a $10/unit incentive.

5. Promote ENERGY STAR® rated high-efficiency central air conditioners:

   A maximum potential of 1,102 customers was assumed for this program over a three-year time period. The administrative costs were assumed to be $14/customer with a $60/ton incentive.

6. Promote residential central air conditioner cycling:

   A maximum potential of 6,615 customers was assumed for this program over a three-year time period. The operating costs were assumed to be $150/participant with a $150/participant incentive.

7. Promote residential refrigerator round-up:

   A maximum potential of 938 customers was assumed for this program over a three-year time period. The operating costs were assumed to be $50/participant, administrative costs were assumed to be $16/customer with a $35/customer incentive.

8. Promote residential geo-heat pumps:

   A maximum potential of 60 customers was assumed for this program over a three-year time period. The administrative costs were assumed to be $250/customer with a $1,100/customer incentive.

9. Promote residential electric heat (in North Dakota only):

   A maximum potential of 287 customers was assumed for this program over a three-year time period. The administrative costs were assumed to be $52/customer with a $25/KW incentive.

3.4.2 COMMERCIAL PROGRAMS (QUANTITATIVE ANALYSIS)

1. Promote ENERGY STAR® -rated high-efficiency central air conditioners:

   A maximum potential of 195 customers was assumed for this program over a three-year time period. The administrative costs were assumed to be $77/customer with a $50/ton incentive.

2. Promote high-efficiency lighting (T-8 retrofit):

   A maximum potential of 1,659 customers was assumed for this program over a five-year time period. The administrative costs were assumed to be $15/customer with a $8/fixture incentive.

3. Promote LED exit sign lighting:

   A maximum potential of 4,148 customers was assumed for this program over a five-year time period. The administrative costs were assumed to be $30/customer with a $10/fixture incentive.

4. Promote commercial central air conditioner cycling:

   A maximum potential of 195 customers was assumed for this program over a three-year time period. The operating costs were assumed to be $150/customer, the administrative costs were assumed to be $15/customer with a $150/customer incentive.

3.5 FEASIBLE DEMAND-SIDE PROGRAMS

The DSM programs that were found feasible in the qualitative and quantitative analyses are summarized in Table 3-4. The DSM analysis resulted in a total of five feasible residential programs and three feasible commercial programs:

Feasible Residential Programs:

Promote ENERGY STAR® refrigerators
Promote ENERGY STAR®-rated high-efficiency central air conditioners
Promote residential central air conditioner cycling
Promote residential refrigerator round-up
Promote uncontrolled electric heat (in North Dakota only)

Feasible Commercial Programs:

Promote ENERGY STAR®-rated high-efficiency central air conditioners
Promote high-efficiency lighting (T-8 retrofit)
Promote commercial central air conditioner cycling

Electric heat promotion (considered for implementation in North Dakota only) has also been included in the list of feasible programs as a load shifting or strategic marketing program that benefits both the utility and the participant.

3.6 FUTURE DEMAND-SIDE PROGRAM ACTIVITY

Recognizing that Montana-Dakota cannot implement all of the feasible DSM programs outlined in Table 3-4, two alternative options were packaged for consideration. These two options were chosen to provide the best fit and most cost-effective programs for Montana-Dakota.

Option A consists of the following four programs:

1. ENERGY STAR® Partnership
2. Promote electric heat (in North Dakota only)

Table 3-4

DSM Analysis Summary
Feasible Programs Based on Both Ratepayer Impact and Societal Benefit Tests

DSM #	DSM Program	Analysis Method	Customer Segment	Program Objective	Program Start Date	Utility B/C Ratio	Rate Payer B/C Ratio	Societal B/C Ratio	Participant B/C Ratio
1	Energy Star Partner - Per ES Plan	Qualitative	R	PS	2006	NA	NA	NA	NA
2	Commercial Energy Audits (Contract)	Qualitative	CI	PS	2006	NA	NA	NA	NA
3	Continue Load Management Rates (As Filed)	Qualitative	RCI	PS					
	- TOD Rate 31	Qualitative	CI	PS/LS	2006	NA	NA	NA	NA
	- Demand Reponse Rate 39 (38)	Qualitative	CI	PS	2006	NA	NA	NA	NA
	- Seasonal Rates	Qualitative	RCI	PS/LS	2006	NA	NA	NA	NA
4	Home Energy Audits (Self Audit)	Qualitative	R	PS	2006	NA	NA	NA	NA
5	Proper A/C Sizing Training Seminars	Qualitative	R	PS	2006	NA	NA	NA	NA
3	Energy Star Refrigerators	Quantitative	R	PS	2006	1.25	2.05	1.19	1.43
5	High Efficiency A/C Residential	Quantitative	R	PS	2006	2.27	4.4	1.28	1.01
6	High Efficiency A/C Commercial	Quantitative	CI	PS	2006	2.73	3.41	1.26	1.27
7	Residential A/C Cycling	Quantitative	R	PS	2006	1.82	1.98	2.37	INF
8	Refrigerator Round-Up	Quantitative	R	PS	2006	1.68	4.83	8.84	INF
11	Commercial Lighting T-8 Retrofit	Quantitative	CI	PS	2006	6.12	12.82	3.27	6.89
13	Commercial A/C Cycling	Quantitative	CI	PS	2006	1.91	1.97	2.63	INF

PS = Peak Shaving *LS = Load Shifting* *C= Commercial* *R= Residential* *I = Industrial*

3. Promote high-efficiency residential central air conditioning
4. Promote commercial lighting T-8 retrofit

These four programs will provide an estimated demand reduction of 6.5 MW at a cost of approximately $100/kW.

Option B consists of the following four programs:

1. ENERGY STAR® Partnership
2. Promote electric heat (in North Dakota only)
3. Promote residential central air conditioner cycling
4. Promote commercial central air conditioner cycling

These four programs will provide an estimated demand reduction of 7.4 MW at a cost of approximately $388/kW.

These proposed packages are outlined in more detail in Table 3-5.

Montana-Dakota will be implementing the programs included in Option A in 2006. Montana-Dakota will continue to study the residential and commercial air conditioner cycling programs in Option B for future potential implementation.

Table 3-5
DSM Alternative Options

Option A

DSM #	DSM Program	Program Start Date	Program Length	Program Life	Total kWh Decreased Project Life	Peak MW Decreased Annual	Est Cost Year 1	Estimated Total Cost
1	Energy Star Partner - Per ES Plan	2006	5	5	NA	NA	$ 3,000	$ 15,000
10	Electric Heat Incentives (ND Only)	2006	3	15	*See Note	-	$ 28,909	$ 86,727
5	High Efficiency A/C Residential	2006	3	15	9,510,438	0.771	$ 71,142	$ 213,426
11	Commercial Lighting T-8 Retrofit	2006	5	10	28,485,600	5.694	$ 66,059	$ 330,295
	Totals				**37,996,038**	**6.47**	**$ 169,110**	**$ 645,448**
						Net Cost per kW		**$ 99.84**

Option B

DSM #	DSM Program	Program Start Date	Program Length	Program Life	Total kWh Decreased Project Life	Peak MW Decreased Annual	Est Cost Year 1	Estimated Total Cost
1	Energy Star Partner - Per ES Plan	2006	5	5	NA	NA	$ 3,000	$ 15,000
10	Electric Heat Incentives (ND Only)	2006	3	15	*See Note	-	$ 28,909	$ 86,727
7	Residential A/C Cycling	2006	3	10	9,178,200	6.62	$ 1,234,789	$ 2,469,578
13	Commercial A/C Cycling	2006	3	10	1,033,119	0.741	$ 138,319	$ 276,638
					10,211,319	**7.36**	**$ 1,405,017**	**$ 2,847,942**
						Net Cost per kW		**$ 387.16**

**** Electric heat added winter kWh 58,838,976 at 3.168 MW annual load***
(Considered for implemention in North Dakota)

SECTION 4

SUPPLY-SIDE RESOURCE PLAN

4.1 POWER SUPPLY CONSIDERATIONS

4.1.1 ECONOMIC, SOCIETAL, GOVERNMENTAL, AND CUSTOMERS ISSUES

Montana-Dakota is committed to providing its customers with reasonably priced, highly reliable electricity. The supply-side resource plan presented herein relies not only on the "least-cost" IRP approach but also takes into consideration factors which are not captured in a strict least cost analysis. These factors, as described below, are important considerations in developing adequate supply resources for the future so that the resulting resources provide the "best cost" options for meeting the requirements of customers. The other factors considered in the analysis are:

- The benefits resulting from wholesale sales of off-peak energy provided by coal-fired, baseload units.
- Societal changes in environmental obligations due to changes in laws and regulations as well as changes in consumer attitude, which cannot be monetarily quantified.
- The possibility of new large load developing in Montana-Dakota's service territory from economic development efforts.
- Renewable resources, especially wind energy development. Total costs for wind turbines (including capital recovery) are dependent on governmental incentives, which are not based on economic evaluations. Governmental incentives notwithstanding, wind energy investments result in relatively high costs for consumers.

For the above reasons, Montana-Dakota is proposing a supply-side resource plan that will consider economic, societal, governmental, and customer issues.

4.1.2 ISSUE OF RELIANCE ON NATURAL GAS

The Integrated Resource Plan filed with the North Dakota Public Service Commission on July 1, 2003 included:

- 78 MW from two new combustion turbines to be added in 2007 to replace the 66.4 MW capacity and energy purchased from Basin Electric Power Cooperative,
- Modifications to existing combustion turbines at Glendive and Miles City in Montana for an additional 7.72 MW in 2010 and 2011, respectively, and
- Another new 39 MW combustion turbine to be added in 2012.

The plan also discussed the possibility of a new coal-fired baseload plant designated as "Lignite Vision 21."

Subsequent to the filing of the 2003 IRP, Montana-Dakota determined that the plan's heavy reliance on gas-fired generation exposed our customers to considerable price and reliability risk associated with fuel cost and availability. The company believes that coal-fired generation, which has lower and less volatile fuel prices, and a more stable fuel supply than natural gas provides a better value for our customers.

4.2 LOAD AND CAPABILITY

4.2.1 EXISTING AND COMMITTED RESOURCES

In addition to its own generation, Montana-Dakota is purchasing power from the Antelope Valley Station Unit No. 2 (AVS II), receiving power from the Western Area Power

Administration (WAPA) under Bill Crediting Program Arrangements, and purchasing peaking capacity from NorthPoint Energy and Northern States Power Company (NSP) as part of its existing and committed resources.

Table 4-1 shows the monthly generating capability as currently accredited by Mid-Continent Area Power Pool (MAPP) for Montana-Dakota's own generation resources. The monthly capabilities shown in the table are determined by the MAPP Uniform Rating of Generating Equipment (URGE) tests for the individual generation resources. MAPP requires its members to run URGE tests on their generation resources at least once a year and accredits the members' generating capability according to the results of these tests. Among the listed resources, the Big Stone and Coyote plants have shared ownership with other utilities, but the capabilities shown are those portions owned by Montana-Dakota.

The AVS II unit, located near Beulah, North Dakota, is leased to and operated by Basin Electric Power Cooperative. Currently, Montana-Dakota is purchasing 66.4 MW of capacity and associated energy from that unit.[1] The AVS II power purchase will be terminated October 31, 2006, at which time a replacement resource will be required.

In July 2004, Montana-Dakota entered into an agreement with NorthPoint Energy Solutions Inc., a wholly-owned subsidiary of Saskatchewan Corporation, to purchase 15 and 25 MW of peaking capacity for the summers of 2005 and 2006, respectively, that will be used as part of the company's generating resources. [3]

Montana-Dakota recently entered into a contract with NSP to provide summer peaking capacity for the summers of 2007-2010 and optionally 2011 and 2012.

4.2.2 LOAD-AND-CAPABILITY COMPARISON

For an understanding of Montana-Dakota's capability to serve the projected loads, a comparison of its summer accredited capability and peak load obligation is shown in

Table 4-1

Uniform Rating Form B

Sheet 1 of 1

MONTHLY NET CAPABILITY SUMMARY BY STATION

Date: 05/26/05

REV 1 Effective 06/01/05

MEMBER: Montana-Dakota Utilities PREPARED BY: Hoa Nguyen DATA FOR: 11/01/04 through 10/31/05

Adjusted for seasonal variations such as fuel, circulating water temperature, steam heat load, ambient air temperature, reservoir storage program, etc.

	*1 BIG STONE	*2 COYOTE	*3 HESKETT	*4 LEWIS & CLARK	SUBTOTAL STEAM	*5 GLENDIVE COMBUSTION	*6 MILES CITY COMBUSTION	*7 WILLISTON COMBUSTION	SUBTOTAL COMBUSTION	SYSTEM TOTAL
NOVEMBER	106.59	106.75	103.07	48.06	364.47	70.30	27.60	10.60	108.50	472.97
DECEMBER	106.59	106.75	103.07	48.06	364.47	72.30	28.92	10.60	111.82	476.29
JANUARY	106.59	106.75	103.07	48.06	364.47	72.55	28.92	10.60	112.07	476.54
FEBRUARY	106.59	106.75	103.07	48.06	364.47	72.55	28.92	10.60	112.07	476.54
MARCH	106.59	106.75	103.07	48.06	364.47	71.90	28.92	10.60	111.42	475.89
APRIL	106.34	106.75	103.07	48.06	364.22	68.60	25.00	10.60	104.20	468.42
MAY	104.91	106.75	103.07	52.30	367.03	74.10	23.70	10.10	107.90	474.93
JUNE	104.82	106.75	103.07	52.30	366.94	78.10	23.10	9.60	110.80	477.74
JULY	103.23	106.75	103.07	52.30	365.35	77.80	22.80	9.60	110.20	475.55
AUGUST	103.55	106.75	103.07	52.30	365.67	77.00	22.70	9.60	109.30	474.97
SEPTEMBER	105.21	106.75	103.07	52.30	367.33	79.10	23.00	10.20	112.30	479.63
OCTOBER	105.91	106.75	103.07	52.30	368.03	85.60	25.80	10.60	122.00	490.03

*1 Big Stone 22.7% of ((468.4 Nov-Mar,467.3-Apr,461.0 May,460.6 Jun,453.6 Jul,455.0 Aug,462.3 Sep,465.4 Oct) + 1.160 Diesel).

*2 Coyote @ 25.0% of (427.0 Nov-Oct). DRS-restricted to 427.0 MW for all months.

*3 Heskett #1 DRS-restricted to 30.00 MW for all months as of May 15, 2000.
Heskett #2 DRS-restricted to 74.60 MW for all months.

*4 Lewis & Clark capability at 100% coal Nov-Apr, 100% gas May-Nov. DRS-restricted to 52.3 MW for all months.

*5 Glendive CT #1 capabilities on gas for May-Oct and oil Nov-Apr. DRS-restricted to 42.55 MW for all months.
Glendive CT #2 capabilities on gas for May-Oct and oil Nov-Apr, and Glendive Diesel (IC-1) capabilities on oil for all months. DRS-restricted to 50.00 MW for all months for both the Glendive CT #2 (48.00 MW) and the Glendive Diesel (2.00 MW).

*6 Miles City capabilities on gas for May-Oct and oil Nov-Apr. DRS-restricted to 30.48 MW for all months.

*7 Williston firm gas for all months.

AWG Approval ______________________

Figures 4-1, 4-2, and 4-3 for the base forecast, the high-growth scenario forecast, and the low-growth scenario forecast.[4] The accredited capability, defined as the capacity available to serve Montana-Dakota's own load, is equal to its net generating capability, including the AVS II capacity purchase, the capacity received from WAPA, and peaking capacity purchased from NorthPoint and NSP. As a member of MAPP, Montana-Dakota is required to maintain an accredited capability equal to or greater than its maximum system demand plus a reserve capacity obligation. The reserve capacity obligation is equal to 15 percent of the annual system peak demand. Therefore, the peak load obligation used on the graphs is the projected summer peak demand plus a 15 percent reserve capacity obligation as required by MAPP.

Figure 4-1 shows that, with the base forecast, Montana-Dakota would have adequate capacity to meet its peak load obligation until 2007 at which time the AVS II capacity purchase will expire and a capacity deficit of 77.5 MW will occur. Therefore, if a 15 percent reserve capacity obligation is to be maintained, additional capacity will be needed in 2007. That capacity deficit will widen to 95.5 MW in 2010, 101.1 MW in 2011, 113.4 MW in 2013, and 185.3 MW in 2025. With the high-growth scenario forecast, as shown in Figure 4-2, a capacity deficit would occur in 2006 (9.1 MW). Like the base forecast, the low-growth scenario forecast shown in Figure 4-3 would not result in a capacity deficit until 2007 (39.0 MW).

4.3 RESOURCE PLAN

In 2001, in order to address future capacity deficits and the considerations discussed in Section 4.1.1, Montana-Dakota started planning for a baseload coal-fired plant. A number of options have been explored to acquire this resource, which would meet long-term load requirements. Those options are described in Section 4.3.1.

Figure 4-1
Load and Capability Comparison
Base Forecast

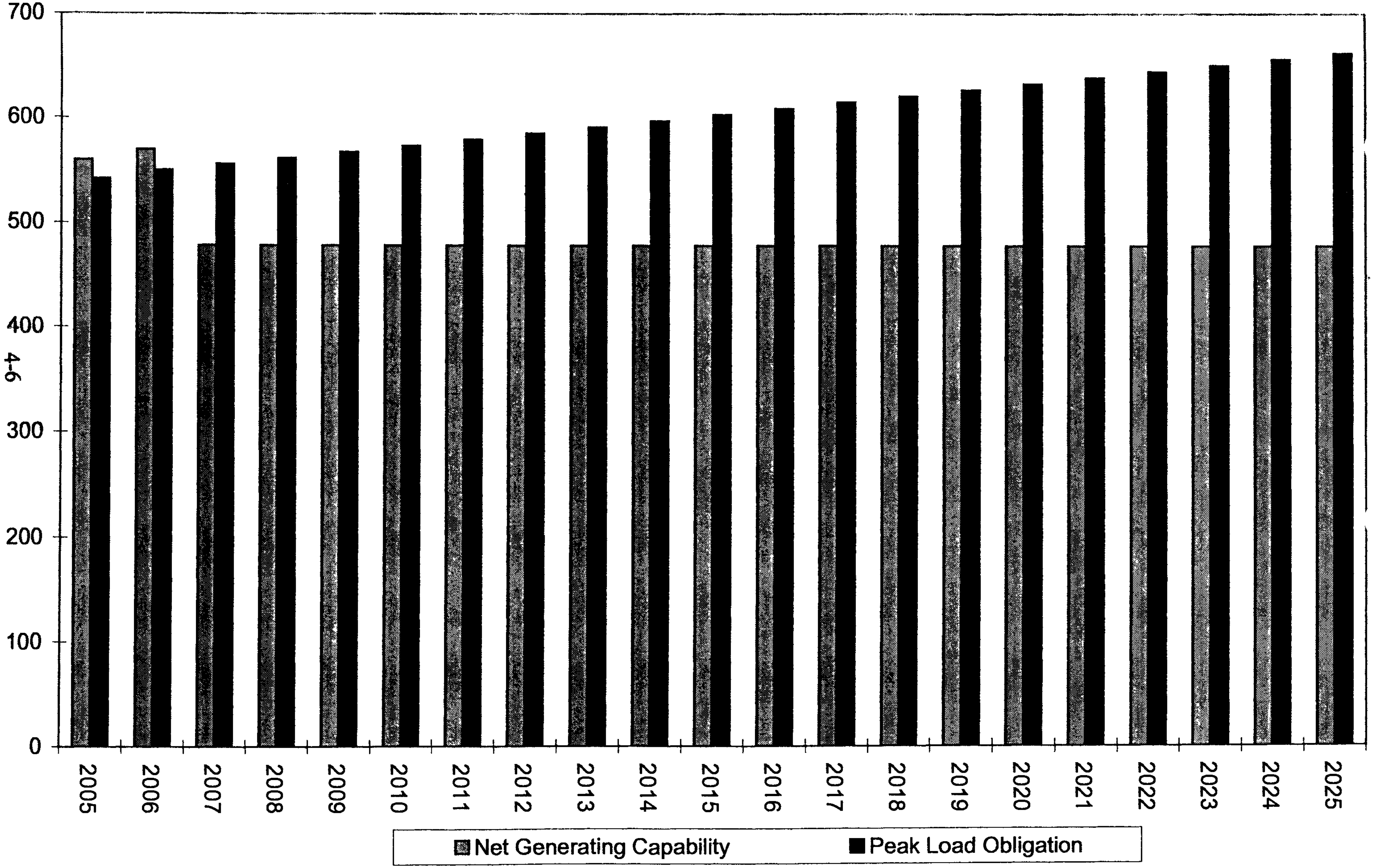


Figure 4-2
Load and Capability Comparison
High-Growth Scenario Forecast

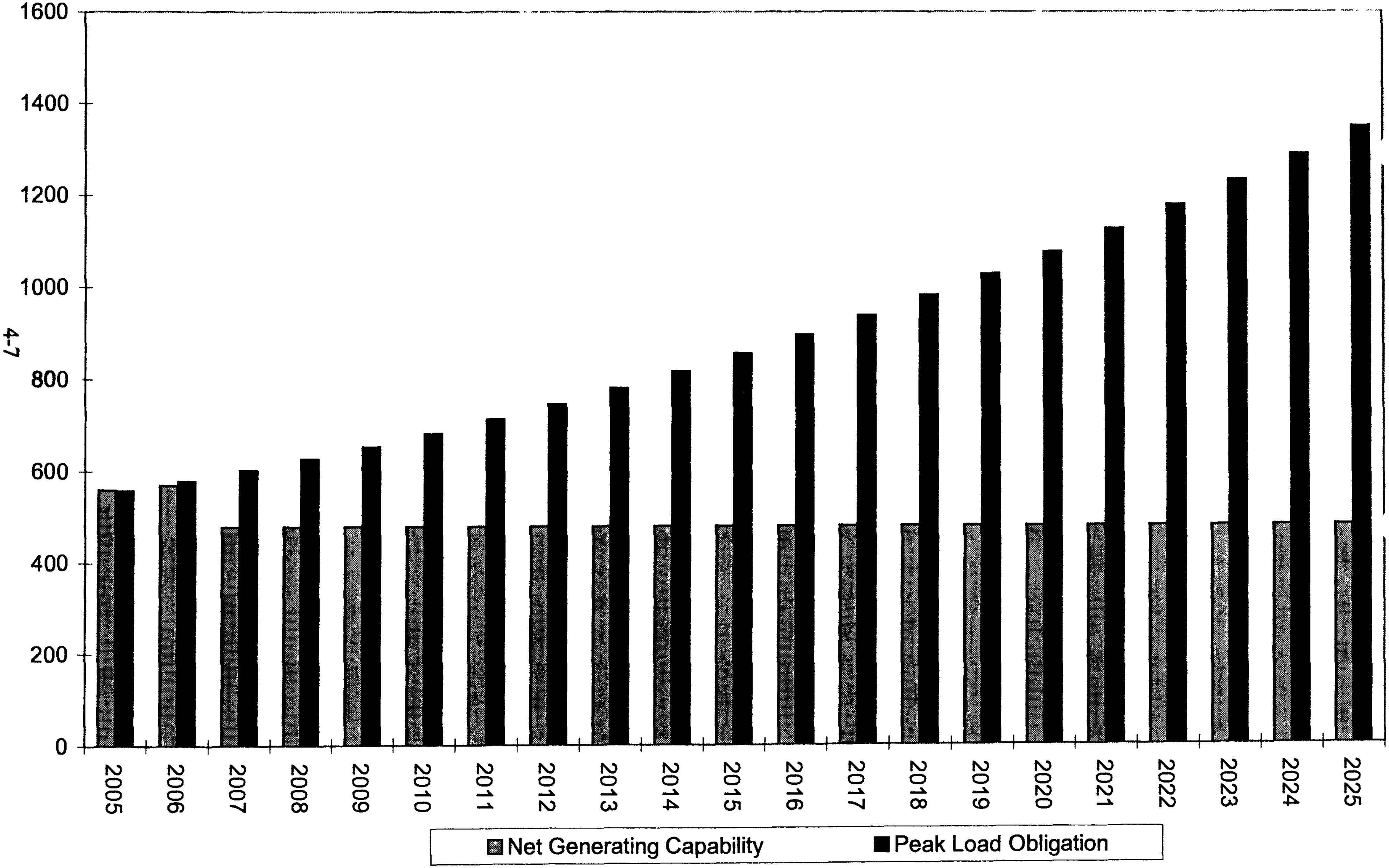
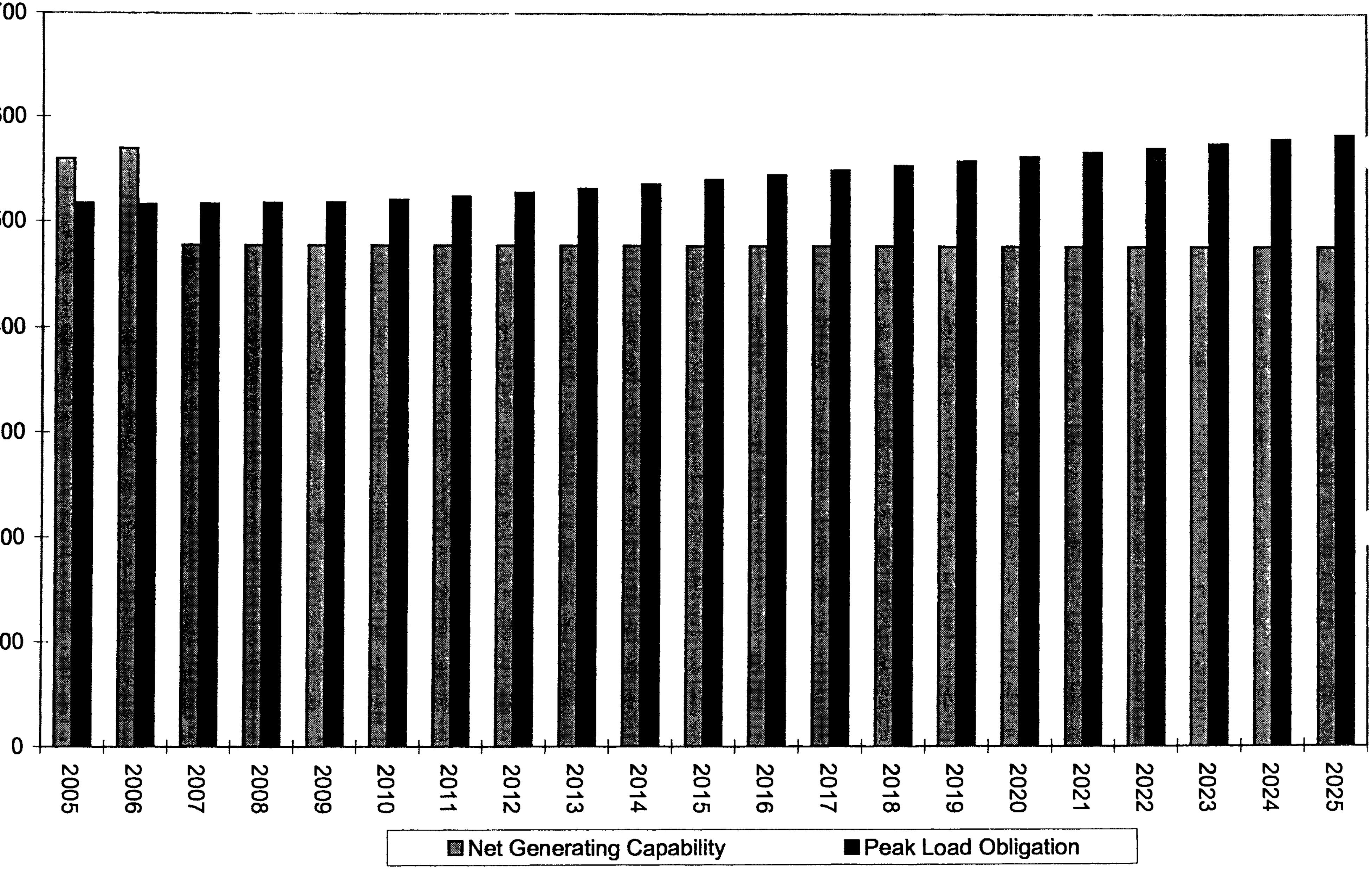


Figure 4-3
Load and Capability Comparison
Low-Growth Scenario Forecast



The company has addressed the power requirements, referred to as "bridge power," from the time the AVS II power purchase expires to the time the baseload unit comes on-line. That time period starts in 2007 and spans to approximately 2010-2013.

4.3.1 FUTURE BASELOAD CAPACITY

For future baseload capacity, Montana-Dakota is actively pursuing the following four options with other utilities or partners:

- A 175 MW coal plant near Gascoyne, North Dakota to be on-line in 2010,
- Part ownership of a 600 MW coal plant addition at the existing Big Stone plant near Big Stone, South Dakota to be on-line in 2011,
- Part ownership of a 600-1200 MW coal project being considered for construction in one of five locations in the upper Midwest to be on-line in 2012 or later (The Resource Coalition), and
- Purchase of power from other utilities or from the energy market.

4.3 1.1 LIGNITE VISION 21 UNIT

Montana-Dakota and Westmoreland Power began the investigation into the Lignite Vision 21 Gascoyne plant with the plant size to be 500 MW. Montana-Dakota estimated that it would need 150 to 175 MW of capacity from the unit with the balance to be sold to the market or to be held by Westmoreland. Because the studied size of the proposed plant was greater than Montana-Dakota's generation requirements, it was vital to either find suitable partners to take shares of the plant output or to sell the excess capacity under long-term contracts.

To identify potential partners, Montana-Dakota and Westmoreland held discussions with 25 utilities and power marketers in the region. Unfortunately those efforts were not successful. Transmission issues were a major concern of other potential partners and also the major obstacle for the plan to sell excess capacity under long-term contracts. New transmission facilities to transport power from Gascoyne to the major load centers would need to be constructed. For lack of partners to share the plant output, In February 2003 Montana-Dakota and Westmoreland decided to focus instead on a 250 MW size plant and then in November 2003 on a 175 MW plant.

Current Status

On May 14, 2004, Montana-Dakota and Westmoreland filed for an air quality permit with the North Dakota Department of Health. The permit is for the 175 MW plant and adjacent lignite mine and was issued on June 2, 2005. Under this permit, construction must begin by December 31, 2006.

4.3.1.2 BIG STONE II UNIT

In April 2001, Otter Tail Power Company suggested developing a business plan for a second generating unit at Big Stone, South Dakota – Big Stone II. That project involves the construction of a 600 MW baseload, sub-bituminous-fired plant planned to be on-line in June 2011. The current list of potential owners of the unit includes:

- Central Minnesota Municipal Power Agency,
- Great River Energy,
- Heartland Consumers Power District,
- Missouri River Energy Services,
- Montana-Dakota Utilities Co.,
- Otter Tail Power Company, and
- Southern Minnesota Municipal Power Agency.

Montana-Dakota's capacity share of the unit would be 116 MW. Compared to the 175 MW Lignite Vision 21 unit, the Big Stone II unit offers several advantages:

- Transmission issues. Because of its location, the Big Stone II unit would require fewer additional transmission facilities to integrate the unit into the grid than the Lignite Vision 21 unit.
- Infrastructure. While the Lignite Vision 21 unit is a "green field" plant that would require the construction to start from scratch, the Big Stone II unit would already have infrastructure in place at the existing Big Stone plant.
- Economy of scale. The 600 MW Big Stone II unit offers lower capital cost per kilowatt and lower operating costs than the 175 MW Lignite Vision 21 unit.

Current Status

The Big Stone II partners are in the process of applying a Certificate of Need with the Minnesota Public Service Commission for the construction of the transmission facilities associated with the unit that will be constructed in Minnesota. The partners are also in the process of applying for an Energy Conversion Facility Siting Permit in South Dakota. Other studies to support permitting and construction are being conducted.

On June 30, 2005, Montana-Dakota signed agreements with the other Big Stone II partners that formalized the structure of the project. Studies to further define the cost of the plant are underway, and formal commitment is scheduled for October 2006, pending the outcome of those studies.

4.3.1 3 RESOURCE COALITION UNIT

In parallel with the Lignite Vision 21 and Big Stone II investigations, Montana-Dakota is also exploring another option. In August 2003, the company joined a group of utilities known as the Resource Coalition to study the feasibility of a jointly owned coal-fired plant and potentially 100 MW of wind energy. The coalition members are:

- Basin Electric Power Cooperative,
- Heartland Consumers Power District,
- Minnkota Electric Cooperative,
- Missouri Basin Power Agency, and
- Montana-Dakota Utilities Co.

Considering the needs of the coalition members, that unit was sized in the 600 - 1200 MW range. Five potential plant sites were selected for study:

- Gascoyne, North Dakota,
- Mobridge, South Dakota,
- Modale, Iowa,
- Stanton, North Dakota, and
- Yankton, South Dakota.

Current Status

Transmission, fuel supply, and other studies are underway for all sites.

4.3.1.4 PURCHASE OF POWER

In addition to the above baseload plant ownership options, Montana-Dakota continues its ongoing efforts to seek opportunities and consider options to purchase power from other utilities in the region or from the energy market.

4.3.2 BRIDGE POWER

This section describes Montana-Dakota's efforts to secure the bridge power to meet customer demand from the time the AVS II power purchase expires to the time the baseload unit comes on line. As shown in Figure 4-1, Montana-Dakota would need 77.5 to 95.5 MW of capacity for the summers of 2007-2010.

4.3.2.1 OMAHA PUBLIC POWER DISTRICT AGREEMENT

On January 9, 2004, Montana-Dakota signed a Participation Power Purchase/Sale Agreement with Omaha Public Power District (OPPD).[5] Under this agreement, Montana-Dakota would have purchased from OPPD the following amounts of capacity and associated energy:

- 70 MW for November and December 2006,
- 80 MW for 2007,
- 90 MW for 2008, and
- 100 MW for 2009 and 2010.

The agreement was contingent upon Montana-Dakota and OPPD securing confirmed firm transmission service to deliver power from OPPD's system to Montana-Dakota's customer load.

The OPPD agreement was cancelled on December 31, 2004 because Montana-Dakota and OPPD could not secure the needed firm transmission service.

4.3.2.2 OCTOBER 2004 REQUEST FOR PROPOSALS

On October 25, 2004, Montana-Dakota issued a request for proposals (RFP) for the purchase of 70 to 100 MW of capacity and associated energy from November 1, 2006 through December 31, 2010.

At the response due date, December 17, 2004, three proposals were received. Of these proposals, only one, which offered a small portion of the needed capacity, was a qualified bid.

4.3.2.3 CURRENT STATUS

Montana-Dakota has negotiated an agreement with Northern States Power Company (NSP) for the purchase of peaking capacity for the following summer seasons:

- 2007 Summer – 85 MW
- 2008 Summer – 90 MW
- 2009 Summer – 95 MW
- 2010 Summer – 100 MW
- 2011 Summer – 105 MW (Optional, if Montana-Dakota exercises to extend the term of the agreement through the 2011 Summer)
- 2012 Summer – 110 MW (Optional, if Montana-Dakota elects to exercise its option for the 2011 Summer, then this option is subject to renegotiation of the terms and conditions of the agreement.)

4.4 SUMMARY

At the time of this IRP filing, Montana-Dakota's supply-side resource plan still faces uncertainties. The decision on which baseload option is the most beneficial for Montana-

Dakota's customers will most likely be made by the third quarter of 2006, and the transmission arrangements for the NSP purchase have not been finalized.

However, for purpose of this IRP, Montana-Dakota assumes its supply-side resource plan consists of:

2006 – 25 MW of Summer peaking capacity from NorthPoint Energy (existing contract)
2007 – 85 MW of Summer peaking capacity from NSP
2008 – 90 MW of Summer peaking capacity from NSP
2009 – 95 MW of Summer peaking capacity from NSP
2010 – 100 MW of Summer peaking capacity from NSP
2011 – 116 MW of Big Stone II.

REFERENCES

1/ Antelope Valley Station Participation Power Purchase/Sale Agreement between Basin Electric Power Cooperative and Montana-Dakota Utilities Co. Dated January 23, 1990.

2/ United States Department of Energy Western Area Power Administration. Contract with Fort Peck Tribes and Montana-Dakota Utilities Co. for Bill Crediting Program Arrangements. Dated January 4, 2001.

3/ Product K System Participation Power Interchange Service #200407-01 between Montana-Dakota Utilities Co. and NorthPoint Energy Solutions Inc. Dated July 15, 2004.

4/ Montana-Dakota Utilities Co. Electric Load Forecast – 2005-2024. Bismarck, North Dakota: Montana-Dakota Utilities Co., December 31, 2004.

5/ MAPP Product J Agreement, Firm Power Interchange Service between Montana-Dakota Utilities Co. and Omaha Public Power District. Dated January 9, 2004.

SECTION 5

SUMMARY

This section of the report presents a nontechnical summary of Montana-Dakota's projected forecast and proposed resource options as a result of this IRP.

Table 5-1 which summarizes the results for the 2006-2015 period. This table represents only proposed action and is subject to periodic reevaluation and possible changes. For example, the size, type, and timing for the next resource addition may depend on updated load forecasts, the feasibility of the coal-fired baseload alternatives, and other factors that affect the energy market. Entries in this table are explained as follows:

- Columns (1) and (2) show the load forecast for the system: Column (1) indicates the projected summer peak demand in megawatts (MW), and column (2) the projected annual energy in gigawatt-hours (GWh).

- Columns (3), (4), and (5) show the implementation of the DSM programs and their impacts on the summer peak demand and annual energy. Columns (3) indicates the first year the DSM programs are implemented, but their MW and GWh impacts will take three or five years to reach customer maximum potentials.

- Columns (6) and (7) reflect the final forecast of summer peak demand and annual energy after adjustments for DSM impacts have been made.

- Columns (8) and (9) show the supply-side additions by MW and type.

- Column (10) reflects the total accredited capability, or the capacity available to serve Montana-Dakota's own load.

- Columns (11) and (12) reflect the resulting reserve margin by MW and percent.

TABLE 5-1

MONTANA-DAKOTA UTILITIES CO.
INTEGRATED RESOURCE PLAN SUMMARY

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Load Forecast		Demand-Side Adjustments			Total Forecast		Supply-Side Additions		Accredited	Reserve	Reserve
YEAR	MW	GWh	DSM Implement.*	MW	GWh	MW	GWh	Installation	MW	Cap (MW)	Cap. (MW)	Margin (%)
2006	478 2	2,406 6	High-efficiency A/C, High-efficiency lighting,	-1 396	6.9	476.8	2,413 5	NorthPoint peaking cap	25 0	569 8	93 0	19 5%
2007	483.4	2,440 4	& Electric heat	-2 792	13 9	480.6	2,454.3	AVS II expiration & NSP peaking cap	-66.4 85 0	563 4	82.8	17.2%
2008	488 6	2,474 2		-4 188	20 8	484 4	2,495 0	NSP peaking cap	90.0	568 4	84 0	17 3%
2009	493 8	2,509 6		-5.327	11 3	488 5	2,520 9	NSP peaking cap	95 0	573.4	84 9	17 4%
2010	499 0	2,536 4		-6 466	1 9	492 5	2,538 3	NSP peaking cap	100 0	578 4	85 9	17 4%
2011	504 2	2,558 9		-6 466	1 9	497 7	2,560 8	Big Stone II	116 0	594.4	96 7	19 4%
2012	509 4	2,580 6		-6 466	1 9	502 9	2,582.5			594 4	91.5	18.2%
2013	514 6	2,601 3		-6.466	1 9	508 1	2,603.2			594 4	86 3	17 0%
2014	519 8	2,618 5		-6 466	1 9	513.3	2,620 4			594 4	81 1	15 8%
2015	525 0	2,635 6		-6 466	1 9	518 5	2,637 5			594 4	75 9	14 6%

* Indicates the first year the DSM programs are implemented Their MW and GWh impacts will take 3 or 5 years to reach maximum customer potentials

SECTION 6

TWO-YEAR ACTION PLAN

This section of the report provides the two-year action plan resulting from the present IRP. Showing how Montana-Dakota intends to implement its long-range resource plan, this action plan covers four areas: load forecasting, demand-side resources, supply-side resources, and other activities.

6.1 LOAD FORECASTING

1. Montana-Dakota will continue to review its load forecasting assumptions and inputs as part of its routine process.

2. As described in Section 2, Montana-Dakota will use an econometric model for the load forecast used in the next IRP.

6.2 DEMAND-SIDE RESOURCES

Based on the results of the demand-side analysis in Section 3, Montana-Dakota will implement the following four DSM programs:

1. ENERGY STAR® Partnership
2. Promote electric heat (in North Dakota only)
3. Promote high-efficiency residential central air conditioning
4. Promote commercial lighting T-8 retrofit

6.3 SUPPLY-SIDE ACTIVITIES

1. Montana-Dakota will continue to investigate the options for its future baseload unit and determine which option is the most beneficial for its customers. The options are:

    - A 175 MW coal plant near Gascoyne, North Dakota to be on-line in 2010,

    - Part ownership of a 600 MW coal plant addition at the existing Big Stone plant near Big Stone, South Dakota to be on-line in 2011,

    - Part ownership of a 600-1200 MW coal project being considered for construction in one of five locations in the upper Midwest to be on-line in 2012 or later (The Resource Coalition), and

    - Purchase of power from other utilities or from the energy market.

2. Montana-Dakota will continue its ongoing efforts to secure transmission for the NSP contract that provide summer peaking capacity for the summers of 2007-2010 and optionally 2011 and 2012.

3. Montana-Dakota will continue to investigate feasible renewable energy options.

6.4 OTHER ACTIVITIES

1. Montana-Dakota will maintain the IRP Public Advisory Group to provide input to and review the company's future IRPs.

2. Montana-Dakota will continue discussions with the Commission and its staff regarding status of the company's Integrated Resource Plans.

SECTION 7

THE IRP PUBLIC ADVISORY GROUP

This section of the report describes the role and the workings of Montana-Dakota's IRP Public Advisory Group (PAG), a broad base advisory board for review and evaluation of the company's IRP process. The first PAG was established for the 1995 IRP, and the PAGs have assisted with all IRPs since then. The 2005 IRP advisory group was established at the beginning of the 2005 planning cycle and held its first meeting in October 2004.

7.1 OBJECTIVE

The objective of the PAG was to provide Montana-Dakota with input to its integrated resource planning process from a nonutility perspective. This advisory group reviewed, evaluated, and recommended modifications to Montana-Dakota's planning process, resource plans, resource acquisition processes, and efficiency programs from the perspective of customers, government agencies, and public interest organizations.

Montana-Dakota considers the PAG's role to be one of providing advice and counsel on the planning process. The company took input from the PAG under advisement in making planning decisions. On the other hand, participation in the PAG does not mitigate the right of a PAG member to appear before the public service commissions on issues involving Montana-Dakota's integrated resource plans.

7.2 PARTICIPANTS

Participants in the PAG were nonutility personnel from the three states served by Montana-Dakota's integrated system: Montana, North Dakota, and South Dakota. The advisory group was structured to approximately reflect the proportions of Montana-Dakota's load in each state: Montana – 30 percent, North Dakota - 60 percent and South Dakota - 10 percent. The PAG members were also selected as to balance representation from consumer advocacy groups, government agencies (including regulatory bodies), business concerns, and academia.

As a result, the PAG consisted of three members from Montana, five members from North Dakota, and one member from South Dakota. In addition, the North Dakota Public Service Commission appointed a representative to participate as an observer. The names and affiliations of the 2005 PAG participants are shown in Table 7-1. Seven of the nine members and the North Dakota PSC observer had served on the 2003 PAG.

TABLE 7-1

PARTICIPANTS OF THE 2005 IRP PUBLIC ADVISORY GROUP

MONTANA

Penny Stras
Action for Eastern Montana
Glendive, Montana

Dr. LeRoy M. Moline
Glendive, Montana

Paul Cartwright
Department of Environmental Quality
Helena, Montana

NORTH DAKOTA

Kim Christianson
North Dakota Department of Commerce
Bismarck, North Dakota

Dr. Patrick O' Neill
Department of Economics
University of North Dakota
Grand Forks, North Dakota

William Ellig
Ritterbush-Ellig-Hulsing PC
Bismarck, North Dakota

Aaron Schmit
Edward Jones
Williston, North Dakota

Rich Wardner
North Dakota State Senate
Dickinson, North Dakota

Illona Jeffcoat-Sacco
North Dakota Public Service Commission
Bismarck, North Dakota
(Participated as an observer)

SOUTH DAKOTA

Kenny Jensen
Jensen Rock & Sand, Inc.
Mobridge, South Dakota

7.3 MEETINGS

Input from the PAG to the IRP process occurred through the PAG meetings and communications between the PAG members and Montana-Dakota personnel. The company funded travel and out-of-pocket expenses for the PAG members to attend the meetings. Their time was absorbed by themselves or by their employers.

At each meeting, the company presented methods, analysis, and findings to the group. The meetings provided an opportunity for the participants to contribute their comments and concerns about work in progress. In this way, the group could raise issues and discuss them, and the company could consider incorporation of the group's input into the IRP.

The 2005 IRP public advisory process had been streamlined to make more efficient use of the PAG members' time and expertise and provide the members with updated information on the rapidly changing electric utility industry. The company's presentations at the meetings were more result-and policy-oriented, rather than focusing on the technical data. Efforts were made to provide the members recent changes within the company and in the electric utility industry, which is moving rapidly toward a market environment. The group's discussions, therefore, tend to concentrate on issues, policies, and overall results.

As a result of the public advisory process, Montana-Dakota was able to produce better analyses and reports with the information and suggestions provided by the group. Table 7-2 shows the 2005 IRP PAG meetings and the main topics discussed at those meetings.

TABLE 7-2

MEETINGS OF THE IRP PUBLIC ADVISORY GROUP

Meeting Date	Main Discussion Topics
October 27, 2004	Organizational meeting
	Updates on Montana-Dakota's activities and the electric utility industry
	Montana-Dakota's power supply options for the future
	Montana-Dakota and Midwest Independent System Operator and the future energy market
	"Restructuring Montana: The Saga Continues"
	Montana-Dakota's peak demand weather sensitivity analysis
	Overview of the IRP process
March 3, 2005	Updates on Montana-Dakota's activities and the electric utility industry
	Briefing on the 2005 Montana Legislature
	2004 Customer Energy Survey
	Load forecast results
	North Dakota Dept. of Commerce Energy Star building
	Energy Efficiency/Renewable Energy activities in North Dakota
	Environmental permitting requirements for power plant construction
	Supply-side resource options
May 3, 2005	Updates on Montana-Dakota's activities and the electric utility industry
	Briefing on the 2005 Montana and North Dakota Legislatures
	Montana-Dakota's plan for demand-side analysis and implementation
	Today's MISO Market
	Demand-side programs from the societal test point-of-view
	Demand-side programs from the ratepayer impact point-of-view
	Potential demand-side programs

Meeting Date	Main Discussion Topics (cont.)
June 8, 2005	Updates on Montana-Dakota's activities and the electric utility industry. Reliability organizations in North America Supply-side resource plan Demand-side program analysis Demand-side resource plan Two-year action plan

The 2005 IRP PAG meetings were held in Bismarck, North Dakota. In addition to presenting the topics for discussion and taking feedback from the PAG members, Montana-Dakota served as a facilitator in setting agendas, taking care of meeting logistics such as meeting notices and expense reimbursements, and documenting the presentations at the meetings.

In addition to the four meetings noted above, Montana-Dakota worked closely with representatives from the North Dakota Department of Commerce, Office of Renewable Energy and Energy Efficiency and the Montana Department of Environmental Quality to choose demand-side programs for consideration and to evaluate those demand-side programs. In addition to phone conversations and emails, the demand-side working group met on June 7, 2005 for this purpose and the demand-side analysis section of this report reflects the work of this group.

Since the PAG functioned in an advisory role, no formal voting procedures were instituted. Montana-Dakota usually strove, however, for a consensus opinion of the PAG on the issues brought before it. The company was willing to discuss any IRP-related topics that were of interest to PAG members. It also invited participants to provide written comments whenever they wanted to document their opinions or concerns.

7.4 CONCLUSIONS

Overall, Montana-Dakota is pleased with its public advisory process. As for the previous IRPs, this process improved the 2005 IRP process and product (report and appendices). The public involvement resulted in better study assumptions and provided useful information to both the company and the PAG participants and their constituents.

APPENDICES

APPENDIX A

HISTORICAL DATA

Appendix A-1

MONTANA DAKOTA UTILITIES CO.
ANNUAL SALES BY CLASS FOR THE STATE OF MONTANA
(KILOWATT HOURS)

Year	Residential	Small C&I	Large C&I	Street Lighting	Other Public Sales	Interdepart-mental	Company Use	Unbilled	Total
1966	68,502,477	49,977,929	72,419,095	3,866,284	3,808,210	1,015,211	377,210	-	199,966,416
1967	68,579,218	50,233,896	98,914,908	4,015,663	3,715,582	1,091,354	810,948	-	227,361,569
1968	71,874,276	52,477,560	118,039,208	4,249,304	3,535,121	1,375,297	723,627	-	252,274,393
1969	78,325,684	53,242,727	138,245,825	5,604,625	3,863,692	1,249,804	709,401	-	281,241,758
1970	82,496,690	55,175,717	153,459,061	6,083,320	3,897,568	1,160,863	737,641	-	303,010,860
1971	85,705,748	55,865,479	163,248,877	6,492,393	4,104,508	958,540	960,127	-	317,335,672
1972	90,077,273	58,161,951	172,396,207	6,600,222	3,795,853	992,915	890,585	-	332,915,006
1973	92,338,476	61,367,352	190,984,413	6,706,073	4,211,624	1,158,025	902,676	-	357,668,639
1974	96,505,351	66,904,551	186,287,388	6,840,674	4,153,930	1,315,961	945,082	-	362,952,937
1975	105,048,515	69,452,309	178,400,297	7,087,080	3,913,278	1,506,121	984,351	-	366,391,951
1976	115,110,425	77,612,604	175,313,131	7,268,240	4,495,249	1,583,748	1,004,267	-	382,387,664
1977	120,454,365	81,073,772	172,531,607	7,359,231	4,657,927	1,548,399	1,036,205	-	388,661,506
1978	129,852,166	87,526,266	175,599,086	7,353,808	4,677,788	4,820,487	1,049,471	-	410,879,072
1979	136,672,460	96,589,760	178,879,168	7,359,189	5,467,739	2,283,782	1,029,716	-	428,281,814
1980	136,149,204	101,715,349	198,015,998	7,459,268	6,123,304	1,797,126	972,817	-	452,233,066
1981	144,334,391	111,228,786	206,717,766	7,487,108	6,381,820	1,715,542	752,755	-	478,618,168
1982	153,313,720	125,817,634	213,636,154	7,407,897	5,634,466	2,943,589	1,651,780	-	510,405,240
1983	150,623,962	108,187,279	249,492,431	7,481,435	7,159,425	1,709,185	917,496	-	525,571,213
1984	149,973,668	101,423,250	272,228,601	7,379,668	6,998,461	3,442,266	900,229	-	542,346,143
1985	142,726,940	106,608,809	281,467,351	7,188,874	6,516,453	1,001,594	639,636	-	546,149,657
1986	133,656,316	101,534,376	277,264,926	7,266,290	5,968,032	189,694	590,579	-	526,470,213
1987	126,119,227	95,806,617	248,018,234	7,290,415	6,493,543	195,663	580,473	-	484,504,172
1988	139,327,515	87,777,108	259,622,149	7,217,742	7,711,112	211,260	616,658	-	502,483,544
1989	133,923,369	85,321,774	255,852,368	7,076,958	7,254,814	226,885	599,867	-	490,256,035
1990	130,093,020	84,487,870	253,081,235	7,009,344	7,148,412	226,321	714,125	-	482,760,327
1991	135,844,961	85,054,308	253,947,072	7,232,332	6,944,172	225,952	606,717	-	489,855,514
1992	126,265,220	82,097,610	246,018,931	7,228,554	6,937,275	215,649	560,531	-	469,323,770
1993	131,148,008	85,150,142	239,566,466	7,228,736	6,709,227	223,166	621,957	-	470,647,702
1994	137,293,020	91,734,345	237,573,170	7,257,426	7,110,947	232,838	679,830	-	481,881,576
1995	139,222,942	92,004,117	231,710,303	7,224,945	6,846,494	228,038	621,915	-	477,858,754
1996	147,421,480	96,007,848	231,515,420	7,237,827	7,135,267	233,336	574,831	-	490,126,009
1997	144,515,075	94,430,882	238,928,697	7,237,555	7,244,423	201,302	556,239	-	493,114,173
1998	144,374,643	96,561,060	237,770,443	7,271,601	7,162,112	213,369	549,751	-	493,902,979
1999	139,939,058	93,535,156	251,450,993	7,241,875	7,037,487	201,768	551,485	-	499,957,822
2000	143,298,426	94,947,102	276,845,617	7,212,210	6,819,914	218,795	456,819	-	529,798,883
2001	144,170,040	94,133,492	282,466,554	7,242,218	6,677,075	218,859	453,240	-	535,361,478
2002	147,916,359	96,252,274	306,159,986	7,240,913	6,893,847	195,977	448,893	-	565,108,249
2003	153,518,427	100,463,048	340,070,071	7,208,314	6,991,783	190,115	501,557	-	608,943,315

Appendix A-2

MONTANA DAKOTA UTILITIES CO.
ANNUAL SALES BY CLASS FOR THE STATE OF NORTH DAKOTA
(KILOWATT HOURS)

Year	Residential	Small C&I	Large C&I	Street Lighting	Other Public Sales	Interdepart-mental	Company Use	Unbilled	Total
1966	177,839,445	101,454,865	62,248,779	12,065,801	9,778,523	242,324	627,634	35,481	364,292,852
1967	178,648,631	101,511,079	66,238,823	12,404,851	10,627,735	235,590	1,496,352	68,626	371,231,687
1968	189,586,695	108,098,127	68,327,053	13,528,733	11,306,057	1,075,808	1,514,551	68,231	393,505,255
1969	203,352,077	117,146,235	69,429,138	14,548,153	11,781,023	3,257,680	1,710,576	66,543	421,291,425
1970	215,129,232	128,966,438	74,006,755	15,405,493	12,432,105	2,976,220	1,632,669	66,670	450,615,582
1971	224,660,134	137,368,067	78,485,841	15,852,055	12,356,099	1,532,592	3,570,747	68,888	473,894,423
1972	241,177,868	141,541,263	85,849,701	16,145,159	12,610,906	230,775	5,480,921	72,184	503,108,777
1973	245,827,613	146,917,105	92,262,004	16,519,767	14,113,173	198,917	5,488,128	71,349	521,398,056
1974	259,763,946	151,905,722	95,263,639	16,812,962	14,147,896	207,547	5,388,873	64,700	543,555,285
1975	284,712,928	174,078,088	107,153,806	17,229,492	14,613,377	194,573	5,283,319	54,272	603,319,855
1976	307,231,757	188,990,076	119,225,930	17,788,799	17,287,746	233,931	5,201,276	58,861	656,018,376
1977	322,066,615	202,204,724	123,518,797	18,705,610	20,388,865	775,960	5,329,555	61,312	693,051,438
1978	360,829,206	226,814,052	131,861,024	19,233,630	22,666,150	448,114	5,583,243	55,953	767,491,372
1979	385,274,877	251,074,945	134,220,720	19,899,710	23,913,957	263,925	5,383,105	56,305	820,087,544
1980	390,283,221	265,468,707	140,987,413	20,492,222	26,160,460	382,762	5,040,756	44,390	848,859,931
1981	408,735,140	273,869,995	175,505,109	21,076,949	24,329,774	244,375	4,212,597	46,134	908,020,073
1982	452,363,924	245,889,852	236,334,289	21,499,821	26,288,435	261,436	4,964,613	47,986	987,650,356
1983	456,184,125	258,134,530	230,553,333	21,370,120	28,270,730	382,443	8,659,379	41,916	1,003,596,576
1984	455,285,616	267,515,911	240,737,178	20,966,383	28,884,506	2,020,361	6,602,362	42,325	1,022,054,642
1985	450,793,794	284,254,986	233,446,499	20,793,870	28,421,516	194,570	6,810,757	39,484	1,024,755,476
1986	434,367,094	282,091,350	232,968,286	20,399,709	29,251,485	283,486	8,387,924	37,451	1,007,786,785
1987	414,769,777	226,151,695	289,829,031	20,488,538	27,652,568	306,718	6,531,047	46,880	985,776,254
1988	449,769,976	199,876,624	348,910,521	20,488,320	27,128,548	233,035	6,339,307	34,969	1,052,781,300
1989	443,827,623	195,738,987	362,960,433	20,407,635	26,027,847	236,202	6,825,024	38,865	1,056,062,616
1990	430,825,093	192,983,257	373,076,254	20,510,585	25,648,820	243,363	6,283,396	37,303	1,049,608,071
1991	450,333,411	196,030,842	383,766,958	20,458,655	30,828,407	266,645	6,137,808	33,378	1,087,856,104
1992	423,260,909	188,693,144	398,197,743	20,663,341	31,720,268	282,076	6,211,805	48,627	1,069,077,913
1993	439,344,573	191,672,169	416,752,959	20,565,116	31,146,204	322,281	5,956,790	46,519	1,105,806,611
1994	456,342,312	203,783,580	445,849,305	20,574,807	32,828,420	316,899	6,987,912	41,960	1,166,725,195
1995	473,310,757	207,631,769	447,406,363	20,664,316	32,139,766	311,888	7,116,061	43,365	1,188,624,285
1996	489,581,963	212,394,753	463,633,627	20,598,257	33,617,666	293,678	7,112,634	42,287	1,227,274,865
1997	485,185,916	215,341,328	464,356,987	20,448,097	35,525,187	276,970	7,039,295	37,836	1,228,211,616
1998	476,555,259	216,137,378	470,352,073	20,780,506	33,387,706	268,955	6,460,961	35,675	1,223,978,513
1999	476,150,870	215,933,149	487,339,322	20,930,538	32,535,686	269,387	6,214,785	24,378	1,239,398,115
2000	480,611,397	220,082,001	496,752,971	20,765,723	32,298,343	276,507	5,758,461	-	1,256,545,403
2001	495,264,092	219,718,551	524,934,913	20,801,786	32,839,971	283,411	5,380,094	-	1,299,222,818
2002	510,649,026	223,725,158	534,095,959	20,845,828	33,601,388	245,882	4,924,187	-	1,328,087,428
2003	518,362,506	230,831,463	538,714,606	20,964,805	33,818,825	243,012	5,146,364	-	1,348,081,581

Appendix A-3

MONTANA DAKOTA UTILITIES CO.
ANNUAL SALES BY CLASS FOR THE STATE OF SOUTH DAKOTA
(KILOWATT HOURS)

Year	Residential	Small C&I	Large C&I	Street Lighting	Other Public Sales	Interdepart-mental	Company Use	Unbilled	Total
1966	42,230,739	22,427,449	6,732,280	2,095,903	1,697,150	1,424	126,325	-	75,311,270
1967	41,997,237	25,800,957	4,063,750	1,979,052	1,847,881	1,153	260,654	-	75,950,684
1968	43,952,926	23,284,225	3,940,603	2,575,843	1,707,100	1,608	268,857	-	75,731,162
1969	46,482,606	24,758,227	929,501	2,598,403	1,841,636	2,207	287,654	-	76,900,234
1970	47,361,709	22,775,007	3,464,385	2,547,642	1,759,567	2,154	269,189	-	78,179,653
1971	49,310,679	22,255,017	4,727,415	2,716,302	1,834,084	2,362	315,769	215	81,161,843
1972	52,980,235	22,785,758	5,347,104	2,813,232	1,918,580	2,270	365,122	-	86,212,301
1973	53,570,804	23,259,175	5,400,790	2,859,812	1,987,540	2,559	432,365	-	87,513,045
1974	56,666,860	23,203,748	5,840,707	2,994,179	2,138,696	2,487	428,561	-	91,275,238
1975	62,824,496	24,817,191	6,748,459	3,128,822	2,030,891	2,433	480,797	-	100,033,089
1976	66,343,302	25,800,602	7,756,873	3,103,016	2,053,227	2,370	467,531	-	105,526,921
1977	65,963,975	26,111,838	8,474,190	3,124,296	1,840,714	3,151	478,536	-	105,996,700
1978	68,589,710	27,328,956	9,693,110	3,113,948	1,774,321	2,966	607,731	-	111,110,742
1979	67,938,559	26,971,950	10,123,460	3,121,871	1,904,825	2,983	620,674	-	110,684,322
1980	64,325,468	26,196,596	10,851,108	3,140,131	2,170,017	3,737	507,507	-	107,194,564
1981	61,878,613	25,902,182	11,243,318	3,083,603	1,830,577	2,970	356,399	-	104,297,662
1982	65,558,005	27,156,570	11,426,316	3,030,031	1,871,552	2,943	607,247	-	109,652,664
1983	65,118,829	26,884,079	12,353,692	3,006,759	1,716,506	2,486	557,667	-	109,640,018
1984	65,920,772	27,933,476	12,698,954	2,964,197	1,816,219	1,782	545,965	-	111,881,365
1985	64,222,969	27,289,287	13,297,147	2,968,984	1,826,822	7,425	829,238	-	110,441,872
1986	62,444,941	27,005,631	14,820,308	2,987,404	1,637,375	22,258	571,879	-	109,489,796
1987	59,644,668	26,773,933	16,227,633	2,986,179	1,857,719	28,687	363,754	-	107,882,573
1988	63,622,038	28,168,260	18,064,220	2,953,900	1,925,245	14,449	419,470	-	115,167,582
1989	61,747,940	28,578,702	19,249,467	2,937,751	2,019,854	13,359	456,236	-	115,003,309
1990	59,041,129	27,674,002	20,540,349	2,938,991	1,879,111	9,908	369,286	-	112,452,776
1991	60,709,134	28,371,913	20,800,179	2,944,664	2,119,069	10,945	398,192	-	115,354,096
1992	56,416,333	27,113,531	21,125,368	2,920,263	2,354,085	10,701	343,584	-	110,283,865
1993	59,615,263	27,986,509	22,314,105	2,921,246	2,116,180	11,786	397,837	-	115,362,926
1994	61,124,471	30,267,538	23,784,346	2,922,998	2,427,771	11,901	422,267	-	120,961,292
1995	62,959,707	31,134,415	24,670,253	2,854,516	3,097,276	11,484	404,093	-	125,131,744
1996	63,638,266	32,141,951	25,352,355	2,872,136	3,137,175	12,172	352,311	-	127,506,366
1997	61,623,748	31,753,237	25,522,619	2,805,901	3,058,443	11,319	342,786	-	125,118,053
1998	59,360,287	32,313,292	25,113,488	2,796,107	3,003,078	9,777	286,457	-	122,882,486
1999	59,567,949	32,498,800	25,977,705	2,807,423	2,954,190	9,857	297,480	-	124,113,404
2000	59,525,312	32,320,913	25,956,274	2,740,106	2,810,931	9,227	308,855	-	123,671,618
2001	61,117,630	33,018,447	25,846,819	2,748,375	2,742,790	9,414	325,833	-	125,809,308
2002	61,780,443	33,800,702	26,645,097	2,691,584	2,737,670	9,884	329,617	-	127,994,997
2003	61,149,061	33,964,499	27,075,451	2,683,876	2,791,070	10,319	319,687	-	127,993,963

Appendix A-4

MONTANA DAKOTA UTILITIES CO.
ANNUAL SALES BY CLASS FOR THE INTEGRATED SYSTEM
(KILOWATT HOURS)

Year	Residential	Small C&I	Large C&I	Street Lighting	Other Public Sales	Interdepart-mental	Company Use	Unbilled	Total
1966	288,572,661	173,860,243	141,400,154	18,027,988	15,283,883	1,258,959	1,131,169	35,481	639,570,538
1967	289,225,086	177,545,932	169,217,481	18,399,566	16,191,198	1,328,097	2,567,954	68,626	674,543,940
1968	305,413,897	183,859,912	190,306,864	20,353,880	16,548,278	2,452,713	2,507,035	68,231	721,510,810
1969	328,160,367	195,147,189	208,604,464	22,751,181	17,486,351	4,509,691	2,707,631	66,543	779,433,417
1970	344,987,631	206,917,162	230,930,201	24,036,455	18,089,240	4,139,237	2,639,499	66,670	831,806,095
1971	359,676,561	215,488,563	246,462,133	25,060,750	18,294,691	2,493,494	4,846,643	69,103	872,391,938
1972	384,235,376	222,488,972	263,593,012	25,558,613	18,325,339	1,225,960	6,736,628	72,184	922,236,084
1973	391,736,893	231,543,632	288,647,207	26,085,652	20,312,337	1,359,501	6,823,169	71,349	966,579,740
1974	412,936,157	242,014,021	287,391,734	26,647,815	20,440,522	1,525,995	6,762,516	64,700	997,783,460
1975	452,585,939	268,347,588	292,302,562	27,445,394	20,557,546	1,703,127	6,748,467	54,272	1,069,744,895
1976	488,685,484	292,403,282	302,295,934	28,160,055	23,836,222	1,820,049	6,673,074	58,861	1,143,932,961
1977	508,484,955	309,390,334	304,524,594	29,189,137	26,887,506	2,327,510	6,844,296	61,312	1,187,709,644
1978	559,271,082	341,669,274	317,153,220	29,701,386	29,118,259	5,271,567	7,240,445	55,953	1,289,481,186
1979	589,885,896	374,636,655	323,223,348	30,380,770	31,286,521	2,550,690	7,033,495	56,305	1,359,053,680
1980	590,757,893	393,380,652	349,854,519	31,091,621	34,453,781	2,183,625	6,521,080	44,390	1,408,287,561
1981	614,948,144	411,000,963	393,466,193	31,647,660	32,542,171	1,962,887	5,321,751	46,134	1,490,935,903
1982	671,235,649	398,864,056	461,396,759	31,937,749	33,794,453	3,207,968	7,223,640	47,986	1,607,708,260
1983	671,926,916	393,205,888	492,399,456	31,858,314	37,146,661	2,094,114	10,134,542	41,916	1,638,807,807
1984	671,180,056	396,872,637	525,664,733	31,310,248	37,699,186	5,464,409	8,048,556	42,325	1,676,282,150
1985	657,743,703	418,153,082	528,210,997	30,951,728	36,764,791	1,203,589	8,279,631	39,484	1,681,347,005
1986	630,468,351	410,631,357	525,053,520	30,653,403	36,856,892	495,438	9,550,382	37,451	1,643,746,794
1987	600,533,672	348,732,245	554,074,898	30,765,132	36,003,830	531,068	7,475,274	46,880	1,578,162,999
1988	652,719,529	315,821,992	626,596,890	30,659,962	36,764,905	458,744	7,375,435	34,969	1,670,432,426
1989	639,498,932	309,639,463	638,062,268	30,422,344	35,302,515	476,446	7,881,127	38,865	1,661,321,960
1990	619,959,242	305,145,129	646,697,838	30,458,920	34,676,343	479,592	7,366,807	37,303	1,644,821,174
1991	646,887,506	309,457,063	658,514,209	30,635,651	39,891,648	503,542	7,142,717	33,378	1,693,065,714
1992	605,942,462	297,904,285	665,342,042	30,812,158	41,011,628	508,426	7,115,920	48,627	1,648,685,548
1993	630,107,844	304,808,820	678,633,530	30,715,098	39,971,611	557,233	6,976,584	46,519	1,691,817,239
1994	654,759,803	325,785,463	707,206,821	30,755,231	42,367,138	561,638	8,090,009	41,960	1,769,568,063
1995	675,493,406	330,770,301	703,786,919	30,743,777	42,083,536	551,410	8,142,069	43,365	1,791,614,783
1996	700,641,709	340,544,552	720,501,402	30,708,220	43,890,108	539,186	8,039,776	42,287	1,844,907,240
1997	691,324,739	341,525,447	728,808,303	30,491,553	45,828,053	489,591	7,938,320	37,836	1,846,443,842
1998	680,290,189	345,011,730	733,236,004	30,848,214	43,552,896	492,101	7,297,169	35,675	1,840,763,978
1999	675,657,877	341,967,105	764,768,020	30,979,836	42,527,363	481,012	7,063,750	24,378	1,863,469,341
2000	683,435,135	347,350,016	799,554,862	30,718,039	41,929,188	504,529	6,524,135	-	1,910,015,904
2001	700,551,762	346,870,490	833,248,286	30,792,379	42,259,836	511,684	6,159,167	-	1,960,393,604
2002	720,345,828	353,778,134	866,901,042	30,778,325	43,232,905	451,743	5,702,697	-	2,021,190,674
2003	733,029,994	365,259,010	905,860,128	30,856,995	43,601,678	443,446	5,967,608	-	2,085,018,859

Appendix A-5

MONTANA-DAKOTA UTILITIES CO.
INTEGRATED SYSTEM SEASONAL PEAKS AND PEAK MONTH LOAD FACTORS 1/
1960 THROUGH 2003

	SUMMER			WINTER			ANNUAL	
YEAR	MW	MONTH	LOAD FACTOR	MW	MONTH 2/	LOAD FACTOR	LOAD FACTOR	PEAK RATIO 3/
1960	76 7	AUG	70 7	109 3	DEC	58 8	50.9	1 425
1961	82 8	AUG	73 7	113 7	JAN	62 0	52.5	1 373
1962	83 8	AUG	76 4	123 2	JAN	65 4	53 7	1 470
1963	95 9	JUL	68 9	127 6	DEC	63.3	52 5	1 331
1964	101.8	AUG	68 2	138 2	DEC	64 2	51 8	1 358
1965	108 4	AUG	68 7	138 0	JAN	68.5	56 5	1 273
1966	114 0	JUL	70.5	149 6	JAN	65 4	58 2	1 312
1967	129.0	JUL	71.3	161 8	JAN	68.1	60 0	1 254
1968	133 3	JUL	69 9	173 5	DEC	65 1	55 0	1 302
1969	153 4	AUG	70 0	178 2	JAN	70 3	62 0	1 162
1970	160 5	JUL	70.2	186 2	DEC	67 6	59 5	1 160
1971	170 9	AUG	72 2	195 7	JAN	70 5	58 2	1 145
1972	174 5	AUG	72 6	209 1	DEC	69 4	58 5	1 198
1973	199 6	AUG	69 9	200 1	DEC	67 3	63 2	1 003
1974	210 0	JUL	71 9	222 0	JAN	66 6	62 7	1 057
1975	230 8	JUL	68 3	238 2	JAN	67 8	59 5	1 032
1976	242 6	AUG	64 8	241 3	JAN	78 1	59 7	0 995
1977	253 7	JUL	61 2	257 8	DEC	71.3	57 9	1 016
1978	257 2	SEP	59 9	268 1	JAN	79 0	62 9	1 042
1979	257.6	JUL	65 0	287 5	JAN	73 7	63 1	1 116
1980	291 2	JUL	64 4	292 0	DEC	73 4	61.7	1 003
1981	315 4	JUL	61 6	333 4	JAN	75 2	59.0	1.057
1982	322 7	AUG	60 8	293 7	DEC	74 9	59 6	0 910
1983	337 5	AUG	68 5	354 1	DEC	72 7	57 5	1 049
1984	354 6	AUG	64 3	330 6	JAN	74 3	58 3	0 932
1985	350 4	JUL	62 7	324 2	DEC	74 2	59 8	0 925
1986	338 0	JUN	57.9	293 2	DEC	73 4	59 2	0 867
1987	358 6	JUL	58 7	306 2	FEB	76 2	54 6	0 854
1988	386 7	JUN	61 6	320 9	FEB	74 1	54 2	0 830
1989	383 6	AUG	57 1	341 6	DEC	69 8	54 4	0 891
1990	381 6	JUL	55 4	330 2	DEC	70.8	53 5	0 865
1991	387 1	JUL	58.0	311 8	DEC	74.3	54.2	0.805
1992	339 1	AUG	60 9	337 5	DEC	73 1	61 4	0 995
1993	350 3	AUG	62 3	332 7	JAN	77 5	61 0	0 950
1994	369 8	AUG	61 8	322.6	DEC	74.5	59 7	0.872
1995	412 7	AUG	59 8	348 7	FEB	68.6	54 0	0 845
1996	393 3	AUG	62 6	343 1	JAN	78 4	58 3	0 872
1997	404 6	JUL	61 6	332 8	JAN	74 4	56 6	0 823
1998	402 5	AUG	63 6	354 2	DEC	70 1	56 9	0 880
1999	420 6	JUL	61 3	342 4	DEC	70 7	54 2	0 814
2000	432 3	AUG	61 3	353 9	DEC	77 4	54 9	0 819
2001	452 9	AUG	62 3	328 9	DEC	78.2	53 0	0 726
2002	458 8	JUL	64 9	343 5	JAN	78 4	53 7	0 749
2003	470 5	AUG	64 3	367 7	JAN	77 2	54 0	0 782

1/ MDU only net peak on combined system as calculated by MDU (excludes REC adjusted peak)
2/ January and February is of the following year.
3/ Ratio of winter peak to preceding summer peak

Appendix A-6

MONTANA-DAKOTA UTILITIES CO.
DEMAND BY STATE AT TIME OF SYSTEM SEASONAL PEAK
(MEGAWATTS)

YEAR	SUMMER ND	SUMMER SD	SUMMER MT	SUMMER INT SYS	WINTER ND	WINTER SD	WINTER MT	WINTER INT SYS
1975	139.4	22.1	69.3	230.8	145.1	22.8	70.3	238.2 *
1976	147.4	24.2	71.0	242.6	147.3	24.1	69.9	241.3 *
1977	155.9	23.5	74.6	254.0	155.1	24.3	78.4	257.8
1978	165.5	20.4	70.3	256.2	165.5	23.9	78.7	268.1 *
1979	166.4	16.4	74.8	257.6	177.2	24.1	86.2	287.5 *
1980	181.5	21.5	88.2	291.2	180.8	21.8	89.4	292.0
1981	202.3	21.0	92.1	315.4	201.5	24.9	106.9	333.3 *
1982	208.0	20.8	93.9	322.7	185.0	21.1	87.6	293.7
1983	221.2	20.9	95.4	337.5	225.7	27.5	100.9	354.1
1984	234.8	23.9	96.0	354.7	209.4	23.0	98.2	330.6 *
1985	233.3	24.4	92.7	350.4	206.9	22.4	94.9	324.2
1986	224.2	22.5	91.4	338.1	196.4	21.2	75.7	293.3
1987	242.1	28.5	88.1	358.7	204.6	22.8	78.8	306.2 *
1988	265.6	28.4	92.7	386.7	212.1	23.7	85.0	320.8 *
1989	265.1	27.6	90.9	383.6	225.6	26.9	89.1	341.6
1990	261.2	26.2	94.2	381.6	218.2	24.1	87.9	330.2
1991	271.9	30.0	85.2	387.1	217.5	19.9	74.4	311.8
1992	234.4	20.9	83.7	339.0	233.4	23.9	80.1	337.4
1993	251.1	23.3	75.9	350.3	225.6	25.5	81.6	332.7 *
1994	253.7	27.9	88.2	369.8	220.9	24.5	77.2	322.6
1995	290.6	27.1	95.0	412.7	236.1	22.5	90.1	348.7 *
1996	272.0	27.1	94.1	393.2	233.6	21.3	88.2	343.1 *
1997	288.0	22.4	94.3	404.7	225.0	20.0	87.8	332.8 *
1998	285.1	25.7	91.7	402.5	248.2	21.6	84.4	354.2
1999	295.0	28.7	96.9	420.6	237.3	21.6	83.6	342.5
2000	302.9	30.1	99.3	432.3	234.7	22.8	96.4	353.9
2001	317.8	29.8	105.4	453.0	235.0	14.3	79.6	328.9
2002	326.0	26.4	106.4	458.8	242.9	14.4	86.2	343.5 *
2003	328.4	28.4	113.7	470.5	251.4	19.4	96.9	367.7 *

* WINTER PEAK IS IN THE FOLLOWING YEAR.

Appendix A-7

Montana-Dakota Utilities Co.
Historical Energy Requirements
Integrated System

YEAR	TOTAL ENERGY REQUIREMENTS MWH	%INC/DEC
1959	463,307	
1960	488,316	5.40%
1961	514,086	5.28%
1962	545,306	6.07%
1963	586,589	7.57%
1964	628,616	7.16%
1965	682,214	8.53%
1966	725,389	6.33%
1967	798,855	10.13%
1968	837,504	4.84%
1969	908,231	8.44%
1970	970,490	6 85%
1971	1,021,876	5.29%
1972	1,073,560	5.06%
1973	1,107,691	3.18%
1974	1,155,351	4.30%
1975	1,210,168	4.74%
1976	1,274,391	5.31%
1977	1,307,542	2.60%
1978	1,418,366	8 48%
1979	1,481,019	4.42%
1980	1,581,612	6.79%
1981	1,629,323	3.02%
1982	1,740,859	6.85%
1983	1,783,753	2.46%
1984	1,815,453	1.78%
1985	1,834,294	1.04%
1986	1,751,503	-4.51%
1987	1,716,377	-2.01%
1988	1,834,232	6.87%
1989	1,828,665	-0.30%
1990	1,788,854	-2.18%
1991	1,836,243	2.65%
1992	1,827,866	-0.46%
1993	1,870,268	2.32%
1994	1,934,561	3.44%
1995	1,952,872	0.95%
1996	2,014,830	3.17%
1997	2,005,195	-0.48%
1998	2,007,534	0.12%
1999	1,996,647	-0.54%
2000	2,077,579	4.05%
2001	2,104,119	1.28%
2002	2,158,431	2.58%
2003	2,226,531	3.16%

APPENDIX B

FORECAST OF EXOGENOUS VARIABLES

Appendix B-1

PERSONAL CONSUMPTION EXPENDITURE DEFLATOR

Year	Personal Consumption Expenditure Deflator (1996=100)	Inflation Rate
1969	26 7	--
1970	28 0	4 9%
1971	29 2	4 3%
1972	30 2	3 4%
1973	31 9	5 6%
1974	35 1	10 0%
1975	38 0	8 3%
1976	40 1	5 5%
1977	42 7	6 5%
1978	45 8	7.3%
1979	49 8	8 7%
1980	55 2	10 8%
1981	60 1	8 9%
1982	63 5	5 7%
1983	66 2	4 3%
1984	68 6	3 6%
1985	71 0	3 5%
1986	72 7	2 4%
1987	75 5	3 9%
1988	78 4	3 8%
1989	81 9	4 5%
1990	85 6	4 5%
1991	88 9	3 9%
1992	91 6	3 0%
1993	93 8	2 4%
1994	95 7	2 0%
1995	97 9	2 3%
1996	100 0	2 1%
1997	101 9	1 9%
1998	103 0	1 1%
1999	104 7	1 7%
2000	107 4	2 6%
2001	109 6	2 0%
2002	111 1	1 4%
2003	113 2	1.9%
2004	115 4	1 9%
2005	117 8	2 1%
2006	120 2	2 0%
2007	122 8	2 2%
2008	125 5	2 2%
2009	128 3	2.2%
2010	131 2	2 3%
2011	134 3	2 4%
2012	137 5	2 4%
2013	140 8	2 4%
2014	144 3	2 5%
2015	147 9	2 5%
2016	151 8	2 6%
2017	155 7	2 6%
2018	159 9	2 7%
2019	164 4	2 8%
2020	169.0	2 8%
2021	174 0	3 0%
2022	179 3	3 0%
2023	185 0	3 2%
2024	190 8	3 1%

SOURCES
1969-2002 U S Department of Commerce
2003-2024 Woods & Poole Economics, Inc

Appendix B-2

GROSS DOMESTIC PRODUCT DEFLATOR

Year	GDP Deflator (1996=100)	Inflation Rate
1969	26 2	–
1970	27.5	5 0%
1971	28 9	5 1%
1972	30 2	4 5%
1973	31 9	5 6%
1974	34 7	8.8%
1975	38 0	9 5%
1976	40 2	5 8%
1977	42 8	6 5%
1978	45 8	7 0%
1979	49 6	8 3%
1980	54 1	9 1%
1981	59.1	9 2%
1982	62 7	6 1%
1983	65.2	4 0%
1984	67 7	3 8%
1985	69 7	3 0%
1986	71 3	2 3%
1987	73 2	2 7%
1988	75 7	3 4%
1989	78 6	3 8%
1990	81.6	3 8%
1991	84 5	3.6%
1992	86 4	2 2%
1993	88 4	2 3%
1994	90 3	2 1%
1995	92 1	2 0%
1996	93 9	2 0%
1997	95 4	1 6%
1998	96 5	1 2%
1999	97 9	1 5%
2000	100 0	2 1%
2001	102 4	2 4%
2002	103 9	1 5%
2003	105 7	1 7%
2004	107 5	1 7%
2005	109 4	1.8%
2006	111 7	2 1%
2007	114 5	2 5%
2008	117 5	2 6%
2009	119.9	2 0%
2010	122 1	1 8%
2011	124 6	2 0%
2012	127 2	2 1%
2013	129 8	2 0%
2014	132 5	2 1%
2015	135 2	2 0%
2016	138 0	2 1%
2017	140 9	2 1%
2018	143 8	2 1%
2019	146 8	2 1%
2020	149 8	2 0%
2021	152 9	2 1%
2022	156 1	2 1%
2023	159 3	2 0%
2024	162 6	2 1%

SOURCES

1969-2003 Actuals - U.S Department of Commerce
2004-2010 GDP forecasted by The Conference Board
2011-2024 Estimates based on the 2004-2010 average yearly growth in GDP forecasted by The Conference Board

Appendix B-3

INTEGRATED SYSTEM ELECTRICITY PRICES
Historical and Forecasted Prices
cents/kWh

YEAR	RESIDENTIAL PRICE	SMALL C&I PRICE	LARGE C&I PRICE
1967	2 760	3.739	1 616
1968	2 734	3 690	1 524
1969	2 697	3 599	1 463
1970	2 674	3.516	1 462
1971	2.660	3 484	1 448
1972	2 637	3 506	1 430
1973	2 684	3 558	1 444
1974	2 797	3 721	1 724
1975	2 916	3 792	1.857
1976	3.504	4.402	2 322
1977	3 900	4 586	2 530
1978	4 231	4 701	2 660
1979	4 358	4 749	2 729
1980	4 447	4 767	2 773
1981	5 589	5 732	3 786
1982	6 664	6 169	4 709
1983	6 671	6 288	4 750
1984	6 966	6 610	5 133
1985	7 135	6 624	5 102
1986	7 208	6 686	5 160
1987	7 430	7 231	5 444
1988	7 331	7 410	5 495
1989	7 245	7 397	5 449
1990	7 253	7 395	5 412
1991	7 255	7 445	5 403
1992	7 267	7 470	5 360
1993	7.231	7 436	5 314
1994	7 234	7 384	5 258
1995	7 125	7 305	5 238
1996	7 078	7 246	5 219
1997	7 156	7 336	5 292
1998	7 187	7.348	5 277
1999	7.155	7 310	5 181
2000	7 073	7 222	5 082
2001	7 136	7 312	5 176
2002	7 062	7 242	5 146
2003	7 107	7 268	5 159
2004	7 468	7 549	5 394
2005	7.528	7.628	5 497
2006	7 607	7 723	5 610
2007	7.821	8 067	5 969
2008	8 121	8 370	6 264
2009	8 327	8 576	6 420
2010	8 537	8 791	6 578
2011	8 748	9 014	6 741
2012	8 965	9 237	6 914
2013	9 194	9 463	7 087
2014	9 409	9 704	7 305
2015	9 629	9 951	7 530
2016	9 854	10 204	7 762
2017	10.084	10 463	8 001
2018	10.320	10 729	8 247
2019	10 561	11.002	8 501
2020	10 808	11 282	8 763
2021	11 061	11 569	9 033
2022	11 319	11 863	9 311
2023	11.584	12 165	9 598
2024	11 855	12 474	9 894

SOURCES
1967-2003· Historical prices calculated from Montana-Dakota Utilities Co , *Electric Operating Revenues Reports*
2004-2024 Forecasted prices

INTERCONNECTED SYSTEM
RESIDENTIAL SECTOR
HOUSEHOLDS AND CUSTOMERS

YEAR	NUMBER OF HOUSEHOLDS	GROWTH RATE	AVERAGE CUSTOMERS	GROWTH RATE
1971	91,246		61,781	
1972	92,956	1 87%	62,857	1 74%
1973	94,768	1 95%	64,131	2 03%
1974	96,439	1 76%	65,760	2 54%
1975	99,759	3 44%	67,700	2 95%
1976	103,434	3 68%	70,269	3 79%
1977	105,549	2 04%	72,854	3 68%
1978	106,886	1 27%	75,276	3 32%
1979	110,044	2 95%	77,814	3 37%
1980	113,293	2 95%	80,419	3 35%
1981	116,881	3 17%	83,073	3 30%
1982	120,678	3 25%	85,712	3 18%
1983	122,290	1 34%	86,732	1 19%
1984	123,126	0 68%	87,126	0 45%
1985	122,774	-0 29%	86,510	-0 71%
1986	120,544	-1 82%	85,316	-1 38%
1987	117,963	-2 14%	84,070	-1 46%
1988	116,944	-0 88%	83,497	-0 68%
1989	115,536	-1 20%	82,720	-0 93%
1990	113,499	-1 76%	82,260	-0 56%
1991	113,134	-0 32%	82,555	0 36%
1992	113,546	0 36%	82,730	0 21%
1993	113,382	-0 14%	83,038	0 37%
1994	113,640	0 23%	83,242	0 25%
1995	114,053	0 36%	83,639	0 48%
1996	115,737	1 48%	84,153	0 61%
1997	115,959	0 19%	84,510	0 42%
1998	116,370	0 35%	84,833	0 38%
1999	116,447	0 07%	84,935 */	0 12%
2000	116,918	0 40%	84,914	-0 02%
2001	116,258	-0 56%	84,866	-0 06%
2002	115,975	-0 24%	85,012	0 17%
2003	116,681	0 61%	85,278	0 31%
2004	117,264	0 50%	85,453	0 21%
2005	117,898	0 54%	85,663	0 25%
2006	118,458	0 47%	85,818	0 18%
2007	119,078	0 52%	86,014	0 23%
2008	119,659	0 49%	86,181	0 19%
2009	120,216	0 47%	86,328	0 17%
2010	120,759	0 45%	86,464	0 16%
2011	121,312	0 46%	86,606	0 16%
2012	121,865	0 46%	86,745	0 16%
2013	122,412	0 45%	86,880	0 16%
2014	122,898	0 40%	86,969	0 10%
2015	123,405	0 41%	87,072	0 12%
2016	123,864	0 37%	87,140	0 08%
2017	124,307	0 36%	87,195	0 06%
2018	124,714	0 33%	87,224	0 03%
2019	125,065	0 28%	87,224	0 00%
2020	125,410	0 28%	87,224	0 00%
2021	125,733	0 26%	87,224	0 00%
2022	126,052	0 25%	87,224	0 00%
2023	126,363	0 25%	87,224	0 00%
2024	126,622	0 20%	87,224	0 00%

*/ Actual customer numbers for 1999 are unavailable due to the installation of a new CIS
This number is an estimate

SOURCES
Households
1971-2001 U S Department of Commerce
2002-2024 Woods & Poole Economics Inc
Customers
1971-2003 Actuals from Montana-Dakota Utilities Co Electric Operating Revenues Reports
2004-2024 SHAPES II forecast

APPENDIX C

ADDITIONAL INPUT DATA

Appendix C-1

MONTANA-DAKOTA UTILITIES CO.
RESIDENTIAL APPLIANCE SATURATION

Single-Family Dwellings	1988	1990	1992	1994	1996	1998	2000	2004	Estimated 2024
Range	87 0	87.5	89.1	88 0	87.9	86 1	86 9	86.3	
Frost-Free Refrigerator	84 6	104 4	108 3	104 3	99.6	100 0	99 5	121.7	
Standard Refngerator	46 8	30.2	27.5	31.1	29.8	29 9	29.7	19.2	
Frost-Free Freezer	14.2	20.5	20.4	18 5	18.3	18.3	18 1	21.7	
Standard Freezer	71 0	100.3	99.8	82 3	81.0	81.1	80.0	79.3	
Dishwasher	53 0	54.0	50.9	49.5	52.1	50 3	57.0	58 0	
Washer	96.3	96.0	96.7	96.8	97.2	96 1	96 0	96 3	
Dryer	87.6	88 3	89.5	88 5	88 4	88 8	88.7	89 2	
Water Heater	35.7	40 5	38.2	36.5	37.8	37.1	38 4	32 8	
Microwave	81.9	90.6	93.5	94.5	96 1	97 3	98.2	100 5	110.0
Color TV	117.7	126 3	128.6	133 3	150 0	154.2	155.0	158.4	175.0
B&W TV	22 8	17.7	14.8	10 8	9 1				1.0
Lightıng	100.0	100.0	100 0	100 0	100.0	100 0	100.0	100.0	120.0
Room Air Condıtionıng	33 6	47.1	45.1	40 9	43.5	42.3	40 0	48.9	60.0
Central Air Conditioning	25.2	33.9	38 7	38 4	42.0	39 6	40 4	52 1	60.0
Electnc Heatıng	8.3	7 4	5.6	6.3	6.2	5 5	8.8	5.6	

Multi-Family Dwellings	1988	1990	1992	1994	1996	1998	2000	2004	Estimated 2024
Range	88 8	92.3	89.9	91 4	89 9	89.9	90 4	94 7	
Frost-Free Refngerator	79 7	60.4	58 9	76.6	70 1	69.2	66.0	93 0	
Standard Refrigerator	47 5	50 5	49.7	52 2	47 7	47.1	45.0	32.3	
Frost-Free Freezer	14.0	22.2	14.2	12 7	10 6	10 8	10.7	14.0	
Standard Freezer	75 1	87 3	83.8	49.8	41.5	42.2	42 2	45.3	
Dishwasher	42 4	39.4	42.0	40.3	41.8	46 8	43.6	49.3	
Washer	74.9	74 4	70.9	71.4	72 1	69.9	67.0	69 9	
Dryer	82 8	77.1	86 2	66 6	66.3	63 1	63 0	64.6	
Water Heater	37.5	32.5	32 4	35.2	33.1	30.1	36.0	30 6	
Microwave	71.9	86 1	89.6	93 6	92.9	91.7	93 6	100 5	110.0
Color TV	100.2	111.4	110.4	116.7	127 0	131.4	132 3	136.9	150 0
B&W TV	16.2	16.6	10.5	7 6	9 2				1.0
Lıghting	100.0	100 0	100.0	100 0	100.0	100.0	100.0	100 0	120.0
Room Air Conditıonıng	51.5	67 3	73.4	71.3	76 3	71.5	64 9	74.7	
Central Aır Condıtıonıng	20.4	21.3	23 2	22 0	23 9	20 3	25.5	34 0	50.0
Electric Heating	22.6	21.1	20 3	21.6	24.6	22.6	29 3	26.8	

Mobile Home Dwellings	1988	1990	1992	1994	1996	1998	2000	2004	Estimated 2024
Range	34.4	31.9	34.3	26.3	40.1	37 0	37.2	41.2	
Frost-Free Refngerator	43.4	46.8	50.6	51.0	51.3	52 8	52.6	80.5	
Standard Refrigerator	61.6	62.6	60.0	58 0	58 4	60 0	59 8	37 1	
Frost-Free Freezer	9.5	16 9	15 4	9.5	11.1	10.5	9.9	10.4	
Standard Freezer	60.7	95.8	96 4	60.6	70.5	66 5	63.2	69 4	
Dıshwasher	38 9	37 4	32.0	34.9	38 5	39 9	45.4	49.1	
Washer	93 8	94.0	92.9	91.5	93.4	92 2	94.3	89.5	
Dryer	88.2	85.0	92 7	84.2	87 0	86 4	85.2	84 2	
Water Heater	25.3	30.5	30.2	30.7	34 3	35 4	31.1	37 7	
Microwave	80 0	87 6	88.9	89.1	95.4	96 7	95.0	95.7	100.0
Color TV	103 0	109.2	116.4	115.4	141 9	132 9	135.1	126 3	150.0
B&W TV	16 5	12.3	11.1	6.3	7.8				1 0
Lighting	100.0	100 0	100.0	100.0	100.0	100 0	100.0	100.0	120.0
Room Air Condıtioning	38.1	45 8	44 7	47 7	45 4	39 1	43.3	42 1	50.0
Central Air Condıtionıng	38 5	43.5	50.4	48.7	51.6	52 7	49 5	63 2	70.0
Electric Heating	7 2	6 6	7.8	4 1	8.8	2 9	5.7	7 9	

Appendix C-2

INTEGRATED SYSTEM
PRICE ELASTICITIES

RESIDENTIAL SECTOR	Short-Term	Long-Term
Ranges	-0.100	-0.250
Frost-free refrigerator	0.000	0.000
Standard refrigerator	0.000	0.000
Frost-free freezer	0.000	0.000
Standard freezer	0.000	0.000
Dishwasher	-0.250	-0.500
Washer	-0.100	-0.250
Dryer	-0.250	-0.500
Water heater	-0.100	-0.250
Microwave	-0.100	-0.250
Color television	0.000	0.000
Black and white television	0.000	0.000
Lighting	-0.100	-0.250
Room air conditioner	-0.250	-0.500
Central air conditioner	-0.250	-0.500
Heating	-0.250	-0.500

SMALL COMMERCIAL & INDUSTRIAL SECTOR	Short-Term	Long-Term
Baseload	-0.050	-0.100
Heating	-0.050	-0.100
Cooling	-0 050	-0.100

LARGE COMMERCIAL & INDUSTRIAL SECTOR	Short-Term	Long-Term
General	-0.150	-0.300

Appendix C-3

MONTANA-DAKOTA UTILITIES CO.
2004 LOAD FORECAST
APPLIANCE CONNECTED LOADS
AND RESULTING ANNUAL ENERGY USE

APPLIANCE	CONNECTED LOAD (WATTS)	ANNUAL USAGE (KWH)
Range	8200	620
Frost-free refrigerator	295	1111
Standard refrigerator	185	711
Frost-free freezer	195	781
Standard freezer	175	614
Dishwasher	449	159
Washer	445	96
Dryer	3962	951
Water heater	4095	3682
Microwave	1040	146
Color TV	150	329
B&W TV	45	97
Lighting	2942	1001
Room air conditioning	1000	369
Central air conditioning	3200	1179
Heating	3400	5420

SOURCES:
- Association of Home Appliance Manufacturers (AHAM)
- Edison Electric Institute (EEI), "Annual Energy Requirements of Electric Household Appliances"
- United Power Association (UPA) Appliance Report
- American Electric Power Service Corp. presentation to American Power Conference.
- Consumer Guide to Home Energy Savings (ACEEE)
- Manitoba Hydro End-Use Load Research Studies

Appendix C-4

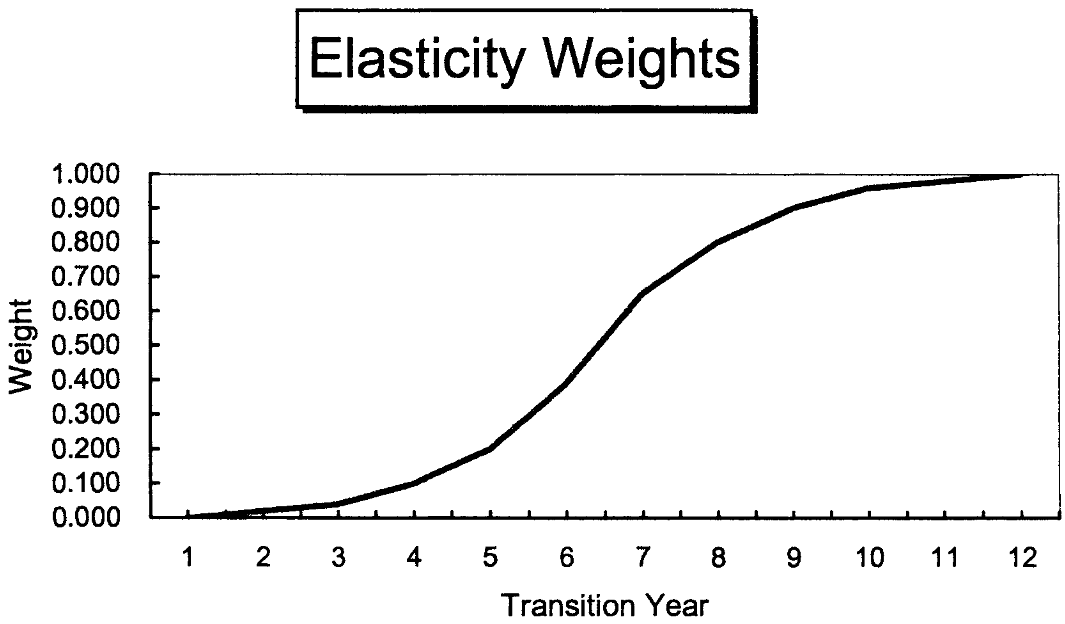
MONTANA-DAKOTA UTILITIES CO.
2004 LOAD FORECAST
APPLIANCE EFFICIENCY TRENDS

APPLIANCE	EFFICIENCY MULTIPLIER	YEAR
Range	1.00	2024
Frost-free refrigerator	0.50	2024
Standard refrigerator	0.50	2024
Frost-free freezer	0.70	2024
Standard freezer	0.70	2024
Dishwasher	1.00	2024
Washer	1.00	2024
Dryer	1.00	2024
Water heater	1.00	2024
Microwave	1.00	2024
Color TV	1.00	2024
B&W TV	1.00	2024
Lighting	1.00	2024
Room air conditioning	1.00	2024
Central air conditioning	1.00	2024
Heating	1.00	2024

Appendix C-5

INTEGRATED SYSTEM
SHAPES II PRICE ELASTICITY WEIGHTS

YEAR	ELASTICITY WEIGHT	YEAR	ELASTICITY WEIGHT
1	0.000	7	0.650
2	0.020	8	0.800
3	0.040	9	0.900
4	0.100	10	0.960
5	0.200	11	0.980
6	0.390	12	1.000



Appendix C-6

INTEGRATED SYSTEM
EMPLOYMENT DATA WITH ALTERNATE FORECAST
FOR SMALL C&I SECTOR

YEAR	EMPLOYMENT	GROWTH RATE	YEAR	EMPLOYMENT	GROWTH RATE
1969	93,209		1997	157,593	1.33%
1970	94,450	1.33%	1998	161,294	2.35%
1971	94,689	0.25%	1999	162,895	0.99%
1972	97,705	3.19%	2000	165,612	1.67%
1973	102,812	5.23%	2001	167,090	0.89%
1974	106,580	3.66%	2002	168,676	0.95%
1975	110,850	4.01%	2003	170,362	1.00%
1976	115,448	4.15%	2004	173,292	1.72%
1977	119,045	3.12%	2005	176,273	1.72%
1978	125,816	5.69%	2006	179,305	1.72%
1979	131,711	4.69%	2007	182,389	1.72%
1980	136,237	3.44%	2008	185,526	1.72%
1981	139,688	2.53%	2009	188,717	1.72%
1982	144,895	3.73%	2010	191,963	1.72%
1983	145,182	0.20%	2011	195,265	1.72%
1984	142,302	-1.98%	2012	198,624	1.72%
1985	138,475	-2.69%	2013	202,040	1.72%
1986	134,156	-3.12%	2014	204,060	1.00%
1987	133,501	-0.49%	2015	206,101	1.00%
1988	134,047	0.41%	2016	208,162	1.00%
1989	136,251	1.64%	2017	210,244	1.00%
1990	138,375	1.56%	2018	212,346	1.00%
1991	140,908	1.83%	2019	214,469	1.00%
1992	142,054	0.81%	2020	216,614	1.00%
1993	145,470	2.40%	2021	218,780	1.00%
1994	152,935	5.13%	2022	220,968	1.00%
1995	153,102	0.11%	2023	223,178	1.00%
1996	155,532	1.59%	2024	225,410	1.00%

SOURCE:
1969-2001: U.S. Department of Commerce
2002-2024: Woods & Poole Economics, Inc. with historical growth rates for 2004-2012

Employment for the following industries are included in the total employment:
Agricultural Services Employment
Construction Employment
Manufacturing Employment
Transportation, Communication, & Public Utilities Employment
Wholesale Trade Employment
Retail Trade Employment
Finance, Insurance, & Real Estate Employment
Service Employment
Federal Civilian Employment
Federal Military Employment
State and Local Government Employment

Appendix C-7

INTEGRATED SYSTEM
EMPLOYMENT DATA
FOR LARGE C&I SECTOR

YEAR	EMPLOYMENT	GROWTH RATE	YEAR	EMPLOYMENT	GROWTH RATE
1969	93,209		1997	157,593	1.33%
1970	94,450	1.33%	1998	161,294	2.35%
1971	94,689	0.25%	1999	162,895	0.99%
1972	97,705	3.19%	2000	165,612	1.67%
1973	102,812	5.23%	2001	167,090	0.89%
1974	106,580	3.66%	2002	168,676	0.95%
1975	110,850	4.01%	2003	170,362	1.00%
1976	115,448	4.15%	2004	172,044	0.99%
1977	119,045	3.12%	2005	173,750	0.99%
1978	125,816	5.69%	2006	175,457	0.98%
1979	131,711	4.69%	2007	177,205	1.00%
1980	136,237	3.44%	2008	178,973	1.00%
1981	139,688	2.53%	2009	180,751	0.99%
1982	144,895	3.73%	2010	182,570	1.01%
1983	145,182	0.20%	2011	184,397	1.00%
1984	142,302	-1.98%	2012	186,265	1.01%
1985	138,475	-2.69%	2013	188,126	1.00%
1986	134,156	-3.12%	2014	190,033	1.01%
1987	133,501	-0.49%	2015	191,950	1.01%
1988	134,047	0.41%	2016	193,871	1.00%
1989	136,251	1.64%	2017	195,833	1.01%
1990	138,375	1.56%	2018	197,797	1.00%
1991	140,908	1.83%	2019	199,792	1.01%
1992	142,054	0.81%	2020	201,786	1.00%
1993	145,470	2.40%	2021	203,818	1.01%
1994	152,935	5.13%	2022	205,852	1.00%
1995	153,102	0.11%	2023	207,922	1.01%
1996	155,532	1.59%	2024	209,999	1.00%

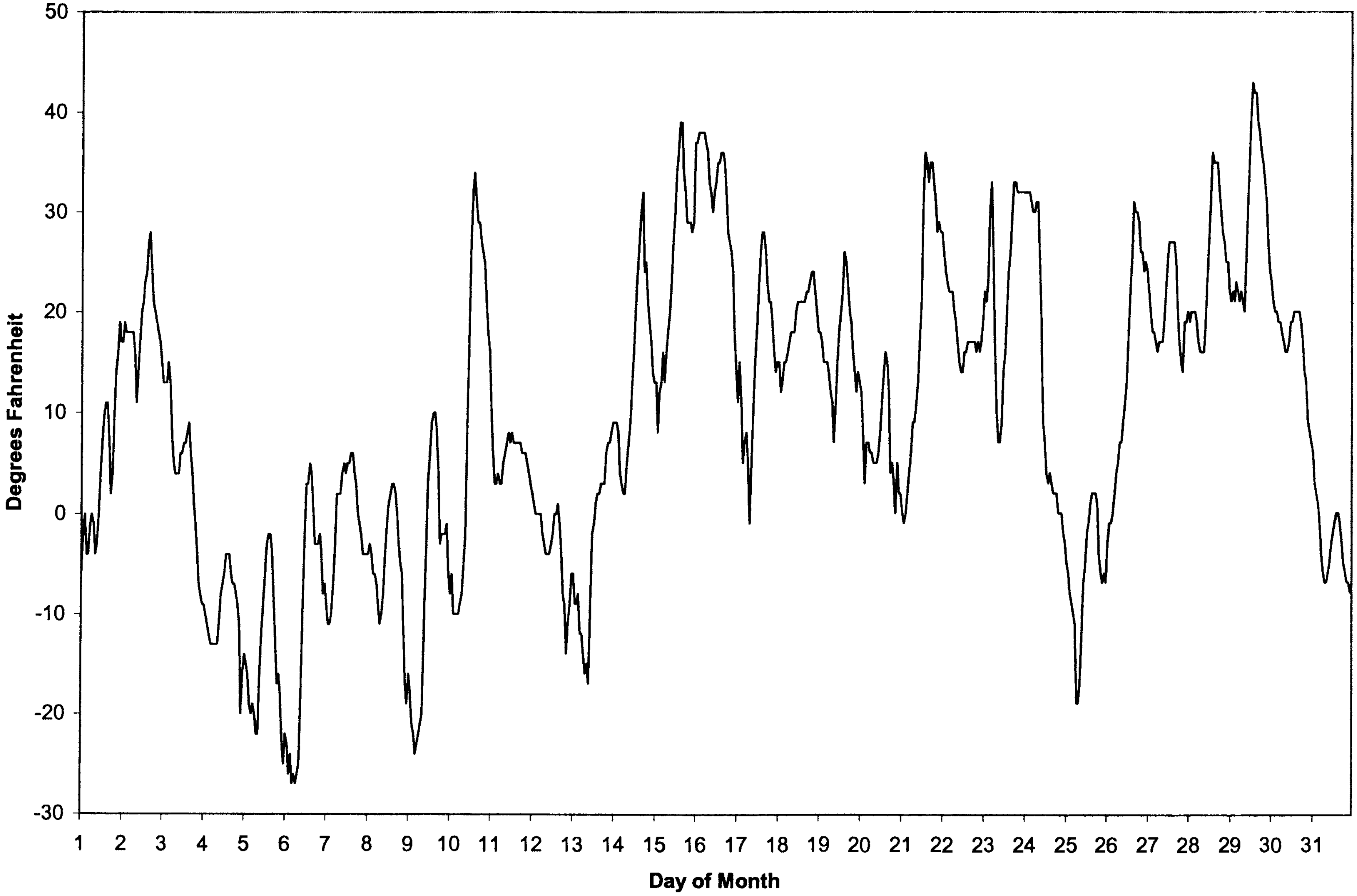
SOURCE:
1969-2001: U.S. Department of Commerce
2002-2024: Woods & Poole Economics, Inc.

Employment for the following industries are included in the total employment:
- Agricultural Services Employment
- Construction Employment
- Manufacturing Employment
- Transportation, Communication, & Public Utilities Employment
- Wholesale Trade Employment
- Retail Trade Employment
- Finance, Insurance, & Real Estate Employment
- Service Employment
- Federal Civilian Employment
- Federal Military Employment
- State and Local Government Employment

APPENDIX D

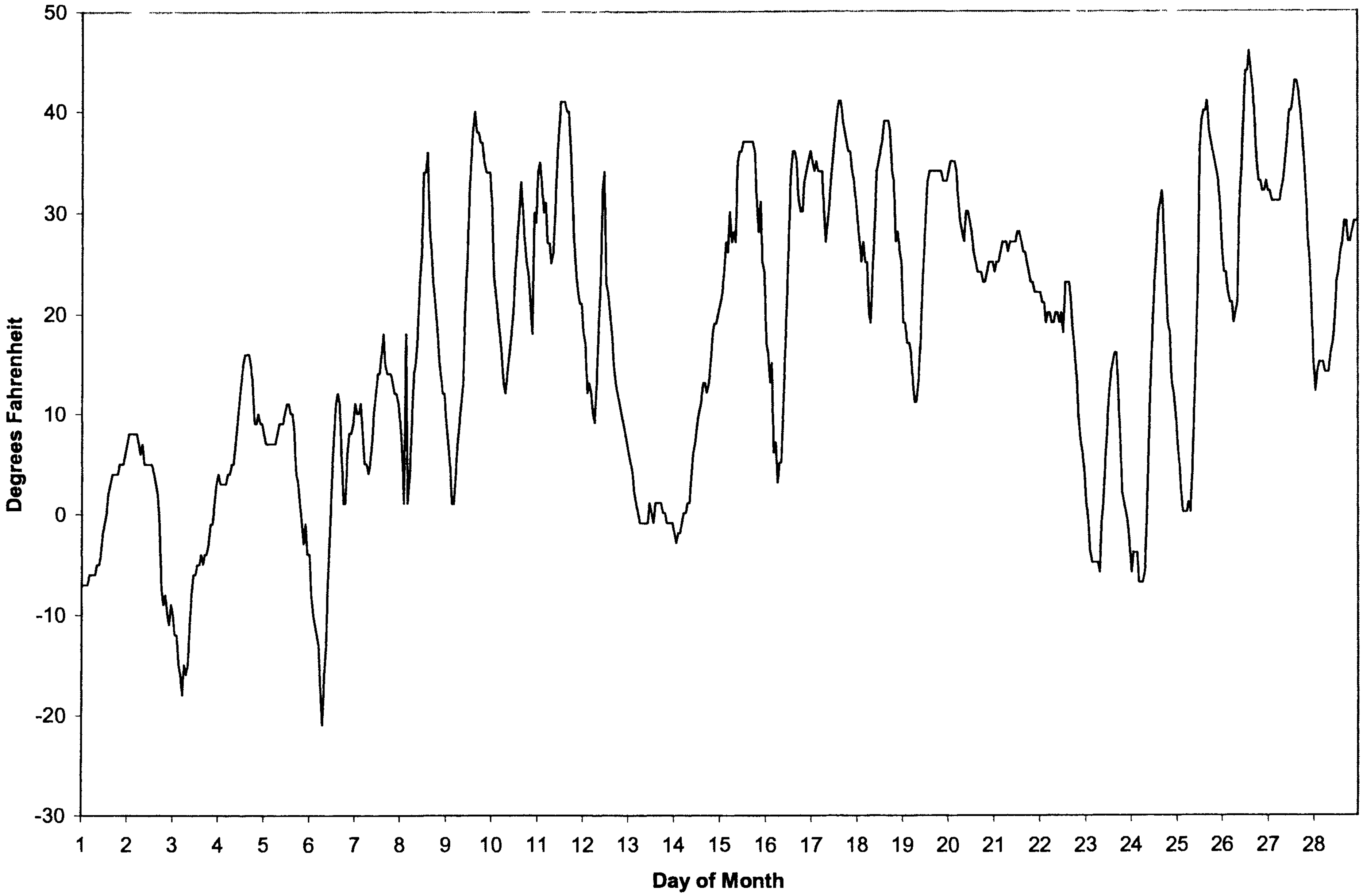
HOURLY TEMPERATURES FOR BISMARCK TYPICAL METEOROLOGICAL YEAR

Bismarck
Hourly Temperatures for January 1988



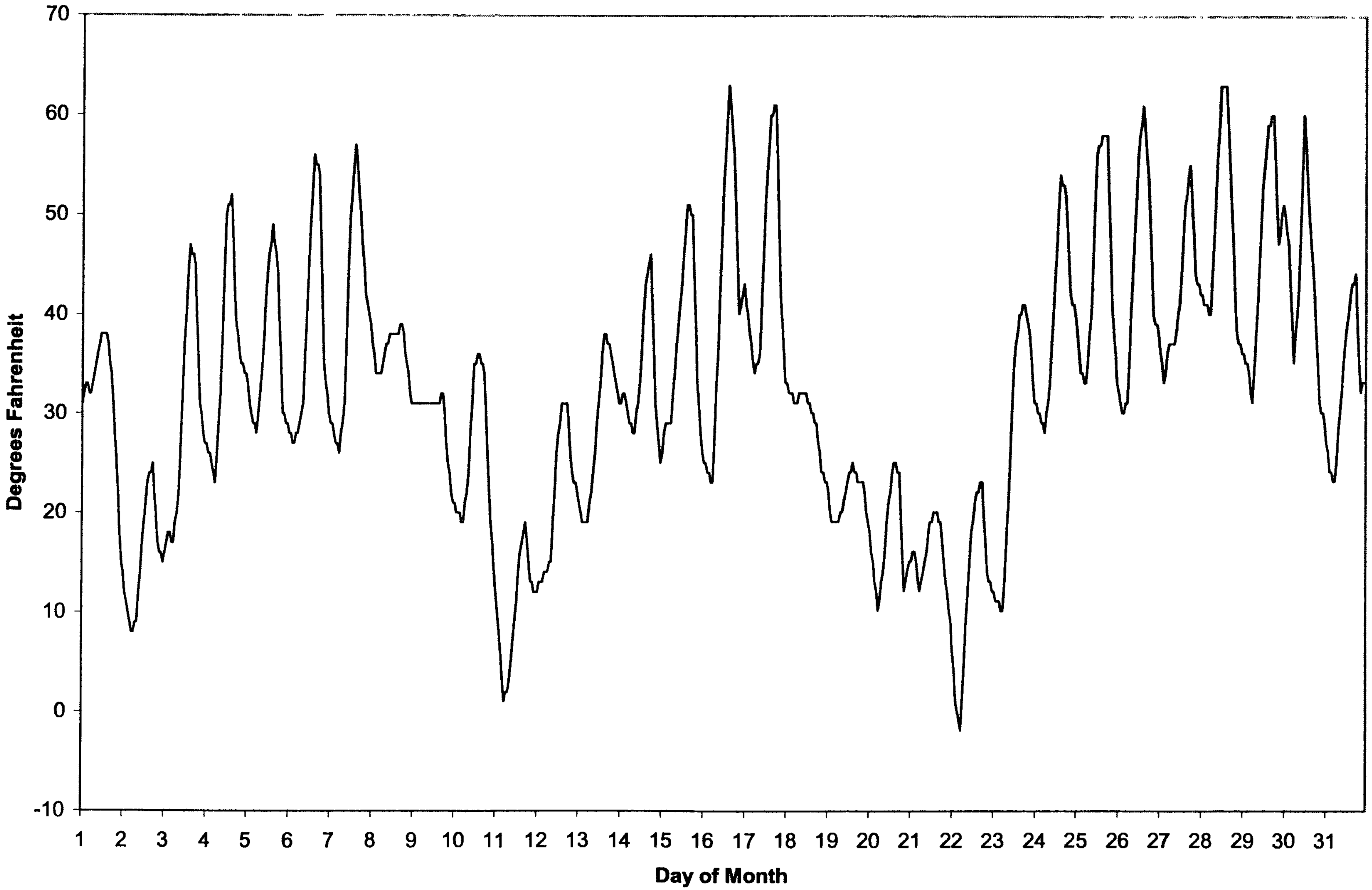
Bismarck

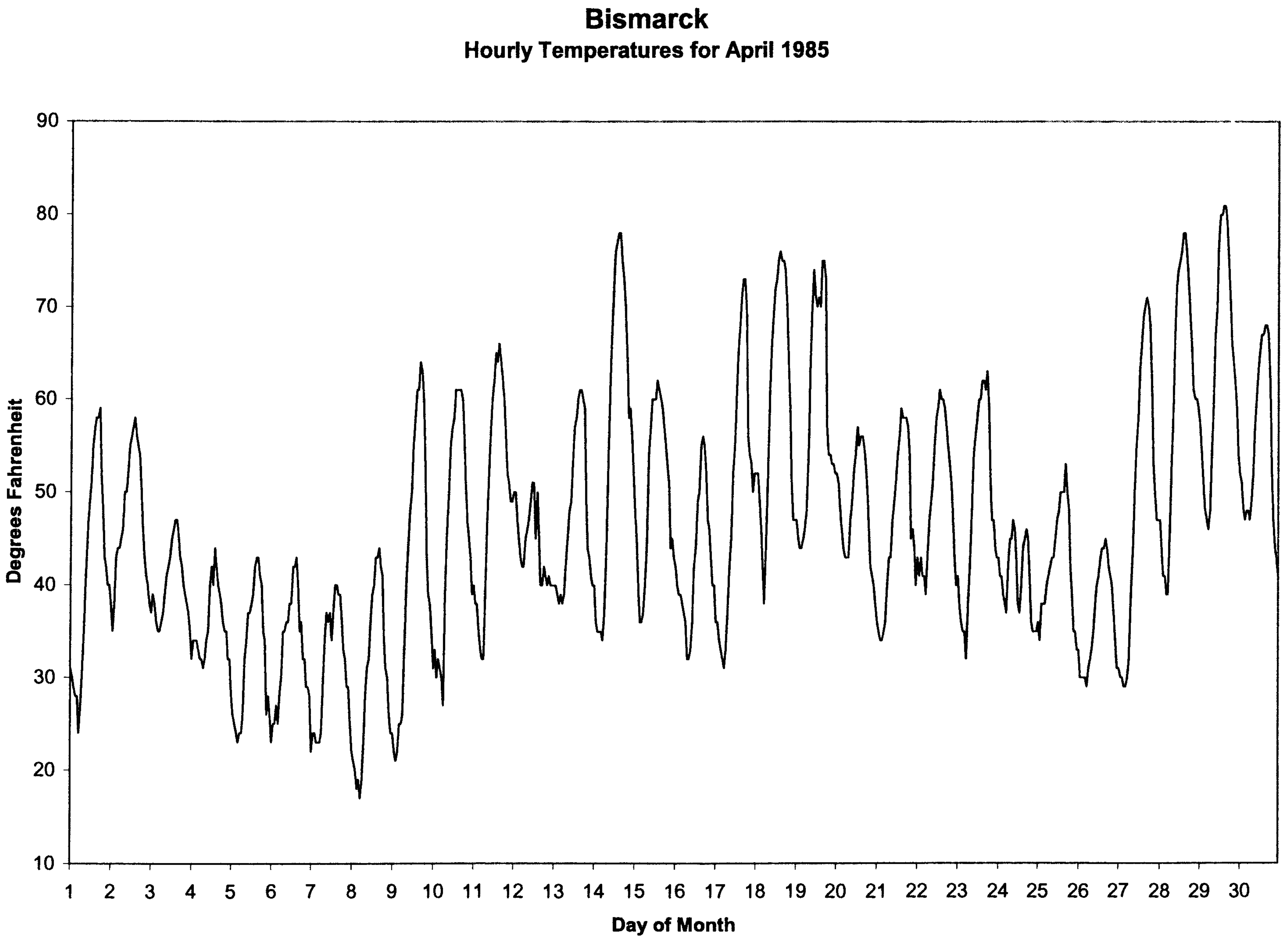
Hourly Temperatures for February 1974

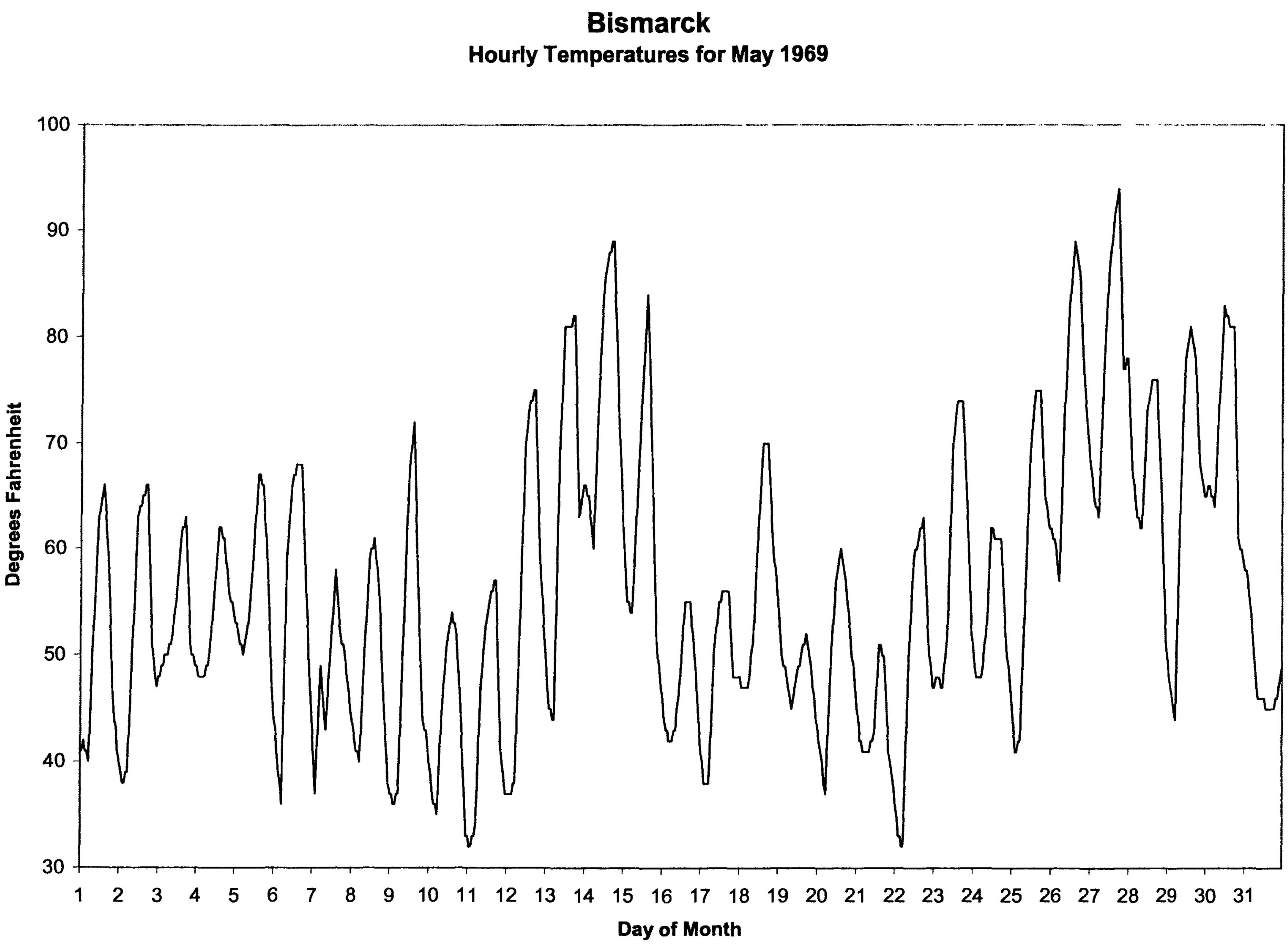


Bismarck

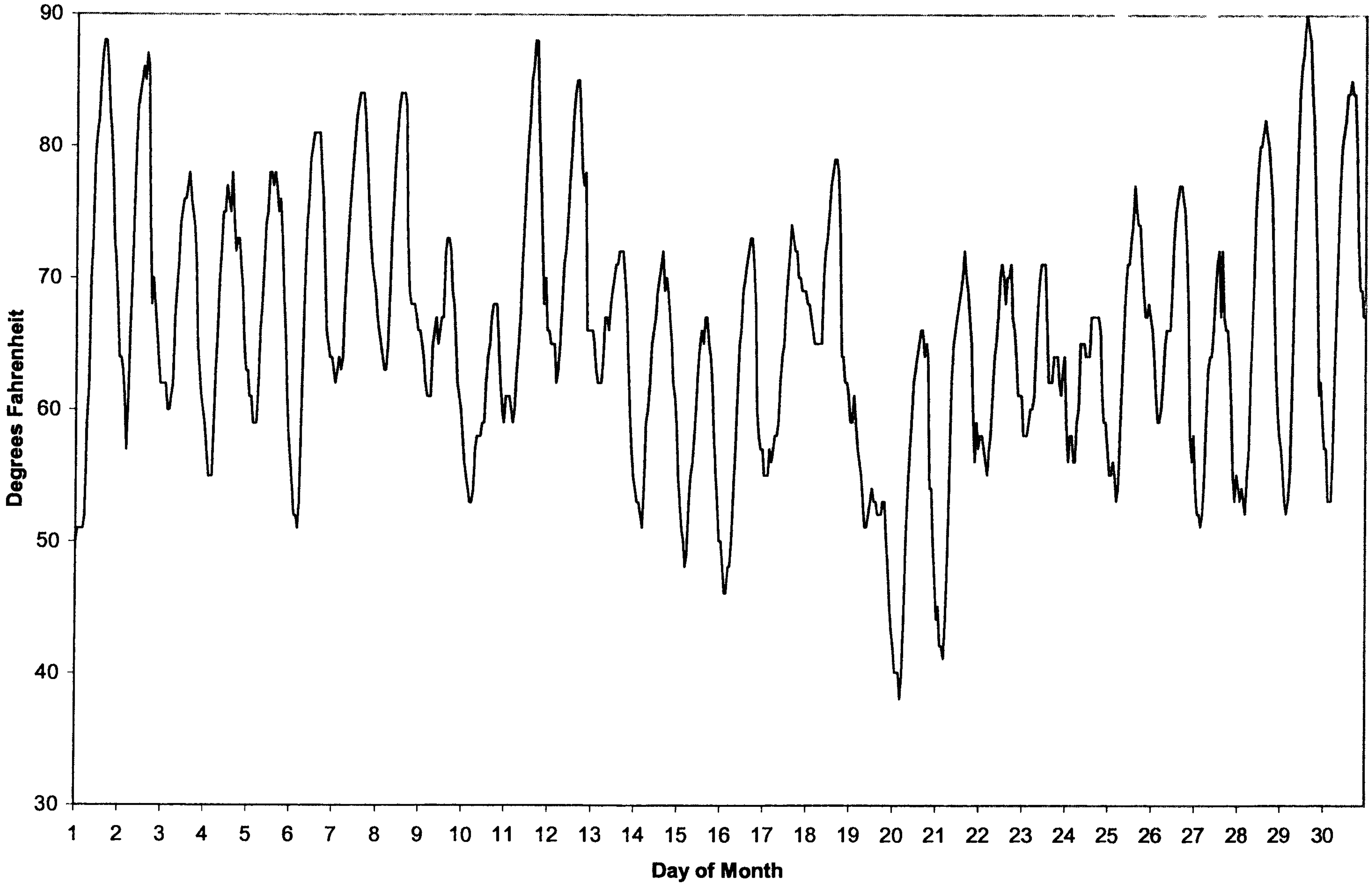
Hourly Temperatures for March 1968



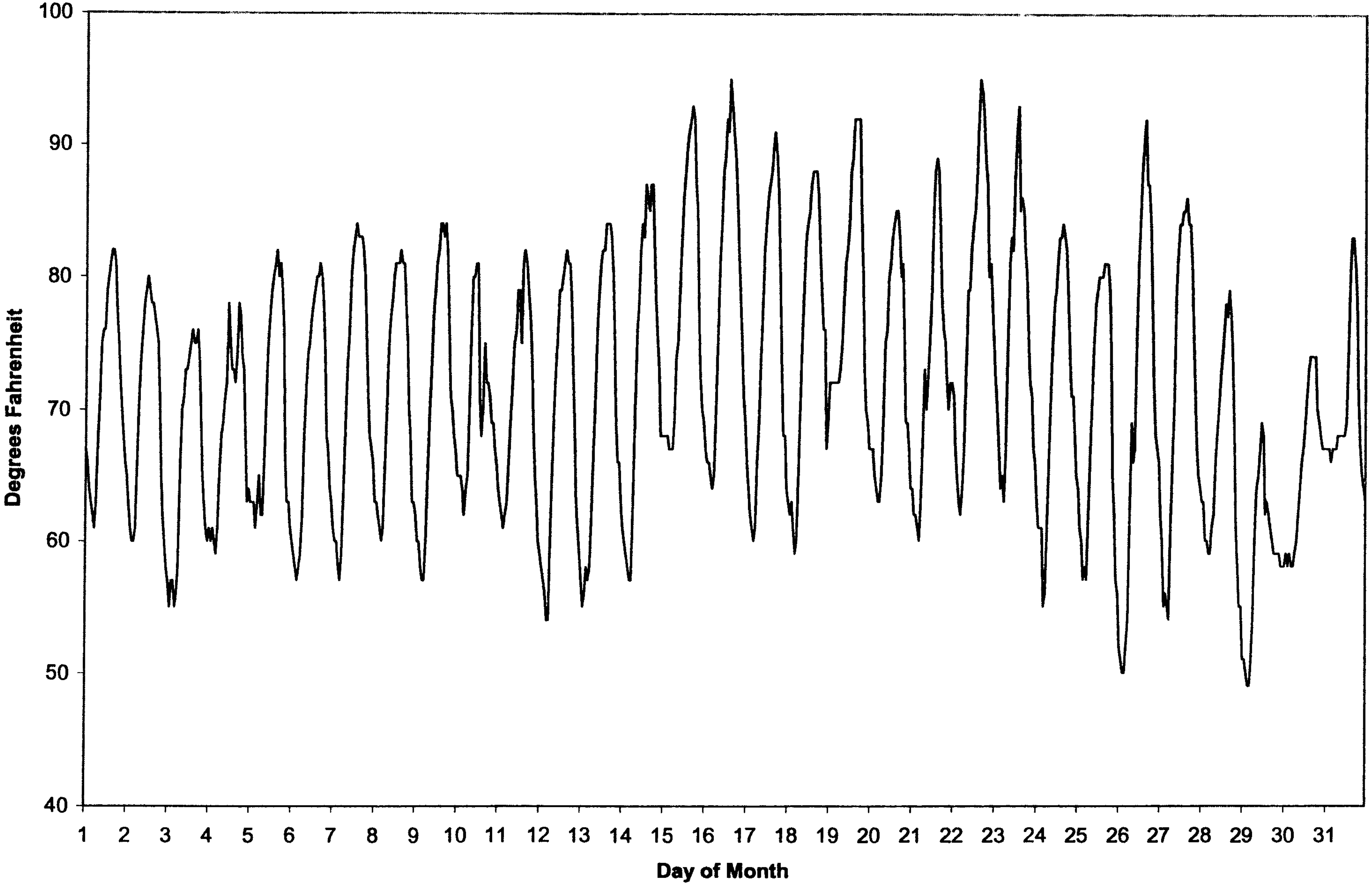

Bismarck
Hourly Temperatures for April 1985
Degrees Fahrenheit
90
80
70
60
50
40
30
20
10
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
Day of Month


Bismarck
Hourly Temperatures for May 1969
Degrees Fahrenheit
100
90
80
70
60
50
40
30
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
Day of Month

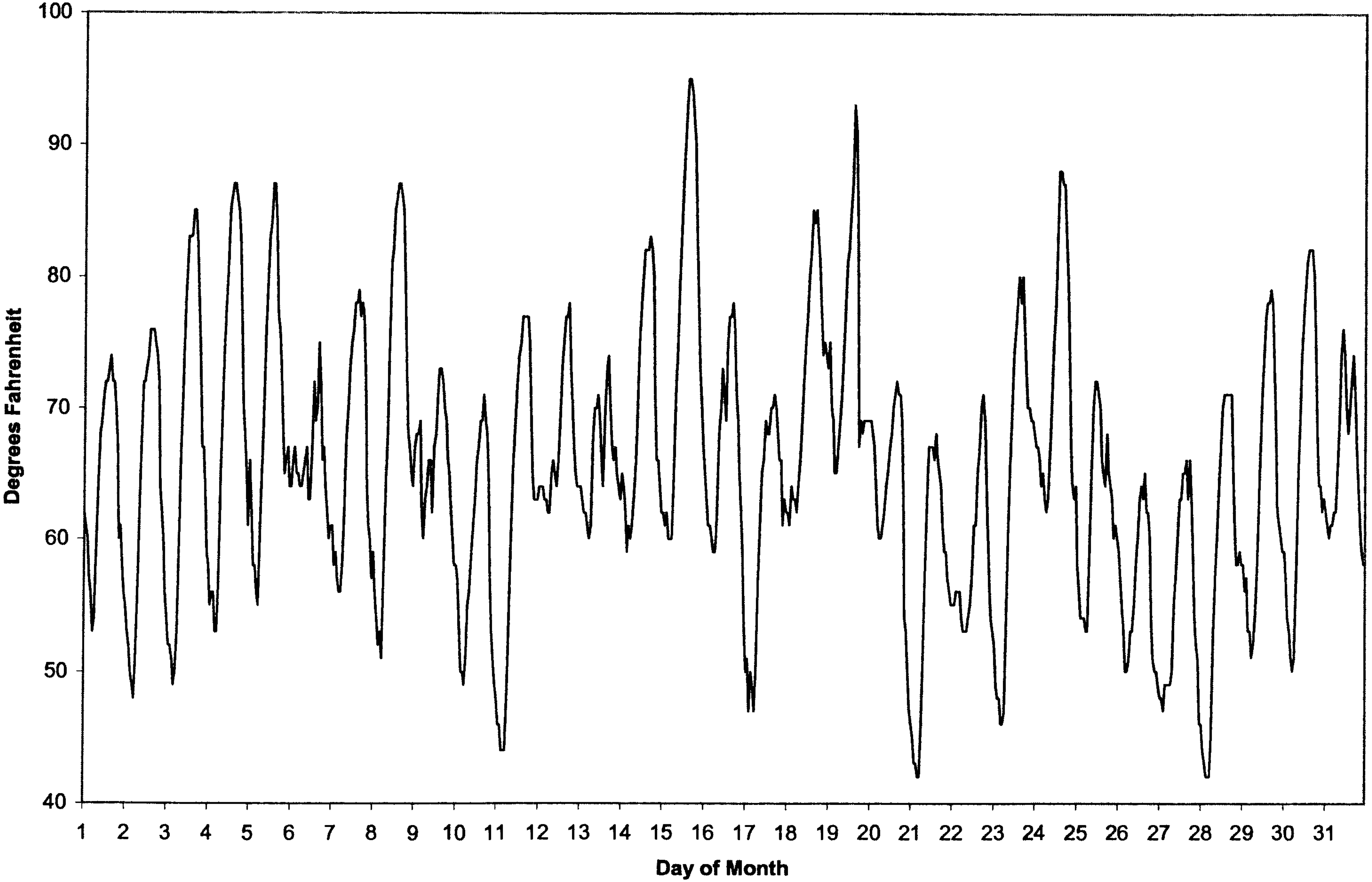
Bismarck
Hourly Temperatures for June 1972



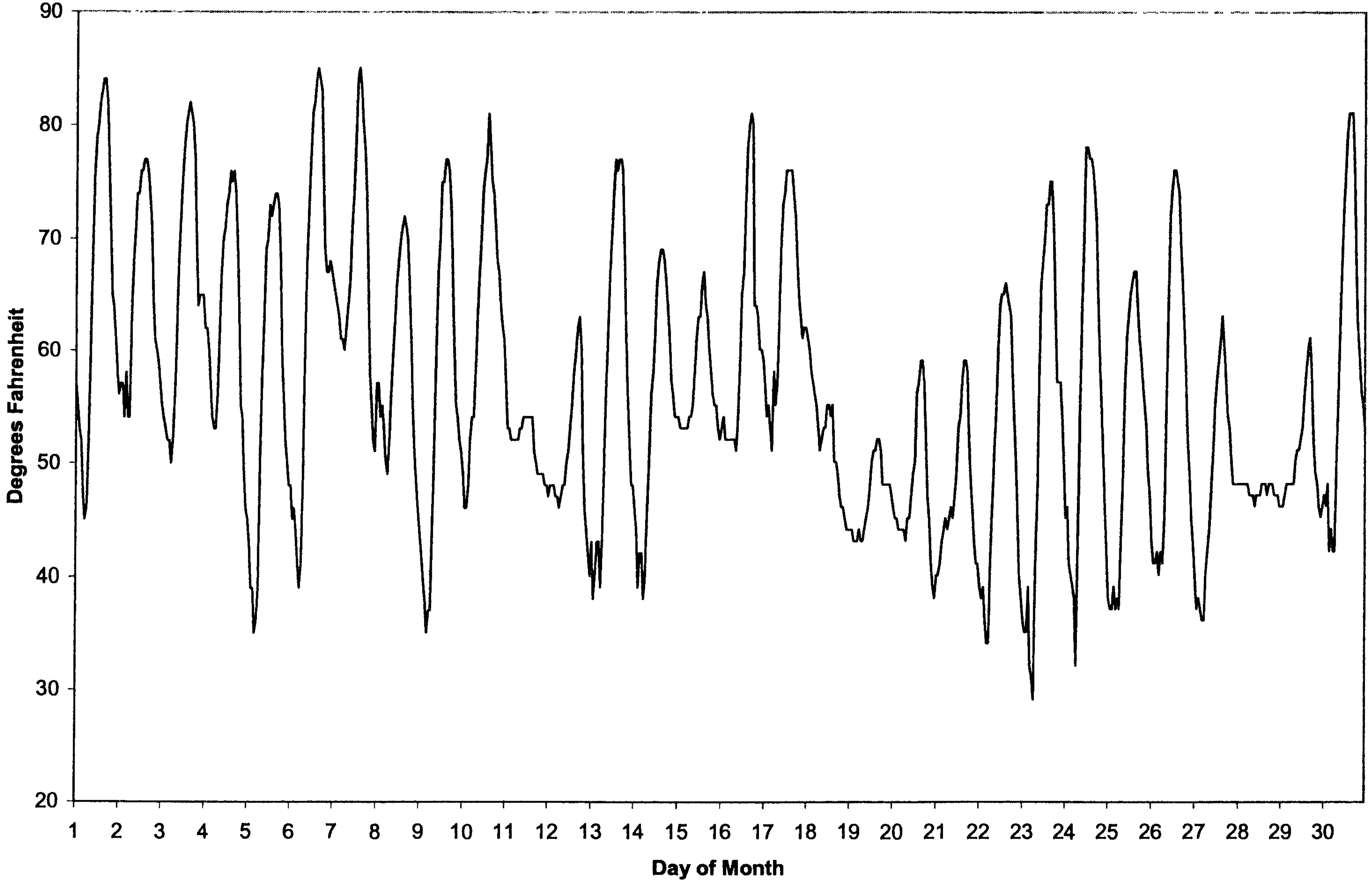
Bismarck
Hourly Temperatures for July 1964



Bismarck
Hourly Temperatures for August 1986

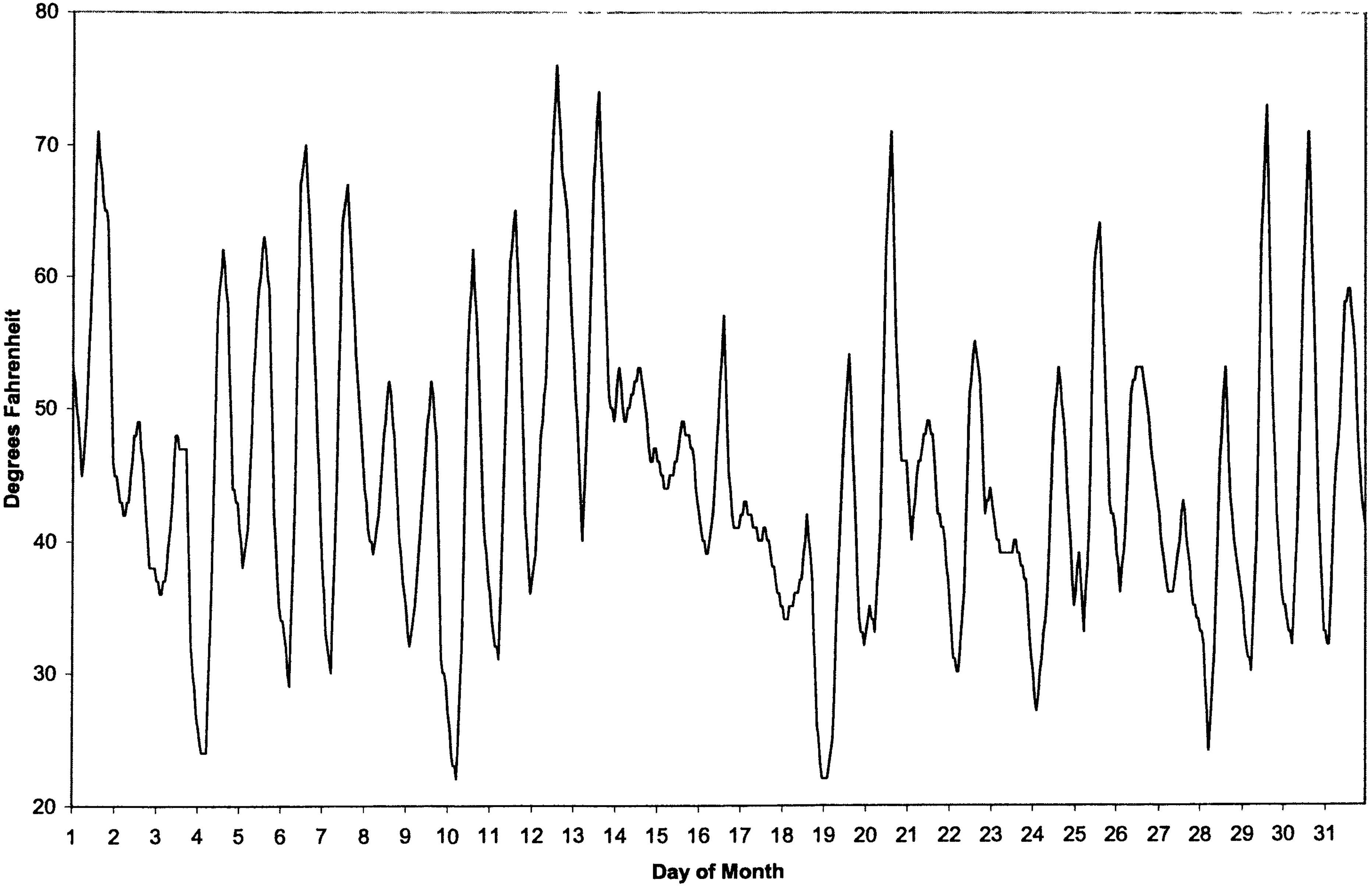


Bismarck
Hourly Temperatures for September 1988

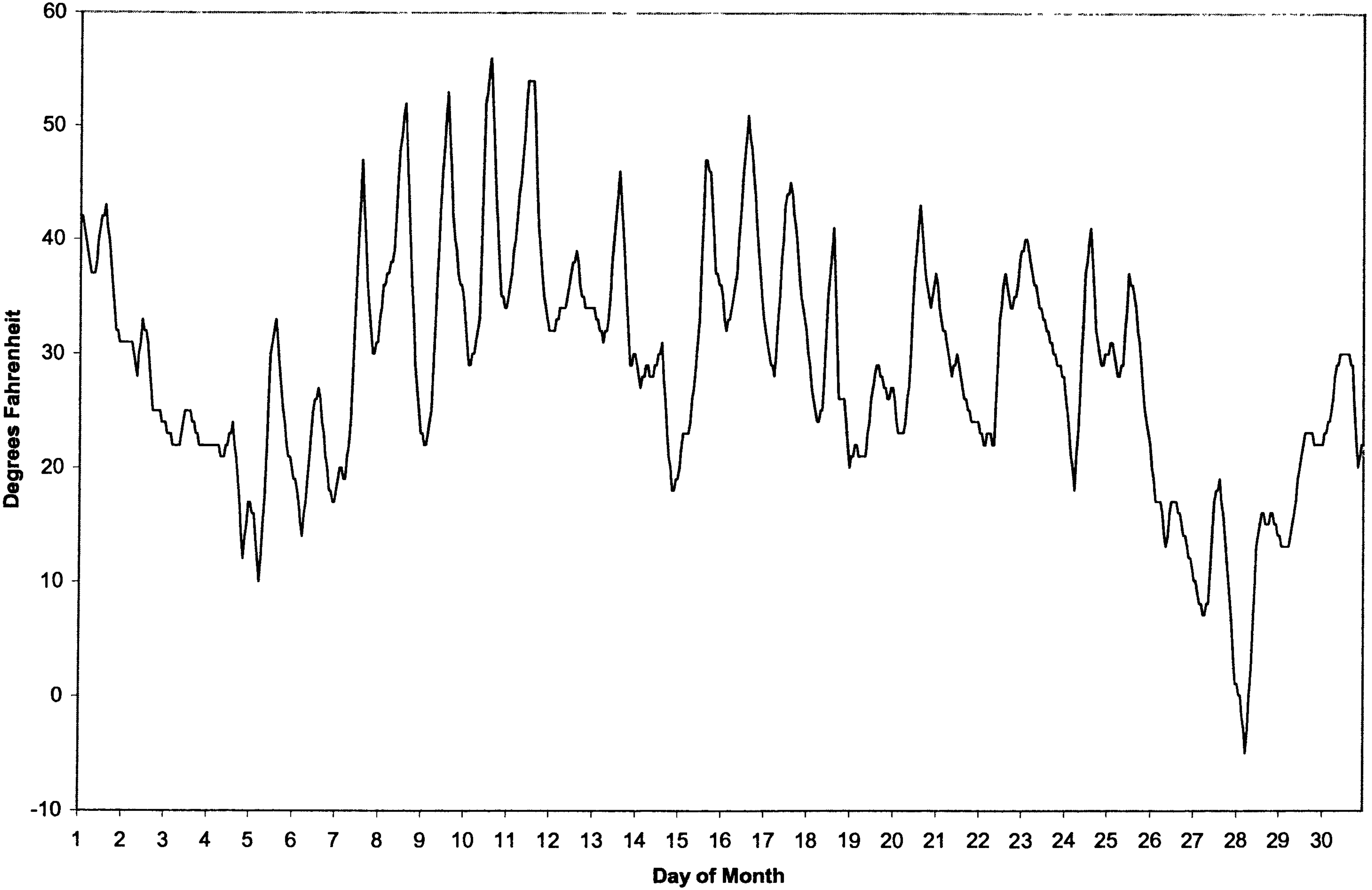


Bismarck

Hourly Temperatures for October 1968

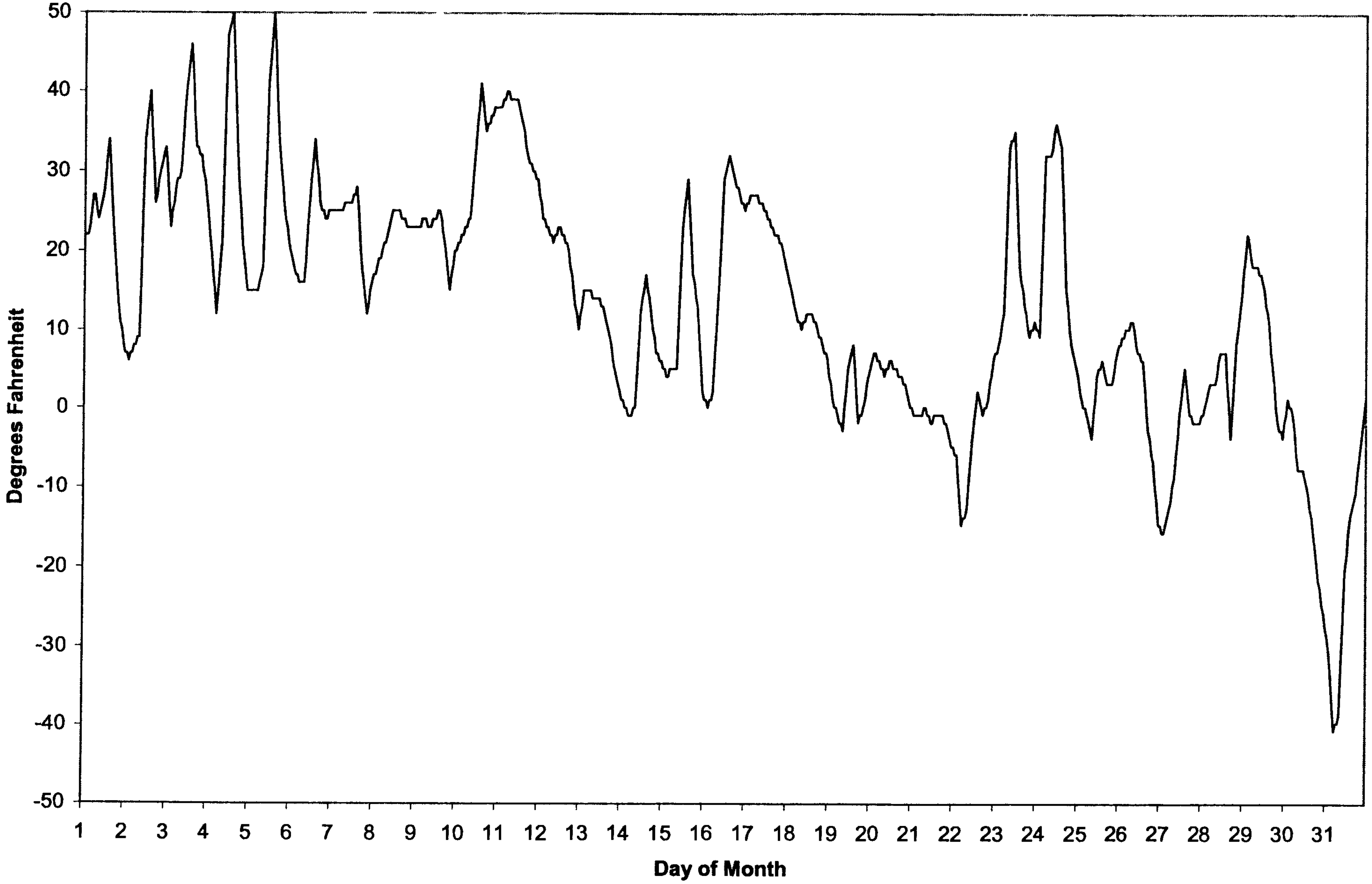


Bismarck
Hourly Temperatures for November 1967



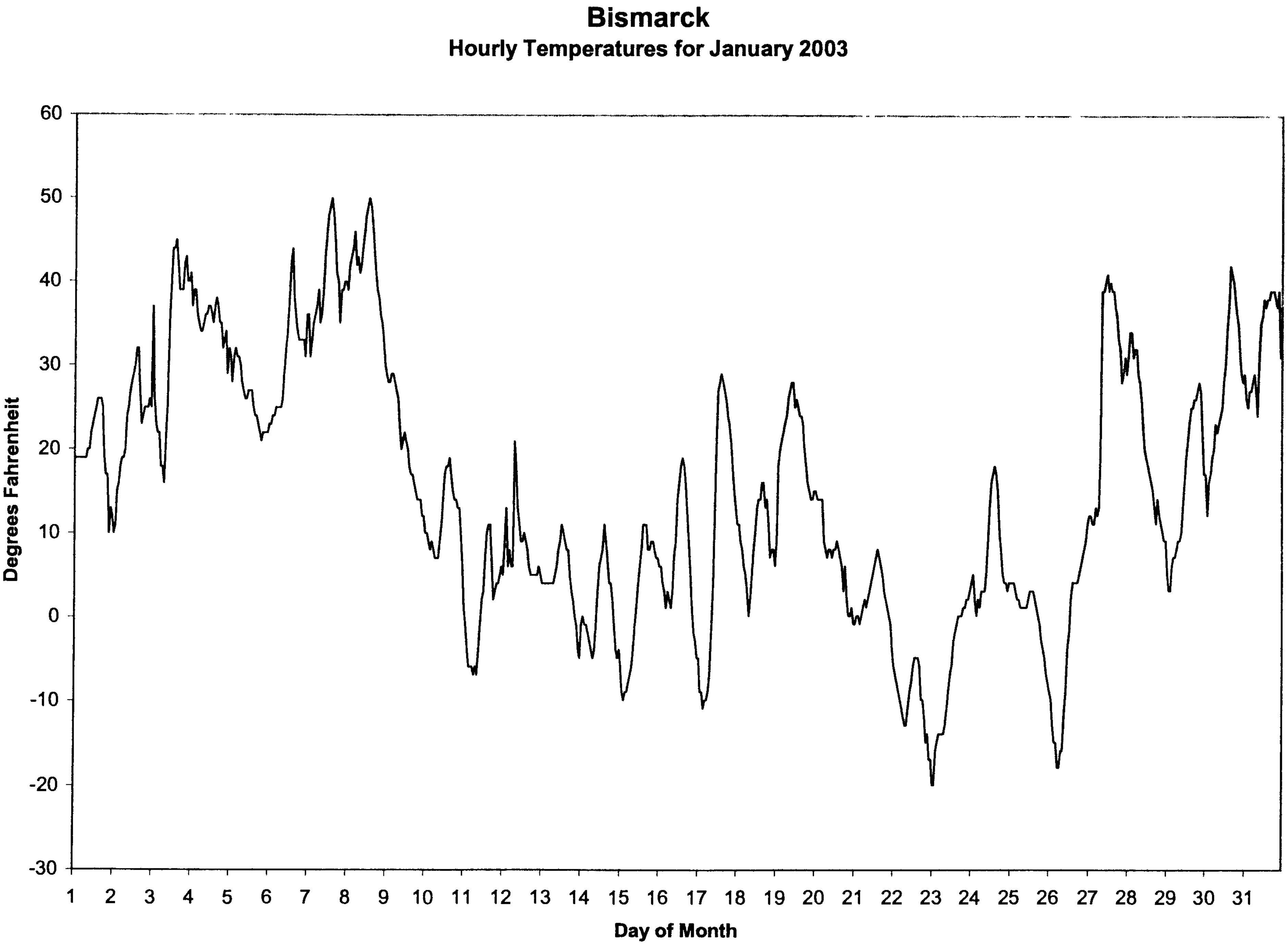
Bismarck

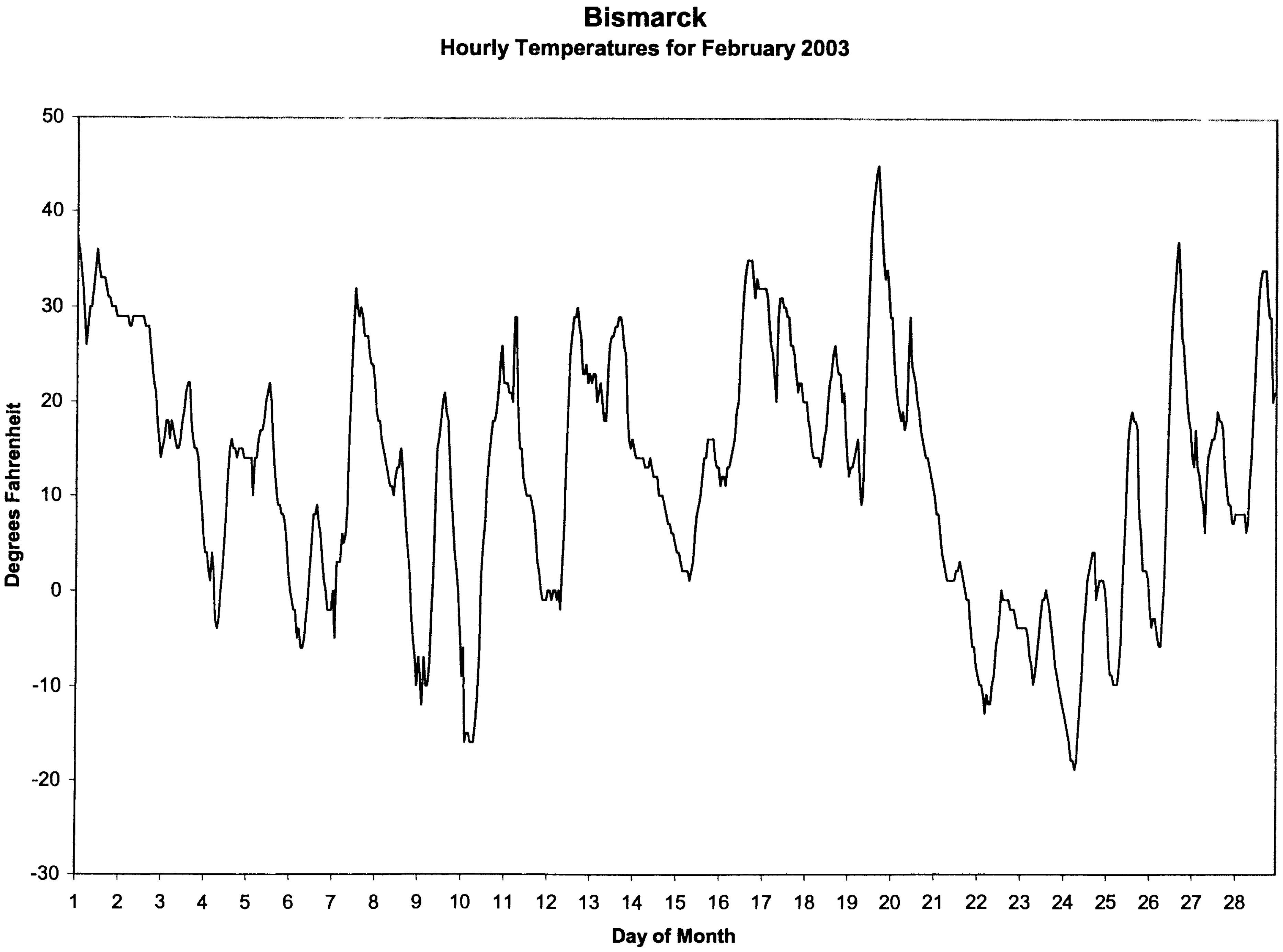
Hourly Temperatures for December 1967



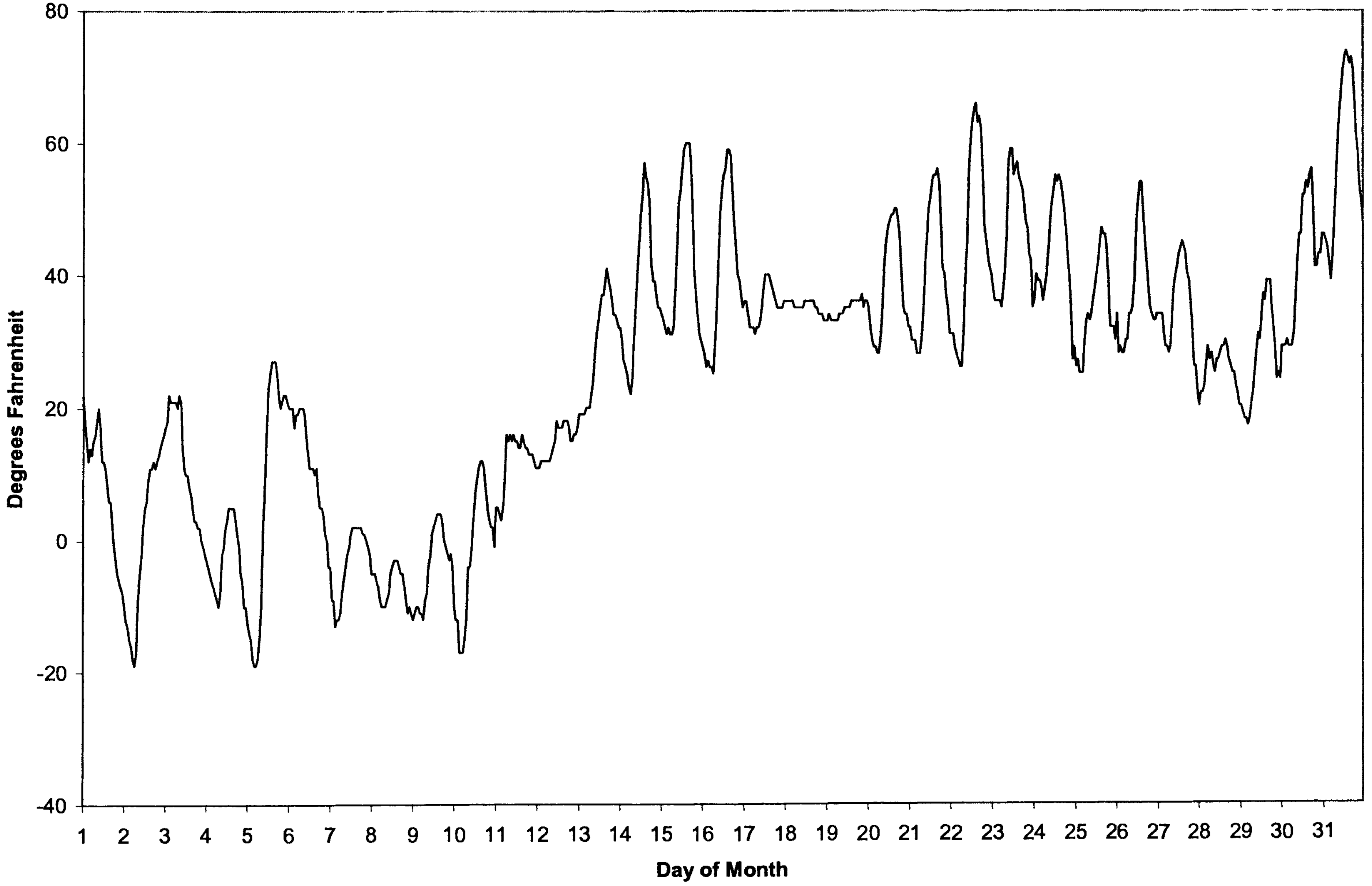
APPENDIX E

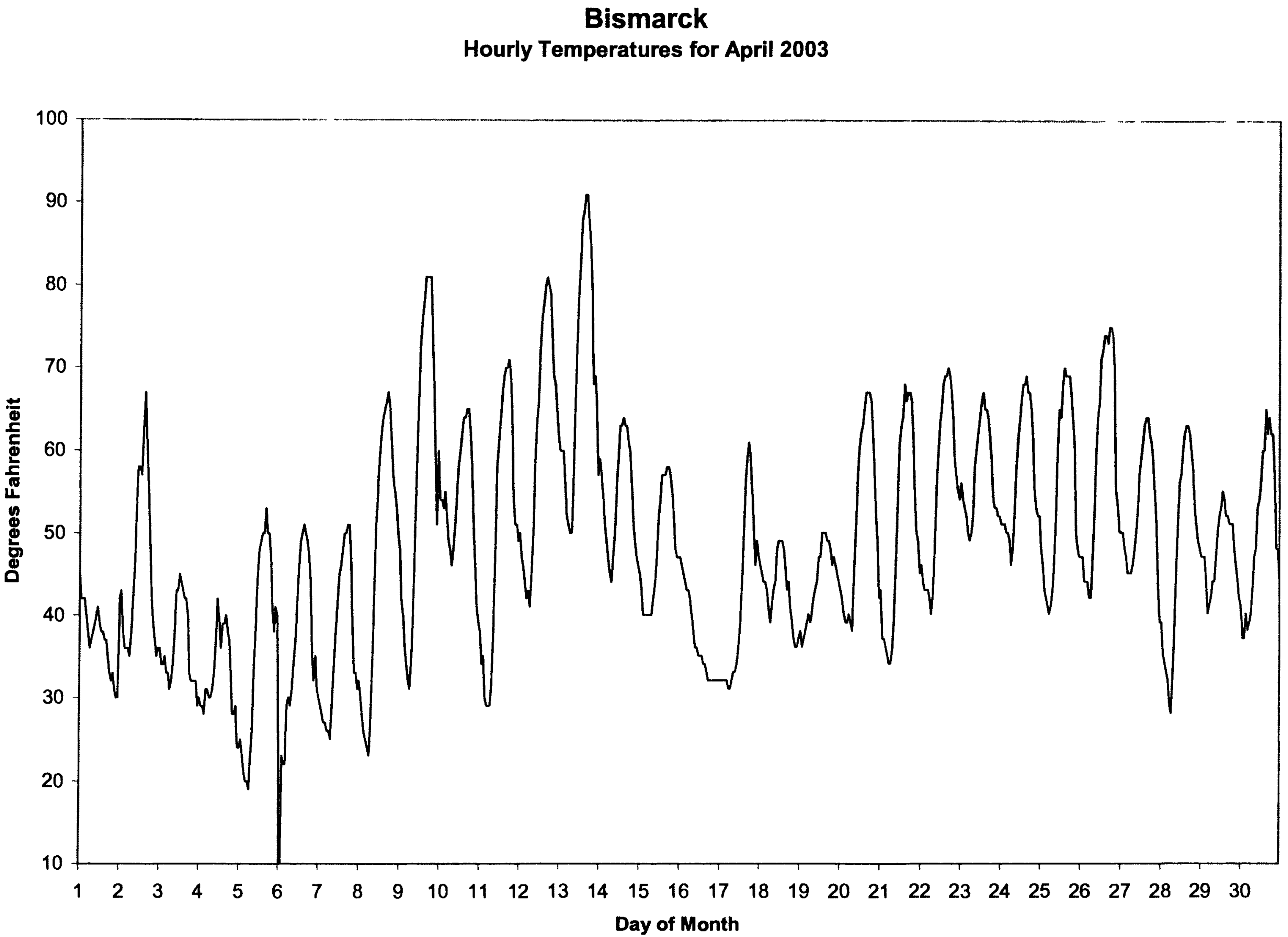
HOURLY TEMPERATURES FOR BISMARCK IN 2003


Bismarck
Hourly Temperatures for January 2003
Degrees Fahrenheit
60
50
40
30
20
10
0
-10
-20
-30
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
Day of Month

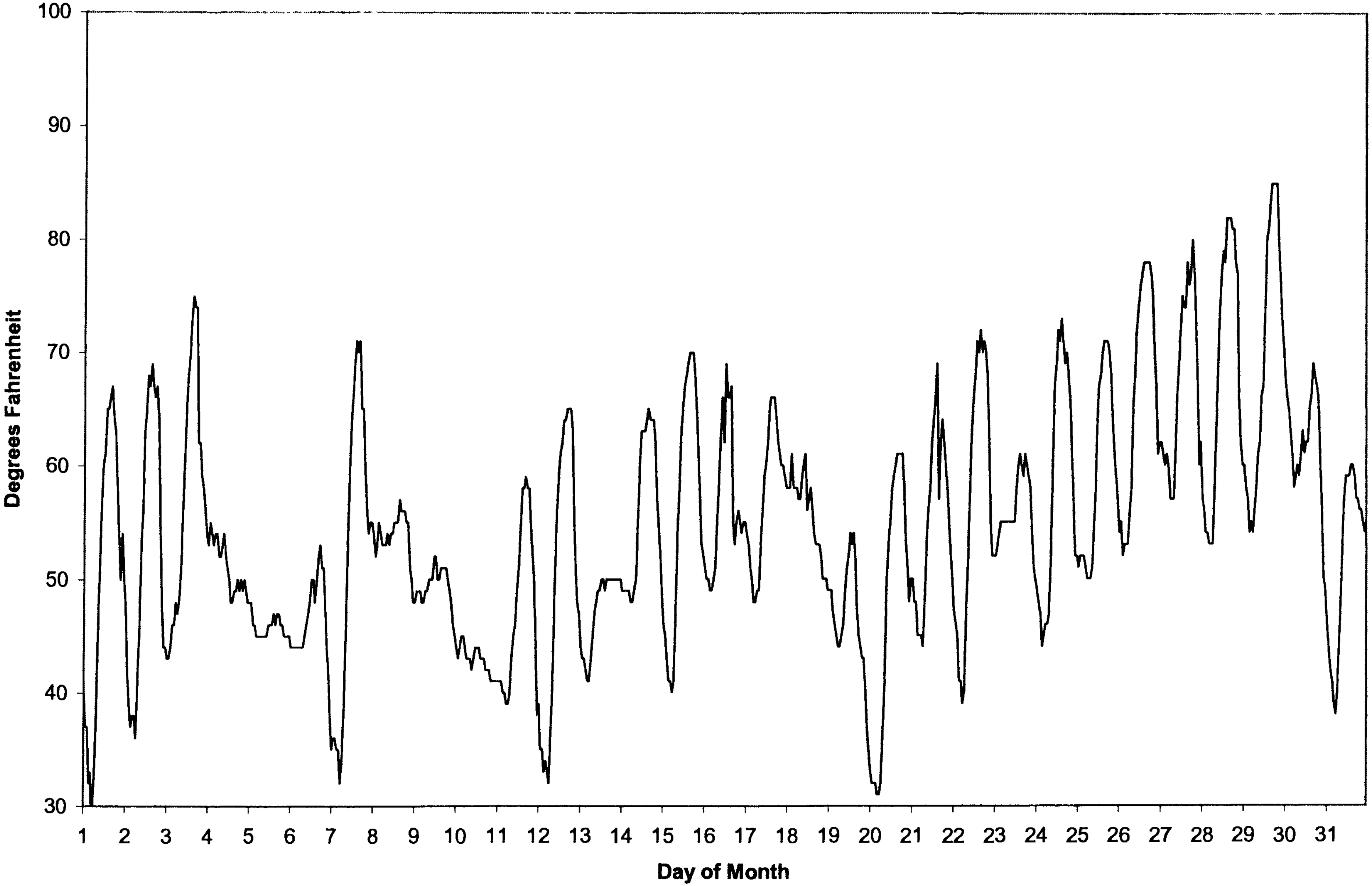

Bismarck
Hourly Temperatures for February 2003
Degrees Fahrenheit
50
40
30
20
10
0
-10
-20
-30
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28
Day of Month

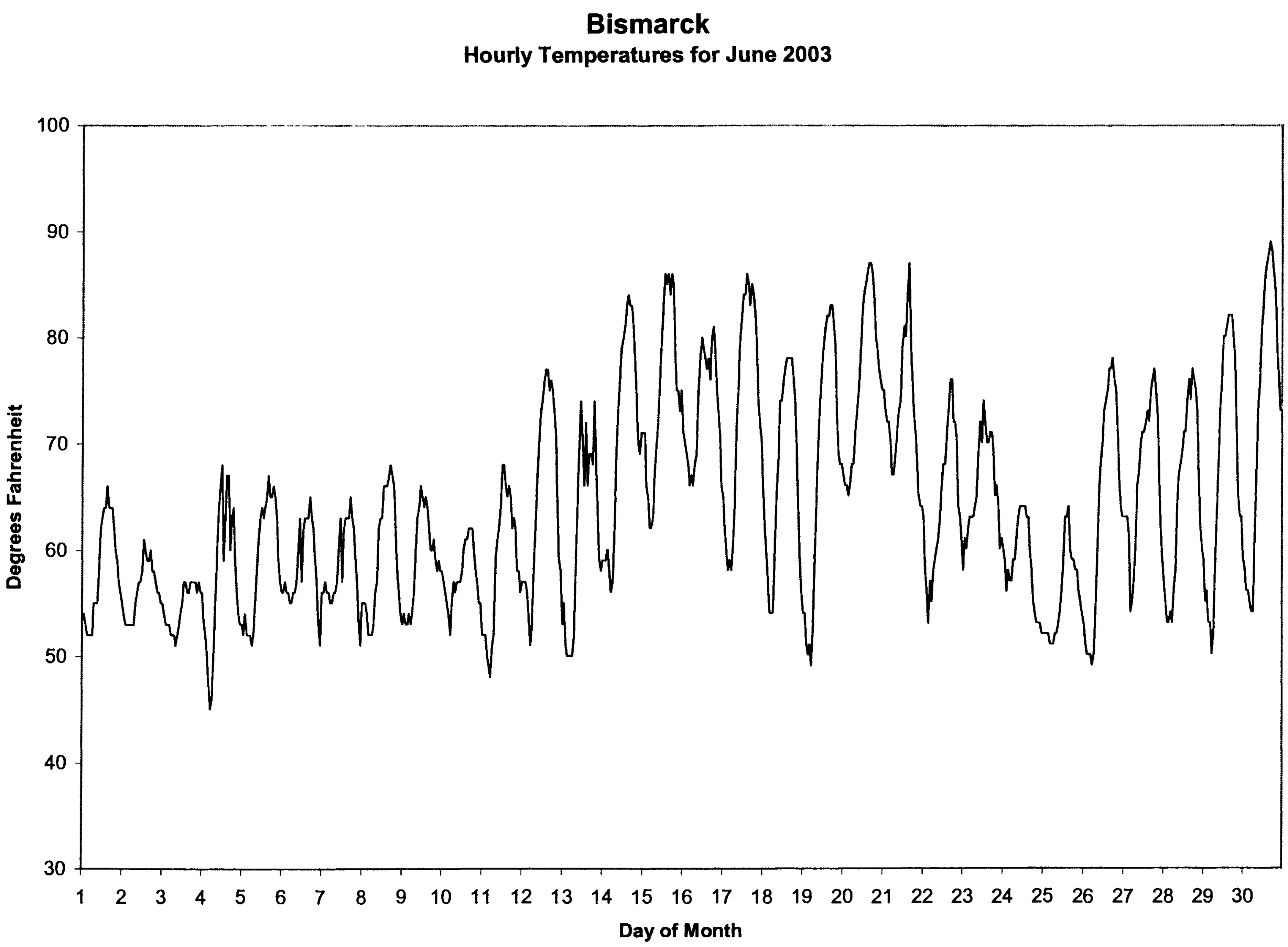
Bismarck
Hourly Temperatures for March 2003



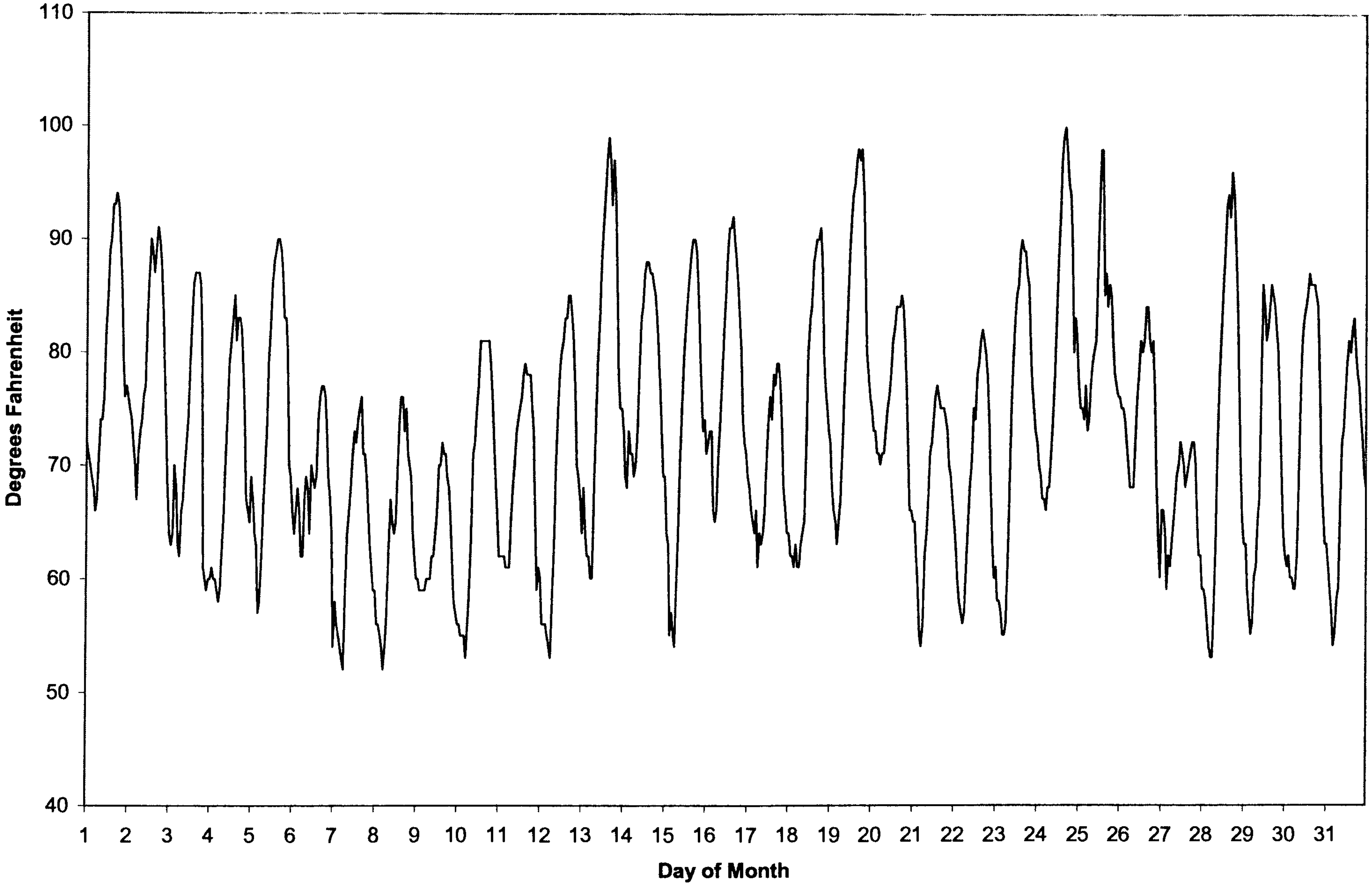

Bismarck
Hourly Temperatures for April 2003
Degrees Fahrenheit
100
90
80
70
60
50
40
30
20
10
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
Day of Month

Bismarck
Hourly Temperatures for May 2003

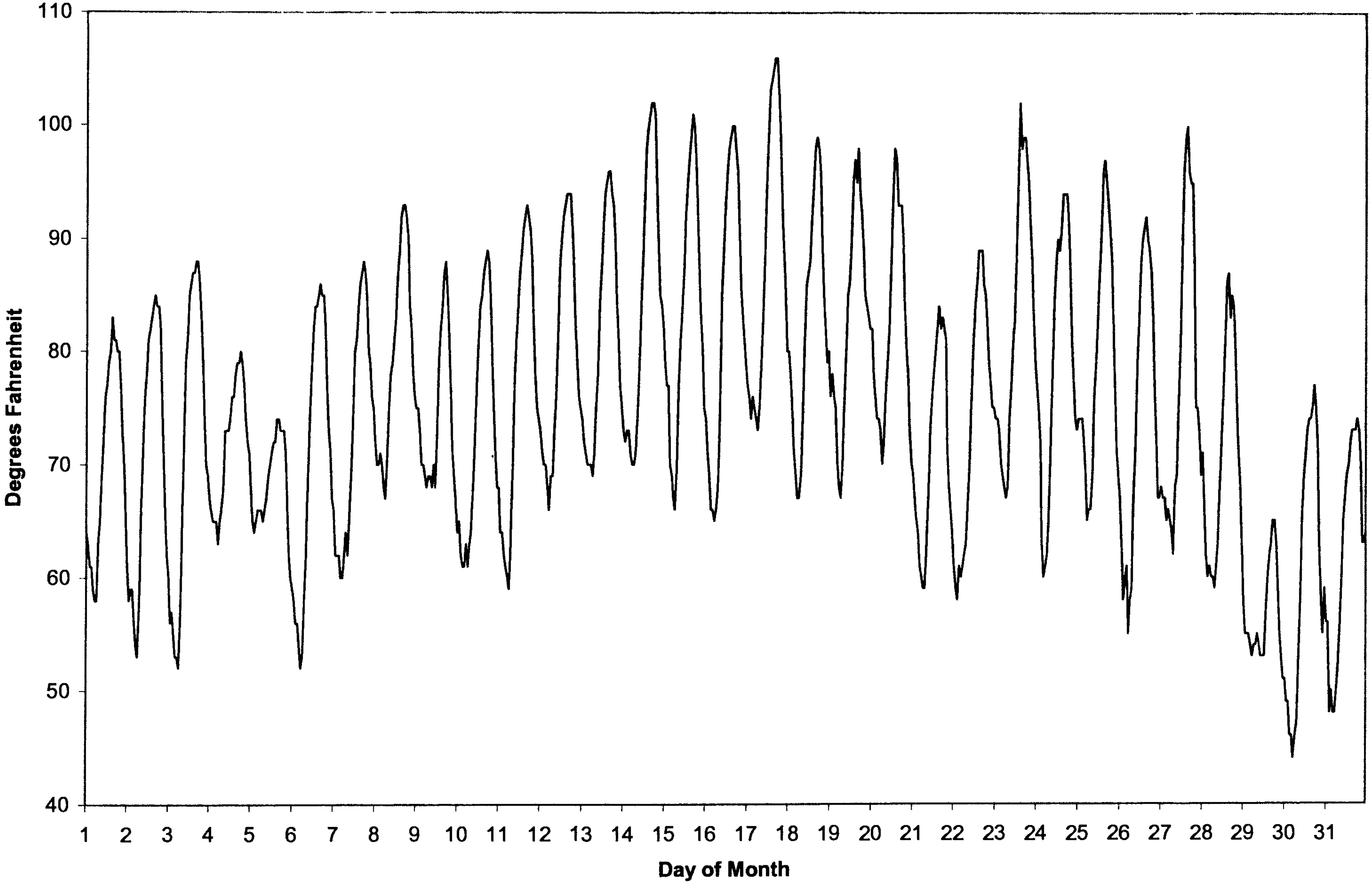



Bismarck
Hourly Temperatures for June 2003
Degrees Fahrenheit
100
90
80
70
60
50
40
30
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
Day of Month

Bismarck
Hourly Temperatures for July 2003

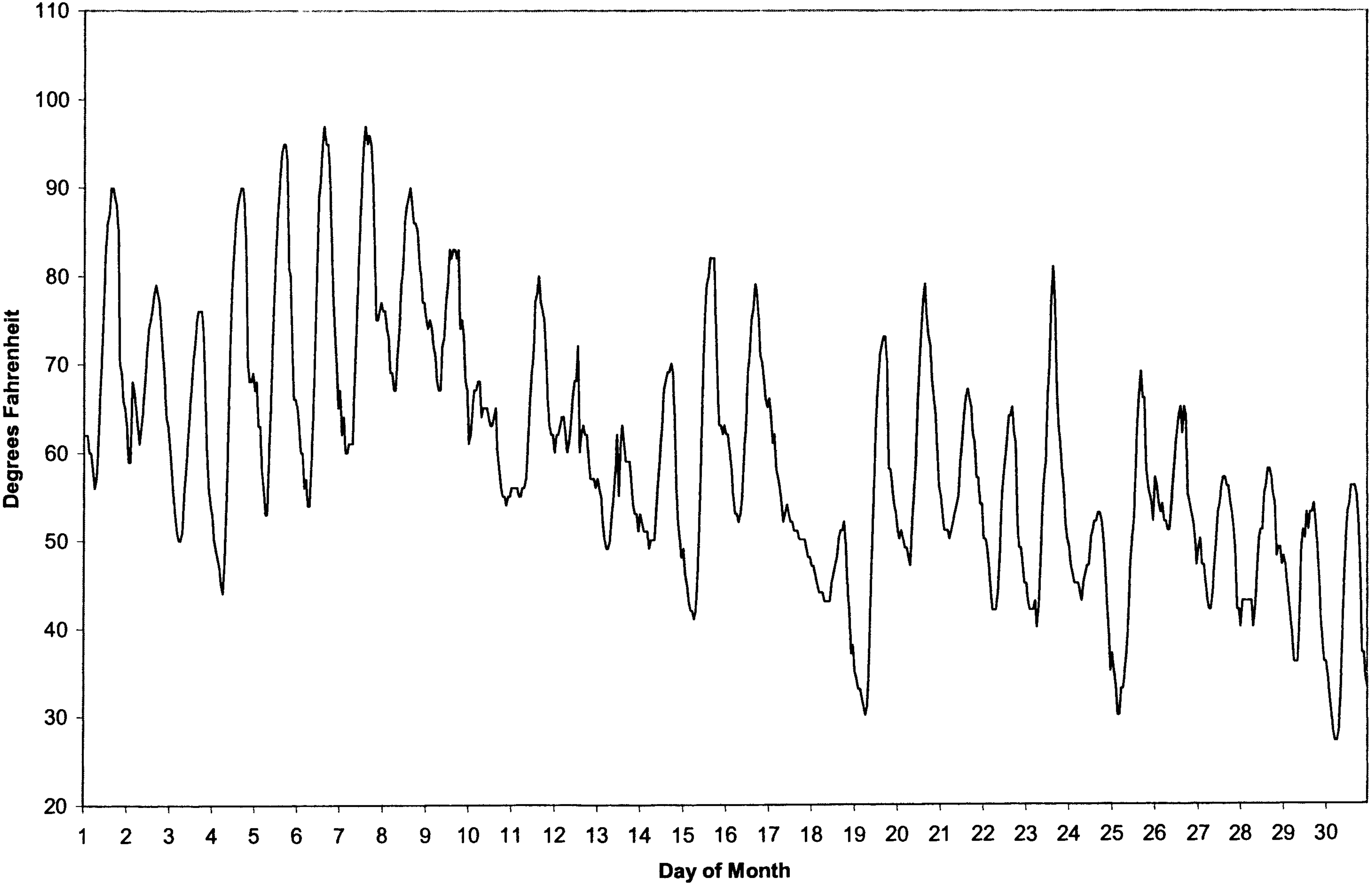


Bismarck
Hourly Temperatures for August 2003

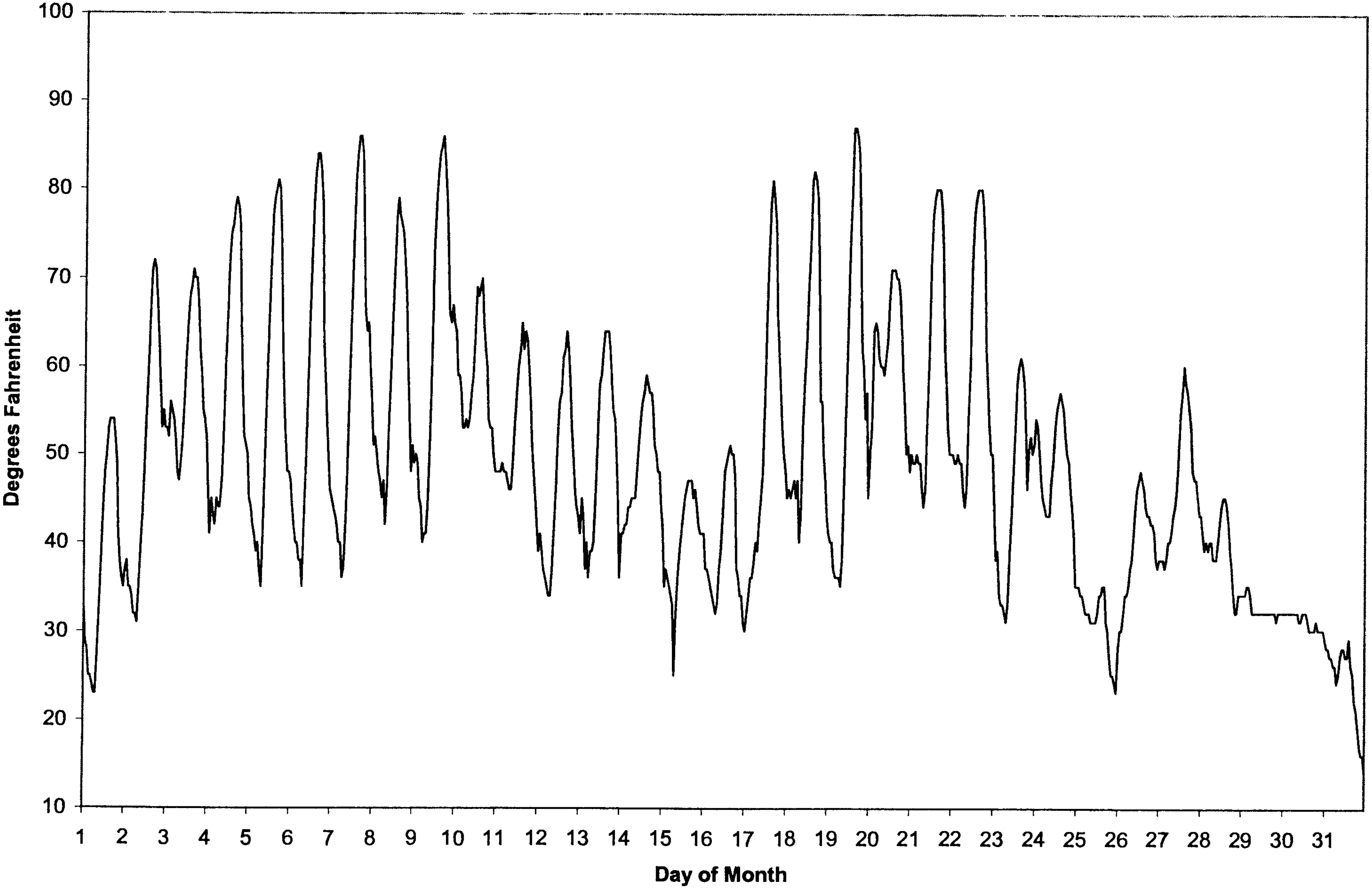


Bismarck

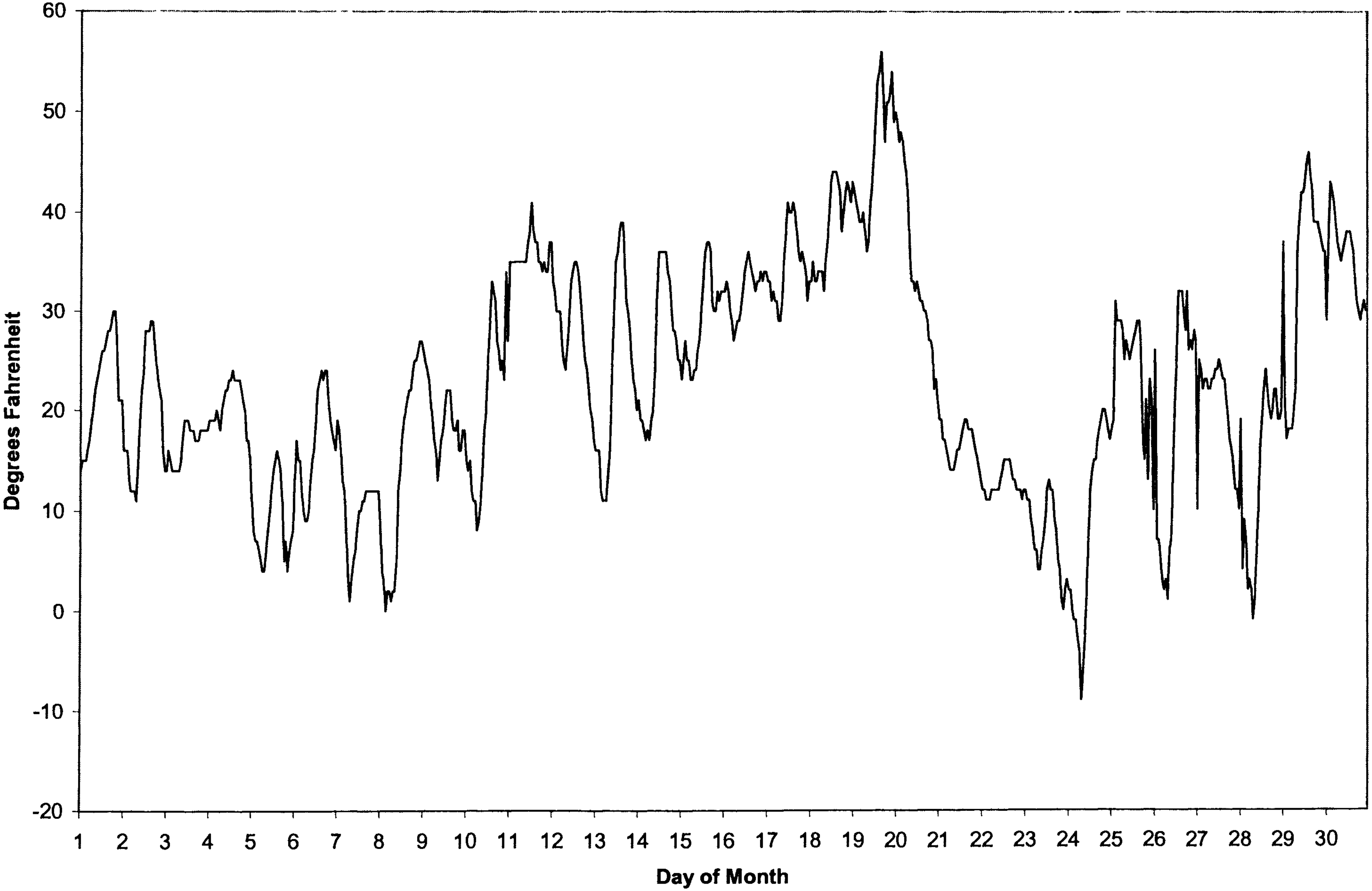
Hourly Temperatures for September 2003



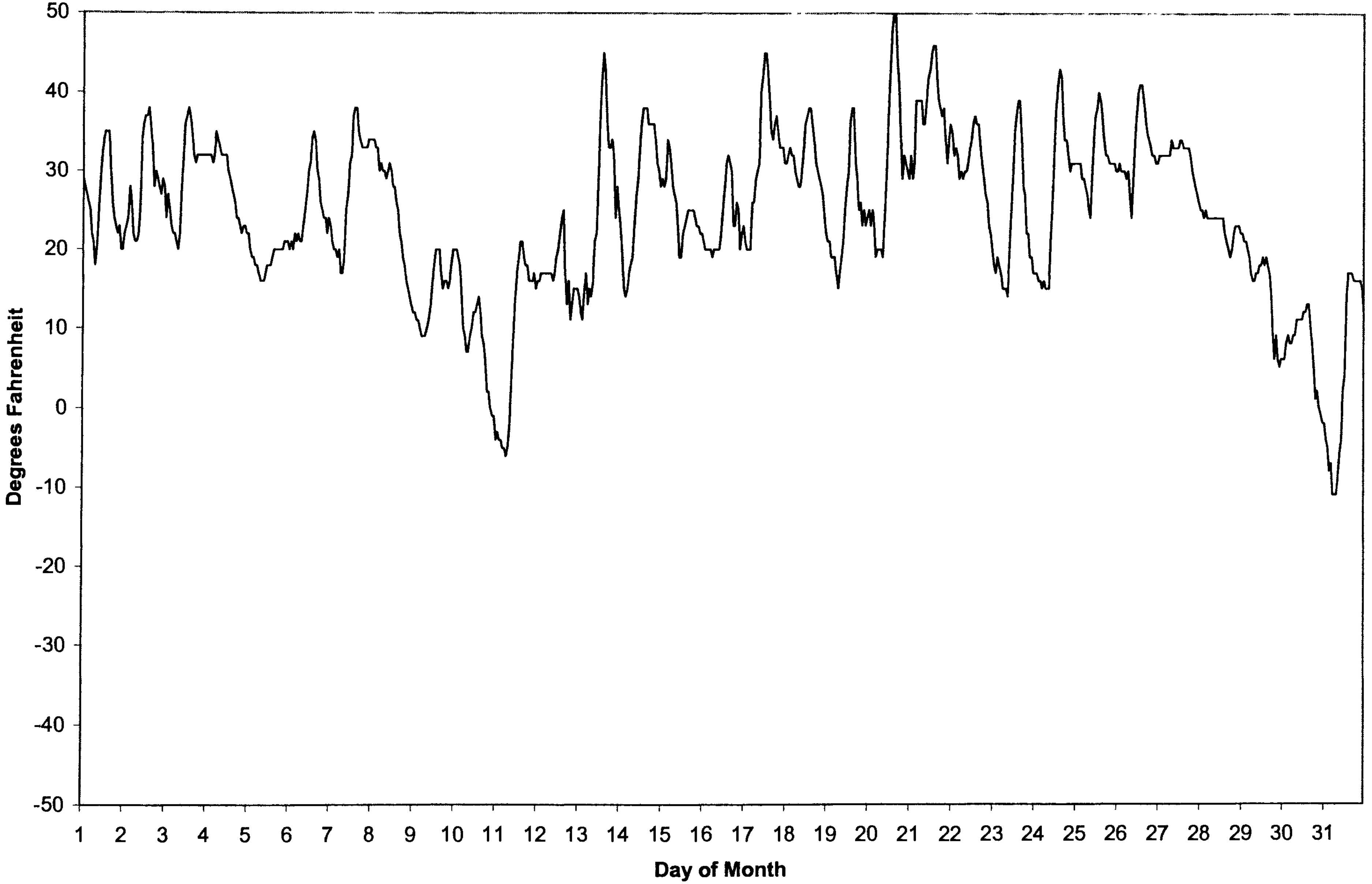
Bismarck
Hourly Temperatures for October 2003



Bismarck
Hourly Temperatures for November 2003



Bismarck
Hourly Temperatures for December 2003



APPENDIX F

DEMAND-SIDE QUALITATIVE ANALYSIS

Residential Energy Audits

Residential customers are continually interested in how they can reduce their electricity bills. Online energy audits can be one way for customers to better understand how they are using energy and what they can do to use it more efficiently. Montana-Dakota would implement an online internet energy audit program that would be linked from Montana-Dakota's web site and provide the customer the opportunity to answer questions regarding their home (for example: demographics, appliances, energy systems and customer practices). In turn, the software would analyze the responses and provide information regarding annual energy costs by home energy system or appliance, monthly energy usage and costs, recommendations for improving home energy efficiency and comfort, estimated cost savings from the implementation of recommendations and links to additional energy consumer information.

Internet energy audits provide a useful tool to residential customers who are interested in reducing the amount of energy they consume in their home. Montana-Dakota has obtained a cost estimate of approximately $50,000 for the license and set-up of an internet audit program with a $10,000 annual maintenance fee for the program.

Although it is difficult to determine how many customers will utilize this program, and even more difficult to determine how many customers will act on the recommendations and implement some conservation measures recommended, this tool would provide the customer an opportunity to evaluate their energy consumption and provide the company an opportunity to educate the consumer on conservation and energy utilization. It is recommended that Montana-Dakota pursue the evaluation of offering an internet audit survey to the residential customer base in order to provide a value added customer service and energy conservation education to the consumer.

Commercial Energy Audits

Commercial customers are continually looking for ways to reduce the cost of their operations and an energy audit can be one way to provide useful information in order to reach their goals and reduce their operational costs. Due to the diverse characteristics of Montana-Dakota's commercial customers the audits can range from being straightforward to very complex in nature. Energy audits would be offered to Montana-Dakota's commercial customer base and promoted through the local Montana-Dakota representative. Requests for audits would be screened to determine if resources are available to conduct the audit internally in a timely manner. If it is determined that a Montana-Dakota representative could not complete the audit in a timely manner, Montana-Dakota would contract with a third party administrator to conduct the audit. Commercial energy audits, of this type, typically cost approximately $.05 per square foot with a minimum of $500 for buildings that are less than 10,000 square feet. All audit results would be delivered to the customer by a Montana-Dakota representative.

As stated earlier in the residential audit program, it is difficult to determine the participation levels for a program such as this and even more difficult to determine if the customer will implement the recommendations, therefore it is difficult to quantify any demand-side saving associated with an audit program. From a consumer education standpoint this program could be very beneficial to the consumer and the company. It is recommended that Montana-Dakota pursue the evaluation of implementing a commercial energy audit program to its customer base.

ENERGY STAR® Partnership

ENERGY STAR® is a government-backed program helping businesses and individuals protect the environment through superior energy efficiency. ENERGY STAR® provides a powerful platform for utilities implementing energy efficiency programs to make a bigger difference in their communities. ENERGY STAR® provides tools and strategies that organizations can use to reduce program costs and implementation timelines. In order to become an ENERGY STAR® partner, Montana-Dakota must sign a partnership agreement and submit an action plan outlining specific ENERGY STAR® initiatives the company will undertake. These initiatives can include such things as advertising, consumer education, incentives programs, and training to name a few. According to the ENERGY STAR® web site, in 2004 alone Americans (with the help of ENERGY STAR®) saved enough energy to power 24 million homes and avoided greenhouse gas emissions equivalent to those from 20 million cars – all while saving $10 billion.

The cost associated with becoming an ENERGY STAR® partner is completely dependent on what type of initiatives are developed and filed with the ENERGY STAR® partnership commitment. It is recommended that Montana-Dakota pursue forming a partnership with ENERGY STAR® and evaluate the specific initiatives the company would like to undertake as an ENERGY STAR® partner.

Load Management Rates

Montana-Dakota currently offers an Optional Time-Of-Day General Electric Service Rate (Rate 31) and an Interruptible Large Power Service Rate (Rate 39) to its North Dakota customers. These rates are designed to provide the customer lower rates in turn for them shifting their use to off-peak hours or interrupting their electric service during peak load conditions. These Load Management Rates provide the company an opportunity to reduce peak demand and shift the load to off-peak time periods (valley filling).

It is recommended that Montana-Dakota continue to offer Load Management Rates to qualifying customers as filed.

Proper Air Conditioner Sizing Training Seminars

Air conditioning load accounts for approximately 13% of total home energy expenses on average. Therefore, a right-sized air conditioner is an important part of an energy-efficient home and will result in improved comfort, durability and lower utility bills. It is common for contractors to install oversized air conditioners because oversized units provide instant cooling and avoid the chance of not meeting the cooling demand in the home. Oversized air conditioners tend to "short-cycle" or run for shorter periods of time than engineered for optimum operation. Air conditioners are at low efficiency when they first start and increase their efficiency gradually usually reaching peak efficiency in about 10 minutes. If a customer purchases an oversized air conditioner, they will be incurring the additional cost of a larger unit, paying more for their utility bill and reduce the comfort in their home due to the unit not being able to properly dehumidify the home. Oversized air conditioning units also create additional peak-load requirements for the utility. Montana-Dakota could benefit from providing training seminars to contractors regarding how to properly size air conditioning. Although it is difficult to determine if the contractors would actually use this training when they are sizing air conditioners for customers, it may provide an opportunity to provide Montana-Dakota's electric consumers to utilize their energy in a more efficient manner as well as provide additional comfort and less cost. Along with these benefits to the customer, it may also reduce Montana-Dakota's peak demand requirements by avoiding the continued installation of oversized air conditioners that run less efficiently. Montana-Dakota would propose to offer a total of five training sessions, throughout the service territory, in early spring. It is estimated that these training sessions will cost approximately $15,000.

It is recommended that Montana-Dakota pursue the evaluation of offering Proper Air Conditioner Sizing Training to contractors within the service territory.

APPENDIX G

DEMAND-SIDE PROGRAM DATA

Energy Star Clothes Washer Program
Quantitative DSM # 1

Customer Class:	Residential	*Electric Water Heating Only*

Cost MDU

	$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Cost	$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 30	$ 15,882	$ 15,882	$ 15,882	$ 47,647
Admin & Advertising	$ 9	$ 5,000	$ 5,000	$ 5,000	$ 15,000
Total Cost	**$ 39**	**$ 20,882**	**$ 20,882**	**$ 20,882**	**$ 62,647**

Notes

Admin & Advertising is estimated at $5,000 per year

Participant Costs (Incremental Cost Basis)

Avg Cost of Standard Efficiency Model	$ 450	Per DOE 2004
Avg Cost of Energy Star Model	$ 750	Per DOE 2004
.	$ 300	

Participation Rate Calc

	% of Cust	Cust	
Total Customers is Class	100 00%	85,712	
Customer with Clothes Washers	92 65%	79,412	Per Customer Survey

Total Clothes washers Available for program	79,412		
Total Estimated Saturation Percentage	2.0%		
Part Rate	1,588	1.85%	Of total Customer Base
Participation Year 1	529		
Participation Year 2	529		
Participation Year 2	529		

Energy Savings Calculation

Clothes Washer Data	kw Conn	Annual kWh	Utilization Factor	
Conventional	0 469	615	10%	Savings is Driven by Reduce Water Consumption
Energy Star	0.192	254	10%	Savings is based on Energy Star Calculator
Energy Savings	**0.277**	**361**		
		Per Part		
Peak Demand Reduction		0.028		
Winter Demand Reduction		0.028		
Summer Energy Reduction		120		
Winter Energy Reduction		241		

** Note water & detergent savings is estiamted at $35 per year (7,000 gallons) entered as Other Part Costs (neg)

Energy Star Dishwasher Program
Quantitative DSM # 2

Customer Class:	Residential	*Electric Water Heating Only*

Cost MDU

	$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Cost	$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 10	$ 3,221	$ 3,221	$ 3,221	$ 9,663
Admin & Advertising	$ 16	$ 5,000	$ 5,000	$ 5,000	$ 15,000
Total Cost	**$ 26**	**$ 8,221**	**$ 8,221**	**$ 8,221**	**$ 24,663**

Notes
Admin & Advertising is estimated at $5,000 per year

Participant Costs (Incremental Cost Basis)

Avg Cost of Standard Efficiency Model	$ 450	Per DOE 2004
Avg Cost of Energy Star Model	$ 500	Per DOE 2004
.	**$ 50**	

Participation Rate Calc

	% of Cust	Cust	
Total Customers is Class	100 00%	85,712	
Customer with Automatic Dishwashers	56 37%	48,316	Per Customer Survey

Total Dishwashers Available for program	48,316		
Total Estimated Saturation Percentage	2 0%		
Part Rate	966	1 13%	Of total Customer Base
Participation Year 1	322		
Participation Year 2	322		
Participation Year 2	322		

Energy Savings Calculation

Dishwasher Data	kw Conn	Annual kWh	Utilization Factor	
Conventional	0	439	20%	Savings is Driven by Reduce Water Consumption
Energy Star	0	336	20%	Savings is based on Energy Star Calculator
Energy Savings	**0**	**103**		
		Per Part		
Peak Demand Reduction		0.000		
Winter Demand Reduction		0.000		
Summer Energy Reduction		34		
Winter Energy Reduction		69		

**** Water savings is estimated at 500 gallons per year! Not used in model as savings insignificant at $1 75/yr/part

Energy Star Refrigerators Program
Quantitative DSM # 3

Customer Class:	Residential

Cost MDU

	$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Cost	$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 10	$ 5,714	$ 5,714	$ 5,714	$ 17,142
Admin & Advertising	$ 9	$ 5,000	$ 5,000	$ 5,000	$ 15,000
Total Cost	**$ 19**	**$ 10,714**	**$ 10,714**	**$ 10,714**	**$ 32,142**

Notes

Admin & Advertising is estimated at $5,000 per year

Participant Costs (Incremental Cost Basis)

Avg Cost of Standard Efficiency Model	$ 700
Avg Cost of Energy Star Model	$ 730
Increased cost of Higher Eff Model	**$ 30**

G-3

Participation Rate Calc

	% of Cust	Cust
Total Customers is Class	100.00%	85,712

Total Refrigerators Available for program	85,712	
Total Estimated Saturation Percentage	2 0%	
Part Rate	1,714	2 00% Of total Customer Base
Participation Year 1	571	
Participation Year 2	571	
Participation Year 2	571	

Energy Savings Calculation

Refrigerators Data	kw Conn	Annual kWh	Utilization Factor	
Conventional	0 8	484	35%	18 Cu Ft Top Freezer ice maker
Energy Star	0 68	410	35%	As per survey results 83% for FF
Energy Savings	0.12	74		
		Per Part		
Peak Demand Reduction		0.042		
Winter Demand Reduction		0 042		
Summer Energy Reduction		25		
Winter Energy Reduction		49		

Energy Star Freezers Program
Quantitative DSM # 4

Customer Class:	Residential

Cost MDU

	$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Cost	$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 10	$ 4,400	$ 4,400	$ 4,400	$ 13,200
Admin & Advertising	$ 11	$ 5,000	$ 5,000	$ 5,000	$ 15,000
Total Cost	**$ 21**	**$ 9,400**	**$ 9,400**	**$ 9,400**	**$ 28,200**

Notes
Admin & Advertising is estimated at $5,000 per year

Participant Costs (Incremental Cost Basis)

Avg Cost of Standard Efficiency Model	$ 329	22 Cu ft Chest Manual DF
Avg Cost of Energy Star Model	$ 362	23 Cu ft Chest Manual DF
Increased cost of Higher Eff Model	**$ 33**	

G-4

Participation Rate Calc

	% of Cust	Cust	
Total Customers is Class	100 00%	85,712	
Customer with Freezers	77 00%	65,998	Per Customer Survey

Total Freezers Available for program	65,998		
Total Estimated Saturation Percentage	2.0%		
Part Rate	1,320	1.54%	Of total Customer Base
Participation Year 1	440		
Participation Year 2	440		
Participation Year 2	440		

Energy Savings Calculation

Freezer Data	kw Conn	Annual kWh	Utilization Factor	
Conventional Freezer	0 9	546	35%	22 Cu ft Chest Manual DF
Energy Star Freezer	0.8	491	35%	
Energy Savings	0 1	55		
		Per Part		
Peak Demand Reduction		0 035		
Winter Demand Reduction		0.035		
Summer Energy Reduction		18		
Winter Energy Reduction		37		

Residential High Efficiency A/C (Energy Star Rated)
Quantitative DSM # 5

Customer Class:	Residential

Cost MDU

			$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Costs			$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 180.00	Incentive	$ 180	$ 66,142	$ 66,142	$ 66,142	$ 198,425
Admin & Advertising			$ 14	$ 5,000	$ 5,000	$ 5,000	$ 15,000
Total Cost			**$ 194**	**$ 71,142**	**$ 71,142**	**$ 71,142**	**$ 213,425**

Notes

Admin is estimated at $5,000 per year for MDU

Incentive is $60 per ton

Participant Costs (Incremental Cost Basis)		
Cost of STD Eff Model (10 SEER)	$ 1,100	3 Ton Armstrong Unit
Cost of High Efficiency Model (14 SEER)	$ 1,900	3 Ton Unit
Increased cost of Higher Eff Model	**$ 800**	

Participation Rate Calc

	% of Cust	Cust	
Total Customers is Class	100 00%	85,712	
Total Customers With Central AC	50 64%	43,405	Per Customer Survey
Total Customers with Evap or Swamp Coolers	0.81%	694	

Total Available for program	44,099		
Total Estimated Saturation Percentage	2.5%		
Total Participants	**1,102**	1 29%	Of total Customer Base
Participation Year 1	367		
Participation Year 2	367		
Participation Year 3	367		

Energy Savings Calculation

Equipment	kw Conn	Annual kWh	Utilization Factor	
10 SEER Unit	3.6	2,160	67%	EPRI
14 Seer Unit	2 57	1,543		
Energy Reduction	1 03	617		

	Per Part
Peak Demand Reduction	0.7
Winter Demand Reduction	0.0
Summer Energy Reduction	617
Winter Energy Reduction	0

Commercial High Efficiency A/C
Quantitative DSM # 6

Customer Class:	Commercial

Cost MDU

			$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Costs			$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 250.00	Incentive	$ 250	$ 16,212	$ 16,212	$ 16,212	$ 48,636
Admin & Advertising			$ 77	$ 5,000	$ 5,000	$ 5,000	$ 15,000
Total Cost			**$ 327**	**$ 21,212**	**$ 21,212**	**$ 21,212**	**$ 63,636**

Notes

Admin is estimated at $5,000 per year for MDU

Incentive is set at $50 per ton

Participant Costs (Incremental Cost Basis)

Cost of STD Eff Model (10 SEER)	$ 2,000	Trane 5 Ton Packaged Unit ($400 per ton Mike S)
Cost of High Efficiency Model (12 SEER)	$ 3,000	Trane 5 Ton Packaged Unit ($600 per ton Mike S)
Increased cost of Higher Eff Model	**$ 1,000**	

Participation Rate Calc

	% of Cust	Cust
Total Customers is Class	100.00%	15,565
Total Customers With Central AC	50.00%	7,783
Total Customers with Evap or Swamp Coolers	0.00%	-

Total Available for program	7,783		
Total Estimated Saturation Percentage	2.5%		
Total Participants	**195**	1.25%	Of total Customer Base
Participation Year 1	65		
Participation Year 2	65		
Participation Year 3	65		

Energy Savings Calculation

Equipment	kw Conn	Annual kWh	Utilization Factor	
10 SEER Unit	6.86	5,400	67%	Trane 5 ton Unit
12 Seer Unit	5.56	4,500		Trane 5 ton Unit
Energy Reduction	1.3	900		

	Per Part
Peak Demand Reduction	0.9
Winter Demand Reduction	0.0
Summer Energy Reduction	900
Winter Energy Reduction	0

Residential A/C Cycling (T-Stat Turnkey)
Quantitative DSM # 7

Customer Class:	Residential

Cost MDU

		$/Part		Total $ Yr 1		Total $ Yr 2		Total $ Yr 3		Total $
Operating Costs (Honeywell Turnkey)	$	285	$	941,819	$	470,909	$	470,909	$	1,883,637
Incentive Costs ($150 t-Stat)	$	89	$	292,904	$	146,452	$	146,452	$	585,809
Admin & Advertising (MDU)	$	0	$	1,000	$	1,000	$	1,000	$	3,000
Total Cost	**$**	**374**	**$**	**1,235,723**	**$**	**618,361**	**$**	**618,361**	**$**	**2,472,446**

Notes
Admin is estimated at $1,000 per year for MDU

Participant Costs
None / Comfort Issues

Participation Rate Calc

	% of Cust	Cust	
Total Customers is Class	100.00%	85,712	
Total Customers With Central AC	50 64%	43,405	Per Customer Survey
Total Customers with Evap or Swamp Coolers	0.81%	694	

Total Available for program	44,099		
Total Estimated Saturation Percentage	15 0%		
Total Participants	**6,615**	7 72%	Of total Customer Base
Participation Year 1	3,307		
Participation Year 2	1,654		
Participation Year 3	1,654		

Energy Savings Calculation

Equipment	kw Conn	Annual kWh		Utilization Factor	
Avg is 1kw per part	1 5	2,160		67%	3 ton Unit, 1 5 kw realized per event
Cycling		100	hrs		100 hrs of curtailment per year or 10% cycling rate
Avg (WAC)	1 5	1809 8			

	Per Part
Peak Demand Reduction	1.0
Winter Demand Reduction	0 000
Summer Energy Reduction	150
Winter Energy Reduction	0

Refrigerator Round-Up Program
Quantitative DSM # 8

Customer Class:	Residential

Cost MDU

	$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Transport & Recycling (Operating)	$ 50	$ 15,625	$ 15,625	$ 15,625	$ 46,876
Incentive Costs	$ 35	$ 10,938	$ 10,938	$ 10,938	$ 32,813
Admin & Advertising	$ 16	$ 5,000	$ 5,000	$ 5,000	$ 15,000
Total Cost	**$ 101**	**$ 31,563**	**$ 31,563**	**$ 31,563**	**$ 94,689**

Notes
Admin & Advertising is estimated at $5,000 per year
Pick up and Recycling is estimated at loaded rate for 1 hr plus mileage & $10 recycling fee at Porter Bros

Participant Costs
None

Participation Rate Calc

	% of Cust	Cust
Total Customers is Class	100.00%	85,712
Total Customers with 2 Refrigerators	34.03%	29,168
Total Customers with 3 or more Refrigerators	2 43%	2,083

Total Refrigerators Available for program	31,251		
Total Estimated Saturation Percentage	3.0%		
Part Rate	938	1 09%	Of total Customer Base
Participation Year 1	313		
Participation Year 2	313		
Participation Year 2	313		

Energy Savings Calculation

Refrigerators Data	kw Conn	Annual kWh	Utilization Factor	
Frost Free	1 5	1200	35%	As per WAPA DSM Pocket Guide 1992
Standard	1	1000	35%	Assumes 1987 vintage 17.3 cu ft
Avg (WAC)	1 415	1166		As per survey results 83% for FF

UPA 1992 Study - Older Fridges

	Per Part
Peak Demand Reduction	0.495
Winter Demand Reduction	0.495
Summer Energy Reduction	389
Winter Energy Reduction	777

Residential GSHP
Quantitative DSM # 9

Customer Class:	Residential

Cost MDU

			$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Costs			$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 1,100 00	Incentive	$ 1,100	$ 22,000	$ 22,000	$ 22,000	$ 66,000
Admin & Advertising			$ 250	$ 5,000	$ 5,000	$ 5,000	$ 15,000
Total Cost			$ 1,350	$ 27,000	$ 27,000	$ 27,000	$ 81,000

Notes
Admin is estimated at $5,000 per year for MDU
Program is based in straight electric areas only

Participant Costs (Incremental Cost Basis)

Furnace & Central Air (STD Eff)	$ 5,000	3 Ton A/C & 75,000 BTU Furnace 80%
GS Heat pump	$ 9,000	3 Ton Unit 17 SEER 14 5 EER
Increased cost of GSHP	$ 4,000	

Participation Rate Calc

	% of Cust	Cust	
Total Customers is Class	100 00%	85,712	2004
Combination Customers	58 69%	50,302	2004
Total Electric Only Customers	41 31%	35,410	2004

Total Available for program	35,410	
Total Estimated Saturation Percentage	0 17%	
Total Participants	60	0 07% Of total Customer Base
Participation Year 1	20	
Participation Year 2	20	
Participation Year 3	20	

Energy Savings Calculation

Equipment	kw Conn	Annual kWh	Utilization Factor	
Std A/C Cooling (10 SEER)	3 6	2,160	67%	
Heat pump Cooling	2 5	1,271		
Cooling Energy Reduction	1 1	889		
Heating Energy Add	2 5	6,638		COP of 3

	Per Part	
Peak Demand Reduction	0 7	
Winter Demand Reduction	-2 5	
Summer Energy Reduction	889	
Winter Energy Reduction	(6,638)	
Savings Electric vs Propane	$ 577	
Electric Heat after tax margin per cooling kwh reduction	$	0 0911

**Heat Pump vs propane at 80% AFUE & 5 yr avg price of $0 89 per gal ($827 annual cost for 930 Gallons)
** Annaul cost of electric heat $250

Electric Heat Promotion
Quantitative DSM # 10

Customer Class:	Residential	*ND Program Only*

Cost MDU

			$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Costs			$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 250 00	Incentive	$ 250	$ 23,909	$ 23,909	$ 23,909	$ 71,728
Admin & Advertising			$ 52	$ 5,000	$ 5,000	$ 5,000	$ 15,000
Total Cost			**$ 302**	**$ 28,909**	**$ 28,909**	**$ 28,909**	**$ 86,728**

Notes

Admin is estimated at $5,000 per year for MDU

Program is based in straight electric areas only for a fuel not supplied by MDU max of 10 kw min of 5 kw ($25 per kw)

Participant Costs (Incremental Cost Basis)

15 kw Electric Furnace	$ 1,200	RHI Price Book plus installation
Installed cost of Electric Furnace	**$ 1,200**	

Participation Rate Calc

	% of Cust	Cust	
Total Customers is Class	100 00%	50,050	2004
Less Combination Customers	71 33%	35,703	2004

Total Available for program	14,347	
Total Estimated Saturation Percentage	2.00%	
Total Participants	**287**	0 57% Of total Customer Base
Participation Year 1	96	
Participation Year 2	96	
Participation Year 3	96	

Energy Savings Calculation

Equipment	kw Conn	Annual kWh	Utilization Factor	
Electric Load	15	14,593	70%	100% Eff
Added Heating Load	-15	(14,593)		

	Per Part
Peak Demand Reduction	0 0
Winter Demand Reduction	(11)
Summer Energy Reduction	-
Winter Energy Reduction	(14,593)
Savings Electric vs Propane	$ 331
Electric Heat after tax margin increase Factor	$ 0 0124

**Electric Heat vs propane at 80% AFUE & 5 yr avg price of $0 89 per gal ($827 annual cost for 930 Gallons)

** Annual Cost on Electric $496 per year

T-8 Lighting Retrofit (4 Lamp fixture model)
Quantitative DSM # 11

Customer Class:	Comm & Ind

Cost MDU

			$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $ Yr 4	Total $ Yr 5	Total $
Operating Costs (Non Incentive)			$ -	$ -	$ -	0	0	$ -	$ -
Incentive Costs	$ 8 00	per fix	$ 184	$ 61,059	$ 61,059	$ 61,059	$ 61,059	$ 61,059	$ 305,293
Admin & Advertising			$ 15	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 25,000
Total Cost			$ 199	$ 66,059	$ 66,059	$ 66,059	$ 66,059	$ 66,059	$ 330,293

Notes

Admin & Advertising is estimated at $5,000 per year

Incentive is like Montana Program that is in place ($10 per fix)

Participant Costs

Avg Cost per Fixture	$	40 00	4 Lamp Fixture with Ballast per ESG Avg Pricing plus labor
Fixtures per Participant		23	
Total Direct Cost per Part	$	920	

Participation Rate Calc

	Cust	
Total Customers is Class	16,592	
Estimated fixtures per Customer	23	Derived from xenergy survey
Estimated Exit Signs on System	381,616	

Total fixtures Available for program	381,616
Estimated Conversion Percentage	10 0%
Part Rate of Light fixtures	38,162
Customer Part Rate	1,659
Participation Year 1	332
Participation Year 2	332
Participation Year 3	332
Participation Year 4	332
Participation Year 5	332

Energy Savings Calculation

Exit Light Data (per Fix)	Watts Conn	Annual kWh	Utilization Factor	hrs/yr	
Existing T-12 4 lamp Fixture	144	360	100%	2500	34 w bulbs energy saving magnetic ballast
T-8 4 Lamp Fixture	107	267	100%	2500	electronic ballast
Reduction Per fixture	37	93	100%		

Energy Reduced	Per Fixture	Per Part
Peak Demand Reduction (season)	0 0373	3 43
Winter Demand Reduction (Season)	0 0373	6.86
Summer Energy Reduction	31	715
Winter Energy Reduction	62	1,430

***** kWh calculation assumes 2,500 hrs per year of operation as is typically for M-F 8-5pm operation**

****** Lighting program with be more comprehensive and include CFL & MH. Incentive with vary depending on Wattage Reduction**

LED Exits Signs (Incandescent Model)
Quantitative DSM # 12

Customer Class.	Comm & Ind

Cost MDU

			$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $ Yr 4	Total $ Yr 5	Total $
Operating Costs (Non Incentive)			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 10 00	per fix	$ 50	$ 8,296	$ 8,296	$ 8,296	$ 8,296	$ 8,296	$ 41,480
Admin & Advertising			$ 30	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 25,000
Total Cost			**$ 80**	**$ 13,296**	**$ 13,296**	**$ 13,296**			**$ 66,480**

Notes

Ads and Admim is $5,000 per year

Incentive is like Montana Program that is in place ($10 per fix)

Participant Costs

Cost Per Exit Light	$	50 00	*Replacement cost as per ESG Todd Kaduan (Retrofit cost is $20/fix)*
Exit Signs per Part		5	
Total Direct Cost per Part	**$**	**250**	

Participation Rate Calc

	Cust	
Total Customers is Class	16,592	
Estimated Exit Signs per Customer	5	derived Per Xenergy Study
Estimated Exit Signs on System	**82,960**	

Total Exit Lights Available for program	82,960
Estimated Conversion Percentage	5 0%
Part Rate of Exit Lights	4,148
Customer Part Rate	830
Participation Year 1	166
Participation Year 2	166
Participation Year 3	166
Participation Year 4	166
Participation Year 5	166

Energy Savings Calculation

Exit Light Data (per Fix)	Watts Conn	Annual kWh	Utilization Factor	kW Redc	kWh Reduc
Existing Incandescent	32	280	100%	0 032	280
Existing CFL	10	88	100%	0 01	88
LED (Replace the others)	5	44	100%	0 005	44

Energy Reduced	Per Fixture	Per Part
Peak Demand Reduction	0 027	0 14
Winter Demand Reduction	0 027	0 14
Summer Energy Reduction	79	394
Winter Energy Reduction	158	788

***** Note For Program development that if CFL's are replaced incentive is reduced to 1/4 of incentive for incandescent**

******* LED Signs Must me energy star rated which is 5 watts or less (1 Watt is the best available)**

Fixture life is 10 years

G-12

Commercial A/C Cycling (T-Stat Turnkey)
Quantitative DSM # 13

Customer Class:	Small Comm

Cost MDU

	$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Costs (Honeywell Turnkey)	$ 1,082	$ 105,258	$ 52,629	$ 52,629	$ 210,517
Incentive Costs ($150 t-Stat)	$ 337	$ 32,737	$ 16,369	$ 16,369	$ 65,474
Admin & Advertising (MDU)	$ 15	$ 1,000	$ 1,000	$ 1,000	$ 3,000
Total Cost	**$ 1,434**	**$ 138,995**	**$ 69,998**	**$ 69,998**	**$ 278,991**

Notes
Admin is estimated at $1,000 per year for MDU

Participant Costs
None / Comfort Issues

Participation Rate Calc

	% of Cust	Cust	
Total Customers is Class	100.00%	15,565	Per Customer Survey
Total Customers in class available for program	50 00%	7,783	Estimate
Total Customer with A/C	50.00%	3,891	

Total Available for program	3,891		
Total Estimated Saturation Percentage	5.0%		
Total Participants	**195**	1.25%	Of total Customer Base
Participation Year 1	97		
Participation Year 2	49		
Participation Year 3	49		

Energy Savings Calculation

Equipment	kw Conn	Annual kWh	Utilization Factor	
Avg is 1kw per part	5 73	5500	67%	Per Trane 5 Ton unit 11 8 SEER
Cycling		100 hrs		100 hrs of curtailment per year or 10% cycling rate
Avg (WAC)	5.73	4582		

	Per Part
Peak Demand Reduction	3 8
Winter Demand Reduction	0.000
Summer Energy Reduction	573
Winter Energy Reduction	0

G-13

APPENDIX H

DEMAND-SIDE ANALYSIS RESULTS

Demand-Side Management Program - DSM

Intergrated Electric System Cost-Effectiveness Analysis

Company Montana-Dakota Utilities Co.

Project. **Energy Star Clothes Washer w/ elec Wtr Ht**

Input Data

1) Retail Rate Summer ($/kWh) =	$0 06987
1a) Retail Rate Winter ($/kWh) =	$0 03431
Escalation Rate =	6.00%
2)Avg System Energy Cost ($/kWh) =	$0 01471
Escalation Rate =	2.15%
3) Retail Summer Demand Cost ($/kW/season) =	$0 00
3a) Retail Winter Demand Cost ($/kW/season) =	$0.00
Escalation Rate =	6 00%
4) System Summer Demand Cost ($/kW/yr)	74 46
Escalation Rate =	2 15%
5) Variable O&M ($/kWh) =	$0.00
Escalation Rate =	1 15%
6) Environmental Damage Factor =	15%
Escalation Rate =	2 15%
7) Total Sales by class (kWh) =	680,614,000
Growth Rate =	0.23%
8) Total Customers by class =	85,712
Growth Rate =	0 18%
9) Utility Discount Rate =	7 34%
10) Social Discount Rate(Tbill) =	4 97%
11) General Input Data Year =	2005
12) Project Analysis Year 1 =	2006
12a) Project Analysis Year 2 =	2007
13) Effective Fed & State Income Tax Rate =	39 00%
14) System Annual Line loss factor	7 88%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$5,000
Direct Operating Costs =	$0
Incentive Costs =	$15,882
Total Utility Project Costs Year 1 =	**$20,882**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$5,000
Direct Operating Costs =	$0
Incentive Costs =	$15,882
Total Utility Project Costs Year 2 =	**$20,882**
15b) Total Utilty Cost Year 3 =	**$20,882.00**
15c) Total Utilty Cost Year 4 =	**$0.00**
15d) Total Utility Cost Year 5 =	**$0.00**
16) Direct Participant Costs ($/Part) =	$300 00
Escalation Rate =	2 15%
17) Other Participant Costs (Annual $/Part) =	($35.00)
Escalation Rate =	2 15%
18) Project Life (Years) =	10
20) Avg Summer kW/part Saved =	0 028
20a) Avg Winter kW/part Saved =	0.028
21) Avg Summer kWh/Part. Saved =	120
21a) Avg Winter kWh/Part Saved =	241
22) Number of Participants (First Year) =	529
22a) Number of Participants (Second Year) =	529
22a) Number of Participants (Third Year) =	529
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$30.00

H-1

Demand-Side Management Program - DSM

Intergrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Energy Star Clothes Washer w/ elec Wtr Ht**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	10
Total Progam Cost (Utility)	$62,646
Total Program Participants	1,587
Utility Cost per Participant (First Year) =	$39.47
Utility Cost per Participant (Program) =	$39.47
Total Summer kW Reduction	44
Total Winter kW Reduction	44
Total Summer Energy Reduction (kWh)	1,713,960
Total Winter Energy Reduction (kWh)	3,442,203
Societal Cost per kwh	$0.03

Test Results

	NPV	B/C
Utility Test	($50,774)	0.62
Ratepayer Test	$30,108	1.55
Societal Benefit Test	($58,841)	0.63
Participant Test	$123,954	1 79

H-3

Table 1
Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Energy Star Clothes Washer w/ elec Wtr Ht**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Peak Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2006	190,969	$0 0150	$0	15	$78 93	$4,039	$20,882	3,783	$24,665	($20,627)
2	2007	381,938	$0 0153	0	30	$83 66	8,341	20,882	7,831	28,713	(20,372)
3	2008	572,907	$0.0157	0	44	$88 68	12,924	20882	12,171	33,053	(20,129)
4	2009	572,907	$0.0160	0	44	$94 00	13,353	0	12,625	12,625	728
5	2010	572,907	$0.0164	0	44	$99 64	13,801	0	13,111	13,111	690
6	2011	572,907	$0 0167	0	44	$105 62	14,268	0	13,631	13,631	637
7	2012	572,907	$0 0171	0	44	$111 96	14,756	0	14,187	14,187	569
8	2013	572,907	$0.0174	0	44	$118 68	15,264	0	14,781	14,781	484
9	2014	572,907	$0 0178	0	44	$125 80	15,796	0	15,415	15,415	381
10	2015	572,907	$0 0182	0	44	$133 35	16,350	0	16,093	16,093	258
11	2016	0	$0 0186	0	0	$141 35	0	0	0	0	0
12	2017	0	$0 0190	0	0	$149 83	0	0	0	0	0
13	2018	0	$0 0194	0	0	$158 82	0	0	0	0	0
14	2019	0	$0 0198	0	0	$168.35	0	0	0	0	0
15	2020	0	$0.0202	0	0	$178 45	0	0	0	0	0
16	2021	0	$0 0207	0	0	$189.15	0	0	0	0	0
Total =		5,156,163			400		$128,892	$62,646	$123,627	$186,273	($57,381)
NPV =							84,569	54,461	80,882	135,343	(50,774)

Total NPV = ($50,774)
Benefit/Cost Ratio = 0 62

(A) = Energy Reduction/Part (21+ 21a) x Participants (22)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part (20) x Participants (22)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13)] x [(A) x Retail Rate (1) - (A x B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **Energy Star Clothes Washer w/ elec Wtr Ht**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2006	$2,870	$0	$1,169	$4,039	$20,882	$20,882	($16,843)
2007	5,862	0	2,478	8,341	20,882	20,882	(12,541)
2008	8,983	0	3,941	12,924	20,882	20,882	(7,958)
2009	9,176	0	4,177	13,353	0	0	13,353
2010	9,373	0	4,428	13,801	0	0	13,801
2011	9,575	0	4,693	14,268	0	0	14,268
2012	9,781	0	4,975	14,756	0	0	14,756
2013	9,991	0	5,274	15,264	0	0	15,264
2014	10,206	0	5,590	15,796	0	0	15,796
2015	10,425	0	5,925	16,350	0	0	16,350
2016	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0
Total =	$86,241	$0	$42,651	$128,892	$62,646	$62,646	$66,246
NPV =	56,926	0	27,643	84,569	54,461	54,461	30,108

Total NPV = $30,108

Benefit/Cost Ratio = 1.55

(A) = Energy Reduction/Part. (21 + 21a) x Participants (22) x Energy Cost (2)

(B) = Energy Reduction/Part (21) x Participants (22) x Variable O&M (5)

(C) = kW Demand Reduction/Part (20) x Participants (22) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

H-4

Table 3

Societal Benefit Test

This test measures the net cost of the program based on total cost including environmental externalities and both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**

Project: **Energy Star Clothes Washer w/ elec Wtr Ht**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2006	$2,870	$0	$1,169	$619	$4,657	$20,882	$139,787	$15,870	$144,799	($140,141)
2007	$5,862	$0	$2,478	$1,306	9,646	20,882	120,061	$15,870	125,073	(115,426)
2008	$8,983	$0	$3,941	$2,066	14,990	20882	119,230	$15,870	124,242	(109,252)
2009	$9,176	$0	$4,177	$2,181	15,534	0	(40,319)	$0	(40,319)	55,853
2010	$9,373	$0	$4,428	$2,302	16,103	0	(41,186)	$0	(41,186)	57,289
2011	$9,575	$0	$4,693	$2,432	16,700	0	(42,071)	$0	(42,071)	58,771
2012	$9,781	$0	$4,975	$2,569	17,324	0	(42,976)	$0	(42,976)	60,300
2013	$9,991	$0	$5,274	$2,714	17,979	0	(43,900)	$0	(43,900)	61,878
2014	$10,206	$0	$5,590	$2,869	18,665	0	(44,843)	$0	(44,843)	63,508
2015	$10,425	$0	$5,925	$3,034	19,384	0	(45,808)	$0	(45,808)	65,192
2016	$0	$0	$0	$0	0	0	0	$0	0	0
2017	$0	$0	$0	$0	0	0	0	$0	0	0
2018	$0	$0	$0	$0	0	0	0	$0	0	0
2019	$0	$0	$0	$0	0	0	0	$0	0	0
2020	$0	$0	$0	$0	0	0	0	$0	0	0
2021	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$86,241	$0	$42,651	$22,092	$150,984	$62,646	$77,976	$47,610	$93,012	$57,972
NPV =	56,926	0	27,643	16,374	100,944	54,461	146,713	41,390	159,785	(58,841)

Total NPV = ($58,841)

Benefit/Cost Ratio = 0 63

(A) = Energy Reduction/Part (21 + 21a) x Participants (22) x Energy Cost (2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW Demand Reduction/Part. (20) x Participants (22) x System Demand Cost (4)

(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)

(E) = (A) + (B) + (C) + (D)

(F) = Total Utility Project Costs (15)

(G) = Direct (16) + Other (17) Participant Costs x Participants (22)

(H) = Incentive Costs (15)

(I) = (F) + (G) - (H)

(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Energy Star Clothes Washer w/ elec Wtr Ht**

		Benefits										Costs				
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Cost (F1)	Winter Demand Cost (F2)	Total Annual Benefits (G)	Direct Part Costs (H)	**Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2006	0 0062	$15,870	63,480	127,489	$0 074	$0 036	15	15	$0 00	$0 00	$25,208	$158,700	($18,913)	$139,787	($114,579)
2007	0.0123	$15,870	126,960	254,978	$0 079	$0 039	30	30	$0 00	$0 00	$35,667	158,700	($38,639)	120,061	(84,394)
2008	0 0123	$15,870	190,440	382,467	$0 083	$0 041	44	44	$0 00	$0 00	$47,347	158,700	($39,470)	119,230	(71,883)
2009	0 0123	$0	190,440	382,467	$0 088	$0 043	44	44	$0 00	$0 00	$33,365	0	($40,319)	(40,319)	73,684
2010	0.0122	$0	190,440	382,467	$0 094	$0.046	44	44	$0 00	$0 00	$35,367	0	($41,186)	(41,186)	76,553
2011	0 0122	0	190,440	382,467	$0.099	$0 049	44	44	$0 00	$0 00	$37,489	0	($42,071)	(42,071)	79,560
2012	0 0122	0	190,440	382,467	$0 105	$0 052	44	44	$0.00	$0.00	$39,739	0	($42,976)	(42,976)	82,714
2013	0 0122	0	190,440	382,467	$0 111	$0 055	44	44	$0 00	$0 00	$42,123	0	($43,900)	(43,900)	86,023
2014	0 0121	0	190,440	382,467	$0 118	$0 058	44	44	$0 00	$0 00	$44,650	0	($44,843)	(44,843)	89,494
2015	0 0121	0	190,440	382,467	$0 125	$0.061	44	44	$0 00	$0.00	$47,329	0	($45,808)	(45,808)	93,137
2016	0 0121	0	0	0	$0 133	$0 065	0	0	$0.00	$0 00	$0	0	$0	0	0
2017	0 0121	0	0	0	$0 141	$0 069	0	0	$0 00	$0 00	$0	0	$0	0	0
2018	0 0121	0	0	0	$0 149	$0 073	0	0	$0 00	$0 00	$0	0	$0	0	0
2019	0.0120	0	0	0	$0 158	$0 078	0	0	$0 00	$0.00	$0	0	$0	0	0
2020	0 0120	0	0	0	$0 167	$0 082	0	0	$0 00	$0 00	$0	0	$0	0	0
2021	0 0120	0	0	0	$0 177	$0 087	0	0	$0.00	$0.00	$0	0	$0	0	0
			1,713,960	3,442,203							$388,285	$476,100	($398,124)	$77,976	$310,309
											$281,437	444,282	(286,799)	157,483	123,954

Total NPV = $123,954
Benefit/Cost Ratio = 1 79

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part (20) x Participants (22)
(E2) = kW Demand Reduction/Part (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)
** Other Participant Costs in this model are water savings due to DSM ($35/yr/part)

H-7

Demand-Side Management Program - DSM

Intergrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**

Project **Energy Star Dishwasher w/ elec Wtr Ht**

Input Data

1) Retail Rate Summer ($/kWh) =	$0 06987
1a) Retail Rate Winter ($/kWh) =	$0 03431
Escalation Rate =	6 00%
2)Avg System Energy Cost ($/kWh) =	$0 01471
Escalation Rate =	2 15%
3) Retail Summer Demand Cost ($/kW/season) =	$0.00
3a) Retail Winter Demand Cost ($/kW/season) =	$0 00
Escalation Rate =	6 00%
4) System Summer Demand Cost ($/kW/yr)	74.46
Escalation Rate =	2 15%
5) Variable O&M ($/kWh) =	$0.00
Escalation Rate =	1.15%
6) Environmental Damage Factor =	15%
Escalation Rate =	2 15%
7) Total Sales by class (kWh) =	680,614,000
Growth Rate =	0.23%
8) Total Customers by class =	85,712
Growth Rate =	0.18%
9) Utility Discount Rate =	7 34%
10) Social Discount Rate(Tbill) =	4 97%
11) General Input Data Year =	2005
12) Project Analysis Year 1 =	2006
12a) Project Analysis Year 2 =	2007
13) Effective Fed & State Income Tax Rate =	39 00%
14) System Annual Line loss factor	7 88%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$5,000
Direct Operating Costs =	$0
Incentive Costs =	$3,221
Total Utility Project Costs Year 1 =	**$8,221**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$5,000
Direct Operating Costs =	$0
Incentive Costs =	$3,221
Total Utility Project Costs Year 2 =	**$8,221**
15b) Total Utilty Cost Year 3 =	**$8,221.00**
15c) Total Utilty Cost Year 4 =	**$0.00**
15d) Total Utility Cost Year 5 =	**$0.00**
16) Direct Participant Costs ($/Part) =	$50 00
Escalation Rate =	2.15%
17) Other Participant Costs (Annual $/Part) =	$0 00
Escalation Rate =	2 15%
18) Project Life (Years) =	10
20) Avg Summer kW/part Saved =	0
20a) Avg Winter kW/part Saved =	0
21) Avg Summer kWh/Part Saved =	34
21a) Avg Winter kWh/Part Saved =	69
22) Number of Participants (First Year) =	322
22a) Number of Participants (Second Year) =	322
22a) Number of Participants (Third Year) =	322
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$30.00

Demand-Side Management Program - DSM

Intergrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Energy Star Dishwasher w/ elec Wtr Ht**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	10
Total Progam Cost (Utility)	$24,663
Total Program Participants	966
Utility Cost per Participant (First Year) =	$25.53
Utility Cost per Participant (Program) =	$25.53
Total Summer kW Reduction	0
Total Winter kW Reduction	0
Total Summer Energy Reduction (kWh)	295,596
Total Winter Energy Reduction (kWh)	599,886
Societal Cost per kwh	$0.04

H-8

Test Results

	NPV	B/C
Utility Test	($25,583)	0.28
Ratepayer Test	($11,554)	0.46
Societal Benefit Test	($26,443)	0.31
Participant Test	$23,060	1.51

Table 1
Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Energy Star Dishwasher w/ elec Wtr Ht**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Peak Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2006	33,166	$0 0150	$0	0	$78.93	$498	$8,221	656	$8,877	($8,378)
2	2007	66,332	$0 0153	0	0	$83 66	1,018	8,221	1,357	9,578	(8,560)
3	2008	99,498	$0.0157	0	0	$88 68	1,560	8221	2,110	10,331	(8,771)
4	2009	99,498	$0 0160	0	0	$94.00	1,594	0	2,189	2,189	(595)
5	2010	99,498	$0 0164	0	0	$99 64	1,628	0	2,274	2,274	(646)
6	2011	99,498	$0 0167	0	0	$105 62	1,663	0	2,364	2,364	(701)
7	2012	99,498	$0.0171	0	0	$111 96	1,699	0	2,461	2,461	(763)
8	2013	99,498	$0 0174	0	0	$118 68	1,735	0	2,565	2,565	(830)
9	2014	99,498	$0 0178	0	0	$125 80	1,772	0	2,675	2,675	(903)
10	2015	99,498	$0 0182	0	0	$133 35	1,811	0	2,794	2,794	(983)
11	2016	0	$0.0186	0	0	$141.35	0	0	0	0	0
12	2017	0	$0.0190	0	0	$149.83	0	0	0	0	0
13	2018	0	$0 0194	0	0	$158.82	0	0	0	0	0
14	2019	0	$0 0198	0	0	$168.35	0	0	0	0	0
15	2020	0	$0 0202	0	0	$178 45	0	0	0	0	0
16	2021	0	$0.0207	0	0	$189 15	0	0	0	0	0
Total =		895,482			0		$14,978	$24,663	$21,444	$46,107	($31,130)
NPV =							9,887	21,441	14,028	35,469	(25,583)

Total NPV = ($25,583)
Benefit/Cost Ratio = 0 28

(A) = Energy Reduction/Part (21+ 21a) x Participants (22)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part (20) x Participants (22)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

H-10

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **Energy Star Dishwasher w/ elec Wtr Ht**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2006	$498	$0	$0	$498	$8,221	$8,221	($7,723)
2007	1,018	0	0	1,018	8,221	8,221	(7,203)
2008	1,560	0	0	1,560	8,221	8,221	(6,661)
2009	1,594	0	0	1,594	0	0	1,594
2010	1,628	0	0	1,628	0	0	1,628
2011	1,663	0	0	1,663	0	0	1,663
2012	1,699	0	0	1,699	0	0	1,699
2013	1,735	0	0	1,735	0	0	1,735
2014	1,772	0	0	1,772	0	0	1,772
2015	1,811	0	0	1,811	0	0	1,811
2016	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0
Total =	$14,978	$0	$0	$14,978	$24,663	$24,663	($9,685)
NPV =	9,887	0	0	9,887	21,441	21,441	(11,554)

Total NPV = ($11,554)

Benefit/Cost Ratio = 0 46

(A) = Energy Reduction/Part (21 + 21a) x Participants (22) x Energy Cost (2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW Demand Reduction/Part. (20) x Participants (22) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Benefit Test

This test measures the net cost of the program based on total cost including environmental externalities and both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**
Project: **Energy Star Dishwasher w/ elec Wtr Ht**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2006	$498	$0	$0	$76	$575	$8,221	$16,100	$9,660	$14,661	($14,086)
2007	$1,018	$0	$0	$159	1,178	8,221	16,100	$9,660	14,661	(13,483)
2008	$1,560	$0	$0	$249	1,809	8221	16,100	$9,660	14,661	(12,852)
2009	$1,594	$0	$0	$260	1,854	0	0	$0	0	1,854
2010	$1,628	$0	$0	$272	1,899	0	0	$0	0	1,899
2011	$1,663	$0	$0	$283	1,946	0	0	$0	0	1,946
2012	$1,699	$0	$0	$296	1,994	0	0	$0	0	1,994
2013	$1,735	$0	$0	$309	2,044	0	0	$0	0	2,044
2014	$1,772	$0	$0	$322	2,094	0	0	$0	0	2,094
2015	$1,811	$0	$0	$336	2,147	0	0	$0	0	2,147
2016	$0	$0	$0	$0	0	0	0	$0	0	0
2017	$0	$0	$0	$0	0	0	0	$0	0	0
2018	$0	$0	$0	$0	0	0	0	$0	0	0
2019	$0	$0	$0	$0	0	0	0	$0	0	0
2020	$0	$0	$0	$0	0	0	0	$0	0	0
2021	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$14,978	$0	$0	$2,563	$17,540	$24,663	$48,300	$28,980	$43,983	($26,443)
NPV =	9,887	0	0	1,907	11,794	21,441	41,990	25,194	38,237	(26,443)

Total NPV = ($26,443)
Benefit/Cost Ratio = 0.31

(A) = Energy Reduction/Part (21 + 21a) x Participants (22) x Energy Cost (2)
(B) = Energy Reduction/Part (21) x Participants (22) x Variable O&M (5)
(C) = kW Demand Reduction/Part. (20) x Participants (22) x System Demand Cost (4)
(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)
(E) = (A) + (B) + (C) + (D)
(F) = Total Utility Project Costs (15)
(G) = Direct (16) + Other (17) Participant Costs x Participants (22)
(H) = Incentive Costs (15)
(I) = (F) + (G) - (H)
(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Energy Star Dishwasher w/ elec Wtr Ht**

Year	Ratio of Part. to Total Customers (A)	Benefits: Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Cost (F1)	Winter Demand Cost (F2)	Total Annual Benefits (G)	Costs: Direct Part Costs (H)	Other Part Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2006	0.0038	$9,660	10,948	22,218	$0.074	$0.036	0	0	$0 00	$0 00	$11,279	$16,100	$0	$16,100	($4,821)
2007	0.0075	$9,660	21,896	44,436	$0.079	$0 039	0	0	$0 00	$0.00	$13,092	16,100	$0	16,100	(3,008)
2008	0 0075	$9,660	32,844	66,654	$0 083	$0 041	0	0	$0 00	$0 00	$15,117	16,100	$0	16,100	(983)
2009	0.0075	$0	32,844	66,654	$0.088	$0 043	0	0	$0.00	$0 00	$5,784	0	$0	0	5,784
2010	0 0074	$0	32,844	66,654	$0 094	$0.046	0	0	$0 00	$0 00	$6,131	0	$0	0	6,131
2011	0 0074	0	32,844	66,654	$0 099	$0 049	0	0	$0 00	$0.00	$6,499	0	$0	0	6,499
2012	0.0074	0	32,844	66,654	$0 105	$0 052	0	0	$0 00	$0 00	$6,889	0	$0	0	6,889
2013	0.0074	0	32,844	66,654	$0 111	$0 055	0	0	$0 00	$0 00	$7,303	0	$0	0	7,303
2014	0.0074	0	32,844	66,654	$0 118	$0.058	0	0	$0 00	$0 00	$7,741	0	$0	0	7,741
2015	0 0074	0	32,844	66,654	$0.125	$0 061	0	0	$0 00	$0 00	$8,205	0	$0	0	8,205
2016	0.0074	0	0	0	$0 133	$0 065	0	0	$0 00	$0 00	$0	0	$0	0	0
2017	0.0074	0	0	0	$0 141	$0 069	0	0	$0 00	$0 00	$0	0	$0	0	0
2018	0 0073	0	0	0	$0 149	$0.073	0	0	$0 00	$0 00	$0	0	$0	0	0
2019	0 0073	0	0	0	$0 158	$0 078	0	0	$0 00	$0.00	$0	0	$0	0	0
2020	0.0073	0	0	0	$0.167	$0 082	0	0	$0.00	$0 00	$0	0	$0	0	0
2021	0 0073	0	0	0	$0 177	$0.087	0	0	$0.00	$0.00	$0	0	$0	0	0
			295,596	599,886							$88,040	$48,300	$0	$48,300	$39,740
											$68,132	45,072	0	45,072	23,060

Total NPV = $23,060
Benefit/Cost Ratio = 1.51

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part (21) x Participants (22)
(C2) = Energy Reduction/Part (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part (20) x Participants (22)
(E2) = kW Demand Reduction/Part (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM

Intergrated Electric System Cost-Effectiveness Analysis

Company	**Montana-Dakota Utilities Co.**
Project	**Energy Star Refrigerators**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.06987
1a) Retail Rate Winter ($/kWh) =	$0.03431
Escalation Rate =	6 00%
2)Avg System Energy Cost ($/kWh) =	$0 01471
Escalation Rate =	2 15%
3) Retail Summer Demand Cost ($/kW/season) =	$0 00
3a) Retail Winter Demand Cost ($/kW/season) =	$0 00
Escalation Rate =	6 00%
4) System Summer Demand Cost ($/kW/yr)	74 46
Escalation Rate =	2 15%
5) Variable O&M ($/kWh) =	$0 00
Escalation Rate =	1 15%
6) Environmental Damage Factor =	15%
Escalation Rate =	2.15%
7) Total Sales by class (kWh) =	680,614,000
Growth Rate =	0.23%
8) Total Customers by class =	85,712
Growth Rate =	0 18%
9) Utility Discount Rate =	7 34%
10) Social Discount Rate(Tbill) =	4 97%
11) General Input Data Year =	2005
12) Project Analysis Year 1 =	2006
12a) Project Analysis Year 2 =	2007
13) Effective Fed & State Income Tax Rate =	39 00%
14) System Annual Line loss factor	7 88%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$5,000
Direct Operating Costs =	$0
Incentive Costs =	$5,714
Total Utility Project Costs Year 1 =	**$10,714**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$5,000
Direct Operating Costs =	$0
Incentive Costs =	$5,714
Total Utility Project Costs Year 2 =	**$10,714**
15b) Total Utilty Cost Year 3 =	**$10,714.00**
15c) Total Utilty Cost Year 4 =	**$0.00**
15d) Total Utility Cost Year 5 =	**$0.00**
16) Direct Participant Costs ($/Part) =	$30.00
Escalation Rate =	2 15%
17) Other Participant Costs (Annual $/Part) =	$0 00
Escalation Rate =	2 15%
18) Project Life (Years) =	10
20) Avg Summer kW/part Saved =	0 042
20a) Avg Winter kW/part Saved =	0 042
21) Avg Summer kWh/Part Saved =	25
21a) Avg Winter kWh/Part Saved =	49
22) Number of Participants (First Year) =	571
22a) Number of Participants (Second Year) =	571
22a) Number of Participants (Third Year) =	571
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$10.00

Demand-Side Management Program - DSM

Intergrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Energy Star Refrigerators**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	10
Total Progam Cost (Utility)	$32,142
Total Program Participants	1,713
Utility Cost per Participant (First Year) =	$18.76
Utility Cost per Participant (Program) =	$18.76
Total Summer kW Reduction	72
Total Winter kW Reduction	72
Total Summer Energy Reduction (kWh)	385,425
Total Winter Energy Reduction (kWh)	755,433
Societal Cost per kwh	$0.05

Test Results

	NPV	B/C
Utility Test	$11,458	1.25
Ratepayer Test	$29,409	2 05
Societal Benefit Test	$10,787	1.19
Participant Test	$20,690	1.43

Table 1

Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Energy Star Refrigerators**

		Cost of Energy Saved						Project Cost			Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Peak Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2006	42,254	$0 0150	$0	24	$78 93	$2,528	$10,714	842	$11,556	($9,028)
2	2007	84,508	$0.0153	0	48	$83 66	5,310	10,714	1,741	12,455	(7,146)
3	2008	126,762	$0 0157	0	72	$88 68	8,368	10714	2,705	13,419	(5,051)
4	2009	126,762	$0.0160	0	72	$94 00	8,793	0	2,805	2,805	5,989
5	2010	126,762	$0 0164	0	72	$99 64	9,243	0	2,911	2,911	6,332
6	2011	126,762	$0 0167	0	72	$105 62	9,718	0	3,025	3,025	6,693
7	2012	126,762	$0 0171	0	72	$111 96	10,219	0	3,147	3,147	7,073
8	2013	126,762	$0.0174	0	72	$118 68	10,749	0	3,277	3,277	7,472
9	2014	126,762	$0 0178	0	72	$125 80	11,309	0	3,416	3,416	7,893
10	2015	126,762	$0.0182	0	72	$133 35	11,900	0	3,564	3,564	8,336
11	2016	0	$0 0186	0	0	$141.35	0	0	0	0	0
12	2017	0	$0 0190	0	0	$149 83	0	0	0	0	0
13	2018	0	$0 0194	0	0	$158 82	0	0	0	0	0
14	2019	0	$0.0198	0	0	$168 35	0	0	0	0	0
15	2020	0	$0 0202	0	0	$178 45	0	0	0	0	0
16	2021	0	$0 0207	0	0	$189 15	0	0	0	0	0
Total =		1,140,858			648		$88,137	$32,142	$27,432	$59,574	$28,563
NPV =							57,352	27,943	17,952	45,894	11,458

Total NPV = $11,458
Benefit/Cost Ratio = 1.25

(A) = Energy Reduction/Part (21+ 21a) x Participants (22)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part (20) x Participants (22)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**
Project: **Energy Star Refrigerators**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2006	$635	$0	$1,893	$2,528	$10,714	$10,714	($8,186)
2007	1,297	0	4,013	5,310	10,714	10,714	(5,404)
2008	1,988	0	6,380	8,368	10,714	10,714	(2,346)
2009	2,030	0	6,763	8,793	0	0	8,793
2010	2,074	0	7,169	9,243	0	0	9,243
2011	2,119	0	7,599	9,718	0	0	9,718
2012	2,164	0	8,055	10,219	0	0	10,219
2013	2,211	0	8,538	10,749	0	0	10,749
2014	2,258	0	9,051	11,309	0	0	11,309
2015	2,307	0	9,594	11,900	0	0	11,900
2016	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0
Total =	$19,082	$0	$69,055	$88,137	$32,142	$32,142	$55,995
NPV =	12,596	0	44,757	57,352	27,943	27,943	29,409

Total NPV = $29,409
Benefit/Cost Ratio = 2.05

(A) = Energy Reduction/Part (21 + 21a) x Participants (22) x Energy Cost (2)
(B) = Energy Reduction/Part (21) x Participants (22) x Variable O&M (5)
(C) = kW Demand Reduction/Part (20) x Participants (22)
x System Demand Cost (4)
(D) = (A) + (B) + (C)
(E) = Total Utility Project Costs (15)
(F) = (E)
(G) = (D) - (F)

Table 3

Societal Benefit Test

This test measures the net cost of the program based on total cost including environmental externalities and both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**
Project: **Energy Star Refrigerators**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2006	$635	$0	$1,893	$387	$2,915	$10,714	$17,130	$5,710	$22,134	($19,219)
2007	$1,297	$0	$4,013	$831	6,141	10,714	17,130	$5,710	22,134	(15,993)
2008	$1,988	$0	$6,380	$1,338	9,706	10714	17,130	$5,710	22,134	(12,428)
2009	$2,030	$0	$6,763	$1,436	10,230	0	0	$0	0	10,230
2010	$2,074	$0	$7,169	$1,542	10,785	0	0	$0	0	10,785
2011	$2,119	$0	$7,599	$1,656	11,374	0	0	$0	0	11,374
2012	$2,164	$0	$8,055	$1,779	11,998	0	0	$0	0	11,998
2013	$2,211	$0	$8,538	$1,911	12,660	0	0	$0	0	12,660
2014	$2,258	$0	$9,051	$2,054	13,363	0	0	$0	0	13,363
2015	$2,307	$0	$9,594	$2,208	14,109	0	0	$0	0	14,109
2016	$0	$0	$0	$0	0	0	0	$0	0	0
2017	$0	$0	$0	$0	0	0	0	$0	0	0
2018	$0	$0	$0	$0	0	0	0	$0	0	0
2019	$0	$0	$0	$0	0	0	0	$0	0	0
2020	$0	$0	$0	$0	0	0	0	$0	0	0
2021	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$19,082	$0	$69,055	$15,144	$103,281	$32,142	$51,390	$17,130	$66,402	$36,879
NPV =	12,596	0	44,757	11,161	68,514	27,943	44,676	14,892	57,727	10,787

Total NPV = $10,787
Benefit/Cost Ratio = 1 19

(A) = Energy Reduction/Part. (21 + 21a) x Participants (22) x Energy Cost (2)
(B) = Energy Reduction/Part (21) x Participants (22) x Variable O&M (5)
(C) = kW Demand Reduction/Part (20) x Participants (22) x System Demand Cost (4)
(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)
(E) = (A) + (B) + (C) + (D)
(F) = Total Utility Project Costs (15)
(G) = Direct (16) + Other (17) Participant Costs x Participants (22)
(H) = Incentive Costs (15)
(I) = (F) + (G) - (H)
(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Energy Star Refrigerators**

		Benefits											Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Cost (F1)	Winter Demand Cost (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2006	0 0066	$5,710	14,275	27,979	$0 074	$0 036	24	24	$0.00	$0 00	$7,785	$17,130	$0	$17,130	($9,345)
2007	0 0133	$5,710	28,550	55,958	$0 079	$0 039	48	48	$0 00	$0 00	$10,109	17,130	$0	17,130	(7,021)
2008	0.0133	$5,710	42,825	83,937	$0.083	$0 041	72	72	$0 00	$0 00	$12,704	17,130	$0	17,130	(4,426)
2009	0.0132	$0	42,825	83,937	$0 088	$0.043	72	72	$0 00	$0 00	$7,413	0	$0	0	7,413
2010	0.0132	$0	42,825	83,937	$0.094	$0 046	72	72	$0 00	$0 00	$7,858	0	$0	0	7,858
2011	0.0132	0	42,825	83,937	$0 099	$0 049	72	72	$0 00	$0 00	$8,330	0	$0	0	8,330
2012	0.0132	0	42,825	83,937	$0 105	$0 052	72	72	$0 00	$0 00	$8,829	0	$0	0	8,829
2013	0.0131	0	42,825	83,937	$0 111	$0 055	72	72	$0.00	$0.00	$9,359	0	$0	0	9,359
2014	0 0131	0	42,825	83,937	$0 118	$0 058	72	72	$0 00	$0 00	$9,921	0	$0	0	9,921
2015	0.0131	0	42,825	83,937	$0 125	$0 061	72	72	$0.00	$0 00	$10,516	0	$0	0	10,516
2016	0 0131	0	0	0	$0 133	$0 065	0	0	$0 00	$0 00	$0	0	$0	0	0
2017	0.0130	0	0	0	$0 141	$0 069	0	0	$0 00	$0 00	$0	0	$0	0	0
2018	0 0130	0	0	0	$0 149	$0 073	0	0	$0.00	$0 00	$0	0	$0	0	0
2019	0.0130	0	0	0	$0 158	$0 078	0	0	$0 00	$0 00	$0	0	$0	0	0
2020	0 0130	0	0	0	$0 167	$0.082	0	0	$0.00	$0 00	$0	0	$0	0	0
2021	0 0129	0	0	0	$0 177	$0 087	0	0	$0 00	$0 00	$0	0	$0	0	0
			385,425	755,433							$92,823	$51,390	$0	$51,390	$41,433
											$68,645	47,956	0	47,956	20,690

Total NPV = $20,690
Benefit/Cost Ratio = 1 43

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part (21) x Participants (22)
(C2) = Energy Reduction/Part (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part (20) x Participants (22)
(E2) = kW Demand Reduction/Part (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM

Intergrated Electric System Cost-Effectiveness Analysis

Company **Montana-Dakota Utilities Co.**

Project **Energy Star Freezers**

Input Data

1) Retail Rate Summer ($/kWh) =	$0 06987
1a) Retail Rate Winter ($/kWh) =	$0 03431
Escalation Rate =	6 00%
2)Avg System Energy Cost ($/kWh) =	$0 01471
Escalation Rate =	2 15%
3) Retail Summer Demand Cost ($/kW/season) =	$0.00
3a) Retail Winter Demand Cost ($/kW/season) =	$0 00
Escalation Rate =	6 00%
4) System Summer Demand Cost ($/kW/yr)	74.46
Escalation Rate =	2 15%
5) Variable O&M ($/kWh) =	$0.00
Escalation Rate =	1 15%
6) Environmental Damage Factor =	15%
Escalation Rate =	2 15%
7) Total Sales by class (kWh) =	680,614,000
Growth Rate =	0.23%
8) Total Customers by class =	85,712
Growth Rate =	0.18%
9) Utility Discount Rate =	7 34%
10) Social Discount Rate(Tbill) =	4 97%
11) General Input Data Year =	2005
12) Project Analysis Year 1 =	2006
12a) Project Analysis Year 2 =	2007
13) Effective Fed & State Income Tax Rate =	39 00%
14) System Annual Line loss factor	7.88%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$5,000
Direct Operating Costs =	$0
Incentive Costs =	$4,400
Total Utility Project Costs Year 1 =	**$9,400**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$5,000
Direct Operating Costs =	$0
Incentive Costs =	$4,400
Total Utility Project Costs Year 2 =	**$9,400**
15b) Total Utilty Cost Year 3 =	**$9,400**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$30 00
Escalation Rate =	2 15%
17) Other Participant Costs (Annual $/Part) =	$0.00
Escalation Rate =	2.15%
18) Project Life (Years) =	10
20) Avg Summer kW/part Saved =	0.035
20a) Avg Winter kW/part Saved =	0.035
21) Avg Summer kWh/Part. Saved =	18
21a) Avg Winter kWh/Part Saved =	37
22) Number of Participants (First Year) =	440
22a) Number of Participants (Second Year) =	440
22a) Number of Participants (Third Year) =	440
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$10.00

Demand-Side Management Program - DSM
Intergrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Energy Star Freezers**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	10
Total Progam Cost (Utility)	$28,200
Total Program Participants	1,320
Utility Cost per Participant (First Year) =	$21.36
Utility Cost per Participant (Program) =	$21.36
Total Summer kW Reduction	46
Total Winter kW Reduction	46
Total Summer Energy Reduction (kWh)	213,840
Total Winter Energy Reduction (kWh)	439,560
Societal Cost per kwh	$0.07

Test Results

	NPV	B/C
Utility Test	$1,219	1.04
Ratepayer Test	$11,438	1.47
Societal Benefit Test	($4,514)	0.90
Participant Test	$5,280	1 14

Table 1

Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**

Project: **Energy Star Freezers**

		Cost of Energy Saved						Project Cost			Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Peak Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2006	24,200	$0 0150	$0	15	$78 93	$1,579	$9,400	477	$9,877	($8,298)
2	2007	48,400	$0.0153	0	31	$83 66	3,320	9,400	988	10,388	(7,068)
3	2008	72,600	$0 0157	0	46	$88 68	5,235	9400	1,536	10,936	(5,700)
4	2009	72,600	$0 0160	0	46	$94 00	5,506	0	1,594	1,594	3,912
5	2010	72,600	$0 0164	0	46	$99 64	5,791	0	1,656	1,656	4,135
6	2011	72,600	$0 0167	0	46	$105.62	6,093	0	1,723	1,723	4,371
7	2012	72,600	$0 0171	0	46	$111.96	6,412	0	1,794	1,794	4,618
8	2013	72,600	$0 0174	0	46	$118 68	6,749	0	1,870	1,870	4,879
9	2014	72,600	$0.0178	0	46	$125 80	7,105	0	1,951	1,951	5,154
10	2015	72,600	$0 0182	0	46	$133.35	7,482	0	2,037	2,037	5,444
11	2016	0	$0.0186	0	0	$141 35	0	0	0	0	0
12	2017	0	$0 0190	0	0	$149 83	0	0	0	0	0
13	2018	0	$0 0194	0	0	$158.82	0	0	0	0	0
14	2019	0	$0.0198	0	0	$168 35	0	0	0	0	0
15	2020	0	$0 0202	0	0	$178 45	0	0	0	0	0
16	2021	0	$0.0207	0	0	$189 15	0	0	0	0	0
Total =		653,400			416		$55,272	$28,200	$15,624	$43,824	$11,449
NPV =							35,954	24,516	10,219	34,735	1,219

Total NPV = $1,219

Benefit/Cost Ratio = 1.04

(A) = Energy Reduction/Part (21+ 21a) x Participants (22)

(B) = System Energy Cost (2)

(C) = (A) x Variable O&M (5)

(D) = kW demand Reduction/Part (20) x Participants (22)

(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)

(G) = Total Utility Project Costs (15)

(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]

(I) = (G) + (H)

(J) = (F) - (I)

H-22

Table 2
Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**
Project: **Energy Star Freezers**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2006	$364	$0	$1,215	$1,579	$9,400	$9,400	($7,821)
2007	743	0	2,577	3,320	9,400	9,400	(6,080)
2008	1,138	0	4,097	5,235	9,400	9,400	(4,165)
2009	1,163	0	4,343	5,506	0	0	5,506
2010	1,188	0	4,604	5,791	0	0	5,791
2011	1,213	0	4,880	6,093	0	0	6,093
2012	1,239	0	5,173	6,412	0	0	6,412
2013	1,266	0	5,483	6,749	0	0	6,749
2014	1,293	0	5,812	7,105	0	0	7,105
2015	1,321	0	6,161	7,482	0	0	7,482
2016	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0
Total =	$10,929	$0	$44,344	$55,272	$28,200	$28,200	$27,072
NPV =	7,214	0	28,740	35,954	24,516	24,516	11,438

Total NPV = $11,438
Benefit/Cost Ratio = 1 47

(A) = Energy Reduction/Part. (21 + 21a) x Participants (22) x Energy Cost (2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW Demand Reduction/Part (20) x Participants (22) x System Demand Cost (4)
(D) = (A) + (B) + (C)
(E) = Total Utility Project Costs (15)
(F) = (E)
(G) = (D) - (F)

Table 3

This test measures the net cost of the program based on total cost including environmental externalities and both the participant's and utility's costs.

Societal Benefit Test

Compar **Montana-Dakota Utilities Co.**
Project: **Energy Star Freezers**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2006	$364	$0	$1,215	$242	$1,821	$9,400	$13,200	$4,400	$18,200	($16,379)
2007	$743	$0	$2,577	$520	3,839	9,400	13,200	$4,400	18,200	(14,361)
2008	$1,138	$0	$4,097	$837	6,073	9400	13,200	$4,400	18,200	(12,127)
2009	$1,163	$0	$4,343	$899	6,405	0	0	$0	0	6,405
2010	$1,188	$0	$4,604	$966	6,758	0	0	$0	0	6,758
2011	$1,213	$0	$4,880	$1,038	7,132	0	0	$0	0	7,132
2012	$1,239	$0	$5,173	$1,116	7,528	0	0	$0	0	7,528
2013	$1,266	$0	$5,483	$1,200	7,949	0	0	$0	0	7,949
2014	$1,293	$0	$5,812	$1,291	8,396	0	0	$0	0	8,396
2015	$1,321	$0	$6,161	$1,388	8,870	0	0	$0	0	8,870
2016	$0	$0	$0	$0	0	0	0	$0	0	0
2017	$0	$0	$0	$0	0	0	0	$0	0	0
2018	$0	$0	$0	$0	0	0	0	$0	0	0
2019	$0	$0	$0	$0	0	0	0	$0	0	0
2020	$0	$0	$0	$0	0	0	0	$0	0	0
2021	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$10,929	$0	$44,344	$9,498	$64,770	$28,200	$39,600	$13,200	$54,600	$10,170
NPV =	7,214	0	28,740	6,999	42,953	24,516	34,426	11,475	47,467	(4,514)

Total NPV = ($4,514)
Benefit/Cost Ratio = 0 90

(A) = Energy Reduction/Part. (21 + 21a) x Participants (22) x Energy Cost (2)
(B) = Energy Reduction/Part (21) x Participants (22) x Vanable O&M (5)
(C) = kW Demand Reduction/Part. (20) x Participants (22) x System Demand Cost (4)
(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)
(E) = (A) + (B) + (C) + (D)
(F) = Total Utility Project Costs (15)
(G) = Direct (16) + Other (17) Participant Costs x Participants (22)
(H) = Incentive Costs (15)
(I) = (F) + (G) - (H)
(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Energy Star Freezers**

Year	Ratio of Part. to Total Customers (A)	Benefits: Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Cost (F1)	Winter Demand Cost (F2)	Total Annual Benefits (G)	Costs: Direct Part Costs (H)	Other Part Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2006	0 0051	$4,400	7,920	16,280	$0 074	$0 036	15	15	$0 00	$0 00	$5,579	$13,200	$0	$13,200	($7,621)
2007	0.0102	$4,400	15,840	32,560	$0 079	$0 039	31	31	$0 00	$0 00	$6,899	13,200	$0	13,200	(6,301)
2008	0.0102	$4,400	23,760	48,840	$0.083	$0 041	46	46	$0 00	$0 00	$8,373	13,200	$0	13,200	(4,827)
2009	0 0102	$0	23,760	48,840	$0 088	$0 043	46	46	$0 00	$0 00	$4,211	0	$0	0	4,211
2010	0.0102	$0	23,760	48,840	$0.094	$0 046	46	46	$0 00	$0 00	$4,464	0	$0	0	4,464
2011	0 0102	0	23,760	48,840	$0.099	$0 049	46	46	$0 00	$0 00	$4,732	0	$0	0	4,732
2012	0.0101	0	23,760	48,840	$0 105	$0 052	46	46	$0.00	$0.00	$5,016	0	$0	0	5,016
2013	0.0101	0	23,760	48,840	$0 111	$0 055	46	46	$0.00	$0 00	$5,317	0	$0	0	5,317
2014	0 0101	0	23,760	48,840	$0 118	$0 058	46	46	$0 00	$0 00	$5,636	0	$0	0	5,636
2015	0 0101	0	23,760	48,840	$0 125	$0 061	46	46	$0.00	$0 00	$5,974	0	$0	0	5,974
2016	0 0101	0	0	0	$0 133	$0.065	0	0	$0 00	$0 00	$0	0	$0	0	0
2017	0 0100	0	0	0	$0.141	$0 069	0	0	$0 00	$0 00	$0	0	$0	0	0
2018	0 0100	0	0	0	$0.149	$0 073	0	0	$0 00	$0.00	$0	0	$0	0	0
2019	0.0100	0	0	0	$0.158	$0 078	0	0	$0.00	$0 00	$0	0	$0	0	0
2020	0 0100	0	0	0	$0 167	$0 082	0	0	$0.00	$0 00	$0	0	$0	0	0
2021	0.0100	0	0	0	$0 177	$0 087	0	0	$0 00	$0 00	$0	0	$0	0	0
			213,840	439,560							$56,200	$39,600	$0	$39,600	$16,600
											$42,233	36,954	0	36,954	5,280

H-24

Total NPV = $5,280
Benefit/Cost Ratio = 1 14

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part (21) x Participants (22)
(C2) = Energy Reduction/Part (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part (20) x Participants (22)
(E2) = kW Demand Reduction/Part (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Company. **Montana-Dakota Utilities Co.**
Project **Residential High Efficiency Air Conditioning**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.06987
1a) Retail Rate Winter ($/kWh) =	$0 03431
Escalation Rate =	6 00%
2)Avg. System Energy Cost ($/kWh) =	$0 01471
Escalation Rate =	2 15%
3) Retail Summer Demand Cost ($/kW/season) =	$0.00
3a) Retail Winter Demand Cost ($/kW/season) =	$0.00
Escalation Rate =	6 00%
4) System Summer Demand Cost ($/kW/yr)	74 46
Escalation Rate =	2.15%
5) Variable O&M ($/kWh) =	$0 00
Escalation Rate =	1 15%
6) Environmental Damage Factor =	15%
Escalation Rate =	2 15%
7) Total Sales by class (kWh) =	680,614,000
Growth Rate =	0.23%
8) Total Customers by class =	85,712
Growth Rate =	0.18%
9) Utility Discount Rate =	7.34%
10) Social Discount Rate(Tbill) =	4 97%
11) General Input Data Year =	2005
12) Project Analysis Year 1 =	2006
12a) Project Analysis Year 2 =	2007
13) Effective Fed & State Income Tax Rate =	39 00%
14) System Annual Line loss factor	7 88%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$5,000
Direct Operating Costs =	$0
Incentive Costs =	$66,142
Total Utility Project Costs Year 1 =	**$71,142**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$5,000
Direct Operating Costs =	$0
Incentive Costs =	$66,142
Total Utility Project Costs Year 2 =	**$71,142**
15b) Total Utilty Cost Year 3 =	**$71,142**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$800 00
Escalation Rate =	2.15%
17) Other Participant Costs (Annual $/Part) =	$0.00
Escalation Rate =	2.15%
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	0 7
20a) Avg Winter kW/part Saved =	0
21) Avg. Summer kWh/Part Saved =	617
21a) Avg Winter kWh/Part. Saved =	0
22) Number of Participants (First Year) =	367
22a) Number of Participants (Second Year) =	367
22a) Number of Participants (Third Year) =	367
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$180.00

Demand-Side Management Program - DSM

Intergrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Residential High Efficiency Air Conditioning**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$213,426
Total Program Participants	1,101
Utility Cost per Participant (First Year) =	$193.85
Utility Cost per Participant (Program) =	$193.85
Total Summer kW Reduction	771
Total Winter kW Reduction	0
Total Summer Energy Reduction (kWh)	9,510,438
Total Winter Energy Reduction (kWh)	0
Societal Cost per kwh	$0.08

Test Results

	NPV	B/C
Utility Test	$456,860	2.27
Ratepayer Test	$631,401	4.40
Societal Benefit Test	$215,951	1.28
Participant Test	$5,019	1.01

Table 1
Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project· **Residential High Efficiency Air Conditioning**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Peak Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2006	226,439	$0 0150	$0	257	$78 93	$23,679	$71,142	7,575	$78,717	($55,038)
2	2007	452,878	$0 0153	0	514	$83 66	49,938	71,142	15,062	86,204	(36,266)
3	2008	679,317	$0.0157	0	771	$88.68	78,999	71142	22,456	93,598	(14,598)
4	2009	679,317	$0.0160	0	771	$94.00	83,329	0	22,316	22,316	61,013
5	2010	679,317	$0.0164	0	771	$99.64	87,910	0	22,173	22,173	65,737
6	2011	679,317	$0.0167	0	771	$105.62	92,757	0	22,028	22,028	70,729
7	2012	679,317	$0.0171	0	771	$111.96	97,885	0	21,879	21,879	76,006
8	2013	679,317	$0.0174	0	771	$118.68	103,312	0	21,727	21,727	81,585
9	2014	679,317	$0.0178	0	771	$125.80	109,054	0	21,571	21,571	87,483
10	2015	679,317	$0 0182	0	771	$133.35	115,132	0	21,412	21,412	93,719
11	2016	679,317	$0 0186	0	771	$141 35	121,564	0	21,250	21,250	100,313
12	2017	679,317	$0 0190	0	771	$149 83	128,371	0	21,085	21,085	107,286
13	2018	679,317	$0.0194	0	771	$158.82	135,577	0	20,916	20,916	114,661
14	2019	679,317	$0 0198	0	771	$168.35	143,204	0	20,743	20,743	122,461
15	2020	679,317	$0.0202	0	771	$178 45	151,278	0	20,566	20,566	130,712
16	2021	0	$0.0207	0	0	$189 15	0	0	0	0	0
Total =		9,510,438			10,790		$1,521,989	$213,426	$302,758	$516,184	$1,005,804
NPV =							816,943	185,542	174,542	360,084	456,860

Total NPV = $456,860
Benefit/Cost Ratio = 2.27

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **Residential High Efficiency Air Conditioning**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2006	$3,403	$0	$20,277	$23,679	$71,142	$71,142	($47,463)
2007	6,951	0	42,986	49,938	71,142	71,142	(21,204)
2008	10,651	0	68,348	78,999	71,142	71,142	7,857
2009	10,880	0	72,449	83,329	0	0	83,329
2010	11,114	0	76,796	87,910	0	0	87,910
2011	11,353	0	81,404	92,757	0	0	92,757
2012	11,597	0	86,288	97,885	0	0	97,885
2013	11,847	0	91,465	103,312	0	0	103,312
2014	12,101	0	96,953	109,054	0	0	109,054
2015	12,361	0	102,770	115,132	0	0	115,132
2016	12,627	0	108,936	121,564	0	0	121,564
2017	12,899	0	115,473	128,371	0	0	128,371
2018	13,176	0	122,401	135,577	0	0	135,577
2019	13,459	0	129,745	143,204	0	0	143,204
2020	13,749	0	137,530	151,278	0	0	151,278
2021	0	0	0	0	0	0	0
Total =	$168,169	$0	$1,353,820	$1,521,989	$213,426	$213,426	$1,308,563
NPV =	93,794	0	723,149	816,943	185,542	185,542	631,401

Total NPV = $631,401

Benefit/Cost Ratio = 4.40

(A) = Energy Reduction/Part. (21 + 21a) x Participants (22) x Energy Cost (2)

(B) = Energy Reduction/Part (21) x Participants (22) x Variable O&M (5)

(C) = kW Demand Reduction/Part (20) x Participants (22) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Benefit Test

This test measures the net cost of the program based on total cost including environmental externalities and both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**
Project: **Residential High Efficiency Air Conditioning**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2006	$3,403	$0	$20,277	$3,628	$27,307	$71,142	$293,600	$66,060	$298,682	($271,375)
2007	$6,951	$0	$42,986	$7,816	57,754	71,142	293,600	$66,060	298,682	(240,928)
2008	$10,651	$0	$68,348	$12,631	91,630	71142	293,600	$66,060	298,682	(207,052)
2009	$10,880	$0	$72,449	$13,609	96,939	0	0	$0	0	96,939
2010	$11,114	$0	$76,796	$14,666	102,576	0	0	$0	0	102,576
2011	$11,353	$0	$81,404	$15,808	108,564	0	0	$0	0	108,564
2012	$11,597	$0	$86,288	$17,040	114,925	0	0	$0	0	114,925
2013	$11,847	$0	$91,465	$18,372	121,683	0	0	$0	0	121,683
2014	$12,101	$0	$96,953	$19,810	128,864	0	0	$0	0	128,864
2015	$12,361	$0	$102,770	$21,363	136,495	0	0	$0	0	136,495
2016	$12,627	$0	$108,936	$23,042	144,605	0	0	$0	0	144,605
2017	$12,899	$0	$115,473	$24,855	153,227	0	0	$0	0	153,227
2018	$13,176	$0	$122,401	$26,815	162,392	0	0	$0	0	162,392
2019	$13,459	$0	$129,745	$28,932	172,137	0	0	$0	0	172,137
2020	$13,749	$0	$137,530	$31,221	182,499	0	0	$0	0	182,499
2021	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$168,169	$0	$1,353,820	$279,609	$1,801,597	$213,426	$880,800	$198,180	$896,046	$905,551
NPV =	93,794	0	723,149	177,986	994,929	185,542	765,724	172,288	778,978	215,951

Total NPV = $215,951
Benefit/Cost Ratio = 1.28

(A) = Energy Reduction/Part (21 + 21a) x Participants (22) x Energy Cost (2)
(B) = Energy Reduction/Part (21) x Participants (22) x Variable O&M (5)
(C) = kW Demand Reduction/Part (20) x Participants (22) x System Demand Cost (4)
(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)
(E) = (A) + (B) + (C) + (D)
(F) = Total Utility Project Costs (15)
(G) = Direct (16) + Other (17) Participant Costs x Participants (22)
(H) = Incentive Costs (15)
(I) = (F) + (G) - (H)
(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential High Efficiency Air Conditioning**

		Benefits										Costs				
Year	Ratio of Part to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Cost (F1)	Winter Demand Cost (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2006	0 0043	$66,060	226,439	0	$0.074	$0 036	257	0	$0 00	$0.00	$82,831	$293,600	$0	$293,600	($210,769)
2007	0 0085	$66,060	452,878	0	$0.079	$0.039	514	0	$0.00	$0 00	$101,614	293,600	$0	293,600	(191,986)
2008	0.0085	$66,060	679,317	0	$0.083	$0 041	771	0	$0 00	$0.00	$122,590	293,600	$0	293,600	(171,010)
2009	0.0085	$0	679,317	0	$0.088	$0 043	771	0	$0.00	$0.00	$59,922	0	$0	0	59,922
2010	0 0085	$0	679,317	0	$0.094	$0 046	771	0	$0.00	$0.00	$63,517	0	$0	0	63,517
2011	0.0085	0	679,317	0	$0.099	$0.049	771	0	$0.00	$0.00	$67,328	0	$0	0	67,328
2012	0 0085	0	679,317	0	$0 105	$0 052	771	0	$0.00	$0 00	$71,368	0	$0	0	71,368
2013	0 0084	0	679,317	0	$0.111	$0 055	771	0	$0 00	$0.00	$75,650	0	$0	0	75,650
2014	0 0084	0	679,317	0	$0.118	$0 058	771	0	$0 00	$0 00	$80,189	0	$0	0	80,189
2015	0.0084	0	679,317	0	$0.125	$0 061	771	0	$0.00	$0.00	$85,001	0	$0	0	85,001
2016	0 0084	0	679,317	0	$0.133	$0.065	771	0	$0 00	$0 00	$90,101	0	$0	0	90,101
2017	0.0084	0	679,317	0	$0 141	$0 069	771	0	$0 00	$0 00	$95,507	0	$0	0	95,507
2018	0 0084	0	679,317	0	$0.149	$0 073	771	0	$0.00	$0 00	$101,237	0	$0	0	101,237
2019	0 0084	0	679,317	0	$0 158	$0 078	771	0	$0.00	$0 00	$107,311	0	$0	0	107,311
2020	0 0083	0	679,317	0	$0.167	$0 082	771	0	$0.00	$0 00	$113,750	0	$0	0	113,750
2021	0.0083	0	0	0	$0.177	$0 087	0	0	$0.00	$0.00	$0	0	$0	0	0
			9,510,438	0							$1,317,916	$880,800	$0	$880,800	$437,116
											$826,955	821,936	0	821,936	5,019

Total NPV = $5,019
Benefit/Cost Ratio = 1.01

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part (21) x Participants (22)
(C2) = Energy Reduction/Part (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part (20) x Participants (22)
(E2) = kW Demand Reduction/Part (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM

Intergrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**

Project **Commercial High Efficiency Air Conditioning**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.03336
1a) Retail Rate Winter ($/kWh) =	$0 03336
Escalation Rate =	6.00%
2)Avg System Energy Cost ($/kWh) =	$0.01471
Escalation Rate =	2.15%
3) Retail Summer Demand Cost ($/kW/season) =	$44.90
3a) Retail Winter Demand Cost ($/kW/season) =	$65.79
Escalation Rate =	6 00%
4) System Summer Demand Cost ($/kW/yr)	74 46
Escalation Rate =	2.15%
5) Variable O&M ($/kWh) =	$0.00
Escalation Rate =	1 15%
6) Environmental Damage Factor =	15%
Escalation Rate =	2 15%
7) Total Sales by class (kWh) =	680,614,000
Growth Rate =	0.23%
8) Total Customers by class =	16,592
Growth Rate =	0.18%
9) Utility Discount Rate =	7 34%
10) Social Discount Rate(Tbill) =	4 97%
11) General Input Data Year =	2005
12) Project Analysis Year 1 =	2006
12a) Project Analysis Year 2 =	2007
13) Effective Fed & State Income Tax Rate =	39 00%
14) System Annual Line loss factor	7 88%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$5,000
Direct Operating Costs =	$0
Incentive Costs =	$16,212
Total Utility Project Costs Year 1 =	**$21,212**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$5,000
Direct Operating Costs =	$0
Incentive Costs =	$16,212
Total Utility Project Costs Year 2 =	**$21,212**
15b) Total Utilty Cost Year 3 =	$21,212.00
15c) Total Utilty Cost Year 4 =	$0.00
15d) Total Utility Cost Year 5 =	$0.00
16) Direct Participant Costs ($/Part.) =	$1,000
Escalation Rate =	2 15%
17) Other Participant Costs (Annual $/Part.) =	$0
Escalation Rate =	2 15%
18) Project Life (Years) =	15
20) Avg Summer kW/part Saved =	0 9
20a) Avg Winter kW/part Saved =	0
21) Avg. Summer kWh/Part. Saved =	900
21a) Avg. Winter kWh/Part Saved =	0
22) Number of Participants (First Year) =	65
22a) Number of Participants (Second Year) =	65
22a) Number of Participants (Third Year) =	65
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$250.00

Demand-Side Management Program - DSM
Intergrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Commercial High Efficiency Air Conditioning**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$63,636
Total Program Participants	195
Utility Cost per Participant (First Year) =	$326.34
Utility Cost per Participant (Program) =	$326.34
Total Summer kW Reduction	176
Total Winter kW Reduction	0
Total Summer Energy Reduction (kWh)	2,457,000
Total Winter Energy Reduction (kWh)	0
Societal Cost per kwh	$0.07

Test Results

	NPV	B/C
Utility Test	$119,776	2.73
Ratepayer Test	$133,581	3.41
Societal Benefit Test	$47,580	1.26
Participant Test	$49,305	1.27

Table 1
Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial High Efficiency Air Conditioning**

		Cost of Energy Saved						Project Cost			
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Peak Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	Cost of Energy Saved Less Project Cost (J)
1	2006	58,500	$0 0150	$0	59	$78 93	$5,496	$21,212	654	$21,866	($16,370)
2	2007	117,000	$0 0153	0	117	$83 66	11,584	21,212	1,285	22,497	(10,913)
3	2008	175,500	$0.0157	0	176	$88 68	18,316	21212	1,893	23,105	(4,789)
4	2009	175,500	$0 0160	0	176	$94 00	19,309	0	1,857	1,857	17,452
5	2010	175,500	$0.0164	0	176	$99.64	20,359	0	1,820	1,820	18,539
6	2011	175,500	$0.0167	0	176	$105 62	21,470	0	1,782	1,782	19,688
7	2012	175,500	$0.0171	0	176	$111 96	22,645	0	1,744	1,744	20,901
8	2013	175,500	$0 0174	0	176	$118.68	23,889	0	1,704	1,704	22,184
9	2014	175,500	$0 0178	0	176	$125 80	25,204	0	1,664	1,664	23,540
10	2015	175,500	$0 0182	0	176	$133.35	26,596	0	1,623	1,623	24,973
11	2016	175,500	$0 0186	0	176	$141.35	28,069	0	1,581	1,581	26,487
12	2017	175,500	$0 0190	0	176	$149 83	29,627	0	1,539	1,539	28,089
13	2018	175,500	$0.0194	0	176	$158.82	31,277	0	1,495	1,495	29,782
14	2019	175,500	$0 0198	0	176	$168 35	33,022	0	1,450	1,450	31,572
15	2020	175,500	$0 0202	0	176	$178.45	34,870	0	1,405	1,405	33,465
16	2021	0	$0.0207	0	0	$189.15	0	0	0	0	0
Total =		2,457,000			2,457		$351,731	$63,636	$23,497	$87,133	$264,598
NPV =							188,903	55,322	13,806	69,128	119,776

Total NPV = $119,776
Benefit/Cost Ratio = 2.73

(A) = Energy Reduction/Part (21+ 21a) x Participants (22)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **Commercial High Efficiency Air Conditioning**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2006	$879	$0	$4,617	$5,496	$21,212	$21,212	($15,716)
2007	1,796	0	9,789	11,584	21,212	21,212	(9,628)
2008	2,752	0	15,564	18,316	21,212	21,212	(2,896)
2009	2,811	0	16,498	19,309	0	0	19,309
2010	2,871	0	17,488	20,359	0	0	20,359
2011	2,933	0	18,537	21,470	0	0	21,470
2012	2,996	0	19,649	22,645	0	0	22,645
2013	3,061	0	20,828	23,889	0	0	23,889
2014	3,126	0	22,078	25,204	0	0	25,204
2015	3,194	0	23,402	26,596	0	0	26,596
2016	3,262	0	24,806	28,069	0	0	28,069
2017	3,332	0	26,295	29,627	0	0	29,627
2018	3,404	0	27,873	31,277	0	0	31,277
2019	3,477	0	29,545	33,022	0	0	33,022
2020	3,552	0	31,318	34,870	0	0	34,870
2021	0	0	0	0	0	0	0
Total =	$43,446	$0	$308,285	$351,731	$63,636	$63,636	$288,095
NPV =	24,232	0	164,672	188,903	55,322	55,322	133,581

Total NPV = $133,581

Benefit/Cost Ratio = 3 41

(A) = Energy Reduction/Part (21 + 21a) x Participants (22) x Energy Cost (2)

(B) = Energy Reduction/Part (21) x Participants (22) x Variable O&M (5)

(C) = kW Demand Reduction/Part (20) x Participants (22) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3
Societal Benefit Test

This test measures the net cost of the program based on total cost including environmental externalities and both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**
Project: **Commercial High Efficiency Air Conditioning**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2006	$879	$0	$4,617	$842	$6,338	$21,212	$65,000	$16,250	$69,962	($63,624)
2007	$1,796	$0	$9,789	$1,813	13,398	21,212	65,000	$16,250	69,962	(56,564)
2008	$2,752	$0	$15,564	$2,928	21,244	21,212	65,000	$16,250	69,962	(48,718)
2009	$2,811	$0	$16,498	$3,154	22,462	0	0	$0	0	22,462
2010	$2,871	$0	$17,488	$3,397	23,755	0	0	$0	0	23,755
2011	$2,933	$0	$18,537	$3,659	25,129	0	0	$0	0	25,129
2012	$2,996	$0	$19,649	$3,942	26,587	0	0	$0	0	26,587
2013	$3,061	$0	$20,828	$4,248	28,137	0	0	$0	0	28,137
2014	$3,126	$0	$22,078	$4,578	29,782	0	0	$0	0	29,782
2015	$3,194	$0	$23,402	$4,935	31,531	0	0	$0	0	31,531
2016	$3,262	$0	$24,806	$5,320	33,389	0	0	$0	0	33,389
2017	$3,332	$0	$26,295	$5,736	35,364	0	0	$0	0	35,364
2018	$3,404	$0	$27,873	$6,186	37,463	0	0	$0	0	37,463
2019	$3,477	$0	$29,545	$6,672	39,694	0	0	$0	0	39,694
2020	$3,552	$0	$31,318	$7,196	42,066	0	0	$0	0	42,066
2021	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$43,446	$0	$308,285	$64,607	$416,338	$63,636	$195,000	$48,750	$209,886	$206,452
NPV =	24,232	0	164,672	41,141	230,045	55,322	169,523	42,381	182,464	47,580

Total NPV = $47,580
Benefit/Cost Ratio = 1 26

(A) = Energy Reduction/Part (21 + 21a) x Participants (22) x Energy Cost (2)
(B) = Energy Reduction/Part (21) x Participants (22) x Variable O&M (5)
(C) = kW Demand Reduction/Part (20) x Participants (22) x System Demand Cost (4)
(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)
(E) = (A) + (B) + (C) + (D)
(F) = Total Utility Project Costs (15)
(G) = Direct (16) + Other (17) Participant Costs x Participants (22)
(H) = Incentive Costs (15)
(I) = (F) + (G) - (H)
(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial High Efficiency Air Conditioning**

		Benefits										Costs				
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Cost (F1)	Winter Demand Cost (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2006	0.0039	$16,250	58,500	0	$0.035	$0.035	59	0	$47.59	$69.74	$21,103	$65,000	$0	$65,000	($43,897)
2007	0.0078	$16,250	117,000	0	$0.037	$0.037	117	0	$50.45	$73.92	$26,538	65,000	$0	65,000	(38,462)
2008	0.0078	$16,250	175,500	0	$0.040	$0.040	176	0	$53.48	$78.36	$32,608	65,000	$0	65,000	(32,392)
2009	0.0078	$0	175,500	0	$0.042	$0.042	176	0	$56.69	$83.06	$17,340	0	$0	0	17,340
2010	0.0078	$0	175,500	0	$0.045	$0.045	176	0	$60.09	$88.04	$18,380	0	$0	0	18,380
2011	0.0078	0	175,500	0	$0.047	$0.047	176	0	$63.69	$93.32	$19,483	0	$0	0	19,483
2012	0.0077	0	175,500	0	$0.050	$0.050	176	0	$67.51	$98.92	$20,652	0	$0	0	20,652
2013	0.0077	0	175,500	0	$0.053	$0.053	176	0	$71.56	$104.86	$21,891	0	$0	0	21,891
2014	0.0077	0	175,500	0	$0.056	$0.056	176	0	$75.86	$111.15	$23,204	0	$0	0	23,204
2015	0.0077	0	175,500	0	$0.060	$0.060	176	0	$80.41	$117.82	$24,597	0	$0	0	24,597
2016	0.0077	0	175,500	0	$0.063	$0.063	176	0	$85.23	$124.89	$26,072	0	$0	0	26,072
2017	0.0077	0	175,500	0	$0.067	$0.067	176	0	$90.35	$132.38	$27,637	0	$0	0	27,637
2018	0.0077	0	175,500	0	$0.071	$0.071	176	0	$95.77	$140.33	$29,295	0	$0	0	29,295
2019	0.0076	0	175,500	0	$0.075	$0.075	176	0	$101.51	$148.74	$31,053	0	$0	0	31,053
2020	0.0076	0	175,500	0	$0.080	$0.080	176	0	$107.61	$157.67	$32,916	0	$0	0	32,916
2021	0.0076	0	0	0	$0.085	$0.085	0	0	$114.06	$167.13	$0	0	$0	0	0
			2,457,000	0							$372,768	$195,000	$0	$195,000	$177,768
											$231,273	181,968	0	181,968	49,305

Total NPV = $49,305
Benefit/Cost Ratio = 1.27

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part (21) x Participants (22)
(C2) = Energy Reduction/Part (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part (20) x Participants (22)
(E2) = kW Demand Reduction/Part (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM

Intergrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**

Project **Residential Air Conditioning Cycling**

Input Data

1) Retail Rate Summer ($/kWh) =	$0 06987
1a) Retail Rate Winter ($/kWh) =	$0 03431
Escalation Rate =	6 00%
2)Avg System Energy Cost ($/kWh) =	$0 01471
Escalation Rate =	2 15%
3) Retail Summer Demand Cost ($/kW/season) =	$0.00
3a) Retail Winter Demand Cost ($/kW/season) =	$0.00
Escalation Rate =	6 00%
4) System Summer Demand Cost ($/kW/yr)	74.46
Escalation Rate =	2 15%
5) Variable O&M ($/kWh) =	$0.00
Escalation Rate =	1.15%
6) Environmental Damage Factor =	15%
Escalation Rate =	2.15%
7) Total Sales by class (kWh) =	680,614,000
Growth Rate =	0.23%
8) Total Customers by class =	85,712
Growth Rate =	0 18%
9) Utility Discount Rate =	7 34%
10) Social Discount Rate(Tbill) =	4 97%
11) General Input Data Year =	2005
12) Project Analysis Year 1 =	2006
12a) Project Analysis Year 2 =	2007
13) Effective Fed & State Income Tax Rate =	39 00%
14) System Annual Line loss factor	7 88%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$1,000
Direct Operating Costs =	$941,819
Incentive Costs =	$292,904
Total Utility Project Costs Year 1 =	**$1,235,723**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$1,000
Direct Operating Costs =	$470,909
Incentive Costs =	$146,452
Total Utility Project Costs Year 2 =	**$618,361**
15b) Total Utilty Cost Year 3 =	$618,361
15c) Total Utilty Cost Year 4 =	$0
15d) Total Utility Cost Year 5 =	$0
16) Direct Participant Costs ($/Part) =	$0.00
Escalation Rate =	2 15%
17) Other Participant Costs (Annual $/Part.) =	$0 00
Escalation Rate =	2.15%
18) Project Life (Years) =	10
20) Avg Summer kW/part Saved =	1
20a) Avg Winter kW/part Saved =	0
21) Avg Summer kWh/Part Saved =	150
21a) Avg Winter kWh/Part Saved =	0
22) Number of Participants (First Year) =	3,307
22a) Number of Participants (Second Year) =	1,654
22a) Number of Participants (Third Year) =	1,654
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$0.00

Demand-Side Management Program - DSM

Intergrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Residential Air Conditioning Cycling**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	10
Total Progam Cost (Utility)	$2,472,445
Total Program Participants	6,615
Utility Cost per Participant (First Year) =	$373.67
Utility Cost per Participant (Program) =	$373.76
Total Summer kW Reduction	6,615
Total Winter kW Reduction	0
Total Summer Energy Reduction (kWh)	9,178,200
Total Winter Energy Reduction (kWh)	0
Societal Cost per kwh	$0.24

Test Results

	NPV	B/C
Utility Test	$1,948,981	1 82
Ratepayer Test	$2,150,280	1.98
Societal Benefit Test	$2,991,912	2.37
Participant Test	$640,020	#DIV/0!

Table 1

Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**

Project: **Residential Air Conditioning Cycling**

		Cost of Energy Saved						Project Cost			Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Peak Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2006	496,050	$0 0150	$0	3,307	$78.93	$268,467	$1,235,723	16,595	$1,252,318	($983,851)
2	2007	744,150	$0 0153	0	4,961	$83 66	426,476	618,361	24,749	643,110	(216,634)
3	2008	992,250	$0 0157	0	6,615	$88.68	602,196	618,361	32,800	651,161	(48,965)
4	2009	992,250	$0 0160	0	6,615	$94 00	637,729	0	32,596	32,596	605,133
5	2010	992,250	$0 0164	0	6,615	$99.64	675,381	0	32,388	32,388	642,993
6	2011	992,250	$0 0167	0	6,615	$105.62	715,279	0	32,175	32,175	683,104
7	2012	992,250	$0 0171	0	6,615	$111 96	757,557	0	31,957	31,957	725,600
8	2013	992,250	$0.0174	0	6,615	$118 68	802,358	0	31,735	31,735	770,623
9	2014	992,250	$0 0178	0	6,615	$125 80	849,834	0	31,508	31,508	818,325
10	2015	992,250	$0 0182	0	6,615	$133 35	900,143	0	31,276	31,276	868,867
11	2016	0	$0.0186	0	0	$141.35	0	0	0	0	0
12	2017	0	$0 0190	0	0	$149 83	0	0	0	0	0
13	2018	0	$0 0194	0	0	$158.82	0	0	0	0	0
14	2019	0	$0 0198	0	0	$168 35	0	0	0	0	0
15	2020	0	$0 0202	0	0	$178 45	0	0	0	0	0
16	2021	0	$0.0207	0	0	$189 15	0	0	0	0	0
Total =		9,178,200			61,188		$6,635,420	$2,472,445	$297,779	$2,770,224	$3,865,195
NPV =							4,338,138	2,187,858	201,299	2,389,157	1,948,981

Total NPV = $1,948,981

Benefit/Cost Ratio = 1 82

(A) = Energy Reduction/Part (21+ 21a) x Participants (22)

(B) = System Energy Cost (2)

(C) = (A) x Variable O&M (5)

(D) = kW demand Reduction/Part (20) x Participants (22)

(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)

(G) = Total Utility Project Costs (15)

(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]

(I) = (G) + (H)

(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **Residential Air Conditioning Cycling**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2006	$7,454	$0	$261,014	$268,467	$1,235,723	$1,235,723	($967,256)
2007	11,422	0	415,053	426,476	618,361	618,361	(191,885)
2008	15,558	0	586,638	602,196	618,361	618,361	(16,165)
2009	15,892	0	621,837	637,729	0	0	637,729
2010	16,234	0	659,147	675,381	0	0	675,381
2011	16,583	0	698,696	715,279	0	0	715,279
2012	16,940	0	740,617	757,557	0	0	757,557
2013	17,304	0	785,054	802,358	0	0	802,358
2014	17,676	0	832,158	849,834	0	0	849,834
2015	18,056	0	882,087	900,143	0	0	900,143
2016	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0
Total =	$153,118	$0	$6,482,302	$6,635,420	$2,472,445	$2,472,445	$4,162,975
NPV =	102,009	0	4,236,129	4,338,138	2,187,858	2,187,858	2,150,280

Total NPV = $2,150,280

Benefit/Cost Ratio = 1.98

(A) = Energy Reduction/Part (21 + 21a) x Participants (22) x Energy Cost (2)

(B) = Energy Reduction/Part (21) x Participants (22) x Variable O&M (5)

(C) = kW Demand Reduction/Part (20) x Participants (22) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3
Societal Benefit Test

This test measures the net cost of the program based on total cost including environmental externalities and both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**
Project: **Residential Air Conditioning Cycling**

	Decreases				Increases					
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2006	$7,454	$0	$261,014	$41,136	$309,603	$1,235,723	$0	$0	$1,235,723	($926,120)
2007	$11,422	$0	$415,053	$66,752	493,227	618,361	0	$0	618,361	(125,134)
2008	$15,558	$0	$586,638	$96,282	698,478	618,361	0	$0	618,361	80,117
2009	$15,892	$0	$621,837	$104,155	741,884	0	0	$0	0	741,884
2010	$16,234	$0	$659,147	$112,676	788,057	0	0	$0	0	788,057
2011	$16,583	$0	$698,696	$121,898	837,177	0	0	$0	0	837,177
2012	$16,940	$0	$740,617	$131,879	889,436	0	0	$0	0	889,436
2013	$17,304	$0	$785,054	$142,681	945,039	0	0	$0	0	945,039
2014	$17,676	$0	$832,158	$154,373	1,004,206	0	0	$0	0	1,004,206
2015	$18,056	$0	$882,087	$167,027	1,067,170	0	0	$0	0	1,067,170
2016	$0	$0	$0	$0	0	0	0	$0	0	0
2017	$0	$0	$0	$0	0	0	0	$0	0	0
2018	$0	$0	$0	$0	0	0	0	$0	0	0
2019	$0	$0	$0	$0	0	0	0	$0	0	0
2020	$0	$0	$0	$0	0	0	0	$0	0	0
2021	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$153,118	$0	$6,482,302	$1,138,858	$7,774,278	$2,472,445	$0	$0	$2,472,445	$5,301,833
NPV =	102,009	0	4,236,129	841,632	5,179,770	2,187,858	0	0	2,187,858	2,991,912

Total NPV = $2,991,912
Benefit/Cost Ratio = 2 37

(A) = Energy Reduction/Part (21 + 21a) x Participants (22) x Energy Cost (2)
(B) = Energy Reduction/Part (21) x Participants (22) x Variable O&M (5)
(C) = kW Demand Reduction/Part. (20) x Participants (22) x System Demand Cost (4)
(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)
(E) = (A) + (B) + (C) + (D)

(F) = Total Utility Project Costs (15)
(G) = Direct (16) + Other (17) Participant Costs x Participants (22)
(H) = Incentive Costs (15)
(I) = (F) + (G) - (H)
(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Air Conditioning Cycling**

		Benefits										Costs				
Year	Ratio of Part to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Cost (F1)	Winter Demand Cost (F2)	Total Annual Benefits (G)	Direct Part Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2006	0 0385	$0	496,050	0	$0.074	$0.036	3,307	0	$0 00	$0.00	$36,739	$0	$0	$0	$36,739
2007	0 0577	$0	744,150	0	$0 079	$0 039	4,961	0	$0 00	$0 00	$58,420	0	$0	0	58,420
2008	0.0576	$0	992,250	0	$0 083	$0 041	6,615	0	$0 00	$0 00	$82,571	0	$0	0	82,571
2009	0 0575	$0	992,250	0	$0 088	$0 043	6,615	0	$0.00	$0 00	$87,526	0	$0	0	87,526
2010	0 0574	$0	992,250	0	$0 094	$0 046	6,615	0	$0.00	$0.00	$92,777	0	$0	0	92,777
2011	0.0573	0	992,250	0	$0 099	$0 049	6,615	0	$0.00	$0.00	$98,344	0	$0	0	98,344
2012	0 0572	0	992,250	0	$0 105	$0 052	6,615	0	$0 00	$0 00	$104,244	0	$0	0	104,244
2013	0 0571	0	992,250	0	$0 111	$0 055	6,615	0	$0 00	$0 00	$110,499	0	$0	0	110,499
2014	0.0570	0	992,250	0	$0 118	$0 058	6,615	0	$0 00	$0 00	$117,129	0	$0	0	117,129
2015	0 0568	0	992,250	0	$0 125	$0 061	6,615	0	$0.00	$0 00	$124,157	0	$0	0	124,157
2016	0 0567	0	0	0	$0 133	$0.065	0	0	$0 00	$0.00	$0	0	$0	0	0
2017	0.0566	0	0	0	$0 141	$0.069	0	0	$0 00	$0.00	$0	0	$0	0	0
2018	0.0565	0	0	0	$0.149	$0.073	0	0	$0 00	$0.00	$0	0	$0	0	0
2019	0.0564	0	0	0	$0 158	$0 078	0	0	$0.00	$0 00	$0	0	$0	0	0
2020	0 0563	0	0	0	$0 167	$0 082	0	0	$0.00	$0 00	$0	0	$0	0	0
2021	0 0562	0	0	0	$0 177	$0.087	0	0	$0.00	$0.00	$0	0	$0	0	0
			9,178,200	0							$912,406	$0	$0	$0	$912,406
											$640,020	0	0	0	640,020

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Total NPV = $640,020
Benefit/Cost Ratio = #DIV/0!

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM

Intergrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**

Project. **Refridgerator Round-Up Program**

Input Data

1) Retail Rate Summer ($/kWh) =	$0 06987
1a) Retail Rate Winter ($/kWh) =	$0 03431
Escalation Rate =	6 00%
2)Avg. System Energy Cost ($/kWh) =	$0.01471
Escalation Rate =	2 15%
3) Retail Summer Demand Cost ($/kW/season) =	$0.00
3a) Retail Winter Demand Cost ($/kW/season) =	$0.00
Escalation Rate =	6 00%
4) System Summer Demand Cost ($/kW/yr)	74.46
Escalation Rate =	2.15%
5) Variable O&M ($/kWh) =	$0 00
Escalation Rate =	1 15%
6) Environmental Damage Factor =	15%
Escalation Rate =	2.15%
7) Total Sales by class (kWh) =	680,614,000
Growth Rate =	0.23%
8) Total Customers by class =	85,712
Growth Rate =	0 18%
9) Utility Discount Rate =	7.34%
10) Social Discount Rate(Tbill) =	4 97%
11) General Input Data Year =	2005
12) Project Analysis Year 1 =	2006
12a) Project Analysis Year 2 =	2007
13) Effective Fed & State income Tax Rate =	39.00%
14) System Annual Line loss factor	7.88%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$5,000
Direct Operating Costs =	$15,625
Incentive Costs =	$10,938
Total Utility Project Costs Year 1 =	**$31,563**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$5,000
Direct Operating Costs =	$15,625
Incentive Costs =	$10,938
Total Utility Project Costs Year 2 =	**$31,563**
15b) Total Utilty Cost Year 3 =	**$31,563.00**
15c) Total Utilty Cost Year 4 =	**$0.00**
15d) Total Utility Cost Year 5 =	**$0.00**
16) Direct Participant Costs ($/Part) =	$0 00
Escalation Rate =	2 15%
17) Other Participant Costs (Annual $/Part.) =	$0.00
Escalation Rate =	2.15%
18) Project Life (Years) =	10
20) Avg Summer kW/part. Saved =	0 495
20a) Avg Winter kW/part Saved =	0 495
21) Avg Summer kWh/Part Saved =	389
21a) Avg Winter kWh/Part. Saved =	777
22) Number of Participants (First Year) =	313
22a) Number of Participants (Second Year) =	313
22a) Number of Participants (Third Year) =	313
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$35 00

Demand-Side Management Program - DSM
Intergrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utillties Co.**
Project:	**Refridgerator Round-Up Program**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	10
Total Progam Cost (Utility)	$94,689
Total Program Participants	939
Utility Cost per Participant (First Year) =	$100.84
Utility Cost per Participant (Program) =	$100.84
Total Summer kW Reduction	465
Total Winter kW Reduction	465
Total Summer Energy Reduction (kWh)	3,287,439
Total Winter Energy Reduction (kWh)	6,566,427
Societal Cost per kwh	$0.01

Test Results

	NPV	B/C
Utility Test	$160,942	1.68
Ratepayer Test	$315,621	4.83
Societal Benefit Test	$421,589	8.84
Participant Test	$484,035	#DIV/0!

Table 1

Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Refridgerator Round-Up Program**

t	Year	Cost of Energy Saved						Project Cost			Cost of Energy Saved Less Project Cost
		Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Peak Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2006	364,958	$0 0150	$0	155	$78 93	$17,713	$31,563	7,240	$38,803	($21,090)
2	2007	729,916	$0.0153	0	310	$83 66	37,128	31,563	14,983	46,546	(9,417)
3	2008	1,094,874	$0.0157	0	465	$88 68	58,387	31,563	23,283	54,846	3,541
4	2009	1,094,874	$0.0160	0	465	$94 00	61,230	0	24,149	24,149	37,080
5	2010	1,094,874	$0 0164	0	465	$99.64	64,228	0	25,076	25,076	39,152
6	2011	1,094,874	$0 0167	0	465	$105 62	67,392	0	26,067	26,067	41,325
7	2012	1,094,874	$0.0171	0	465	$111 96	70,731	0	27,127	27,127	43,605
8	2013	1,094,874	$0.0174	0	465	$118 68	74,256	0	28,259	28,259	45,996
9	2014	1,094,874	$0 0178	0	465	$125 80	77,976	0	29,469	29,469	48,507
10	2015	1,094,874	$0 0182	0	465	$133 35	81,903	0	30,761	30,761	51,142
11	2016	0	$0 0186	0	0	$141 35	0	0	0	0	0
12	2017	0	$0 0190	0	0	$149.83	0	0	0	0	0
13	2018	0	$0 0194	0	0	$158 82	0	0	0	0	0
14	2019	0	$0 0198	0	0	$168.35	0	0	0	0	0
15	2020	0	$0 0202	0	0	$178 45	0	0	0	0	0
16	2021	0	$0.0207	0	0	$189.15	0	0	0	0	0
Total =		9,853,866			4,183		$610,944	$94,689	$236,413	$331,102	$279,842
NPV =							397,939	82,318	154,680	236,998	160,942

Total NPV = $160,942
Benefit/Cost Ratio = 1.68

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part (20) x Participants (22)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **Refridgerator Round-Up Program**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2006	$5,484	$0	$12,229	$17,713	$31,563	$31,563	($13,850)
2007	11,204	0	25,925	37,128	31,563	31,563	5,565
2008	17,167	0	41,220	58,387	31,563	31,563	26,824
2009	17,536	0	43,694	61,230	0	0	61,230
2010	17,913	0	46,315	64,228	0	0	64,228
2011	18,298	0	49,094	67,392	0	0	67,392
2012	18,692	0	52,040	70,731	0	0	70,731
2013	19,093	0	55,162	74,256	0	0	74,256
2014	19,504	0	58,472	77,976	0	0	77,976
2015	19,923	0	61,980	81,903	0	0	81,903
2016	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0
Total =	$164,814	$0	$446,130	$610,944	$94,689	$94,689	$516,255
NPV =	108,791	0	289,148	397,939	82,318	82,318	315,621

Total NPV = $315,621

Benefit/Cost Ratio = 4 83

(A) = Energy Reduction/Part (21 + 21a) x Participants (22) x Energy Cost (2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW Demand Reduction/Part (20) x Participants (22) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Benefit Test

This test measures the net cost of the program based on total cost including environmental externalities and both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**
Project: **Refridgerator Round-Up Program**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2006	$5,484	$0	$12,229	$2,714	$20,427	$31,563	$0	$10,955	$20,608	($181)
2007	$11,204	$0	$25,925	$5,811	42,940	31,563	0	$10,955	20,608	22,332
2008	$17,167	$0	$41,220	$9,335	67,722	31,563	0	$10,955	20,608	47,114
2009	$17,536	$0	$43,694	$10,000	71,230	0	0	$0	0	71,230
2010	$17,913	$0	$46,315	$10,715	74,944	0	0	$0	0	74,944
2011	$18,298	$0	$49,094	$11,485	78,877	0	0	$0	0	78,877
2012	$18,692	$0	$52,040	$12,313	83,044	0	0	$0	0	83,044
2013	$19,093	$0	$55,162	$13,205	87,460	0	0	$0	0	87,460
2014	$19,504	$0	$58,472	$14,164	92,140	0	0	$0	0	92,140
2015	$19,923	$0	$61,980	$15,198	97,101	0	0	$0	0	97,101
2016	$0	$0	$0	$0	0	0	0	$0	0	0
2017	$0	$0	$0	$0	0	0	0	$0	0	0
2018	$0	$0	$0	$0	0	0	0	$0	0	0
2019	$0	$0	$0	$0	0	0	0	$0	0	0
2020	$0	$0	$0	$0	0	0	0	$0	0	0
2021	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$164,814	$0	$446,130	$104,941	$715,885	$94,689	$0	$32,865	$61,824	$654,061
NPV =	108,791	0	289,148	77,397	475,336	82,318	0	28,571	53,747	421,589

Total NPV = $421,589
Benefit/Cost Ratio = 8 84

(A) = Energy Reduction/Part (21 + 21a) x Participants (22) x Energy Cost (2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW Demand Reduction/Part. (20) x Participants (22) x System Demand Cost (4)
(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)
(E) = (A) + (B) + (C) + (D)

(F) = Total Utility Project Costs (15)
(G) = Direct (16) + Other (17) Participant Costs x Participants (22)
(H) = Incentive Costs (15)
(I) = (F) + (G) - (H)
(J) = (E) - (I)

Table 4

Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Refridgerator Round-Up Program**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Cost (F1)	Winter Demand Cost (F2)	Total Annual Benefits (G)	Direct Part Costs (H)	Other Part Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2006	0.0036	$10,955	121,757	243,201	$0.074	$0.036	155	155	$0.00	$0.00	$28,817	$0	$0	$0	$28,817
2007	0.0073	$10,955	243,514	486,402	$0.079	$0.039	310	310	$0.00	$0.00	$48,823	0	$0	0	48,823
2008	0.0073	$10,955	365,271	729,603	$0.083	$0.041	465	465	$0.00	$0.00	$71,166	0	$0	0	71,166
2009	0.0073	$0	365,271	729,603	$0.088	$0.043	465	465	$0.00	$0.00	$63,823	0	$0	0	63,823
2010	0.0072	$0	365,271	729,603	$0.094	$0.046	465	465	$0.00	$0.00	$67,653	0	$0	0	67,653
2011	0.0072	0	365,271	729,603	$0.099	$0.049	465	465	$0.00	$0.00	$71,712	0	$0	0	71,712
2012	0.0072	0	365,271	729,603	$0.105	$0.052	465	465	$0.00	$0.00	$76,015	0	$0	0	76,015
2013	0.0072	0	365,271	729,603	$0.111	$0.055	465	465	$0.00	$0.00	$80,576	0	$0	0	80,576
2014	0.0072	0	365,271	729,603	$0.118	$0.058	465	465	$0.00	$0.00	$85,410	0	$0	0	85,410
2015	0.0072	0	365,271	729,603	$0.125	$0.061	465	465	$0.00	$0.00	$90,535	0	$0	0	90,535
2016	0.0072	0	0	0	$0.133	$0.065	0	0	$0.00	$0.00	$0	0	$0	0	0
2017	0.0071	0	0	0	$0.141	$0.069	0	0	$0.00	$0.00	$0	0	$0	0	0
2018	0.0071	0	0	0	$0.149	$0.073	0	0	$0.00	$0.00	$0	0	$0	0	0
2019	0.0071	0	0	0	$0.158	$0.078	0	0	$0.00	$0.00	$0	0	$0	0	0
2020	0.0071	0	0	0	$0.167	$0.082	0	0	$0.00	$0.00	$0	0	$0	0	0
2021	0.0071	0	0	0	$0.177	$0.087	0	0	$0.00	$0.00	$0	0	$0	0	0
			3,287,439	6,566,427							$684,531	$0	$0	$0	$684,531
											$484,035	0	0	0	484,035

Total NPV = $484,035
Benefit/Cost Ratio = #DIV/0!

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part (20) x Participants (22)
(E2) = kW Demand Reduction/Part (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM

Intergrated Electric System Cost-Effectiveness Analysis

Company **Montana-Dakota Utilities Co.**

Project **Residential Ground Source Heat Pump**

Input Data

1) Retail Rate Summer ($/kWh) =	$0 06987
1a) Retail Rate Winter ($/kWh) =	$0.03431
Escalation Rate =	6 00%
2)Avg System Energy Cost ($/kWh) =	$0.01471
Escalation Rate =	2.15%
3) Retail Summer Demand Cost ($/kW/season) =	$0.00
3a) Retail Winter Demand Cost ($/kW/season) =	$0.00
Escalation Rate =	6 00%
4) System Summer Demand Cost ($/kW/yr)	74 46
Escalation Rate =	2 15%
5)Heating margin increase per cooling reduc ($/kWl	$0.09
Escalation Rate =	1 15%
6) Environmental Damage Factor =	15%
Escalation Rate =	2 15%
7) Total Sales by class (kWh) =	680,614,000
Growth Rate =	0.23%
8) Total Customers by class =	85,712
Growth Rate =	0.18%
9) Utility Discount Rate =	7 34%
10) Social Discount Rate(Tbill) =	4 97%
11) General Input Data Year =	2005
12) Project Analysis Year 1 =	2006
12a) Project Analysis Year 2 =	2007
13) Effective Fed & State Income Tax Rate =	39 00%
14) System Annual Line loss factor	7 88%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$5,000
Direct Operating Costs =	$0
Incentive Costs =	$22,000
Total Utility Project Costs Year 1 =	**$27,000**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$5,000
Direct Operating Costs =	$0
Incentive Costs =	$22,000
Total Utility Project Costs Year 2 =	**$27,000**
15b) Total Utilty Cost Year 3 =	**$27,000**
15c) Total Utility Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$4,000 00
Escalation Rate =	2 15%
17) Other Participant Costs (Annual $/Part) =	$0.00
Escalation Rate =	2.15%
17a) Other Participant Savings vs propane (Annual $/ Part)	$577.00
18) Project Life (Years) =	15
20) Avg Summer kW/part Saved =	0 7
20a) Avg Winter kW/part Saved =	0
21) Avg Summer kWh/Part Saved =	889
21a) Avg Winter kWh/Part. Saved =	0
22) Number of Participants (First Year) =	20
22a) Number of Participants (Second Year) =	20
22a) Number of Participants (Third Year) =	20
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$1,100 00

Demand-Side Management Program - DSM

Intergrated Electric System Cost-Effectiveness Analysis

Summary Information

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Ground Source Heat Pump**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$81,000
Total Program Participants	60
Utility Cost per Participant (First Year) =	$1,350.00
Utility Cost per Participant (Program) =	$1,350.00
Total Summer kW Reduction	42
Total Winter kW Reduction	0
Total Summer Energy Reduction (kWh)	746,760
Total Winter Energy Reduction (kWh)	0
Societal Cost per kwh	$0.30

Test Results

	NPV	B/C
Utility Test	$4,938	1.06
Ratepayer Test	($23,644)	0.66
Societal Benefit Test	($164,732)	0.26
Participant Test	$185,502	1.83

Table 1
Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Ground Source Heat Pump**

		Cost of Energy Saved						Project Cost			Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	After Tax Added Margin Heating Load (C)	Peak Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2006	17,780	$0.0150	$1,637	14	$78.93	$3,009	$27,000	595	$27,595	($24,586)
2	2007	35,560	$0.0153	3,311	28	$83.66	6,199	27,000	1,183	28,183	(21,983)
3	2008	53,340	$0.0157	5,023	42	$88.68	9,584	27,000	1,763	28,763	(19,179)
4	2009	53,340	$0.0160	5,081	42	$94.00	9,884	0	1,752	1,752	8,131
5	2010	53,340	$0.0164	5,140	42	$99.64	10,197	0	1,741	1,741	8,456
6	2011	53,340	$0.0167	5,199	42	$105.62	10,526	0	1,730	1,730	8,797
7	2012	53,340	$0.0171	5,258	42	$111.96	10,871	0	1,718	1,718	9,153
8	2013	53,340	$0.0174	5,319	42	$118.68	11,234	0	1,706	1,706	9,528
9	2014	53,340	$0.0178	5,380	42	$125.80	11,614	0	1,694	1,694	9,920
10	2015	53,340	$0.0182	5,442	42	$133.35	12,013	0	1,681	1,681	10,332
11	2016	53,340	$0.0186	5,505	42	$141.35	12,433	0	1,669	1,669	10,764
12	2017	53,340	$0.0190	5,568	42	$149.83	12,873	0	1,656	1,656	11,218
13	2018	53,340	$0.0194	5,632	42	$158.82	13,337	0	1,642	1,642	11,694
14	2019	53,340	$0.0198	5,697	42	$168.35	13,824	0	1,629	1,629	12,195
15	2020	53,340	$0.0202	5,762	42	$178.45	14,336	0	1,615	1,615	12,722
16	2021	0	$0.0207	0	0	$189.15	0	0	0	0	0
Total =		746,760			588		$161,935	$81,000	$23,773	$104,773	$57,162
NPV =							89,061	70,417	13,705	84,122	4,938

Total NPV = $4,938
Benefit/Cost Ratio = 1.06

(A) = Energy Reduction/Part (21+ 21a) x Participants (22)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part (20) x Participants (22)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **Residential Ground Source Heat Pump**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2006	$267	$0	$1,105	$1,372	$27,000	$27,000	($25,628)
2007	546	0	2,343	2,888	27,000	27,000	(24,112)
2008	836	0	3,725	4,561	27,000	27,000	(22,439)
2009	854	0	3,948	4,802	0	0	4,802
2010	873	0	4,185	5,058	0	0	5,058
2011	891	0	4,436	5,328	0	0	5,328
2012	911	0	4,702	5,613	0	0	5,613
2013	930	0	4,984	5,915	0	0	5,915
2014	950	0	5,284	6,234	0	0	6,234
2015	971	0	5,601	6,571	0	0	6,571
2016	991	0	5,937	6,928	0	0	6,928
2017	1,013	0	6,293	7,306	0	0	7,306
2018	1,035	0	6,670	7,705	0	0	7,705
2019	1,057	0	7,071	8,127	0	0	8,127
2020	1,080	0	7,495	8,574	0	0	8,574
2021	0	0	0	0	0	0	0
Total =	$13,205	$0	$73,778	$86,982	$81,000	$81,000	$5,982
NPV =	7,365	0	39,409	46,773	70,417	70,417	(23,644)

Total NPV =	($23,644)
Benefit/Cost Ratio =	0.66

(A) = Energy Reduction/Part. (21 + 21a) x Participants (22) x Energy Cost (2)

(B) = Energy Reduction/Part (21) x Participants (22) x Variable O&M (5)

(C) = kW Demand Reduction/Part (20) x Participants (22) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Benefit Test

This test measures the net cost of the program based on total cost including environmental externalities and both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**

Project: **Residential Ground Source Heat Pump**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2006	$267	$0	$1,105	$210	$1,582	$27,000	$80,000	$22,000	$85,000	($83,418)
2007	$546	$0	$2,343	$452	3,340	27,000	80,000	$22,000	85,000	(81,660)
2008	$836	$0	$3,725	$729	5,290	27,000	80,000	$22,000	85,000	(79,710)
2009	$854	$0	$3,948	$784	5,587	0	0	$0	0	5,587
2010	$873	$0	$4,185	$844	5,902	0	0	$0	0	5,902
2011	$891	$0	$4,436	$908	6,236	0	0	$0	0	6,236
2012	$911	$0	$4,702	$977	6,590	0	0	$0	0	6,590
2013	$930	$0	$4,984	$1,052	6,966	0	0	$0	0	6,966
2014	$950	$0	$5,284	$1,132	7,366	0	0	$0	0	7,366
2015	$971	$0	$5,601	$1,219	7,790	0	0	$0	0	7,790
2016	$991	$0	$5,937	$1,313	8,241	0	0	$0	0	8,241
2017	$1,013	$0	$6,293	$1,415	8,720	0	0	$0	0	8,720
2018	$1,035	$0	$6,670	$1,524	9,229	0	0	$0	0	9,229
2019	$1,057	$0	$7,071	$1,642	9,769	0	0	$0	0	9,769
2020	$1,080	$0	$7,495	$1,770	10,344	0	0	$0	0	10,344
2021	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$13,205	$0	$73,778	$15,971	$102,954	$81,000	$240,000	$66,000	$255,000	($152,046)
NPV =	7,365	0	39,409	10,179	56,952	70,417	208,644	57,377	221,684	(164,732)

Total NPV = ($164,732)

Benefit/Cost Ratio = 0.26

(A) = Energy Reduction/Part (21 + 21a) x Participants (22) x Energy Cost (2)

(B) = Energy Reduction/Part (21) x Participants (22) x Variable O&M (5)

(C) = kW Demand Reduction/Part (20) x Participants (22) x System Demand Cost (4)

(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)

(E) = (A) + (B) + (C) + (D)

(F) = Total Utility Project Costs (15)

(G) = Direct (16) + Other (17) Participant Costs x Participants (22)

(H) = Incentive Costs (15)

(I) = (F) + (G) - (H)

(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Ground Source Heat Pump**

Year	Ratio of Part. to Total Customers (A)	Benefits: Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Cost (F1)	Winter Demand Cost (F2)	Total Annual Benefits (G)	Costs: Direct Part Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2006	0.0002	$22,000	17,780	0	$0 074	$0.036	14	0	$0 00	$0 00	$34,857	$80,000	$0	$80,000	($45,14
2007	0 0005	$22,000	35,560	0	$0 079	$0 039	28	0	$0 00	$0 00	$47,872	80,000	$0	80,000	(32,12
2008	0 0005	$22,000	53,340	0	$0 083	$0 041	42	0	$0 00	$0 00	$61,059	80,000	$0	80,000	(18,941)
2009	0.0005	$0	53,340	0	$0 088	$0 043	42	0	$0 00	$0 00	$39,325	0	$0	0	39,325
2010	0 0005	$0	53,340	0	$0.094	$0.046	42	0	$0 00	$0 00	$39,607	0	$0	0	39,607
2011	0.0005	0	53,340	0	$0 099	$0 049	42	0	$0 00	$0 00	$39,907	0	$0	0	39,907
2012	0 0005	0	53,340	0	$0 105	$0.052	42	0	$0 00	$0 00	$40,224	0	$0	0	40,224
2013	0.0005	0	53,340	0	$0 111	$0 055	42	0	$0 00	$0 00	$40,560	0	$0	0	40,560
2014	0 0005	0	53,340	0	$0.118	$0.058	42	0	$0 00	$0 00	$40,916	0	$0	0	40,916
2015	0 0005	0	53,340	0	$0 125	$0 061	42	0	$0 00	$0 00	$41,294	0	$0	0	41,294
2016	0 0005	0	53,340	0	$0 133	$0.065	42	0	$0 00	$0 00	$41,695	0	$0	0	41,695
2017	0.0005	0	53,340	0	$0 141	$0.069	42	0	$0 00	$0 00	$42,119	0	$0	0	42,119
2018	0 0005	0	53,340	0	$0.149	$0.073	42	0	$0 00	$0 00	$42,569	0	$0	0	42,569
2019	0.0005	0	53,340	0	$0 158	$0.078	42	0	$0.00	$0 00	$43,046	0	$0	0	43,046
2020	0.0005	0	53,340	0	$0 167	$0 082	42	0	$0.00	$0.00	$43,552	0	$0	0	43,552
2021	0 0005	0	0	0	$0 177	$0 087	0	0	$0 00	$0.00	$0	0	$0	0	0
			746,760	0							$638,602	$240,000	$0	$240,000	$398,602
											$409,462	223,961	0	223,961	185,502

Total NPV = $185,502
Benefit/Cost Ratio = 1 83

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM

Intergrated Electric System Cost-Effectiveness Analysis

Company. **Montana-Dakota Utilities Co.**

Project **Residential Electric Heat Promotion**

H-55

Input Data

1) Retail Rate Summer ($/kWh) =	$0.06987
1a) Retail Rate Winter ($/kWh) =	$0.03431
Escalation Rate =	6 00%
2)Avg System Energy Cost ($/kWh) =	$0.01471
Escalation Rate =	2 15%
3) Retail Summer Demand Cost ($/kW/season) =	$0.00
3a) Retail Winter Demand Cost ($/kW/season) =	$0.00
Escalation Rate =	6 00%
4) System Summer Demand Cost ($/kW/yr)	74 46
Escalation Rate =	2 15%
5)After tax Heating margin increase ($/kWh) =	$0.0124
Escalation Rate =	1 15%
6) Environmental Damage Factor =	15%
Escalation Rate =	2.15%
7) Total Sales by class (kWh) =	680,614,000
Growth Rate =	0.23%
8) Total Customers by class =	85,712
Growth Rate =	0.18%
9) Utility Discount Rate =	7 34%
10) Social Discount Rate(Tbill) =	4 97%
11) General Input Data Year =	2005
12) Project Analysis Year 1 =	2006
12a) Project Analysis Year 2 =	2007
13) Effective Fed & State Income Tax Rate =	39 00%
14) System Annual Line loss factor	7 88%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$5,000
Direct Operating Costs =	$0
Incentive Costs =	$23,909
Total Utility Project Costs Year 1 =	**$28,909**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$5,000
Direct Operating Costs =	$0
Incentive Costs =	$23,909
Total Utility Project Costs Year 2 =	**$28,909**
15b) Total Utilty Cost Year 3 =	**$28,909**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part) =	$1,200 00
Escalation Rate =	2.15%
17) Other Participant Costs (Annual $/Part) =	$0 00
Escalation Rate =	2.15%
17a) Other Participant Savings vs propane (Annual $/ Part)	$331.00
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	0
20a) Avg Winter kW/part Saved =	0
21) Avg Summer kWh/Part Saved =	0
21a) Avg. Winter kWh/Part Saved =	0
21b) Avg Winter kwh / part increase	14,593
22) Number of Participants (First Year) =	96
22a) Number of Participants (Second Year) =	96
22a) Number of Participants (Third Year) =	96
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$250.00

Demand-Side Management Program - DSM

Intergrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project.	**Residential Electric Heat Promotion**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$86,727
Total Program Participants	288
Utility Cost per Participant (First Year) =	$301.14
Utility Cost per Participant (Program) =	$301.14
Total Summer kW Reduction	0
Total Winter kW Reduction	0
Total Summer Energy Reduction (kWh)	0
Total Winter Energy Reduction (kWh)	0
Societal Cost per kwh	#DIV/0!

Test Results

	NPV	B/C
Utility Test	$378,623	6.02
Ratepayer Test	($75,396)	0.00
Societal Benefit Test	($313,250)	0.00
Participant Test	$563,761	2.75

Table 1
Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Electric Heat Promotion**

t	Year	Cost of Energy Saved: Total Energy (kWh) Reduction (A)	System Energy Cost (B)	After Tax Heating load Margin Increase (C)	Peak Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Project Cost: Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	Cost of Energy Saved Less Project Cost (J)
1	2006	0	$0 0150	$17,571	0	$78 93	$17,571	$28,909	0	$28,909	($11,338)
2	2007	0	$0 0153	$35,547	0	$83.66	35,547	28,909	0	28,909	6,638
3	2008	0	$0 0157	$53,933	0	$88.68	53,933	28,909	0	28,909	25,024
4	2009	0	$0 0160	$54,553	0	$94.00	54,553	0	0	0	54,553
5	2010	0	$0 0164	$55,181	0	$99.64	55,181	0	0	0	55,181
6	2011	0	$0.0167	$55,815	0	$105.62	55,815	0	0	0	55,815
7	2012	0	$0 0171	$56,457	0	$111.96	56,457	0	0	0	56,457
8	2013	0	$0 0174	$57,107	0	$118 68	57,107	0	0	0	57,107
9	2014	0	$0 0178	$57,763	0	$125 80	57,763	0	0	0	57,763
10	2015	0	$0 0182	$58,428	0	$133 35	58,428	0	0	0	58,428
11	2016	0	$0 0186	$59,099	0	$141 35	59,099	0	0	0	59,099
12	2017	0	$0.0190	$59,779	0	$149 83	59,779	0	0	0	59,779
13	2018	0	$0 0194	$60,467	0	$158.82	60,467	0	0	0	60,467
14	2019	0	$0 0198	$61,162	0	$168.35	61,162	0	0	0	61,162
15	2020	0	$0 0202	$61,865	0	$178 45	61,865	0	0	0	61,865
16	2021	0	$0.0207	0	0	$189.15	0	0	0	0	0
Total =		0			0		$804,728	$86,727	$0	$86,727	$718,001
NPV =							454,019	75,396	0	75,396	378,623

Total NPV = $378,623
Benefit/Cost Ratio = 6.02

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part (20) x Participants (22)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **Residential Electric Heat Promotion**

Year	Decreases: Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Increases: Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2006	$0	$0	$0	$0	$28,909	$28,909	($28,909)
2007	0	0	0	0	28,909	28,909	(28,909)
2008	0	0	0	0	28,909	28,909	(28,909)
2009	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0
Total =	$0	$0	$0	$0	$86,727	$86,727	($86,727)
NPV =	0	0	0	0	75,396	75,396	(75,396)

Total NPV = ($75,396)

Benefit/Cost Ratio = 0 00

(A) = Energy Reduction/Part (21 + 21a) x Participants (22) x Energy Cost (2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW Demand Reduction/Part. (20) x Participants (22) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Benefit Test

This test measures the net cost of the program based on total cost including environmental externalities and both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**

Project: **Residential Electric Heat Promotion**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2006	$0	$0	$0	$0	$0	$28,909	$115,200	$24,000	$120,109	($120,109)
2007	$0	$0	$0	$0	0	28,909	115,200	$24,000	120,109	(120,109)
2008	$0	$0	$0	$0	0	28,909	115,200	$24,000	120,109	(120,109)
2009	$0	$0	$0	$0	0	0	0	$0	0	0
2010	$0	$0	$0	$0	0	0	0	$0	0	0
2011	$0	$0	$0	$0	0	0	0	$0	0	0
2012	$0	$0	$0	$0	0	0	0	$0	0	0
2013	$0	$0	$0	$0	0	0	0	$0	0	0
2014	$0	$0	$0	$0	0	0	0	$0	0	0
2015	$0	$0	$0	$0	0	0	0	$0	0	0
2016	$0	$0	$0	$0	0	0	0	$0	0	0
2017	$0	$0	$0	$0	0	0	0	$0	0	0
2018	$0	$0	$0	$0	0	0	0	$0	0	0
2019	$0	$0	$0	$0	0	0	0	$0	0	0
2020	$0	$0	$0	$0	0	0	0	$0	0	0
2021	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$0	$0	$0	$0	$0	$86,727	$345,600	$72,000	$360,327	($360,327)
NPV =	0	0	0	0	0	75,396	300,448	62,593	313,250	(313,250)

Total NPV = ($313,250)

Benefit/Cost Ratio = 0.00

(A) = Energy Reduction/Part (21 + 21a) x Participants (22) x Energy Cost (2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW Demand Reduction/Part (20) x Participants (22) x System Demand Cost (4)

(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)

(E) = (A) + (B) + (C) + (D)

(F) = Total Utility Project Costs (15)

(G) = Direct (16) + Other (17) Participant Costs x Participants (22)

(H) = Incentive Costs (15)

(I) = (F) + (G) - (H)

(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Electric Heat Promotion**

Year	Ratio of Part. to Total Customers (A)	Benefits Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Cost (F1)	Winter Demand Cost (F2)	Total Annual Benefits (G)	Costs Direct Part Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2006	0 0011	$24,000	0	0	$0 074	$0 036	0	0	$0 00	$0.00	$55,776	$115,200	$0	$115,200	($59,424)
2007	0.0022	$24,000	0	0	$0.079	$0 039	0	0	$0 00	$0 00	$87,552	115,200	$0	115,200	(27,648)
2008	0.0022	$24,000	0	0	$0 083	$0.041	0	0	$0 00	$0 00	$119,328	115,200	$0	115,200	4,128
2009	0 0022	$0	0	0	$0.088	$0 043	0	0	$0.00	$0 00	$95,328	0	$0	0	95,328
2010	0 0022	$0	0	0	$0.094	$0 046	0	0	$0 00	$0 00	$95,328	0	$0	0	95,328
2011	0 0022	0	0	0	$0 099	$0 049	0	0	$0 00	$0.00	$95,328	0	$0	0	95,328
2012	0 0022	0	0	0	$0 105	$0 052	0	0	$0 00	$0.00	$95,328	0	$0	0	95,328
2013	0 0022	0	0	0	$0.111	$0.055	0	0	$0 00	$0.00	$95,328	0	$0	0	95,328
2014	0 0022	0	0	0	$0 118	$0 058	0	0	$0 00	$0 00	$95,328	0	$0	0	95,328
2015	0.0022	0	0	0	$0.125	$0 061	0	0	$0.00	$0 00	$95,328	0	$0	0	95,328
2016	0 0022	0	0	0	$0 133	$0 065	0	0	$0.00	$0 00	$95,328	0	$0	0	95,328
2017	0 0022	0	0	0	$0 141	$0 069	0	0	$0.00	$0.00	$95,328	0	$0	0	95,328
2018	0 0022	0	0	0	$0 149	$0.073	0	0	$0 00	$0.00	$95,328	0	$0	0	95,328
2019	0 0022	0	0	0	$0 158	$0.078	0	0	$0 00	$0 00	$95,328	0	$0	0	95,328
2020	0 0022	0	0	0	$0 167	$0 082	0	0	$0.00	$0.00	$95,328	0	$0	0	95,328
2021	0.0022	0	0	0	$0.177	$0 087	0	0	$0.00	$0 00	$0	0	$0	0	0
			0	0							$1,406,592	$345,600	$0	$345,600	$1,060,992
											$886,265	322,503	0	322,503	563,761

Total NPV = $563,761
Benefit/Cost Ratio = 2 75

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

H-60

Demand-Side Management Program - DSM

Intergrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**

Project: **T-8 Lighting Retrofit 4 Lamp Model**

Input Data

1) Retail Rate Summer ($/kWh) =	$0 03336
1a) Retail Rate Winter ($/kWh) =	$0 03336
Escalation Rate =	6 00%
2)Avg. System Energy Cost ($/kWh) =	$0.01471
Escalation Rate =	2 15%
3) Retail Summer Demand Cost ($/kW/season) =	$44 90
3a) Retail Winter Demand Cost ($/kW/season) =	$65 79
Escalation Rate =	6 00%
4) System Summer Demand Cost ($/kW/yr)	74.46
Escalation Rate =	2 15%
5) Variable O&M ($/kWh) =	$0.00
Escalation Rate =	1.15%
6) Environmental Damage Factor =	15%
Escalation Rate =	2.15%
7) Total Sales by class (kWh) =	680,614,000
Growth Rate =	0.23%
8) Total Customers by class =	16,592
Growth Rate =	0.18%
9) Utility Discount Rate =	7.34%
10) Social Discount Rate(Tbill) =	4 97%
11) General Input Data Year =	2005
12) Project Analysis Year 1 =	2006
12a) Project Analysis Year 2 =	2007
13) Effective Fed & State Income Tax Rate =	39.00%
14) System Annual Line loss factor	7.88%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$5,000
Direct Operating Costs =	$0
Incentive Costs =	$61,059
Total Utility Project Costs Year 1 =	**$66,059**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$5,000
Direct Operating Costs =	$0
Incentive Costs =	$61,059
Total Utility Project Costs Year 2 =	**$66,059**
15b) Total Utilty Cost Year 3 =	**$66,059**
15c) Total Utilty Cost Year 4 =	**$66,059**
15d) Total Utility Cost Year 5 =	**$66,059**
16) Direct Participant Costs ($/Part.) =	$920 00
Escalation Rate =	2.15%
17) Other Participant Costs (Annual $/Part.) =	$0 00
Escalation Rate =	2.15%
18) Project Life (Years) =	10
20) Avg Summer kW/part. Saved =	3.43
20a) Avg Winter kW/part Saved =	6 86
21) Avg. Summer kWh/Part Saved =	715
21a) Avg. Winter kWh/Part Saved =	1,430
22) Number of Participants (First Year) =	332
22a) Number of Participants (Second Year) =	332
22a) Number of Participants (Third Year) =	332
22a) Number of Participants (Fourth Year) =	332
22a) Number of Participants (Fifth Year) =	332
23) Incentive/Participant (All) =	$184.00

Demand-Side Management Program - DSM

Intergrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**T-8 Lighting Retrofit 4 Lamp Model**

Cost Summary

Program Promotion (Years)	5
Project Life (Years)	10
Total Progam Cost (Utility)	$330,295
Total Program Participants	1,660
Utility Cost per Participant (First Year) =	$198 97
Utility Cost per Participant (Program) =	$198.97
Total Summer kW Reduction	5,694
Total Winter kW Reduction	11,388
Total Summer Energy Reduction (kWh)	9,495,200
Total Winter Energy Reduction (kWh)	18,990,400
Societal Cost per kwh	$0.04

Test Results

	NPV	B/C
Utility Test	$2,877,444	6.12
Ratepayer Test	$3,171,477	12.82
Societal Benefit Test	$2,861,099	3.27
Participant Test	$7,844,481	6.89

Table 1
Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **T-8 Lighting Retrofit 4 Lamp Model**

		Cost of Energy Saved						Project Cost			Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Peak Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2006	712,140	$0.0150	$0	1,139	$78 93	$100,580	$66,059	8,544	$74,603	$25,977
2	2007	1,424,280	$0.0153	0	2,278	$83 66	212,406	66,059	18,036	84,095	128,311
3	2008	2,136,420	$0 0157	0	3,416	$88 68	336,464	66,059	28,578	94,637	241,827
4	2009	2,848,560	$0 0160	0	4,555	$94 00	473,816	66,059	40,280	106,339	367,477
5	2010	3,560,700	$0 0164	0	5,694	$99 64	625,610	66,059	53,261	119,320	506,290
6	2011	3,560,700	$0 0167	0	5,694	$105.62	660,904	0	56,376	56,376	604,529
7	2012	3,560,700	$0 0171	0	5,694	$111 96	698,267	0	59,707	59,707	638,561
8	2013	3,560,700	$0 0174	0	5,694	$118.68	737,823	0	63,267	63,267	674,556
9	2014	3,560,700	$0 0178	0	5,694	$125 80	779,702	0	67,073	67,073	712,629
10	2015	3,560,700	$0 0182	0	5,694	$133.35	824,042	0	71,137	71,137	752,905
11	2016	0	$0 0186	0	0	$141 35	0	0	0	0	0
12	2017	0	$0 0190	0	0	$149.83	0	0	0	0	0
13	2018	0	$0 0194	0	0	$158 82	0	0	0	0	0
14	2019	0	$0 0198	0	0	$168.35	0	0	0	0	0
15	2020	0	$0 0202	0	0	$178 45	0	0	0	0	0
16	2021	0	$0 0207	0	0	$189.15	0	0	0	0	0
Total =		28,485,600			45,550		$5,449,616	$330,295	$466,258	$796,553	$4,653,062
NPV =							3,439,877	268,400	294,034	562,433	2,877,444

Total NPV = $2,877,444
Benefit/Cost Ratio = 6 12

(A) = Energy Reduction/Part (21+ 21a) x Participants (22)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part (20) x Participants (22)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x
[(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **T-8 Lighting Retrofit 4 Lamp Model**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2006	$10,701	$0	$89,880	$100,580	$66,059	$66,059	$34,521
2007	21,862	0	190,545	212,406	66,059	66,059	146,347
2008	33,498	0	302,966	336,464	66,059	66,059	270,405
2009	45,624	0	428,192	473,816	66,059	66,059	407,757
2010	58,256	0	567,355	625,610	66,059	66,059	559,551
2011	59,508	0	601,396	660,904	0	0	660,904
2012	60,788	0	637,480	698,267	0	0	698,267
2013	62,095	0	675,728	737,823	0	0	737,823
2014	63,430	0	716,272	779,702	0	0	779,702
2015	64,794	0	759,248	824,042	0	0	824,042
2016	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0
Total =	$480,554	$0	$4,969,062	$5,449,616	$330,295	$330,295	$5,119,321
NPV =	307,863	0	3,132,014	3,439,877	268,400	268,400	3,171,477

Total NPV = $3,171,477

Benefit/Cost Ratio = 12 82

(A) = Energy Reduction/Part. (21 + 21a) x Participants (22) x Energy Cost (2)

(B) = Energy Reduction/Part (21) x Participants (22) x Variable O&M (5)

(C) = kW Demand Reduction/Part (20) x Participants (22)
x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Benefit Test

This test measures the net cost of the program based on total cost including environmental externalities and both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**

Project: **T-8 Lighting Retrofit 4 Lamp Model**

	Decreases				Increases					
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2006	$10,701	$0	$89,880	$15,411	$115,992	$66,059	$305,440	$61,088	$310,411	($194,419)
2007	$21,862	$0	$190,545	$33,246	245,652	66,059	305,440	$61,088	310,411	(64,759)
2008	$33,498	$0	$302,966	$53,795	390,259	66,059	305,440	$61,088	310,411	79,848
2009	$45,624	$0	$428,192	$77,385	551,201	66,059	305,440	$61,088	310,411	240,790
2010	$58,256	$0	$567,355	$104,373	729,983	66,059	305,440	$61,088	310,411	419,572
2011	$59,508	$0	$601,396	$112,632	773,536	0	0	$0	0	773,536
2012	$60,788	$0	$637,480	$121,557	819,825	0	0	$0	0	819,825
2013	$62,095	$0	$675,728	$131,205	869,028	0	0	$0	0	869,028
2014	$63,430	$0	$716,272	$141,633	921,335	0	0	$0	0	921,335
2015	$64,794	$0	$759,248	$152,906	976,948	0	0	$0	0	976,948
2016	$0	$0	$0	$0	0	0	0	$0	0	0
2017	$0	$0	$0	$0	0	0	0	$0	0	0
2018	$0	$0	$0	$0	0	0	0	$0	0	0
2019	$0	$0	$0	$0	0	0	0	$0	0	0
2020	$0	$0	$0	$0	0	0	0	$0	0	0
2021	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$480,554	$0	$4,969,062	$944,143	$6,393,759	$330,295	$1,527,200	$305,440	$1,552,055	$4,841,704
NPV =	307,863	0	3,132,014	682,431	4,122,308	268,400	1,241,012	248,202	1,261,210	2,861,099

Total NPV = $2,861,099

Benefit/Cost Ratio = 3.27

(A) = Energy Reduction/Part (21 + 21a) x Participants (22) x Energy Cost (2)
(B) = Energy Reduction/Part (21) x Participants (22) x Variable O&M (5)
(C) = kW Demand Reduction/Part (20) x Participants (22) x System Demand Cost (4)
(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)
(E) = (A) + (B) + (C) + (D)

(F) = Total Utility Project Costs (15)
(G) = Direct (16) + Other (17) Participant Costs x Participants (22)
(H) = Incentive Costs (15)
(I) = (F) + (G) - (H)
(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **T-8 Lighting Retrofit 4 Lamp Model**

Year	Ratio of Part. to Total Customers (A)	Benefits: Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Cost (F1)	Winter Demand Cost (F2)	Total Annual Benefits (G)	Costs: Direct Part Costs (H)	Other Part Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2006	0 0200	$61,088	237,380	474,760	$0.035	$0 035	1,139	2,278	$47.59	$69 74	$299,297	$305,440	$0	$305,440	($6,1
2007	0 0399	$61,088	474,760	949,520	$0 037	$0 037	2,278	4,555	$50 45	$73 92	$566,091	305,440	$0	305,440	260,65
2008	0 0398	$61,088	712,140	1,424,280	$0 040	$0 040	3,416	6,833	$53.48	$78 36	$864,042	305,440	$0	305,440	558,602
2009	0 0397	$61,088	949,520	1,899,040	$0 042	$0.042	4,555	9,110	$56.69	$83 06	$1,195,930	305,440	$0	305,440	890,490
2010	0.0397	$61,088	1,186,900	2,373,800	$0.045	$0.045	5,694	11,388	$60.09	$88 04	$1,564,754	305,440	$0	305,440	1,259,314
2011	0 0396	0	1,186,900	2,373,800	$0.047	$0.047	5,694	11,388	$63 69	$93 32	$1,593,886	0	$0	0	1,593,886
2012	0 0395	0	1,186,900	2,373,800	$0 050	$0 050	5,694	11,388	$67.51	$98 92	$1,689,519	0	$0	0	1,689,519
2013	0 0394	0	1,186,900	2,373,800	$0 053	$0 053	5,694	11,388	$71.56	$104 86	$1,790,890	0	$0	0	1,790,890
2014	0.0394	0	1,186,900	2,373,800	$0 056	$0.056	5,694	11,388	$75.86	$111 15	$1,898,344	0	$0	0	1,898,344
2015	0 0393	0	1,186,900	2,373,800	$0 060	$0 060	5,694	11,388	$80 41	$117 82	$2,012,244	0	$0	0	2,012,244
2016	0.0392	0	0	0	$0 063	$0 063	0	0	$85 23	$124 89	$0	0	$0	0	0
2017	0 0392	0	0	0	$0.067	$0 067	0	0	$90.35	$132.38	$0	0	$0	0	0
2018	0 0391	0	0	0	$0 071	$0 071	0	0	$95.77	$140 33	$0	0	$0	0	0
2019	0.0390	0	0	0	$0 075	$0 075	0	0	$101.51	$148.74	$0	0	$0	0	0
2020	0 0390	0	0	0	$0 080	$0.080	0	0	$107.61	$157 67	$0	0	$0	0	0
2021	0 0389	0	0	0	$0.085	$0 085	0	0	$114.06	$167.13	$0	0	$0	0	0
			9,495,200	18,990,400							$13,474,998	$1,527,200	$0	$1,527,200	$11,947,798
											$9,176,596	1,332,115	0	1,332,115	7,844,481

Total NPV = $7,844,481
Benefit/Cost Ratio = 6.89

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part (21) x Participants (22)
(C2) = Energy Reduction/Part (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM

Intergrated Electric System Cost-Effectiveness Analysis

Company	**Montana-Dakota Utilities Co.**
Project	**LED Exit Signs (Incandescent Model)**

Input Data

1) Retail Rate Summer ($/kWh) =	$0 03336
1a) Retail Rate Winter ($/kWh) =	$0 03336
Escalation Rate =	6 00%
2)Avg System Energy Cost ($/kWh) =	$0 01471
Escalation Rate =	2.15%
3) Retail Summer Demand Cost ($/kW/season) =	$44.90
3a) Retail Winter Demand Cost ($/kW/season) =	$65 79
Escalation Rate =	6 00%
4) System Summer Demand Cost ($/kW/yr)	74 46
Escalation Rate =	2 15%
5) Variable O&M ($/kWh) =	$0.00
Escalation Rate =	1 15%
6) Environmental Damage Factor =	15%
Escalation Rate =	2 15%
7) Total Sales by class (kWh) =	680,614,000
Growth Rate =	0.23%
8) Total Customers by class =	16,592
Growth Rate =	0 18%
9) Utility Discount Rate =	7 34%
10) Social Discount Rate(Tbill) =	4 97%
11) General Input Data Year =	2005
12) Project Analysis Year 1 =	2006
12a) Project Analysis Year 2 =	2007
13) Effective Fed & State Income Tax Rate =	39 00%
14) System Annual Line loss factor	7 88%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$5,000
Direct Operating Costs =	$0
Incentive Costs =	$8,296
Total Utility Project Costs Year 1 =	**$13,296**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$5,000
Direct Operating Costs =	$0
Incentive Costs =	$8,296
Total Utility Project Costs Year 2 =	**$13,296**
15b) Total Utilty Cost Year 3 =	**$13,296.00**
15c) Total Utilty Cost Year 4 =	**$13,296.00**
15d) Total Utility Cost Year 5 =	**$13,296.00**
16) Direct Participant Costs ($/Part) =	$250 00
Escalation Rate =	2 15%
17) Other Participant Costs (Annual $/Part) =	$0 00
Escalation Rate =	2 15%
18) Project Life (Years) =	10
20) Avg Summer kW/part Saved =	0 14
20a) Avg Winter kW/part Saved =	0 14
21) Avg Summer kWh/Part Saved =	394
21a) Avg Winter kWh/Part Saved =	788
22) Number of Participants (First Year) =	166
22a) Number of Participants (Second Year) =	166
22a) Number of Participants (Third Year) =	166
22a) Number of Participants (Fourth Year) =	166
22a) Number of Participants (Fifth Year) =	166
23) Incentive/Participant (All) =	$50 00

Demand-Side Management Program - DSM

Intergrated Electric System Cost-Effectiveness Analysis

Summary Information

Company.	**Montana-Dakota Utilities Co.**
Project:	**LED Exit Signs (Incandescent Model)**

Cost Summary

Program Promotion (Years)	5
Project Life (Years)	10
Total Progam Cost (Utility)	$66,480
Total Program Participants	830
Utility Cost per Participant (First Year) =	$80.10
Utility Cost per Participant (Program) =	$80.10
Total Summer kW Reduction	116
Total Winter kW Reduction	116
Total Summer Energy Reduction (kWh)	2,616,160
Total Winter Energy Reduction (kWh)	5,232,320
Societal Cost per kwh	$0.02

Test Results

	NPV	B/C
Utility Test	$13,707	1.10
Ratepayer Test	$94,720	2.75
Societal Benefit Test	($10,806)	0.94
Participant Test	$216,729	2.20

Table 1
Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **LED Exit Signs (Incandescent Model)**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Peak Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2006	196,212	$0.0150	$0	23	$78.93	$4,783	$13,296	2,354	$15,650	($10,867)
2	2007	392,424	$0.0153	0	46	$83.66	9,912	13,296	4,969	18,265	(8,353)
3	2008	588,636	$0.0157	0	70	$88.68	15,412	13,296	7,874	21,170	(5,758)
4	2009	784,848	$0.0160	0	93	$94.00	21,309	13,296	11,098	24,394	(3,085)
5	2010	981,060	$0.0164	0	116	$99.64	27,630	13,296	14,675	27,971	(341)
6	2011	981,060	$0.0167	0	116	$105.62	28,669	0	15,533	15,533	13,137
7	2012	981,060	$0.0171	0	116	$111.96	29,758	0	16,451	16,451	13,308
8	2013	981,060	$0.0174	0	116	$118.68	30,899	0	17,432	17,432	13,467
9	2014	981,060	$0.0178	0	116	$125.80	32,094	0	18,480	18,480	13,614
10	2015	981,060	$0.0182	0	116	$133.35	33,347	0	19,600	19,600	13,747
11	2016	0	$0.0186	0	0	$141.35	0	0	0	0	0
12	2017	0	$0.0190	0	0	$149.83	0	0	0	0	0
13	2018	0	$0.0194	0	0	$158.82	0	0	0	0	0
14	2019	0	$0.0198	0	0	$168.35	0	0	0	0	0
15	2020	0	$0.0202	0	0	$178.45	0	0	0	0	0
16	2021	0	$0.0207	0	0	$189.15	0	0	0	0	0
Total =		7,848,480			930		$233,814	$66,480	$128,466	$194,946	$38,868
NPV =							148,743	54,022	81,013	135,036	13,707

Total NPV = $13,707
Benefit/Cost Ratio = 1.10

(A) = Energy Reduction/Part (21+ 21a) x Participants (22)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part (20) x Participants (22)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **LED Exit Signs (Incandescent Model)**

Year	Decreases: Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Increases: Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2006	$2,948	$0	$1,834	$4,783	$13,296	$13,296	($8,513)
2007	6,023	0	3,889	9,912	13,296	13,296	(3,384)
2008	9,229	0	6,183	15,412	13,296	13,296	2,116
2009	12,570	0	8,739	21,309	13,296	13,296	8,013
2010	16,051	0	11,579	27,630	13,296	13,296	14,334
2011	16,396	0	12,273	28,669	0	0	28,669
2012	16,749	0	13,010	29,758	0	0	29,758
2013	17,109	0	13,790	30,899	0	0	30,899
2014	17,476	0	14,618	32,094	0	0	32,094
2015	17,852	0	15,495	33,347	0	0	33,347
2016	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0
Total =	$132,404	$0	$101,409	$233,814	$66,480	$66,480	$167,334
NPV =	84,824	0	63,919	148,743	54,022	54,022	94,720

Total NPV = $94,720

Benefit/Cost Ratio = 2 75

(A) = Energy Reduction/Part (21 + 21a) x Participants (22) x Energy Cost (2)

(B) = Energy Reduction/Part (21) x Participants (22) x Variable O&M (5)

(C) = kW Demand Reduction/Part (20) x Participants (22) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Benefit Test

This test measures the net cost of the program based on total cost including environmental externalities and both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**

Project. **LED Exit Signs (Incandescent Model)**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2006	$2,948	$0	$1,834	$733	$5,515	$13,296	$41,500	$8,300	$46,496	($40,981)
2007	$6,023	$0	$3,889	$1,551	11,464	13,296	41,500	$8,300	46,496	(35,032)
2008	$9,229	$0	$6,183	$2,464	17,877	13,296	41,500	$8,300	46,496	(28,619)
2009	$12,570	$0	$8,739	$3,480	24,789	13,296	41,500	$8,300	46,496	(21,707)
2010	$16,051	$0	$11,579	$4,610	32,239	13,296	41,500	$8,300	46,496	(14,257)
2011	$16,396	$0	$12,273	$4,886	33,555	0	0	$0	0	33,555
2012	$16,749	$0	$13,010	$5,180	34,939	0	0	$0	0	34,939
2013	$17,109	$0	$13,790	$5,495	36,394	0	0	$0	0	36,394
2014	$17,476	$0	$14,618	$5,830	37,924	0	0	$0	0	37,924
2015	$17,852	$0	$15,495	$6,188	39,535	0	0	$0	0	39,535
2016	$0	$0	$0	$0	0	0	0	$0	0	0
2017	$0	$0	$0	$0	0	0	0	$0	0	0
2018	$0	$0	$0	$0	0	0	0	$0	0	0
2019	$0	$0	$0	$0	0	0	0	$0	0	0
2020	$0	$0	$0	$0	0	0	0	$0	0	0
2021	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$132,404	$0	$101,409	$40,417	$274,231	$66,480	$207,500	$41,500	$232,480	$41,751
NPV =	84,824	0	63,919	29,366	178,109	54,022	168,616	33,723	188,915	(10,806)

Total NPV = ($10,806)

Benefit/Cost Ratio = 0.94

(A) = Energy Reduction/Part (21 + 21a) x Participants (22) x Energy Cost (2)

(B) = Energy Reduction/Part (21) x Participants (22) x Variable O&M (5)

(C) = kW Demand Reduction/Part (20) x Participants (22) x System Demand Cost (4)

(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)

(E) = (A) + (B) + (C) + (D)

(F) = Total Utility Project Costs (15)

(G) = Direct (16) + Other (17) Participant Costs x Participants (22)

(H) = Incentive Costs (15)

(I) = (F) + (G) - (H)

(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **LED Exit Signs (Incandescent Model)**

Year	Ratio of Part. to Total Customers (A)	Benefits: Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Cost (F1)	Winter Demand Cost (F2)	Total Annual Benefits (G)	Costs: Direct Part. Costs (H)	Other Part Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2006	0 0100	$8,300	65,404	130,808	$0.035	$0 035	23	23	$47 59	$69 74	$17,965	$41,500	$0	$41,500	($23,535)
2007	0 0199	$8,300	130,808	261,616	$0 037	$0.037	46	46	$50 45	$73 92	$28,790	41,500	$0	41,500	(12,710)
2008	0 0199	$8,300	196,212	392,424	$0 040	$0.040	70	70	$53.48	$78 36	$40,879	41,500	$0	41,500	(621)
2009	0 0199	$8,300	261,616	523,232	$0 042	$0 042	93	93	$56.69	$83.06	$54,345	41,500	$0	41,500	12,845
2010	0 0198	$8,300	327,020	654,040	$0 045	$0.045	116	116	$60.09	$88 04	$69,310	41,500	$0	41,500	27,810
2011	0 0198	0	327,020	654,040	$0.047	$0 047	116	116	$63 69	$93 32	$64,671	0	$0	0	64,671
2012	0 0198	0	327,020	654,040	$0 050	$0.050	116	116	$67.51	$98.92	$68,551	0	$0	0	68,551
2013	0 0197	0	327,020	654,040	$0 053	$0 053	116	116	$71 56	$104 86	$72,664	0	$0	0	72,664
2014	0 0197	0	327,020	654,040	$0 056	$0 056	116	116	$75 86	$111 15	$77,024	0	$0	0	77,024
2015	0 0197	0	327,020	654,040	$0 060	$0 060	116	116	$80.41	$117 82	$81,645	0	$0	0	81,645
2016	0 0196	0	0	0	$0.063	$0 063	0	0	$85 23	$124 89	$0	0	$0	0	0
2017	0 0196	0	0	0	$0 067	$0 067	0	0	$90.35	$132 38	$0	0	$0	0	0
2018	0 0195	0	0	0	$0 071	$0 071	0	0	$95 77	$140 33	$0	0	$0	0	0
2019	0 0195	0	0	0	$0.075	$0.075	0	0	$101 51	$148 74	$0	0	$0	0	0
2020	0 0195	0	0	0	$0 080	$0.080	0	0	$107 61	$157 67	$0	0	$0	0	0
2021	0.0194	0	0	0	$0.085	$0 085	0	0	$114.06	$167 13	$0	0	$0	0	0
			2,616,160	5,232,320							$575,845	$207,500	$0	$207,500	$368,345
											$397,723	180,994	0	180,994	216,729

Total NPV = $216,729
Benefit/Cost Ratio = 2 20

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part (21) x Participants (22)
(C2) = Energy Reduction/Part (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM

Intergrated Electric System Cost-Effectiveness Analysis

Company **Montana-Dakota Utilities Co.**

Project **Commercial Air Conditioning Cycling**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.03336
1a) Retail Rate Winter ($/kWh) =	$0.03336
Escalation Rate =	6.00%
2)Avg. System Energy Cost ($/kWh) =	$0.01471
Escalation Rate =	2.15%
3) Retail Summer Demand Cost ($/kW/season) =	$44 90
3a) Retail Winter Demand Cost ($/kW/season) =	$65.79
Escalation Rate =	6 00%
4) System Summer Demand Cost ($/kW/yr)	74 46
Escalation Rate =	2 15%
5) Variable O&M ($/kWh) =	$0.00
Escalation Rate =	1.15%
6) Environmental Damage Factor =	15%
Escalation Rate =	2 15%
7) Total Sales by class (kWh) =	680,614,000
Growth Rate =	0.23%
8) Total Customers by class =	16,592
Growth Rate =	0 18%
9) Utility Discount Rate =	7 34%
10) Social Discount Rate(Tbill) =	4 97%
11) General Input Data Year =	2005
12) Project Analysis Year 1 =	2006
12a) Project Analysis Year 2 =	2007
13) Effective Fed & State Income Tax Rate =	39 00%
14) System Annual Line loss factor	7 88%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$1,000
Direct Operating Costs =	$105,258
Incentive Costs =	$32,737
Total Utility Project Costs Year 1 =	**$138,995**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$1,000
Direct Operating Costs =	$52,629
Incentive Costs =	$16,369
Total Utility Project Costs Year 2 =	**$69,998**
15b) Total Utilty Cost Year 3 =	$69,998
15c) Total Utilty Cost Year 4 =	$0
15d) Total Utility Cost Year 5 =	$0
16) Direct Participant Costs ($/Part) =	$0 00
Escalation Rate =	2 15%
17) Other Participant Costs (Annual $/Part) =	$0.00
Escalation Rate =	2 15%
18) Project Life (Years) =	10
20) Avg Summer kW/part. Saved =	3.8
20a) Avg Winter kW/part Saved =	0
21) Avg. Summer kWh/Part Saved =	573
21a) Avg. Winter kWh/Part Saved =	0
22) Number of Participants (First Year) =	97
22a) Number of Participants (Second Year) =	49
22a) Number of Participants (Third Year) =	49
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$150.00

Demand-Side Management Program - DSM
Intergrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Commercial Air Conditioning Cycling**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	10
Total Progam Cost (Utility)	$278,991
Total Program Participants	195
Utility Cost per Participant (First Year) =	$1,432.94
Utility Cost per Participant (Program) =	$1,430.72
Total Summer kW Reduction	741
Total Winter kW Reduction	0
Total Summer Energy Reduction (kWh)	1,033,119
Total Winter Energy Reduction (kWh)	0
Societal Cost per kwh	$0.21

Test Results

	NPV	B/C
Utility Test	$231,808	1.91
Ratepayer Test	$238,965	1.97
Societal Benefit Test	$359,099	2 63
Participant Test	$369,189	#DIV/0!

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Table 1 — This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Utility Test

to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial Air Conditioning Cycling**

		Cost of Energy Saved						Project Cost			Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Peak Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2006	55,581	$0.0150	$0	369	$78 93	$29,928	$138,995	622	$139,617	($109,689)
2	2007	83,658	$0.0153	0	555	$83 66	47,700	69,998	919	70,917	(23,217)
3	2008	111,735	$0 0157	0	741	$88 68	67,466	69,998	1,205	71,203	(3,737)
4	2009	111,735	$0 0160	0	741	$94 00	71,447	0	1,182	1,182	70,264
5	2010	111,735	$0.0164	0	741	$99 64	75,664	0	1,159	1,159	74,506
6	2011	111,735	$0 0167	0	741	$105 62	80,134	0	1,135	1,135	78,999
7	2012	111,735	$0 0171	0	741	$111 96	84,870	0	1,110	1,110	83,760
8	2013	111,735	$0 0174	0	741	$118 68	89,889	0	1,085	1,085	88,804
9	2014	111,735	$0 0178	0	741	$125 80	95,207	0	1,060	1,060	94,148
10	2015	111,735	$0 0182	0	741	$133 35	100,843	0	1,033	1,033	99,810
11	2016	0	$0.0186	0	0	$141 35	0	0	0	0	0
12	2017	0	$0 0190	0	0	$149 83	0	0	0	0	0
13	2018	0	$0 0194	0	0	$158 82	0	0	0	0	0
14	2019	0	$0.0198	0	0	$168 35	0	0	0	0	0
15	2020	0	$0.0202	0	0	$178 45	0	0	0	0	0
16	2021	0	$0.0207	0	0	$189.15	0	0	0	0	0
Total =		1,033,119			6,851		$743,149	$278,991	$10,510	$289,501	$453,648
NPV =							485,802	246,837	7,157	253,994	231,808

Total NPV = $231,808
Benefit/Cost Ratio = 1 91

(A) = Energy Reduction/Part (21+ 21a) x Participants (22)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part (20) x Participants (22)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2 — This test compares the cost of energy saved to the total

Ratepayer Impact Test — *cost of saving that same amount of energy and its impact on all ratepayers.*

Company: **Montana-Dakota Utilities Co.**

Project: **Commercial Air Conditioning Cycling**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2006	$835	$0	$29,093	$29,928	$138,995	$138,995	($109,067)
2007	1,284	0	46,416	47,700	69,998	69,998	(22,298)
2008	1,752	0	65,714	67,466	69,998	69,998	(2,532)
2009	1,790	0	69,657	71,447	0	0	71,447
2010	1,828	0	73,836	75,664	0	0	75,664
2011	1,867	0	78,267	80,134	0	0	80,134
2012	1,908	0	82,963	84,870	0	0	84,870
2013	1,949	0	87,940	89,889	0	0	89,889
2014	1,990	0	93,217	95,207	0	0	95,207
2015	2,033	0	98,810	100,843	0	0	100,843
2016	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0
Total =	$17,236	$0	$725,913	$743,149	$278,991	$278,991	$464,158
NPV =	11,481	0	474,321	485,802	246,837	246,837	238,965

Total NPV = $238,965

Benefit/Cost Ratio = 1.97

(A) = Energy Reduction/Part (21 + 21a) x Participants (22) x Energy Cost (2)

(B) = Energy Reduction/Part (21) x Participants (22) x Variable O&M (5)

(C) = kW Demand Reduction/Part (20) x Participants (22) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 5

Societal Benefit Test

This test measures the net cost of the program based on total cost including environmental externalities and both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**
Project: **Commercial Air Conditioning Cycling**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2006	$835	$0	$29,093	$4,586	$34,514	$138,995	$0	$14,550	$124,445	($89,931)
2007	$1,284	$0	$46,416	$7,466	55,167	69,998	0	$7,350	62,648	(7,481)
2008	$1,752	$0	$65,714	$10,787	78,253	69,998	0	$7,350	62,648	15,605
2009	$1,790	$0	$69,657	$11,669	83,115	0	0	$0	0	83,115
2010	$1,828	$0	$73,836	$12,623	88,288	0	0	$0	0	88,288
2011	$1,867	$0	$78,267	$13,656	93,790	0	0	$0	0	93,790
2012	$1,908	$0	$82,963	$14,775	99,645	0	0	$0	0	99,645
2013	$1,949	$0	$87,940	$15,985	105,874	0	0	$0	0	105,874
2014	$1,990	$0	$93,217	$17,294	112,502	0	0	$0	0	112,502
2015	$2,033	$0	$98,810	$18,712	119,555	0	0	$0	0	119,555
2016	$0	$0	$0	$0	0	0	0	$0	0	0
2017	$0	$0	$0	$0	0	0	0	$0	0	0
2018	$0	$0	$0	$0	0	0	0	$0	0	0
2019	$0	$0	$0	$0	0	0	0	$0	0	0
2020	$0	$0	$0	$0	0	0	0	$0	0	0
2021	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$17,236	$0	$725,913	$127,553	$870,702	$278,991	$0	$29,250	$249,741	$620,961
NPV =	11,481	0	474,321	94,256	580,058	246,837	0	25,877	220,960	359,099

Total NPV = $359,099
Benefit/Cost Ratio = 2 63

(A) = Energy Reduction/Part. (21 + 21a) x Participants (22) x Energy Cost (2)
(B) = Energy Reduction/Part (21) x Participants (22) x Variable O&M (5)
(C) = kW Demand Reduction/Part (20) x Participants (22) x System Demand Cost (4)
(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)
(E) = (A) + (B) + (C) + (D)

(F) = Total Utility Project Costs (15)
(G) = Direct (16) + Other (17) Participant Costs x Participants (22)
(H) = Incentive Costs (15)
(I) = (F) + (G) - (H)
(J) = (E) - (I)

Participant Test

directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial Air Conditioning Cycling**

Year	Ratio of Part. to Total Customers (A)	Benefits: Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Cost (F1)	Winter Demand Cost (F2)	Total Annual Benefits (G)	Costs: Direct Part Costs (H)	Other Part Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2006	0 0058	$14,550	55,581	0	$0.035	$0.035	369	0	$47.59	$69 74	$34,059	$0	$0	$0	$34,0[illegible]
2007	0.0088	$7,350	83,658	0	$0 037	$0 037	555	0	$50.45	$73.92	$38,475	0	$0	0	38,4[illegible]
2008	0 0088	$7,350	111,735	0	$0 040	$0 040	741	0	$53 48	$78.36	$51,416	0	$0	0	51,416
2009	0 0087	$0	111,735	0	$0 042	$0 042	741	0	$56 69	$83 06	$46,710	0	$0	0	46,710
2010	0 0087	$0	111,735	0	$0 045	$0 045	741	0	$60 09	$88.04	$49,512	0	$0	0	49,512
2011	0 0087	0	111,735	0	$0.047	$0 047	741	0	$63 69	$93 32	$52,483	0	$0	0	52,483
2012	0 0087	0	111,735	0	$0 050	$0 050	741	0	$67 51	$98 92	$55,632	0	$0	0	55,632
2013	0 0087	0	111,735	0	$0.053	$0 053	741	0	$71 56	$104 86	$58,970	0	$0	0	58,970
2014	0 0087	0	111,735	0	$0 056	$0 056	741	0	$75 86	$111 15	$62,508	0	$0	0	62,508
2015	0.0086	0	111,735	0	$0.060	$0.060	741	0	$80.41	$117 82	$66,258	0	$0	0	66,258
2016	0 0086	0	0	0	$0 063	$0 063	0	0	$85 23	$124 89	$0	0	$0	0	0
2017	0 0086	0	0	0	$0 067	$0 067	0	0	$90.35	$132 38	$0	0	$0	0	0
2018	0.0086	0	0	0	$0.071	$0 071	0	0	$95 77	$140.33	$0	0	$0	0	0
2019	0 0086	0	0	0	$0 075	$0 075	0	0	$101 51	$148 74	$0	0	$0	0	0
2020	0 0086	0	0	0	$0 080	$0 080	0	0	$107 61	$157 67	$0	0	$0	0	0
2021	0 0085	0	0	0	$0 085	$0 085	0	0	$114 06	$167.13	$0	0	$0	0	0
			1,033,119	0							$516,022	$0	$0	$0	$516,022
											$369,189	0	0	0	369,189

Total NPV = $369,189
Benefit/Cost Ratio = #DIV/0!

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part (21) x Participants (22)
(C2) = Energy Reduction/Part (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part (20) x Participants (22)
(E2) = kW Demand Reduction/Part (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

APPENDIX I

CALCULATIONS OF LEVELIZED FIXED CHARGE RATES

Computation of Levelized Fixed Charges -- Page 1 of 3
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Levelized Fixed Charged Rate for the Lignite Vision 21 Unit
Book Life = 25 years

Basic assumptions used in this study are shown below:
Conventional bond financing is used.

Weighted cost of capital

Debt	0.03100	
PFD	0.00000	
Common	0.05450	
Composite		0.07341 (at 39.00% tax rate)

Capitalization Ratios

Long term debt	= 50.00 %
Preferred stock	= 0.00 %
Common stock	= 50.00 %

Interest rates

Bonds	= 6.20 %
Preferred stock	= 0.00 %
Common stock	= 10.90 %

Tax rates

Income taxes	= 39.00 %	
Deferred federal income tax	= 35.00 %	
Investment credit	= 0.00 %	Amortized over 0 years

Book life = 25 years   Tax life = 20 years
Depreciation method used for tax purposes is TABLE-87
Deferred federal income tax reflects normalization
Salvage value = 0.0 %
General tax rate = 1.37 % on gross plant
Insurance and O&M = 0.00 % on gross plant

The results obtained based on the foregoing assumptions are as follows:

Sum of P.W. values	Capital recovery factor	Levelized fixed charge
133.640	0.09812	13.113

Levelized income tax	Levelized return on capital
2.206	5.539
2.206	5.539

Computation of Levelized Fixed Charges -- Page 2 of 3
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Year	Supporting Charges: Debt	Supporting Charges: Preferred	Supporting Charges: Common	Book Deprectn	General Taxes	O&M and Insurance	Income Tax & Revenue Adj. - Net	Total Charges	Present Worth Factor	Present Worth Value	Acculm. PW Value
1	3.1000	0.0000	5.4500	4.0000	1.3680	0.0000	3.5008	17.4188	0.9212	16.0468	16.0468
2	2.9787	0.0000	5.2368	4.0000	1.3680	0.0000	3.1370	16.7205	0.8487	14.1902	30.2370
3	2.8198	0.0000	4.9574	4.0000	1.3680	0.0000	2.9939	16.1391	0.7818	12.6180	42.8550
4	2.6667	0.0000	4.6883	4.0000	1.3680	0.0000	2.8547	15.5777	0.7202	11.2198	54.0748
5	2.5191	0.0000	4.4288	4.0000	1.3680	0.0000	2.7192	15.0351	0.6635	9.9760	64.0508
6	2.3765	0.0000	4.1781	4.0000	1.3680	0.0000	2.5870	14.5096	0.6113	8.8690	72.9199
7	2.2386	0.0000	3.9356	4.0000	1.3680	0.0000	2.4580	14.0001	0.5631	7.8836	80.8034
8	2.1050	0.0000	3.7007	4.0000	1.3680	0.0000	2.3318	13.5054	0.5188	7.0060	87.8094
9	1.9753	0.0000	3.4727	4.0000	1.3680	0.0000	2.1900	13.0059	0.4779	6.2155	94.0249
10	1.8463	0.0000	3.2459	4.0000	1.3680	0.0000	2.0449	12.5051	0.4403	5.5054	99.5303
11	1.7173	0.0000	3.0191	4.0000	1.3680	0.0000	1.8999	12.0043	0.4056	4.8686	104.3989
12	1.5883	0.0000	2.7923	4.0000	1.3680	0.0000	1.7549	11.5034	0.3736	4.2980	108.6969
13	1.4592	0.0000	2.5654	4.0000	1.3680	0.0000	1.6099	11.0026	0.3442	3.7871	112.4840
14	1.3302	0.0000	2.3386	4.0000	1.3680	0.0000	1.4649	10.5018	0.3171	3.3300	115.8140
15	1.2012	0.0000	2.1118	4.0000	1.3680	0.0000	1.3199	10.0009	0.2921	2.9214	118.7354
16	1.0722	0.0000	1.8850	4.0000	1.3680	0.0000	1.1749	9.5001	0.2691	2.5565	121.2920
17	0.9432	0.0000	1.6582	4.0000	1.3680	0.0000	1.0299	8.9992	0.2479	2.2310	123.5230
18	0.8142	0.0000	1.4314	4.0000	1.3680	0.0000	0.8848	8.4984	0.2284	1.9409	125.4639
19	0.6852	0.0000	1.2046	4.0000	1.3680	0.0000	0.7398	7.9976	0.2104	1.6826	127.1465
20	0.5562	0.0000	0.9778	4.0000	1.3680	0.0000	0.5948	7.4967	0.1938	1.4530	128.5995
21	0.4271	0.0000	0.7509	4.0000	1.3680	0.0000	0.5966	7.1427	0.1786	1.2754	129.8749
22	0.3224	0.0000	0.5668	4.0000	1.3680	0.0000	0.6247	6.8819	0.1645	1.1320	131.0069
23	0.2418	0.0000	0.4251	4.0000	1.3680	0.0000	0.5341	6.5690	0.1515	0.9954	132.0023
24	0.1612	0.0000	0.2834	4.0000	1.3680	0.0000	0.4435	6.2561	0.1396	0.8734	132.8757
25	0.0806	0.0000	0.1417	4.0000	1.3680	0.0000	0.3529	5.9432	0.1286	0.7643	133.6400
25	0.0806	0.0000	0.1417	4.0000	1.3680	0.0000	0.3529	5.9432	0.1286	0.7643	133.6400

Computation of Levelized Fixed Charges -- Page 3 of 3
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	Gross Income Tax	Rev. Adjmts. Due to Flow-thru Accel.Dep	Rev. Adjmts. Due to Investmt Tax Crdt	Deferred Federal Income Tx	Current Income Tx Liability	Net Income Tax & Rev. Adjustmnts	Tax Depreciation Accel.	Tax Depreciation Normal	Amortized Investmnt Tax Crdt.	Net Investmnt	Yearly LFCR
1	3.4844	0.0000	0.0000	-0.0875	3.5883	3.5008	3.7500	5.0000	0.0000	100.0000	17.4188
2	3.3481	0.0000	0.0000	1.1266	2.0104	3.1370	7.2190	5.0000	0.0000	96.0875	17.0840
3	3.1695	0.0000	0.0000	0.9369	2.0570	2.9939	6.6770	5.0000	0.0000	90.9609	16.7945
4	2.9974	0.0000	0.0000	0.7620	2.0927	2.8547	6.1770	5.0000	0.0000	86.0239	16.5266
5	2.8315	0.0000	0.0000	0.5995	2.1196	2.7192	5.7130	5.0000	0.0000	81.2620	16.2752
6	2.6712	0.0000	0.0000	0.4497	2.1372	2.5870	5.2850	5.0000	0.0000	76.6624	16.0378
7	2.5162	0.0000	0.0000	0.3108	2.1472	2.4580	4.8880	5.0000	0.0000	72.2127	15.8133
8	2.3660	0.0000	0.0000	0.1827	2.1491	2.3318	4.5220	5.0000	0.0000	67.9019	15.6006
9	2.2202	0.0000	0.0000	0.1617	2.0283	2.1900	4.4620	5.0000	0.0000	63.7192	15.3975
10	2.0752	0.0000	0.0000	0.1617	1.8832	2.0449	4.4620	5.0000	0.0000	59.5575	15.2030
11	1.9302	0.0000	0.0000	0.1617	1.7382	1.8999	4.4620	5.0000	0.0000	55.3958	15.0164
12	1.7852	0.0000	0.0000	0.1617	1.5932	1.7549	4.4620	5.0000	0.0000	51.2341	14.8372
13	1.6402	0.0000	0.0000	0.1617	1.4482	1.6099	4.4620	5.0000	0.0000	47.0723	14.6651
14	1.4952	0.0000	0.0000	0.1617	1.3032	1.4649	4.4620	5.0000	0.0000	42.9106	14.4999
15	1.3502	0.0000	0.0000	0.1617	1.1582	1.3199	4.4620	5.0000	0.0000	38.7489	14.3411
16	1.2052	0.0000	0.0000	0.1617	1.0132	1.1749	4.4620	5.0000	0.0000	34.5872	14.1887
17	1.0602	0.0000	0.0000	0.1617	0.8682	1.0299	4.4620	5.0000	0.0000	30.4255	14.0425
18	0.9151	0.0000	0.0000	0.1617	0.7231	0.8848	4.4620	5.0000	0.0000	26.2638	13.9022
19	0.7701	0.0000	0.0000	0.1617	0.5781	0.7398	4.4620	5.0000	0.0000	22.1021	13.7677
20	0.6251	0.0000	0.0000	0.1617	0.4331	0.5948	4.4620	5.0000	0.0000	17.9404	13.6388
21	0.4801	0.0000	0.0000	-0.6216	1.2182	0.5966	2.2240	0.0000	0.0000	13.7787	13.5180
22	0.3624	0.0000	0.0000	-1.4000	2.0247	0.6247	0.0000	0.0000	0.0000	10.4003	13.4063
23	0.2718	0.0000	0.0000	-1.4000	1.9341	0.5341	0.0000	0.0000	0.0000	7.8003	13.3019
24	0.1812	0.0000	0.0000	-1.4000	1.8435	0.4435	0.0000	0.0000	0.0000	5.2003	13.2042
25	0.0906	0.0000	0.0000	-1.4000	1.7529	0.3529	0.0000	0.0000	0.0000	2.6003	13.1125

Computation of Levelized Fixed Charges -- Page 1 of 3
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Levelized Fixed Charged Rate for the Lignite Vision 21 Unit
Book Life = 33 years

Basic assumptions used in this study are shown below:
Conventional bond financing is used.

Weighted cost of capital

Debt	0.03100	
PFD	0.00000	
Common	0.05450	
Composite		0.07341 (at 39.00% tax rate)

Capitalization Ratios

Long term debt	= 50.00 %
Preferred stock	= 0.00 %
Common stock	= 50.00 %

Interest rates

Bonds	= 6.20 %
Preferred stock	= 0.00 %
Common stock	= 10.90 %

Tax rates

Income taxes	= 39.00 %	
Deferred federal income tax	= 35.00 %	
Investment credit	= 0.00 %	Amortized over 0 years

Book life = 33 years   Tax life = 20 years
Depreciation method used for tax purposes is TABLE-87
Deferred federal income tax reflects normalization
Salvage value = 0.0 %
General tax rate = 1.37 % on gross plant
Insurance and O&M = 0.00 % on gross plant

The results obtained based on the foregoing assumptions are as follows:

Sum of P.W. values	Capital recovery factor	Levelized fixed charge
133.472	0.09161	12.228

Levelized income tax	Levelized return on capital
2.200	5.629
2.200	5.629

Computation of Levelized Fixed Charges -- Page 2 of 3
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	Supporting Charges										
Year	Debt	Preferred	Common	Book Deprectn	General Taxes	O&M and Insurance	Income Tax & Revenue Adj. - Net	Total Charges	Present Worth Factor	Present Worth Value	Acculm. PW Value
1	3.1000	0.0000	5.4500	3.0303	1.3680	0.0000	3.4372	16.3855	0.9212	15.0949	15.0949
2	2.9983	0.0000	5.2711	3.0303	1.3680	0.0000	3.0954	15.7631	0.8487	13.3777	28.4726
3	2.8589	0.0000	5.0261	3.0303	1.3680	0.0000	2.9743	15.2575	0.7818	11.9287	40.4013
4	2.7254	0.0000	4.7914	3.0303	1.3680	0.0000	2.8570	14.7720	0.7202	10.6395	51.0408
5	2.5973	0.0000	4.5662	3.0303	1.3680	0.0000	2.7434	14.3052	0.6635	9.4917	60.5325
6	2.4742	0.0000	4.3499	3.0303	1.3680	0.0000	2.6332	13.8556	0.6113	8.4693	69.0018
7	2.3558	0.0000	4.1417	3.0303	1.3680	0.0000	2.5262	13.4220	0.5631	7.5580	76.5598
8	2.2417	0.0000	3.9411	3.0303	1.3680	0.0000	2.4219	13.0031	0.5188	6.7454	83.3052
9	2.1316	0.0000	3.7475	3.0303	1.3680	0.0000	2.3021	12.5795	0.4779	6.0117	89.3169
10	2.0221	0.0000	3.5550	3.0303	1.3680	0.0000	2.1790	12.1545	0.4403	5.3510	94.6679
11	1.9127	0.0000	3.3626	3.0303	1.3680	0.0000	2.0560	11.7295	0.4056	4.7572	99.4251
12	1.8032	0.0000	3.1701	3.0303	1.3680	0.0000	1.9329	11.3045	0.3736	4.2237	103.6488
13	1.6937	0.0000	2.9777	3.0303	1.3680	0.0000	1.8099	10.8795	0.3442	3.7448	107.3936
14	1.5842	0.0000	2.7852	3.0303	1.3680	0.0000	1.6868	10.4546	0.3171	3.3150	110.7086
15	1.4748	0.0000	2.5927	3.0303	1.3680	0.0000	1.5638	10.0296	0.2921	2.9298	113.6384
16	1.3653	0.0000	2.4003	3.0303	1.3680	0.0000	1.4407	9.6046	0.2691	2.5847	116.2230
17	1.2558	0.0000	2.2078	3.0303	1.3680	0.0000	1.3177	9.1796	0.2479	2.2757	118.4988
18	1.1463	0.0000	2.0154	3.0303	1.3680	0.0000	1.1946	8.7546	0.2284	1.9994	120.4982
19	1.0369	0.0000	1.8229	3.0303	1.3680	0.0000	1.0716	8.3296	0.2104	1.7525	122.2507
20	0.9274	0.0000	1.6304	3.0303	1.3680	0.0000	0.9485	7.9047	0.1938	1.5321	123.7828
21	0.8179	0.0000	1.4380	3.0303	1.3680	0.0000	0.9722	7.6264	0.1786	1.3617	125.1445
22	0.7327	0.0000	1.2882	3.0303	1.3680	0.0000	1.0223	7.4416	0.1645	1.2241	126.3686
23	0.6717	0.0000	1.1809	3.0303	1.3680	0.0000	0.9537	7.2045	0.1515	1.0917	127.4603
24	0.6106	0.0000	1.0735	3.0303	1.3680	0.0000	0.8850	6.9675	0.1396	0.9727	128.4330
25	0.5496	0.0000	0.9662	3.0303	1.3680	0.0000	0.8164	6.7304	0.1286	0.8656	129.2985
26	0.4885	0.0000	0.8588	3.0303	1.3680	0.0000	0.7478	6.4934	0.1185	0.7693	130.0678
27	0.4274	0.0000	0.7515	3.0303	1.3680	0.0000	0.6791	6.2563	0.1091	0.6828	130.7507
28	0.3664	0.0000	0.6441	3.0303	1.3680	0.0000	0.6105	6.0193	0.1005	0.6052	131.3559
29	0.3053	0.0000	0.5368	3.0303	1.3680	0.0000	0.5419	5.7823	0.0926	0.5356	131.8914
30	0.2443	0.0000	0.4294	3.0303	1.3680	0.0000	0.4733	5.5452	0.0853	0.4732	132.3646
31	0.1832	0.0000	0.3221	3.0303	1.3680	0.0000	0.4046	5.3082	0.0786	0.4173	132.7819
32	0.1221	0.0000	0.2147	3.0303	1.3680	0.0000	0.3360	5.0711	0.0724	0.3672	133.1491
33	0.0611	0.0000	0.1074	3.0303	1.3680	0.0000	0.2674	4.8341	0.0667	0.3225	133.4716
33	0.0611	0.0000	0.1074	3.0303	1.3680	0.0000	0.2674	4.8341	0.0667	0.3225	133.4716

Computation of Levelized Fixed Charges -- Page 3 of 3
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	Gross Income Tax	Rev. Adjmts. Due to Flow-thru Accel.Dep	Rev. Adjmts. Due to Investmt Tax Crdt	Deferred Federal Income Tx	Current Income Tx Liability	Net Income Tax & Rev. Adjustmnts	Tax Depreciation Accel.	Tax Depreciation Normal	Amortized Investmnt Tax Crdt.	Net Investmnt	Yearly LFCR
1	3.4844	0.0000	0.0000	0.2519	3.1853	3.4372	3.7500	5.0000	0.0000	100.0000	16.3855
2	3.3701	0.0000	0.0000	1.4660	1.6293	3.0954	7.2190	5.0000	0.0000	96.7178	16.0871
3	3.2134	0.0000	0.0000	1.2763	1.6979	2.9743	6.6770	5.0000	0.0000	92.2215	15.8329
4	3.0633	0.0000	0.0000	1.1013	1.7556	2.8570	6.1770	5.0000	0.0000	87.9148	15.5994
5	2.9194	0.0000	0.0000	0.9389	1.8045	2.7434	5.7130	5.0000	0.0000	83.7832	15.3812
6	2.7811	0.0000	0.0000	0.7891	1.8441	2.6332	5.2850	5.0000	0.0000	79.8139	15.1761
7	2.6480	0.0000	0.0000	0.6502	1.8760	2.5262	4.8880	5.0000	0.0000	75.9945	14.9828
8	2.5197	0.0000	0.0000	0.5221	1.8998	2.4219	4.5220	5.0000	0.0000	72.3140	14.8003
9	2.3959	0.0000	0.0000	0.5011	1.8010	2.3021	4.4620	5.0000	0.0000	68.7616	14.6265
10	2.2729	0.0000	0.0000	0.5011	1.6779	2.1790	4.4620	5.0000	0.0000	65.2302	14.4603
11	2.1498	0.0000	0.0000	0.5011	1.5549	2.0560	4.4620	5.0000	0.0000	61.6988	14.3010
12	2.0268	0.0000	0.0000	0.5011	1.4318	1.9329	4.4620	5.0000	0.0000	58.1674	14.1482
13	1.9038	0.0000	0.0000	0.5011	1.3088	1.8099	4.4620	5.0000	0.0000	54.6360	14.0015
14	1.7807	0.0000	0.0000	0.5011	1.1857	1.6868	4.4620	5.0000	0.0000	51.1046	13.8607
15	1.6577	0.0000	0.0000	0.5011	1.0627	1.5638	4.4620	5.0000	0.0000	47.5732	13.7255
16	1.5346	0.0000	0.0000	0.5011	0.9396	1.4407	4.4620	5.0000	0.0000	44.0418	13.5958
17	1.4116	0.0000	0.0000	0.5011	0.8166	1.3177	4.4620	5.0000	0.0000	40.5104	13.4713
18	1.2885	0.0000	0.0000	0.5011	0.6935	1.1946	4.4620	5.0000	0.0000	36.9790	13.3519
19	1.1655	0.0000	0.0000	0.5011	0.5705	1.0716	4.4620	5.0000	0.0000	33.4476	13.2375
20	1.0424	0.0000	0.0000	0.5011	0.4474	0.9485	4.4620	5.0000	0.0000	29.9162	13.1279
21	0.9194	0.0000	0.0000	-0.2822	1.2544	0.9722	2.2240	0.0000	0.0000	26.3848	13.0257
22	0.8236	0.0000	0.0000	-1.0606	2.0829	1.0223	0.0000	0.0000	0.0000	23.6367	12.9317
23	0.7550	0.0000	0.0000	-1.0606	2.0143	0.9537	0.0000	0.0000	0.0000	21.6670	12.8442
24	0.6863	0.0000	0.0000	-1.0606	1.9457	0.8850	0.0000	0.0000	0.0000	19.6973	12.7627
25	0.6177	0.0000	0.0000	-1.0606	1.8770	0.8164	0.0000	0.0000	0.0000	17.7276	12.6866
26	0.5491	0.0000	0.0000	-1.0606	1.8084	0.7478	0.0000	0.0000	0.0000	15.7579	12.6154
27	0.4804	0.0000	0.0000	-1.0606	1.7398	0.6791	0.0000	0.0000	0.0000	13.7882	12.5488
28	0.4118	0.0000	0.0000	-1.0606	1.6711	0.6105	0.0000	0.0000	0.0000	11.8185	12.4864
29	0.3432	0.0000	0.0000	-1.0606	1.6025	0.5419	0.0000	0.0000	0.0000	9.8488	12.4279
30	0.2745	0.0000	0.0000	-1.0606	1.5339	0.4733	0.0000	0.0000	0.0000	7.8791	12.3730
31	0.2059	0.0000	0.0000	-1.0606	1.4652	0.4046	0.0000	0.0000	0.0000	5.9094	12.3214
32	0.1373	0.0000	0.0000	-1.0606	1.3966	0.3360	0.0000	0.0000	0.0000	3.9397	12.2730
33	0.0686	0.0000	0.0000	-1.0606	1.3280	0.2674	0.0000	0.0000	0.0000	1.9700	12.2276