Montana-Dakota Utilities Co.
2009 Integrated Resource Plan

Submitted to the North Dakota Public Service Commission
July 1, 2009

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

INTEGRATED RESOURCE PLAN

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<u>EXECUTIVE SUMMARY</u>

Montana-Dakota Utilities Co.'s (Montana-Dakota) 2009 Integrated Resource Plan (IRP) conducted for the integrated electric system comprised of its service territories in the States of Montana, North Dakota and South Dakota continues a 22-year practice of determining the best value resource plan for its customers. The purpose of integrated resource planning is to consider all resource options reasonably available to meet the end-use customer's demand for reliable, cost-effective, and environmentally responsible electricity. Such resources may consist of a combination of traditional generating stations, distributed generation, renewable resources, demand-side management programs, and new and emerging technologies.

The IRP process at Montana-Dakota encompasses four main areas: load forecasting, demand-side analysis, supply-side analysis, and integration and risk analysis (Figure E-1). A summary of the study results for each of these areas is provided.

The **load forecasting** activities employ an econometric forecasting method to predict the integrated system customers' future demand for electricity. The long-term forecast is an estimate of energy requirements and peak demand for twenty years into the future. The results for the base forecast show that, during the 2009-2028 time period, the projected average annual growth rate for the summer peak demand is 1.6 percent, while the annual energy requirements are expected to increase at a rate of 1.7 percent annually.

The **demand-side analysis** is an evaluation process to determine the potentially feasible demand-side management (DSM) programs applicable to Montana-Dakota's system. The DSM evaluation is performed on a number of residential and commercial programs selected through a joint effort between Montana-Dakota and the IRP Public Advisory Group (PAG). Based on the demand-side analysis discussed in Chapter 3, ten DSM programs were shown to provide the best-fit and the most cost-effective options for Montana-Dakota's customers as part of its total resource plan. Those ten programs are:

1. Residential Air Conditioner Cycling program
2. ENERGY STAR® Appliance rebates
3. ENERGY STAR® Residential Air Conditioner rebates
4. Refrigerator Round-up program

5. Interruptible Demand Response rates
6. High-Efficiency Commercial Motor rebates
7. High-Efficiency Commercial Air Conditioner rebates
8. Commercial Lighting Retrofit rebates
9. Residential New Construction Bundle rebates
10. Residential Lighting program

The ten programs will provide an estimated non-coincident demand reduction of 22.7 MW upon full implementation.

The **supply-side analysis** is an evaluation process to determine the potentially feasible generation options applicable to Montana-Dakota's system. Montana-Dakota has considered resources committed to, but not on-line yet as part of the existing generation portfolio. Those resources that have been committed to but not yet commercially available include: Big Stone Unit II expected to come on-line in June 2015, the Glen Ullin Station 6 waste heat unit expected to come on-line in July 2009, an addition to the existing Diamond Willow wind farm expected to come on-line the fourth quarter of 2010, and the Cedar Hills wind farm expected to come on-line the fourth quarter of 2010. The potential options studied included combustion turbines, combined cycle units, coal-fired units, wind generation, and purchased power.

The **integration and risk** process considers the feasible supply-side and demand-side options to determine a least-cost resource expansion plan. A number of scenarios were investigated to determine the sensitivity of the least-cost plan to several factors that may impact the expansion plan. The analytical tool used for the integration process was the Electric Generation Expansion Analysis System (EGEAS), a capacity expansion program developed by the Electric Power Research Institute. The results of the integration and risk process are then considered as part of the overall decision in determining the best resource plan for Montana-Dakota and its customers.

The **results** of the supply-side and integration analysis indicate that the least-cost resource plan for Montana-Dakota consists of the following resources in addition to the existing generation portfolio and the committed new resources described above:

- Additional capacity purchase for the 2011-2014 period,
- Two 75 MW combustion turbines in 2015 and 2021, and
- Implementation of 22.7 MW of additional demand side resources between 2010 and 2012.

Table E-1 presents Montana-Dakota's resource mix (in megawatt and percent) by fuel/unit type for 2010, 2015, and 2020 upon the implementation of the resource plan identified in this IRP.

Table E-1

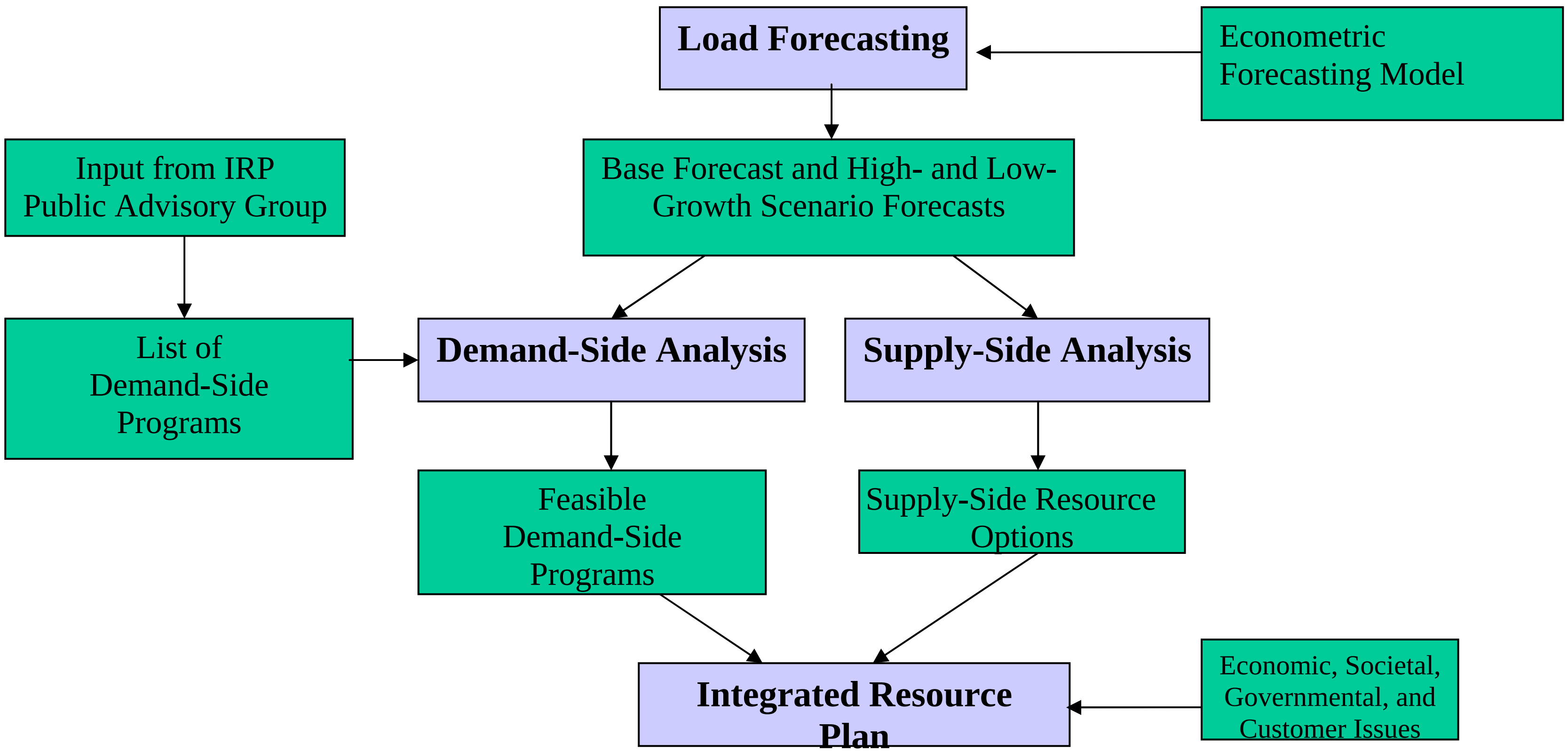
Montana-Dakota's Capacity Mix (in MW and Percent) for the Least-Cost Resource Expansion Plan

Fuel/Unit Type	2010	2015	2020
Natural Gas/Peaking	113.7 (17%)	179.1 (24%)	179.1 (24%)
Purchased Power	112.8 (17%)	2.8 (0%)	2.8 (0%)
Renewable	57.5 (9%)	57.5 (8%)	57.5 (8%)
Demand-Side/Interruptible	7.6 (1%)	22.7 (3%)	22.7 (3%)
Fossil/Base Load	368.7 (56%)	499.7 (66%)	499.7 (66%)

The 2009 IRP process and product (report and attachments) were enhanced with the participation of Montana-Dakota's IRP Public Advisory Group (PAG). The PAG has been a valuable tool within the IRP process since 1994. The 2009 advisory group was established at the beginning of the 2009 planning cycle and provided Montana-Dakota with input throughout the 2009 IRP process.

FIGURE E-1

MONTANA-DAKOTA UTILITIES CO.



CHAPTER 1

ENVIRONMENTAL CONSIDERATIONS

MDU Resources Group, Inc's Corporate Environmental Statement states:

> *"Our company will operate efficiently to meet the needs of the present without compromising the ability of future generations to meet their own needs. Our environmental goals are:*
>
> - *To minimize waste and maximize resources;*
> - *To support environmental laws and regulations that are based on sound science and cost-effective technology; and*
> - *To comply with or exceed all applicable environmental laws, regulations and permit requirements".*

Montana-Dakota strives to maintain compliance and operate in an environmentally proactive manner, while taking into consideration the cost to customers. Montana-Dakota has been involved with renewable energy analysis for many years. Montana-Dakota's commitment to environmental stewardship is evidenced as follows:

<u>Wind Resources</u>

Montana-Dakota has been involved in wind studies and projects for over fifteen years. Since 1993, when we first participated in the development of a regional wind monitoring network, we have offered a "green power" program to our customers and involved in two power purchase agreements with wind developers in North Dakota. The wind projects did not come to fruition due to contractor default, and the "green power" program was not implemented because there were not enough customers willing to sign up to cost-effectively implement the program.

Montana-Dakota constructed a 19.5 MW wind farm near Baker, Montana, named Diamond Willow Wind Farm; this was commercially available in February 2008. Montana Dakota will be installing an additional 10 MW at the Diamond Willow location in 2010.

Montana-Dakota is also constructing a 19.5 MW wind farm near the town of Rhame, in the southwest corner of North Dakota named the Cedar Hills Wind Farm.

The Diamond Willow and Cedar Hills wind projects will serve to meet all or a portion of the renewable standards/objectives applicable in Montana, North Dakota and South Dakota.

Air Quality

All power generation owned or operated by Montana-Dakota complies with federal and state air quality requirements.

Montana-Dakota has been an active sponsor of research on technology that removes mercury from lignite-based electric generation facilities. Montana-Dakota's Lewis & Clark Station in Sidney, MT conducted testing in the summers of 2007 and 2008 to assess a variety of mercury removal products and equipment. As required by the Montana Department of Environmental Quality, Lewis & Clark Station will install an activated carbon and oxidizing agent injection system to reduce its mercury emissions by approximately ninety percent starting in 2010.

The design of the proposed Big Stone Unit II unit includes state of the art emission equipment as well as a super-critical boiler and a joint scrubber with Big Stone I. Overall, when operational, the Big Stone complex (Units I and II) will produce fewer emissions than the existing Big Stone I plant does alone today.

Waste Heat Recovery

Montana-Dakota is constructing a 7.5 MW organic Rankine cycle unit on the Northern Border Pipeline near the town of Glen Ullin, in central North Dakota. The Glen Ullin Station 6 waste heat unit will use high temperature exhaust gas (which is currently wasted to the atmosphere) from a combustion turbine as the primary heat source. The exhaust gas will pass through a large heat exchanger to heat a thermal oil heat transfer fluid before being discharged to the atmosphere. The heated thermal oil will then pass through a number of additional heat exchangers to superheat an organic working fluid, which will expand through a turbine to generate electricity. Given that waste heat is utilized as the "fuel" for this facility, no other types of fuel are required and therefore emissions are insignificant.

SF6 Reduction

Sulfur hexafluoride gas (SF6) has been used for many years as a means of arc suppression in high voltage circuit breakers. However, SF6 has been identified as a greenhouse gas. Montana-Dakota is a participant in the EPA's voluntary "SF6 Emission Reduction Partnership," helping to reduce SF6 emissions in the electric utility industry. Through this program, Montana-Dakota has replaced a number of high-volume and leaking SF6 breakers with significantly smaller-volume breakers to reduce the potential of SF6 gas being released into the atmosphere due to a leak in the breakers. Montana-Dakota's 2008 report indicates continued reductions in inadvertent releases, and a 97 percent reduction since the company established its baseline emissions in 2004.

Canadian Clean Power Coalition

Montana-Dakota continues to be heavily involved in researching technologies that will continue to allow coal to play a part in our energy mix. Montana-Dakota is a participating member within the Canadian Clean Power Coalition (CCPC) which was formed as an association of generating companies in Canada along with the Electric Power Research institute (EPRI) with a mandate to research, develop, and demonstrate commercially viable clean coal technology.

Commitment to Reducing Greenhouse Gases

In 2003, Montana-Dakota joined other utilities, through a memorandum of understanding from the Edison Electric Institute to the Department of Energy, to commit to reduce the utility industry's carbon dioxide emission intensity by three to five percent by 2010. Montana-Dakota has shown its commitment by reducing the company's carbon dioxide emissions intensity by approximately seven percent as of 2008, relative to emissions in 2003. The reductions were realized through utility operation changes and customer energy efficiency projects, as well as renewable energy projects.

Montana-Dakota has been active in researching options for carbon dioxide capture, sequestration, and beneficial uses. The company has been a member of the Plains CO_2 Reduction Partnership (PCOR) since its inception in 2003. The partnership is led by the Energy and Environmental Research Center at the University of North Dakota and is one of seven regional partnerships across the United States.

Montana-Dakota actively monitors legislative activity related to greenhouse gases at both the state and federal level, as well as through relevant trade organizations.

Demand Side Management (DSM) activities

Montana-Dakota has been involved in activities to reduce customer's bills and save capacity through demand-side measures since the late 1970s. Montana-Dakota has offered time-of-day rates, dual fuel space heating rates, large commercial interruptible rates, and a radio-controlled load management system since the mid-1980s in various parts of its system. Montana-Dakota's commitment to DSM continues with its partnership in ENERGY STAR® and its continued implementation of cost-effective DSM programs as the results of the 2005 and 2007 IRPs.

As part of its IRP process, Montana-Dakota continues to analyze and make decisions taking into consideration environmental stewardship and customer cost impacts.

CHAPTER 2

LOAD FORECASTING

Montana-Dakota uses an econometric model as its forecasting tool. The econometric models for the 2009-2028 forecast were developed with the assistance of Christensen Associates Energy Consulting, LLC of Madison, Wisconsin, using the statistical software package SAS®.

An econometric model is a set of equations that expresses electricity use as a function of underlying factors such as customer income, price of electricity and alternate fuels, and weather. The strengths of econometric forecasting models include:

- Econometric models explicitly measure the effects of underlying causes of trends and patterns.
- Econometric models provide statistical evaluation of forecast uncertainty.
- Econometric models utilize economic and demographic information that is easily understood.
- Econometric models can be readily re-estimated.

The load forecasting process develops a forecast for annual energy sales and a forecast for peak demand.

<u>Energy Sales Forecast</u>

The energy sales forecast is disaggregated into five sales sectors:

- Residential sector.
- Small Commercial & 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.
- Large Commercial & 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.
- Street Lighting. This sector consists of energy for public street and highway lighting.

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

The LC&I sector was disaggregated into six sub-categories which were then forecasted separately. Five large customers were forecasted individually and all other LC&I energy sales were categorized as General LC&I energy sales (energy sales to all other LC&I customers) and forecasted as a group.

Econometric equations were developed to forecast energy sales for the three primary customer categories – residential, SC&I, and General LC&I – while energy sales forecasts for the street lighting and miscellaneous sectors were developed primarily using linear regression. The criteria for acceptance of the variables to be used in the econometric models is 90 percent confidence level, but the final econometric equations resulted in nearly all accepted variables having confidence levels higher than 95 percent. The energy sales forecasts for the five LC&I end-uses were developed using a combination of regressions and information available from Montana-Dakota’s field personnel regarding these large customers. More detail regarding the specific econometric factors used in the energy sales forecast are included in the detailed description of the load forecast in Attachment A.

<u>Peak Demand Forecast</u>

The peak demand forecast is developed for the summer peaking season on a total system basis. From Montana-Dakota’s residential appliance saturation surveys and other available information, it is known that air conditioning is becoming more prevalent over time and the air conditioning load is driving much of the increase in summer peak demand.

The peak demand forecast was developed through the use of an econometric analysis where weighted average temperatures for Bismarck, North Dakota (70%), Miles City, Montana (15%) and Williston, North Dakota (15%) were used as part of the equation in order to capture weather diversity across the integrated system.

Any known interruptions (Interruptible Rate 39/Demand Response Rate 38 and/or outages) that occurred at the time of the summer peak were added to the historical actual summer peak used in the regression analysis. The summer peak value thus represents the peak as it would have occurred had there not been any interruptions. More detail regarding the specific factors used in the peak demand forecast are included in the detailed description of the load forecast in Attachment A.

Forecast Adjustments

The forecast methodology for both energy sales and peak demand results in an initial energy sales forecast by sales sector and an initial peak demand forecast. Reductions to the energy sales forecasts by sector and to the peak demand forecast are made to reflect demand-side management programs. Once these reductions are reflected in the energy sales forecasts, the total of the energy sales forecasts by class are adjusted by the loss factor to arrive at the final forecast of total energy requirements.

Demand-Side Management (DSM) Reductions

As reflected in IRPs filed with the North Dakota and Montana Public Service Commissions, the following DSM programs have been or are expected to be implemented, and the reduction in energy and peak demand is reflected in the final forecast:

- Conservation Programs
    - Energy Star® Refrigerator rebates
    - Energy Star® Freezer rebates
    - Refrigerator Round-up program
    - LED Exit Sign rebates
    - Commercial High-efficiency Air conditioner rebates
    - High-Efficiency Motor rebates
- Demand Response Programs
    - Interruptible Large Power Rates 38 & 39
    - Residential Air Conditioner Cycling
    - Commercial Air Conditioner Cycling

Losses

The energy sales forecast reflects the energy delivered to Montana-Dakota's customers' meters. The total amount of electricity provided by generating resources to meet Montana-Dakota's customers' energy needs is greater than what is delivered to the meters and is called the total energy requirements. The difference between the energy sales and total energy requirements reflects the losses that occur within the transmission and distribution system.

The percentage of the annual energy losses has varied from year to year. The average value for the past ten years is 7.896 percent. Using this value for all future years, the total system hourly loads are calculated for each year during the study period.

Final Energy Requirements and Peak Demand Forecast

The forecasted energy sales and system peak demand are first adjusted to reflect the effects of the DSM programs that are being implemented and then adjusted for losses to calculate the total energy requirements and demand forecast. This is the amount of energy and capacity that needs to be generated or purchased to meet Montana-Dakota's customers' energy needs.

The final forecast results are presented on the following Table 2-1 summarizing the total energy requirements and seasonal peak demand.

Table 2-1

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

			SUMMER PEAK - MW						
	TOTAL ENERGY REQUIREMENTS		INTERRUPTIBLE LOADS NOT	Rate 38/39 INTRPT	CONSRVTN & DEMAND	PEAK DEMAND		WINTER PEAK */ AFTER DSM	
YEAR	MWh	%GROWTH	INTERRUPTED	LOADS	RESPONSE	AFTER DSM	% CHG	MW	%GROWTH
1998	2,007,534					402.5		354.2	
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%				452.9	4.77%	328.9	-7.06%
2002	2,158,431	2.58%				458.8	1.30%	343.5	4.44%
2003	2,226,531	3.16%				470.5	2.55%	367.7	7.05%
2004	2,204,012	-1.01%				458.4	-2.57%	383.9	4.41%
2005	2,327,117	5.59%				459.1	0.15%	387.2	0.86%
2006	2,397,793	3.04%				485.5	5.75%	397.2	2.58%
2007	2,510,540	4.70%				525.6	8.26%	407.3	2.54%
2008	2,596,990	3.44%				476.6	-9.32%	455.0	11.71%
2009	2,571,064	-1.00%	515.9	9.6	6.3	500.0	4.91%	400.0	-12.09%
2010	2,623,027	2.02%	525.0	11.1	11.0	502.9	0.58%	402.3	0.58%
2011	2,666,898	1.67%	533.2	11.1	13.0	509.1	1.23%	407.3	1.23%
2012	2,750,872	3.15%	555.0	11.1	13.0	530.9	4.28%	428.0	5.08%
2013	2,849,843	3.60%	566.8	11.1	13.0	542.7	2.22%	438.2	2.38%
2014	2,918,996	2.43%	579.2	11.1	13.0	555.1	2.28%	448.9	2.46%
2015	2,974,139	1.89%	587.5	11.1	13.0	563.4	1.50%	455.6	1.48%
2016	3,018,569	1.49%	595.9	11.1	13.0	571.8	1.49%	462.3	1.48%
2017	3,063,902	1.50%	604.4	11.1	13.0	580.3	1.49%	469.1	1.47%
2018	3,103,483	1.29%	612.2	11.1	13.0	588.1	1.34%	475.3	1.33%
2019	3,143,697	1.30%	620.2	11.1	13.0	596.1	1.36%	481.7	1.35%
2020	3,184,640	1.30%	628.3	11.1	13.0	604.2	1.36%	488.2	1.35%
2021	3,226,322	1.31%	636.5	11.1	13.0	612.4	1.36%	494.8	1.34%
2022	3,268,816	1.32%	644.9	11.1	13.0	620.8	1.37%	501.5	1.36%
2023	3,312,089	1.32%	653.4	11.1	13.0	629.3	1.37%	508.3	1.36%
2024	3,356,092	1.33%	662.0	11.1	13.0	637.9	1.37%	515.2	1.35%
2025	3,400,924	1.34%	670.8	11.1	13.0	646.7	1.38%	522.2	1.37%
2026	3,446,391	1.34%	679.7	11.1	13.0	655.6	1.38%	529.3	1.36%
2027	3,492,606	1.34%	688.7	11.1	13.0	664.6	1.37%	536.5	1.36%
2028	3,539,500	1.34%	697.9	11.1	13.0	673.8	1.38%	543.9	1.37%

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

Forecast Uncertainty

Forecasting is a process permeated with uncertainty. The demand and energy projections produced by the econometric process results in a forecast based solely on the information used as inputs to the equations. 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 considered. This uncertainty can be expressed by peak demand forecasts that reflect temperatures which correspond to higher confidence levels as well as high-growth and low-growth scenarios in energy forecasts.

Effect of Temperature on Peak Demand

The final forecast results were developed assuming average temperatures at the time of the system peak. However, there are some shortcomings associated with this methodology. First, with an average temperature forecast, by definition actual peak demand 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 can be an appearance that peak demand is under-forecasted when the actual temperature at the time of system peak exceeds average temperatures.

A study is conducted annually by Montana-Dakota's System Operations & Planning staff to establish the relationship between summer peak demand and temperature at the time of system peak. As part of the study, the Company's historical July and August demands and corresponding temperatures at times when the temperatures equaled or exceeded 85°F on Mondays through Thursdays are analyzed. The fall 2008 study results indicated each one degree increase in temperature at the time of summer peak would result in an increase of approximately 6.5 MW in summer peak demand.

Further statistical analysis of temperatures at the time of system peak for the years 1984 through 2008 (prior to 1984 Montana-Dakota was a winter peaking utility) provided the results shown in the following Table 2-2.

Table 2-2

Temperature Probability at Peak and Effect on Peak Demand

Probability	Weighted Average Temperature	Approximate Increase in Peak Demand (MW)
50.0%	97.1	0.0
75.0%	100.0	18.9
80.0%	100.8	24.1
85.0%	101.6	29.3
90.0%	102.7	36.4
95.0%	104.3	46.8
97.0%	105.3	53.3

As Table 2-2 shows, with a weighted average temperature of 97.1°F at the time of peak, there is a 50 percent probability the temperature at peak would be lower than 97.1°F and a 50 percent probability the temperature at peak would be higher than 97.1°F. This forecast is referred to as the 50/50 demand forecast.

Also from Table 2-2, there is a 90 percent probability actual temperatures at the time of the system peak will not exceed 102.7°F. However, at this temperature (102.7°F), the system peak demand would be 36.4 MW higher than the demand in the base, or 50/50, forecast. This forecast is called the 90/10 forecast and provides a peak demand forecast that represents a 90 percent probability the actual peak demand will not exceed the forecast value and a 10 percent probability the actual peak demand will be higher than the forecast value. Table 2-3 summarizes the results of the 50/50 probability and 90/10 probability demand forecasts.

Table 2-3

Alternate Summer Peak Demand Forecast Comparison

Year	Base Forecast (97.1 degrees F) 50/50 Forecast (MW)	Growth Rate	Alternate Forecast (102.7 degrees F) 90/10 Forecast (MW) */
2009	500.0		536.4
2010	502.9	0.58%	539.5
2011	509.1	1.23%	546.2
2012	530.9	4.28%	569.6
2013	542.7	2.22%	582.3
2014	555.1	2.28%	595.6
2015	563.4	1.50%	604.5
2016	571.8	1.49%	613.5
2017	580.3	1.49%	622.6
2018	588.1	1.34%	631.0
2019	596.1	1.36%	639.6
2020	604.2	1.36%	648.3
2021	612.4	1.36%	657.1
2022	620.8	1.37%	666.1
2023	629.3	1.37%	675.2
2024	637.9	1.37%	684.4
2025	646.7	1.38%	693.8
2026	655.6	1.38%	703.3
2027	664.6	1.37%	713.0
2028	673.8	1.38%	722.9

*/ The growth rate for the 90/10 Forecast scenario is assumed to be the same as that of the 50/50 Forecast scenario.

High-Growth and Low-Growth Scenario Forecasts

Another approach to express forecast uncertainty in this study was to simulate high-growth and low-growth scenarios which represent the corresponding 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, 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.

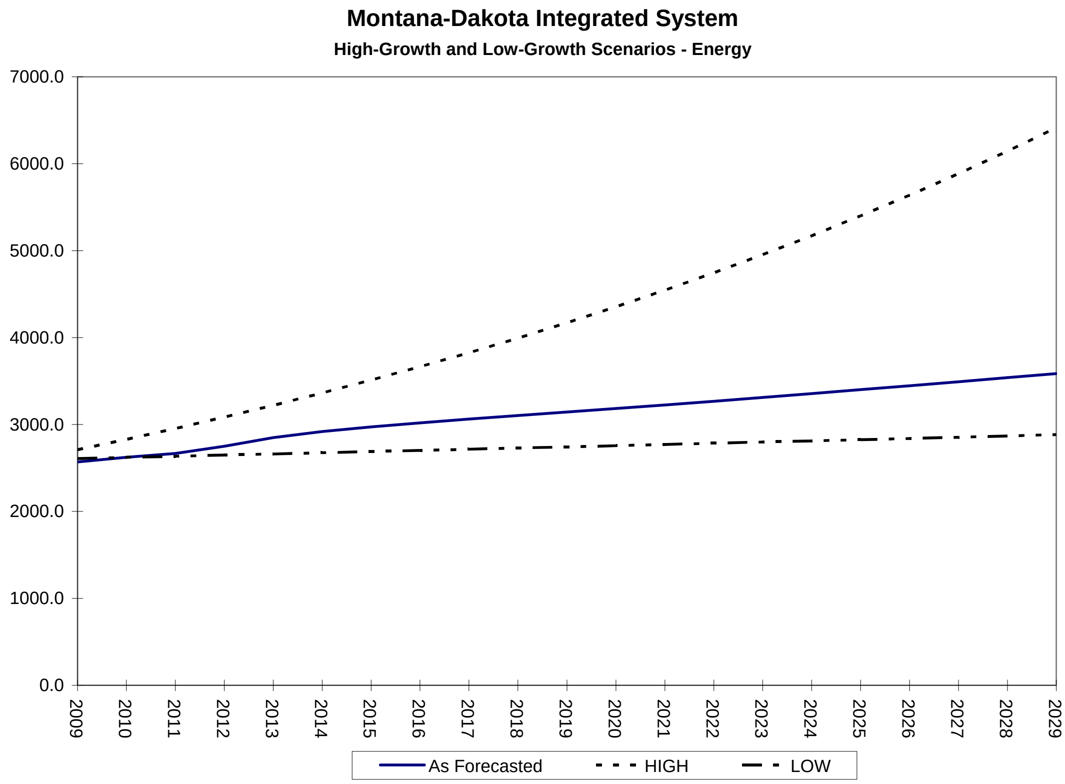
As a result, for the high-growth scenario, an average growth rate of 4.4 percent per year was assumed to occur during the 20-year forecast horizon. For the low-growth scenario, an average growth rate of 0.5 percent per year was assumed to occur during the 20-year forecast horizon. Demand for each scenario was derived by applying the load factors calculated from the base forecast to the high-growth and low-growth scenario forecasted energy. The results of the high- and low-growth scenarios for energy and demand are shown on Table 2-4. The following page presents the graphs of the numeric results.

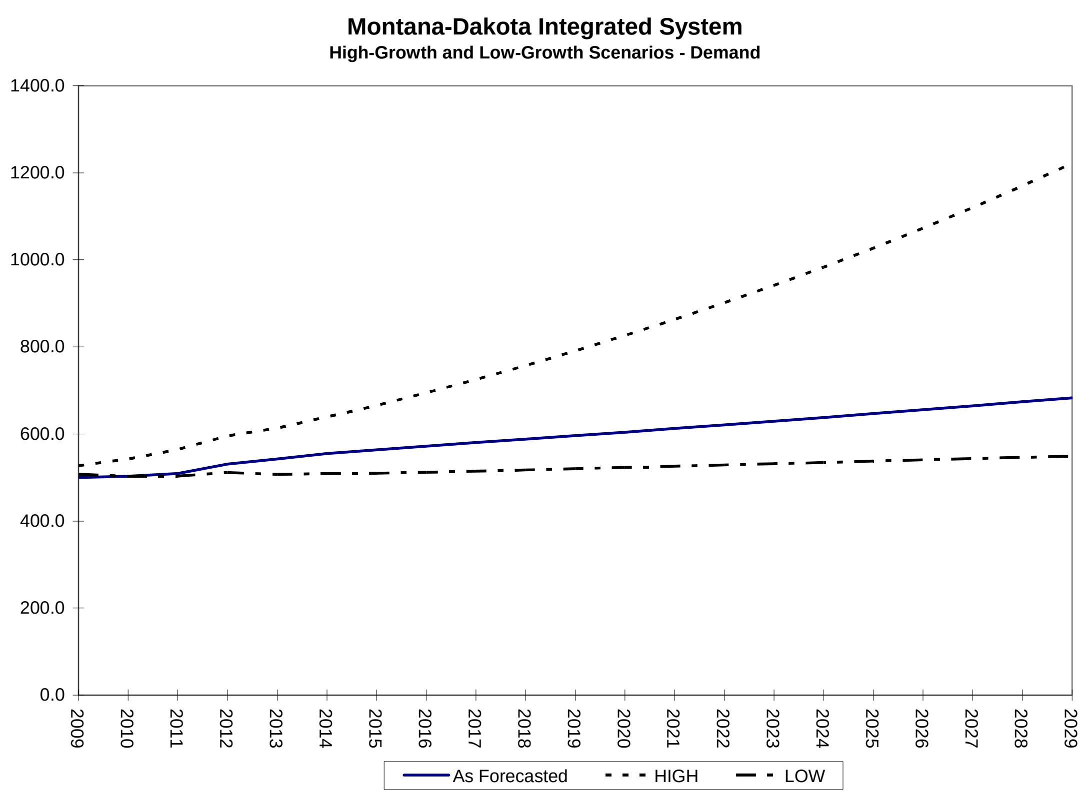
Table 2-4

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

	ENERGY			DEMAND		
	Forecast	HIGH 1/	LOW 2/	Forecast	HIGH	LOW
2009	2571.1	2711.3	2610.0	500.0	527.3	507.6
2010	2623.0	2830.6	2623.0	502.9	542.7	502.9
2011	2666.9	2955.1	2636.2	509.1	564.1	503.2
2012	2750.9	3085.1	2649.3	530.9	595.4	511.3
2013	2849.8	3220.9	2662.6	542.7	613.4	507.0
2014	2919.0	3362.6	2675.9	555.1	639.5	508.9
2015	2974.1	3510.6	2689.3	563.4	665.0	509.4
2016	3018.6	3665.0	2702.7	571.8	694.2	512.0
2017	3063.9	3826.3	2716.2	580.3	724.7	514.5
2018	3103.5	3994.6	2729.8	588.1	757.0	517.3
2019	3143.7	4170.4	2743.5	596.1	790.8	520.2
2020	3184.6	4353.9	2757.2	604.2	826.0	523.1
2021	3226.3	4545.5	2771.0	612.4	862.8	526.0
2022	3268.8	4745.5	2784.8	620.8	901.2	528.9
2023	3312.1	4954.3	2798.7	629.3	941.3	531.8
2024	3356.1	5172.3	2812.7	637.9	983.1	534.6
2025	3400.9	5399.8	2826.8	646.7	1026.8	537.5
2026	3446.4	5637.4	2840.9	655.6	1072.4	540.4
2027	3492.6	5885.5	2855.1	664.6	1119.9	543.3
2028	3539.5	6144.4	2869.4	673.8	1169.7	546.2
2029	3587.0	6414.8	2883.8	683.1	1221.6	549.2

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).


Montana-Dakota Integrated System
High-Growth and Low-Growth Scenarios - Energy
7000.0
6000.0
5000.0
4000.0
3000.0
2000.0
1000.0
0.0
2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029
As Forecasted
HIGH
LOW


Montana-Dakota Integrated System
High-Growth and Low-Growth Scenarios - Demand
1400.0
1200.0
1000.0
800.0
600.0
400.0
200.0
0.0
2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029
As Forecasted
HIGH
LOW

CHAPTER 3

DEMAND SIDE MANAGEMENT ANALYSIS

Demand-Side Management is a resource planning tool a utility can use to meet two objectives: (1) to potentially offset future generation resource costs through load management and/or conservation measures and (2) to enhance customer service through the offering of programs to customers that will help reduce their overall demand and/or energy requirements. Demand-Side Management, or 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.*

With the demand for electricity growing, Montana-Dakota recognizes the value DSM can play in meeting its future energy requirements. Montana-Dakota examined potential DSM programs that would be best suited to the Company's load shape and would provide a portfolio of conservation and demand response programs across all customer classes. These potential programs were selected through a joint effort of Montana-Dakota and the IRP Public Advisory Group. However, the implementation of DSM programs cannot be realized without cost consideration to the utility, its customers/ratepayers, and society. All interests need to be balanced to achieve the results at an affordable cost to both the utility and its customers.

<u>Potential DSM Programs</u>

Montana-Dakota explored the feasibility of offering twelve DSM programs to its customer base.

<u>Residential Programs</u>

1. Promote a direct-control central air conditioner cycling program through the use of a controllable thermostat (with no cash incentive).

2. Promote a direct-control central air conditioner cycling program through the use of a controllable thermostat (with a cash incentive).

3. Promote ENERGY STAR® residential central air conditioners.

4. Promote ENERGY STAR® appliances to residential customers

5. Promote a refrigerator round-up program, whereby customers are offered a cash incentive to allow the Company to remove an older refrigerator.

6. Promote a residential lighting program whereby customers are offered free compact fluorescent light bulbs.

7. Promote a residential new home construction bundle that includes central air conditioner, compact fluorescent light bulbs, and ENERGY STAR® appliances.

Commercial Programs

1. Promote Interruptible Demand Response rate in North Dakota and implement that rate in South Dakota and Montana.

2. Promote high-efficiency motors.

3. Promote commercial high-efficiency air conditioners.

4. Promote a high-efficiency lighting program.

5. Promote a direct-control demand response program for irrigation.

Benefit/Cost Analysis

To determine which programs should be considered most beneficial, and therefore be included as resource options in the integration process, a benefit/cost analysis was made for each of the 12 DSM programs. The basic function of the analysis was to calculate each DSM program's benefits and costs to determine the cost effectiveness of each respective program on a stand-alone basis. The programs were evaluated using four different cost-effectiveness tests: the Participant Test, the Utility Test, the Ratepayer Test, and the Societal Cost Test. The *Participant Test* considers the economic impact of a program on the participating customers, the *Utility Test* considers the impact on the utility, the *Ratepayer Test* includes all quantifiable benefits and costs of a given program and considers its impact on all ratepayers, and the *Societal Cost Test* is similar to the *Ratepayer Test*, but also includes environmental externalities to consider the impact on the "society." In determining whether a program is beneficial, Montana-Dakota relied on the resulting benefit/cost ratio of the Ratepayer Test as well as the practicality of the program installation.

Beneficial DSM Programs

Based on the benefit/cost analysis and practicality of program installation, the following ten programs have been identified as beneficial DSM programs and are included as resource options in the integration process:

1. Residential Air Conditioner Cycling program (with no incentive)
2. ENERGY STAR® Appliance rebates
3. ENERGY STAR® Residential Air Conditioner rebates
4. Refrigerator Round-up program
5. Interruptible Demand Response rates
6. High-Efficiency Commercial Motor rebates
7. Commercial High-Efficiency Central Air Conditioner rebates
8. Commercial Lighting Retrofit rebates
9. Residential New Construction Bundle rebate
10. Residential Lighting program

The implementation of the DSM programs to Montana-Dakota's portfolio will benefit all customers as shown by the Ratepayer Test results included in Attachment B. Table 3-1 shows the estimated costs and potential reductions in energy and peak demand associated with the demand response programs, the conservation programs, and the total DSM portfolio recommended in this IRP. As shown in the table, implementing the ten DSM programs will provide Montana-Dakota an estimated demand reduction of 22.7 MW and an estimated energy reduction of 170,810,314 KWh over the projected life of the programs. The DSM program cost is approximately $370/kW or $0.049/kWh over the projected life of the program. The first year program costs are estimated at $1,403,167 with a total estimated cost of $5,391,212 over the two-year plan implementation period.

Table 3-1

Summary of the DSM Portfolio

Total DSM Program	2010	2011	IRP Totals	Project Life
Demand Response Programs Only				
Participants	1,202	6,503	7,705	10,008
kWh Saved	226,560	999,108	1,225,668	22,715,587
Annual kW Avoided *	2,374	8,632	11,006	15,106
Administrative Costs	$209	$209	$418	
Operating Costs	$898,067	$3,422,745	$4,320,812	
Incentive Costs	$30,000	$60,000	$90,000	
Total Costs	**$928,276**	**$3,482,954**	**$4,411,230**	**$6,411,145**
Total Demand Response Cost per kWh	$4.10	$3.49	$3.60	$0.28
Total Demand Response Cost per kW	$391.02	$403.49	$400.80	$424.41
Conservation Programs Only				
Participants	5748	5803	11551	17549
kWh Saved	3,697,940	3,755,483	7,453,423	148,094,726
Annual kW Avoided *	1,677	1,748	3,425	7,642
Administrative Costs	$88,774	$88,774	177548	-
Operating Costs	$7,853	$7,928	15781	-
Incentive Costs	$378,264	$408,389	786653	-
Total Costs	**$474,891**	**$505,091**	**$979,982**	**$1,962,573**
Total Demand Response Cost per kWh	$0.13	$0.13	$0.13	$0.01
Total Demand Response Cost per kW	$283.18	$288.95	$286.13	$256.81
Total Program				
Participants	6950	12306	19256	27557
kWh Saved	3,924,500	4,754,592	8,679,092	170,810,314
Annual kW Avoided *	4,051	10,380	14,431	22,748
Administrative Costs	$88,983	$88,983	177966	-
Operating Costs	$905,920	$3,430,673	4336593	-
Incentive Costs	$408,264	$468,389	876653	-
Total Costs	**$1,403,167**	**$3,988,045**	**$5,391,212**	**$8,373,720**
Total Cost Per kWh	**$0.36**	**$0.84**	**$0.62**	**$0.049**
Total Cost Per kW	**$346.38**	**$384.20**	**$373.59**	**$368.11**

Among the ten feasible DSM programs listed above, in addition to the ENERGY STAR® Partnership of which the benefits are not quantifiable, five programs have been offered as the results of the 2005 and 2007 IRPs: ENERGY STAR® residential air conditioners, ENERGY STAR® appliances, refrigerator round-up, commercial lighting, and interruptible demand response rate. A summary of current program results for 2007-2008 is provided in Attachment B. All six of these DSM programs are expected to continue to be implemented and, in some cases with enhancements.

Also, three programs were planned to be implemented in 2008 based on the 2007 IRP, but their implementation was delayed until 2010: air conditioner cycling, commercial high-efficiency air conditioner, and commercial high-efficiency motor. As the result of the demand-side analysis in this IRP, two new DSM programs, residential lighting and residential new construction bundle, were found feasible. Montana-Dakota expects to implement these five programs as the results of this IRP.

CHAPTER 4

SUPPLY-SIDE RESOURCE ANALYSIS

The objective of the supply side analysis is to identify the available and most cost-effective supply-side resources to be added to Montana-Dakota's generating system. The resources must be proven technology and be able to maintain the system reliability that Montana-Dakota's customers have come to expect. The selected supply-side resources, together with the feasible Demand Side Management (DSM) programs are then used as input to the integration analysis, the final process to determine the least-cost integrated resource plan.

The supply-side analysis considers all supply-side alternatives currently available to Montana-Dakota as well as those resources to which Montana-Dakota has made a commitment to install or purchase. A detailed discussion of the supply-side model assumptions, characteristics of the existing generation, the committed resources, and the proposed resources is included in Attachment C.

Committed Supply-Side Options

Existing Generation

Montana-Dakota's existing generation is comprised of base load generation at Heskett Station (Units I and II), Lewis & Clark, and Montana-Dakota's shares of Coyote station and Big Stone Unit I, and peaking generation at Glendive (Units I and II), Miles City, and Williston. Montana-Dakota also has the Diamond Willow Wind Farm and a diesel unit in Glendive. Williston is modeled in EGEAS to be retired with the addition of the next non-purchase resource after 2010. Total summer capacity available from the existing units is 486.9 MW.

Big Stone Unit II

Montana-Dakota has been participating in the development of the proposed jointly-owned Big Stone Unit II project. The project involves the construction of a nominal 580 MW base load, super critical sub-bituminous-fired plant planned to be on-line in 2015. The current co-owners are:

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

Montana-Dakota's expected capacity share of the unit would be not more than 22.58 percent or 131 MW. The final joint decision to construct Big Stone Unit II has not yet been made, but the Company's intentions are to participate, and as a majority of the permits have been approved, Big Stone Unit II was considered a committed unit in the EGEAS model.

Montana and North Dakota Wind

In December 2008, Montana-Dakota announced the plan to develop a 19.5 MW wind farm located approximately five miles west of Rhame, North Dakota. This new wind farm is to be named Cedar Hills, and will be used to meet the North Dakota renewable objective. North Dakota legislature has enacted a renewable objective that recommends the purchase of renewable energy up to ten percent of a utility's energy sold in North Dakota by 2015.

Montana-Dakota also announced an expansion of the Diamond Willow wind farm by an additional 10.5 MW. This would increase the capability of Diamond Willow to 30 MW, which would meet the requirements of Montana law regarding the purchase of renewable energy up to 15 percent of a utility's energy sold in Montana.

Purchased Power

Montana-Dakota entered into an agreement with Xcel Energy Services' operating company Northern States Power (NSP) in December 2005 for the purchase of peaking capacity. For the next two years, capacity purchases are as follows:

2009 Summer – 95 MW

2010 Summer – 100 MW

Montana-Dakota also contracted with NSP in April 2007 to purchase an additional 10 MW of summer peaking capacity through 2010. The purpose of the additional capacity purchase is to cover the potential impacts on summer peak demand as determined by the 90/10 forecast. As shown in Chapter 3, Montana-Dakota can expect to see approximately 6.5 MW of additional peak demand for every one degree Fahrenheit increase in temperature above the normal peak temperature of 97.1 degrees Fahrenheit. In 2009 Montana-Dakota would be deficient approximately 17 MW if the weather condition assumed in the 90/10 forecast occurs, even with the additional 10 MW capacity purchase.

The Western Area Power Administration (WAPA) Ft. Peck Bill Crediting arrangement will continue whereby Montana-Dakota will receive between 2.5 to 3.2 MW of capacity, associated reserves, and energy from WAPA. This arrangement is set to expire in 2020.

NSP Contract Extension

Montana-Dakota has the option to extend the December 2005 contract with NSP through the summer of 2011. The capacity will increase to 105 MW under the same price and terms and conditions as those for the preceding years. This option was modeled as a committed resource in EGEAS, although Montana-Dakota has not formally announced its intent to exercise the option.

Proposed Supply-Side Options

Generic Coal

In addition to Big Stone Unit II modeled as a committed resource, generic coal-fired base load generation was also considered in this study. Base load generation is generally characterized as having a high capital cost with low operating costs, while providing a stable capacity and energy source. With a low operating cost, base load units produce large amounts of energy at a relatively low cost. The high capital costs are then spread over the large amount of energy.

Generic Combustion Turbines

Simple cycle combustion turbines are primarily used for supplying a limited amount of energy since they are fueled by either natural gas or oil. Combustion turbines have a relatively low capital cost, but the energy produced is at a high cost because of the high fuel cost. Combustion turbines can be installed with a relatively short lead time (two to three years).

Generic Combined Cycle

A conventional combined cycle (CC) unit burns a low sulfur distillate oil or natural gas in a combustion turbine/electric generator. The hot exhaust gases from the turbine pass through a heat recovery steam generator that produces steam for a conventional steam turbine/electric generator. Because combined cycle units use natural gas or fuel oil as fuel, the units are high-cost energy producers and their capital costs are between those of a combustion turbine and a base load unit. The advantage of a combined cycle unit is that it is more efficient to operate than a combustion turbine, but its hours of operation could be limited because of its high energy costs compared to other available resources.

Generic Wind

In addition to the Diamond Willow and Cedar Hills wind farms, generic wind generation was also allowed to compete with other future resource options. Wind is characterized as having high installation costs, but very low energy costs, since there is no cost for the fuel (wind), only operating and maintenance costs. Also, a $20/MWh (after tax) Production Tax Credit, which was modeled as a negative variable O&M, was assumed to be in effect for wind generation until 2012. However, the disadvantage of wind is that it is an intermittent resource because of its variability. Therefore, the installation of wind requires other additional resource to produce energy during times of less than desirable wind conditions.

Purchased Power

Purchased power alternatives were assumed available for the 2011-2014 time period. Montana-Dakota issued a request for proposal (RFP) on December 22, 2008 for power during this period until Big Stone Unit II comes on line. Based on the responses to the RFP, purchased power was modeled on an annual basis, as opposed to the summer season only, for the 2012-2014 time period.

Load and Capability

Existing and Committed Resources

The need for any type of new resource, whether it is a supply-side resource or the implementation of demand-side programs, is primarily driven by the forecast of the peak demand and energy needs of customers. In addition, the retirement of aging and high maintenance existing facilities will also trigger the need for new resources. At present, Montana-Dakota is modeling the retirement of the Williston turbines with the next non-purchase resource addition beyond 2010. However, due to the termination of the Northern States Power (NSP) contract after the summer of 2010 and increasing demand for electricity by its customers, Montana-Dakota will need to install new resources or purchase power to maintain reliable service to its customers. 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.

The accredited capability, defined as the capacity available to serve Montana-Dakota's own load, is equal to its net generating capability, including purchased power. As a member of the Mid-Continent Area Power Pool (MAPP) Generation Reserve Sharing Pool (GRSP), Montana-Dakota is required to maintain an accredited capability equal to or greater than its maximum system demand plus a 15 percent reserve capacity obligation. Therefore, the peak load obligation shown on the tables is the projected summer peak demand plus the 15 percent GRSP requirement.

Table 4-1 shows, with the base forecast and the existing capacity purchase contracts, Montana-Dakota has adequate capacity to meet its peak load obligation through 2010. However, if Montana-Dakota is to have sufficient capacity to meet its customers' demand as well as the 15 percent minimum reserve capacity obligation, in 2011 an additional 8.3 MW of capacity will be needed. The capacity deficit will still be 26.5 MW in 2015 (even with Big Stone Unit II coming on-line) and rising to 95.3 MW in 2022. With the high-growth scenario forecast, as shown in Table 4-2, a capacity deficit would occur in 2009 (26.9 MW) growing to 210.8 MW in 2015. The low-growth scenario forecast shown in Table 4-3 would not result in a capacity deficit until 2012 (87.2 MW) increasing to 94.9 MW in 2014, and then not deficit again until 2021 (3.2 MW).

In order to address future capacity deficits, Montana-Dakota will need new demand-side and/or supply-side resources. This IRP will provide the direction for the selection of new resources to effectively and reliably meet customers' requirements.

Table 4-1

Montana-Dakota Utilities Co. Integrated System
Load and Capability Comparison – 01 May 2009

BASE FORECAST

Year	Summer Generating Capability	WAPA Bill Crediting	NSP Peaking Purchase	Summer Total Capability	Summer Peak Demand	Peak Load Obligation	Surplus/Deficit (+)/(-)
2009	486.87	2.8	105.0	599.17	500.0	575.0	24.17
2010	491.37	2.8	110.0	610.89	502.9	578.3	32.59
2011	498.09	2.8	105.0	605.89	534.1	614.2	-8.31
2012	498.09	2.8		500.89	539.7	620.7	-119.81
2013	498.09	2.8		500.89	547.7	629.9	-129.01
2014	498.09	2.8		500.89	555.9	639.3	-138.41
2015	616.69	2.8		622.29	564.2	648.8	-26.51
2016	616.69	2.8		622.29	572.6	658.5	-36.21
2017	616.69	2.8		622.29	581.1	668.3	-46.01
2018	616.69	2.8		622.29	588.9	677.2	-54.91
2019	616.69	2.8		622.29	596.9	686.4	-64.11
2020	616.69	2.8		622.29	605.0	695.8	-73.51
2021	616.69			619.49	613.2	705.2	-85.71
2022	616.69			619.49	621.6	714.8	-95.31

Table 4-2

Montana-Dakota Utilities Co. Integrated System
Load and Capability Comparison – 01 May 2009

HIGH-GROWTH FORECAST

Year	Summer Generating Capability	WAPA Bill Crediting	NSP Peaking Purchase	Summer Total Capability	Summer Peak Demand	Peak Load Obligation	Surplus/Deficit (+)/(-)
2009	486.87	2.8	105.0	599.17	544.4	626.1	-26.93
2010	491.37	2.8	110.0	610.89	562.8	647.2	-36.31
2011	498.09	2.8	105.0	605.89	609.4	700.8	-94.91
2012	498.09	2.8		500.89	636.4	731.9	-231.01
2013	498.09	2.8		500.89	664.5	764.2	-263.31
2014	498.09	2.8		500.89	693.7	797.8	-296.91
2015	616.69	2.8		622.29	724.4	833.1	-210.81
2016	616.69	2.8		622.29	756.5	870.0	-247.71
2017	616.69	2.8		622.29	789.8	908.3	-286.01
2018	616.69	2.8		622.29	824.6	948.3	-326.01
2019	616.69	2.8		622.29	861.0	990.2	-367.91
2020	616.69	2.8		622.29	899.0	1033.9	-411.61
2021	616.69			619.49	938.8	1079.6	-457.31
2022	616.69			619.49	980.4	1127.5	-505.21

Table 4-3

Montana-Dakota Utilities Co. Integrated System
Load and Capability Comparison – 01 May 2009

LOW-GROWTH FORECAST

Year	Summer Generating Capability	WAPA Bill Crediting	NSP Peaking Purchase	Summer Total Capability	Summer Peak Demand	Peak Load Obligation	Surplus/Deficit (+)/(-)
2009	486.87	2.8	105.0	599.17	485.6	558.4	40.77
2010	491.37	2.8	110.0	610.89	483.2	555.7	55.19
2011	498.09	2.8	105.0	605.89	518.0	595.7	10.19
2012	498.09	2.8		500.89	511.4	588.1	-87.21
2013	498.09	2.8		500.89	514.9	592.1	-91.21
2014	498.09	2.8		500.89	518.1	595.8	-94.91
2015	616.69	2.8		622.29	521.5	599.7	22.59
2016	616.69	2.8		622.29	525.0	603.8	18.49
2017	616.69	2.8		622.29	528.2	607.4	14.89
2018	616.69	2.8		622.29	531.5	611.2	11.09
2019	616.69	2.8		622.29	534.9	615.1	7.19
2020	616.69	2.8		622.29	538.2	618.9	3.39
2021	616.69			619.49	541.5	622.7	-3.21
2022	616.69			619.49	544.9	626.6	-7.11

CHAPTER 5
INTEGRATION AND RISK ANALYSIS

The integration process considers all the demand-side programs discussed in Chapter 3 and the supply-side options discussed in Chapter 4 and integrates them into a single least-cost plan. A computer program called Electric Generation Expansion Analysis System version 9.02 (EGEAS), developed by the Electric Power Research Institute (EPRI), is used to perform the resource expansion analysis and develop the least-cost integrated resource plan.

<u>Integration of Demand- and Supply-Side Resources</u>

As indicated in Chapter 2, the DSM programs identified in the 2007 IRP have been or are expected to be implemented, and the reduction in energy and peak demand is reflected in Montana-Dakota's load forecast: Therefore, those programs were already integrated with the supply-side options in all EGEAS runs.

As the result of the demand-side analysis in Attachment B of this IRP, two new DSM programs, Residential Lighting and Residential New Construction Bundle, were found feasible. The demand-side analysis also showed higher expected customer participation, compared to those predicted in the 2007 IRP, for the Residential Air Conditioner Cycling and Commercial Lighting programs. The impact of the two new programs and the incremental customer participations of the other two are bundled in a "New DSM Package," which was allowed to compete with the supply-side options in a separate EGEAS run.

<u>Sensitivity Analysis</u>

Because business and economic conditions are changing rapidly today, many of the parameters used in this study may change in the future. Sensitivity analysis was performed to see how the resource expansion plans would be affected by variations of certain key parameters.

<u>*Carbon Tax*</u>

With the potential of a future carbon penalty applied to fossil fuel units, a carbon tax was modeled to assess the impact on the resource expansion plan. The assumed carbon tax was applied to all carbon emissions from Montana-Dakota's fossil fuel units starting in 2015. While no carbon tax was modeled in the base case, Montana-Dakota considered a wide-range of prices for carbon tax used in the industry and decided to use $30 and $50 per ton of CO_2 prices for sensitivity analysis. Montana-Dakota recognizes the amount and applicability of any carbon penalty has not yet been established, but conducted this sensitivity analysis to begin to understand possible impacts to our customers of the various options being discussed across the nation.

High Natural Gas Prices

Natural gas purchased from a third-party marketer and delivered under a transportation service arrangement was assumed for the existing turbines, generic combustion turbines, and generic combined cycle plants. The gas was priced for delivery at $7.30/MBTU starting in 2009, and escalated up by an average of three percent annually for the base case. However, with the volatility of natural gas prices, there is a need to consider what impact higher gas prices would have on the least-cost plan. Therefore, two high gas price scenarios were also developed, whereby the gas price used in the base case was increased by $4/MBTU and by $12/MBTU in the year 2012. In both scenarios, the gas prices were escalated by three percent annually after 2012.

The gas price modeled in the base case was developed in the fall of 2008 based on Montana-Dakota's view of the long-term outlook of natural gas pricing. At the time this IRP report is prepared (June 2009), however, the short-term outlook remains bearish. The discovery of natural gas in the shale rock formations in the southern and eastern portions of the United States have been prolific over the past couple of years, and drilling was very active during 2008 as high natural gas prices drove natural gas and oil drilling rig counts to high levels. This along with the downturn in the U.S. and world economies has left the world in a current oversupply situation. This supply/demand imbalance is expected to remain until late 2009 or may run well into 2010 depending on when the economy recovers and how rapid the depletion rate of the producing wells tapers off. The supply/demand imbalance should continue to put downward pressure on the price of natural gas from a fundamental view of the market. Speculators will have a play in the pricing of natural gas and could put upward pressure on gas prices.

The long-term outlook for natural gas pricing continues to be perceived that natural gas will be a fuel of choice and will result in higher natural gas prices than we are currently experiencing. The outcome of carbon legislation could have a big impact on demand and pricing for natural gas in the future as the carbon foot print is considered less for natural gas than other fossil fuels for electric generation. Montana-Dakota believes the gas prices modeled in the base case are valid over the 50 years considered by the resource expansion analysis.

Renewable Portfolio Standard (RPS)

Along with the potential of a future carbon tax is the potential for a national RPS. Montana-Dakota is already required to meet an RPS in Montana, while both North Dakota and South Dakota have a renewable objective or goal. Therefore, with the state renewable laws and the potential for a national RPS, Montana-Dakota conducted an analysis that simulated meeting a renewable requirement of ten percent by 2015, fifteen percent by 2020, and twenty percent by 2025 with wind generation, the most abundant and feasible renewable resource in Montana-Dakota's service territory.

High- and Low-Growth Scenario Forecasts

The base forecast in Chapter 2 projected summer peak demand would increase at an average rate of 2.1 percent per year for the next five years and at an average rate of 1.6 percent per year through 2028, while energy requirements would increase at an average rate of 2.58 percent per year for the next five years, and an average rate of 1.70 percent per year through 2028. The forecast also established high-growth and low-growth scenarios in which energy requirements were assumed to grow at 4.4 percent and 0.5 percent per year respectively. EGEAS runs were made using both the high- and low-growth load forecasts to determine the least-cost resource plan under those scenarios.

Installed Costs

Costs of materials associated with the construction of generation have generally increased both in the United States and the rest of the world. The base case costs for all generation options reflect the present price forecasts, but for purposes of risk analysis, Montana-Dakota considered the impact of higher installed costs of new generation on the resource plan. Therefore, to determine the sensitivity of the base case to the installed cost increase, a sensitivity scenario with installed cost of combustion turbines increased by 20 percent was considered.

Big Stone Unit II Not Available

The last sensitivity analyzed was the scenarios in which Big Stone Unit II would not be available to Montana-Dakota. In these scenarios, Montana-Dakota also studied the effects of the potential carbon tax on its generating system.

CHAPTER 6

RESULTS

This section presents the resulting Integrated Resource Plan, taking into consideration the results of the resource expansion analysis as well as other factors Montana-Dakota deems critical in determining the resource to be acquired. The additional factors not modeled in EGEAS but considered when determining the final resource plan are, as follows:

Economic, Societal, Governmental, and Customers Issues

Montana-Dakota is committed to providing its customers with competitively priced, highly reliable electricity. The integrated resource planning process must not rely solely on the results of a computer model analysis, but must also consider risks and other factors that are essential to provide the overall best choices for meeting the requirements of customers. The factors considered in the analysis are:

- Fuel price stability,
- Benefits resulting from participation in wholesale sales of off-peak energy and other programs under the Midwest ISO,
- The possibility of unexpected new large load developing in Montana-Dakota's service territory,
- Renewable resources that may not be price competitive but which have societal support or mandates, and
- Public interest programs.

Midwest ISO (MISO) Market

Montana-Dakota sells surplus energy into the regional market, under a tariff which shares the profits from those sales with customers. With the beginning of the Midwest ISO energy market in 2005 and the Ancillary Service Market (ASM) and Capacity markets in 2009, the ability of Montana-Dakota to use its existing resources within these markets has further expanded. Therefore, when considering which resources to consider as benefiting retail customers, the presence of these other markets is a factor.

Montana-Dakota continues to perform integrated resource planning based on the obligation to serve its customers with a stable and reliable power supply. The MISO energy market provides new opportunities and benefits to Montana-Dakota, but Montana-Dakota cannot rely totally on the market for its power supply requirements.

The MISO market provides a source for energy when prices are lower than Montana-Dakota's generating costs, or when, due to planned maintenance or forced outages, Montana-Dakota needs to purchase energy to maintain reliability. The market also provides a means whereby Montana-Dakota can sell energy into the market from its generating facilities that is not needed by Montana-Dakota customers, with the margins benefiting the customers by offsetting generation costs.

The MISO capacity market is very new. Montana-Dakota will examine the market and evaluate the possibility of meeting some future capacity requirements from the market. However, until this market is more mature, Montana-Dakota intends to provide energy and capacity to meet customer requirements from Montana-Dakota owned generation or bilateral purchases, such as the existing NSP contracts.

<u>Unexpected New Load</u>

The load forecast does not include unexpected new commercial and industrial loads in Montana-Dakota's service territory that had not been announced at the time the forecast was prepared. In the business world, often new large projects are not announced until such time as marketing studies, feasibility studies, and financing have been arranged. The load forecast takes a conservative approach regarding those types of loads, but in order to be able to serve them reliably, Montana-Dakota must have adequate generation resources to meet their demand when they come on-line.

<u>Renewable Resource Development</u>

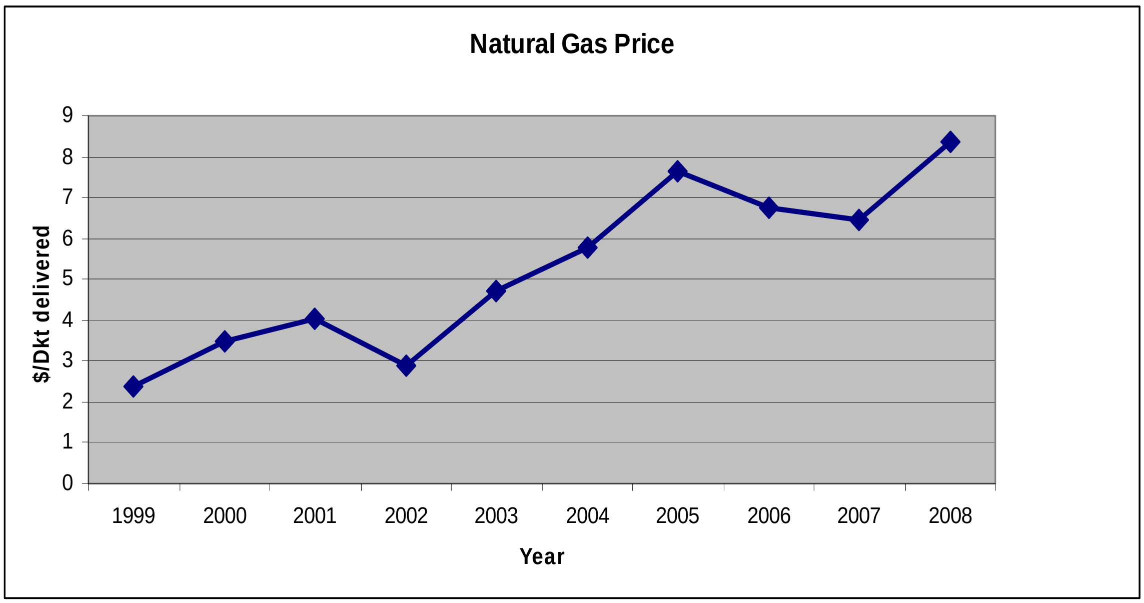
Montana-Dakota's service territory and its surrounding area have a robust wind resource. Wind development and proposed wind development, cannot be ignored when considering new resources. Even though wind technology and costs have made wind more competitive, total costs for wind turbines (including capital recovery) are still dependent on governmental incentives, which are not based on economic evaluations. In addition, legislative requirements are driving the need for increased wind generation which is a factor to be considered regardless of the economics of installing renewable generation sources. Increasing development of wind generation in the MISO region will have an impact on the operation of baseload units in the area.

Reliance on Natural Gas

About twenty percent of Montana-Dakota's owned generating capacity is natural gas fired. As shown on Figure 6-1, natural gas prices have been volatile and increasing over the last ten years.

Figure 6-1

Annual Historical Natural Gas Prices Based on 12-Month Average



With uncertainty as to what will happen with gas prices, Montana-Dakota must consider whether or not it is prudent to increase the percentage of its capacity that is dependent upon natural gas as its fuel source in its evaluation of the least-cost plans generated by EGEAS.

Resource Expansion Analysis Results

The most probable load forecast, fuel prices, and installed costs were modeled in the EGEAS base case. The DSM programs identified in the 2007 IRP were modeled as committed resources as they have been included in the load forecast. The base case least-cost plan consists of the installation of combustion turbines in 2015 (75 MW), 2021 (43 MW), and 2025 (43 MW), and includes purchased power in the 2011-2014 period.

Along with these resources are the committed resources: Glen Ullin Station 6 in 2009, the expansion of Diamond Willow in 2010, Cedar Hills in 2010, the extension of the NSP contract to 2011, and Big Stone Unit II in 2015.

As identified by the demand-side analysis in Chapter 3, two new DSM programs, Residential Lighting and Residential New Construction Bundle, were found feasible. It also showed higher expected customer participations, compared to those predicted in the 2007 IRP, for the Residential Air Conditioner Cycling and Commercial Lighting programs. The impact of the two new programs and the incremental customer participation in the other two are bundled in a "New DSM Package."

When the "New DSM Package" was added as an additional resource option in the base case, it was selected to be implemented in 2010, taking until 2012 to reach its full customer participation. This DSM package lowered the NPV by about 2.5% from the base case. Compared to the base case, the expansion resource plan had the same amounts of purchase power requirements in 2011 (10 MW) and 2012 (120 MW), but 10 MW less in 2013 (120 MW) and 2014 (130 MW). The 75 MW combustion turbine was still needed in 2015 and, instead of the two 43 MW combustion turbines in 2021 and 2025, one 75 MW combustion turbine was selected in 2021.

The sensitivity scenarios indicate that the base case resource plan is very robust under all assumptions. Load growth makes a significant impact on the resource selection: As expected, the low-growth scenario indicates the need for less peaking capacity, while the high-growth scenario shows much more peaking capacity is needed than is shown in the base case plan. The high gas price scenarios also support the base case selections for capacity.

The cost of materials and labor as well as potential environmental costs put upward pressure on the cost estimates for both base load coal-fired units and combustion turbines. The scenario in which the installed cost of combustion turbines increased by 20 percent also selected the same capacity additions as in the base case.

The carbon tax scenarios show the economic impact of a tax on carbon on Montana-Dakota's generating system: The total cost increases, but the capacity additions stay the same. Similarly, the RPS scenario shows that, if Montana-Dakota is required to add more renewable resources to satisfy the RPS requirements, the total cost would increase, but the need for non-renewable capacity until 2020 would remain the same as in the base case.

Finally, scenarios in which Big Stone Unit II would not be available to Montana-Dakota were studied. In these scenarios, Montana-Dakota also studied the effects of the potential carbon tax on its generating system. From the resource addition viewpoint, without Big Stone Unit II in 2015, Montana-Dakota will have to add combustion turbines in 2015, 2016, 2020, and 2025 if Big Stone Unit II is not part of Montana-Dakota's resource portfolio in 2015. For all studied carbon tax levels ($0 in the base case and $30 and $50 per ton in the sensitivity cases), such a resource expansion plan (with all peaking capacity additions) would result in a higher total cost. The results come from the fact that, from the CO_2 emission viewpoint, Big Stone Unit II is a very efficient unit. Its generated energy will displace the energy from the older, less efficient existing coal-fired units, causing those units to run less and therefore lowering Montana-Dakota's total carbon footprint. Table 6-2 shows a comparison of CO_2 intensity and total CO_2 emissions between the base case and the "No Big Stone Unit II" case.

Table 6-2

CO_2 measurements of Base Case and "No Big Stone Unit II" Case

	CO_2 Intensity & Total CO_2 Emissions							
	CO_2 Intensity (lbs/MWh)				Total CO_2 Emissions (1,000 Tons)			
	2014	2015	2020	2025	2014	2015	2020	2025
Base Case	2,383	2,184	2,207	2,227	3,464	3,249	3,518	3,794
No Big Stone Unit II	2,383	2,371	2,357	2,336	3,464	3,506	3,743	3,971

Integrated Resource Plan

Based on the results of the supply-side and integration analysis (Attachment C), the resource plan resulting from the base case with the "New DSM Package" added as a resource option is the best choice for Montana-Dakota's customers. In this plan, Montana-Dakota is to purchase capacity between 2011 and 2014 and build two 75 MW combustion turbines in 2015 and 2021, in addition to the continuation and implementation of the ten DSM programs identified in Chapter 3 between 2010 and 2012. These DSM programs would amount to 22.2 MW of peak demand reduction.

Along with these resources are the committed resources: Glen Ullin Station 6 in 2009, the expansion of Diamond Willow and Cedar Hills in 2010, the extension of the NSP contract to 2011, and Big Stone Unit II in 2015. Table 6-3 shows the capacity mix (in megawatts and percent) by fuel and unit type for 2010, 2015, and 2020 for the least-cost resource expansion plan.

Table 6-3:

Montana-Dakota's Capacity Mix (in MW and Percent) for the Least-Cost Resource Expansion Plan

Fuel/Unit Type	2010	2015	2020
Natural Gas/Peaking	113.7 (17%)	179.1 (24%)	179.1 (24%)
Purchased Power	112.8 (17%)	2.8 (0%)	2.8 (0%)
Renewable	57.5 (9%)	57.5 (8%)	57.5 (8%)
Demand-Side/Interruptible	7.6 (1%)	22.7 (3%)	22.7 (3%)
Fossil/Base Load	368.7 (56%)	499.7 (66%)	499.7 (66%)

CHAPTER 7

TWO-YEAR ACTION PLAN

This section of the report provides the two-year action plan resulting from the present IRP. The plan describes the specific activities that Montana-Dakota intends to implement for its long-range integrated resource plan.

Load Forecasting

- Montana-Dakota will continue to review its load forecasting assumptions and inputs as part of its routine process.
- Montana-Dakota will evaluate the accuracy of its forecasts to determine the areas that need improvements.

Demand-Side Resources

- Montana-Dakota expects to implement the ten DSM programs identified in Chapter 3. As shown in Attachment B, the DSM implementation will include:
  - Continuation and enhancements of the five currently offered DSM programs
  - Implementation of the remaining three DSM programs identified in the 2007 IRP, and
  - Implementation of two new DSM programs.

Supply-Side Activities

- Montana-Dakota will continue to pursue ownership in Big Stone Unit II.
- Montana-Dakota will construct the Glen Ullin Station 6 waste heat unit, the addition to the existing Diamond Willow wind farm, and the Cedar Hills wind farm.
- Montana-Dakota will exercise the option to extend an existing power purchase agreement through the summer of 2011.
- Montana-Dakota will pursue a power purchase agreement for the 2012-2014 time period as the result of its Request for Proposal issued in December 2008.
- Montana-Dakota will continue to investigate the feasibility of a 75 MW

combustion turbine in 2015 as well as other resource options as opportunities arise.

Other Activities

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

CHAPTER 8

PUBLIC ADVISORY GROUP

This chapter 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 2009 IRP advisory group was established at the beginning of the 2009 planning cycle and held its first meeting in September 2008.

Objective

The objective of the PAG was to provide Montana-Dakota with input to its integrated resource planning process from a non-utility 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.

Participants

Participants in the PAG are non-utility 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 2009 PAG participants are shown in Table 8-1.

Table 8-1

The 2009 IRP Public Advisory Group

Montana

Barbara Roberts
Director of Energy Program
Action for Eastern Montana
Glendive, Montana

Dr. LeRoy M. Moline
Glendive, Montana

Jeff Blend
Department of Environmental Quality
Helena, Montana

North Dakota

Bill Huether*
Ryan Rauschenberger
Andrea Holl Pfennig
North Dakota Department of Commerce
Bismarck, North Dakota
*(*Mr. Huether passed away in October 2008)*

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

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

Bruce Conway
MERC Services, LLC
Williston, North Dakota

Rich Wardner
North Dakota State Senator
Dickinson, North Dakota

Annette Bendish
North Dakota Public Service Commission
Bismarck, North Dakota
(Participated as an observer)

South Dakota

Christine Martin-Goldsmith
Goldsmith Heck Engineers, Inc.
Mobridge, South Dakota

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 meeting dates and the items discussed at each meeting are contained in Attachment D.

The 2009 IRP public advisory process was designed to make 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 discussion of recent changes within the Company and in the electric utility industry, which is moving rapidly toward a market environment. The group's discussions, therefore, tended to concentrate on issues, policies, and overall results. As a result of the public advisory process, Montana-Dakota was able to produce better analysis and reports with the information and suggestions provided by the group.

The 2009 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 held, Montana-Dakota worked closely with the PAG demand-side subgroup which consisted of representatives from the North Dakota Department of Commerce, North Dakota Public Service Commission staff, Montana Department of Environmental Quality, and Action for Eastern Montana to select the demand-side programs for consideration and to help evaluate those demand-side programs.

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.

Conclusions

Montana-Dakota is pleased with its public advisory process. The method improved the 2009 IRP development and product (report and attachments). The public involvement resulted in better study assumptions and provided useful information to both the company and the PAG participants and their constituents.

Attachment A

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC LOAD FORECAST
INTEGRATED SYSTEM (MT, ND, SD)
2009–2028

Prepared by
Montana-Dakota Utilities Co.
Electric System Operations & Planning Department

December 31, 2008

ELECTRIC LOAD FORECAST

TABLE OF CONTENTS

Executive Summary

New long-range (20-year) forecasts of Montana-Dakota Utilities Co.'s (Montana-Dakota) electric energy requirements and peak demands for the Integrated System of Montana, North Dakota, and South Dakota have been prepared by the Electric System Operations & Planning Department. From 1988 through 2005, Montana-Dakota used SHAPES II, an end-use forecasting model, as its forecasting tool. Prior to 1988, econometric and time-series methods of forecasting were used. Montana-Dakota has returned to an econometric methodology of forecasting with the forecasts developed beginning in 2006.

INTEGRATED SYSTEM

Total annual energy for the Integrated System is projected to grow at an average rate of 2.58% per year for the next five years and at an average rate of 1.70% per year through 2028. Integrated System peak demand is projected to grow at an average rate of 2.1% per year for the next five years and an average rate of 1.6% per year through 2028. Much of the higher rate of growth can be attributed to the Keystone XL Pipeline load that is anticipated to come on-line in June 2012. This new load will add significantly to both energy and demand in the amount of nearly 5% by 2015 when it is in full operation.

The effects of the demand-side management (DSM) programs that are being implemented in the Integrated System are reflected in the sales and peak demand forecasts. Montana-Dakota's 2007 Integrated Resource Plans in North Dakota and Montana recommended the implementation of a portfolio of nine DSM programs beginning in 2008 which will impact sales and demand. These impacts are reflected in the forecast.

Econometric Overview

Montana-Dakota uses an econometric model as its forecasting tool. The econometric models for this year's forecast were developed with the assistance of Christensen Associates Energy Consulting, LLC of Madison, Wisconsin, using the statistical software package SAS®.

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 alternate fuels, and weather.

The strengths of econometric forecasting models include:

- Econometric models explicitly measure the effects of underlying causes of trends and patterns.
- Econometric models provide statistical evaluation of forecast uncertainty.
- Econometric models utilize economic and demographic information that is easily understood.
- Econometric models can be readily re-estimated.

The econometric method combines economics theory and statistical techniques to produce a system of simultaneous equations. The method starts with estimating causal relationships between electric energy consumptions (the dependent variable) and factors influencing electricity use (the independent variables). The relationship is estimated by applying regression analysis or other more sophisticated methods to time-series data. Once the relationships are established, inserting forecasts of the independent variables into the equation yields projections of the dependent variable.

A number of demographic and econometric variables were tested for fit in the process of developing the Integrated System forecasts. Various combinations of variables were tested for statistical significance when evaluating the data to be used in each equation. The following is a list of variables that were available for both the historical time period being analyzed and forecasted time period:

Residential price of electricity
Small Commercial & Industrial price of electricity
Large Commercial & Industrial price of electricity
Residential price of alternate fuel (natural gas)
Commercial price of alternate fuel (natural gas)
Personal Income per Capita
Personal Income
Heating Degree Days (HDD) for Bismarck, ND
Cooling Degree Days (CDD) for Bismarck, ND
Population
Number of Households

Employment
Persons per Household
Total Retail Sales
Temperature at the time of peak for Bismarck, ND; Williston, ND; and Miles City, MT

The variables used in each resulting equation are noted in the narrative that follows for each sales sector forecast. The forecast process begins by estimating the full models and then removing variables for which the estimated coefficient either has the wrong sign or is not statistically significantly different from zero (using a *p-value* of 0.10).

Data Sources

At the time this analysis was begun for the Integrated System (July 2008), the most recent year for which a complete set of weather and actual monthly sales by sector was available was 2007.

The data used in the development of the forecast that are available in-house include Montana-Dakota's rate projections, and historical sales, energy, demand, losses, natural gas and electricity prices, and number of customers or bills.

In addition to the data available in-house, most of the economic and demographic data are obtained from Woods & Poole Economics, Inc. (W&P) of Washington, D.C. by county. The W&P data are apportioned and adjusted to represent the data for the Montana-Dakota service territory. Other data sources include the National Oceanic and Atmospheric Administration (NOAA), U.S. Census Bureau, and others.

The forecasts for the Integrated System are developed annually. Likewise, the W&P data by county are available annually from the regional model developed by W&P. W&P revises the regional model from one year to the next to reflect new computational techniques and new sources of regional economic and demographic information. Each year, W&P produces new projections based on an updated historical database and revised assumptions. Therefore, the data provided by W&P captures the economic conditions in place at the time that the W&P forecasts are produced.

While national economic conditions can change quite quickly, data from W&P is provided once per year and therefore may not reflect the most current economic climate. For Montana-Dakota's service territory, this is not always a concern since this area is somewhat isolated from factors affecting the rest of the country; economic trends felt nationally usually take a year or two or more before their impact reaches this area. While the current economic downturn was felt by the majority of the country in the last year, Montana-Dakota's service territory was enjoying a robust agricultural sector, additional oil field drilling activity, and increased energy usage resulting from high oil prices. In fact, at the end of February 2009, of the 50 states, only Alaska, North Dakota, and Wyoming were not in a recession according to Moody's Economy.com. Therefore, the forecast for the Integrated System continues to reflect fairly strong growth.

Degree days are used to estimate how hot or cold the climate is and how much energy may be needed to keep buildings cool or warm. Heating degree days, HDDs, are calculated by subtracting the mean daily temperature from 65°F, and summing only positive values over a given period of time, while cooling degree days, CDDs, are calculated by subtracting 65°F from the mean daily temperature, and summing only positive values over a given period of time.

For the Integrated System, Bismarck and Mandan, ND account for approximately one-third of Montana-Dakota's electric sales annually. For this reason and because HDD and CDD numbers are annual values and the change in magnitude from one year to another is more relevant in the analysis than the actual value, Bismarck HDD and CDD values were used to represent the Integrated System weather in each year any time that degree day information was needed in the econometric equations developed. HDD and CDD are from NOAA for Bismarck, ND.

Historical personal income per capita is calculated to be personal income divided by the total population for those counties in which Montana-Dakota provides electric utility service. Historical personal income is available from the W&P data which come from the U.S. Department of Commerce, Bureau of Economic Analysis. Historical population data are also from the U.S. Department of Commerce. Forecasted personal income and population data are projections provided by W&P.

Historical company data used in the development of the forecasts are included in Appendix A for the Integrated System. Appendices A-1 through A-4 list annual sales by customer class for Montana, North Dakota, South Dakota, and the Integrated System for the years 1966-2008, respectively. Appendix A-5 lists the seasonal peaks and load factors of the Integrated System for the years 1960-2008. Appendix A-6 lists demand by state at the time of the system peak for the summer and winter seasons.

Appendix B contains historical and forecasted values for the exogenous variables for the Integrated System.

Integrated System

Overview

Econometric equations were used to develop a long-range (20-year) electric load forecast for Montana-Dakota's Integrated System, which is comprised of Montana-Dakota's service territories in Montana, North Dakota, and South Dakota.

At the time this analysis was begun (July 2008), the most recent year for which a complete set of weather, prices, monthly sales by sector, and other historical information was available was for year-ending 2007. The equations developed used historical data available through 2007 and were designed to forecast the time period 2008-2028.

Montana-Dakota's Integrated System consists of the counties listed in the table below. These counties are located in eastern Montana, north-central South Dakota, and western and central North Dakota.

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, Brown County is excluded from the database because it 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 would reflect too much of the economic activity that occurs in Aberdeen.

1. Forecast Methodology - Sales

The Integrated System sales forecast is disaggregated into five sales sectors:

- Residential sector.
- Small Commercial & Industrial (SC&I) sector. This sector consists of those commercial and industrial customers whose monthly peak demand averages less than 50 kilowatts over a year's time.
- Large Commercial & Industrial (LC&I) sector. This sector consists of those commercial and industrial customers whose monthly peak demand averages more than 50 kilowatts over a year's time.
- Street Lighting. This sector consists of energy for public street and highway lighting.
- Miscellaneous. This sector includes energy for sales to other public authorities, interdepartmental sales, and company use.

The LC&I sector was further broken down into six end-use categories which were then forecasted separately: Tesoro Refinery sales, Westmoreland Coal Mining sales, Montana Oil Field sales, Sabin Metals sales, Keystone XL Pipeline sales, and General LC&I sales. The General LC&I sales are those LC&I sales that did not fall into the first five end-use categories.

Econometric equations were developed to forecast sales for the three primary customer categories – residential, SC&I, and General LC&I – while sales forecasts for the street lighting and miscellaneous sectors were developed primarily using linear regression. The sales forecasts for the five LC&I end-uses were developed using a combination of regressions and information available from Montana-Dakota's field personnel regarding these large customers.

The development of the sales forecasts for each of the five sales sectors is explained below.

1.1. Residential

The residential sales forecast is derived by developing a forecast of residential use per customer and a forecast of number of residential customers. In this way, it is possible for residential sales to depend on variables such as the residential price of electricity, alternate fuel prices for residential customers (natural gas), personal income per household, heating degree days, cooling degree days, number of households, and year. Higher electricity prices and lower income may result in less electricity use, while higher alternate fuel prices as well as colder than normal winters (more heating degree days) and hotter than normal summers (more cooling degree days) may result in more electricity consumption. Historical and forecasted values for these variables are available and were tested for statistical significance in developing the residential econometric equation. The historical and forecasted values for these variables are given in Appendix B.

The final use per residential customer model is as follows:

$$\ln(res\_upc_t) = a + b^{CDD} \times CDD_t + b^{HDD} \times HDD_t$$
$$+ b^{Inc} \times \ln(phhld\_inc_t) + b^{yr} \times year_t + e_t$$

where:

ln	= natural logarithm;
res_upc_t	= residential use per customer;
CDD_t	= cooling degree days;
HDD_t	= heating degree days;
$phhld\_inc_t$	= real personal income per household; and
$year_t$	= year (1983-2007), which serves as a time trend variable.

The *a* and the *b*'s are the estimated parameters, and e_t is the error term. All variables are actual calendar year values.

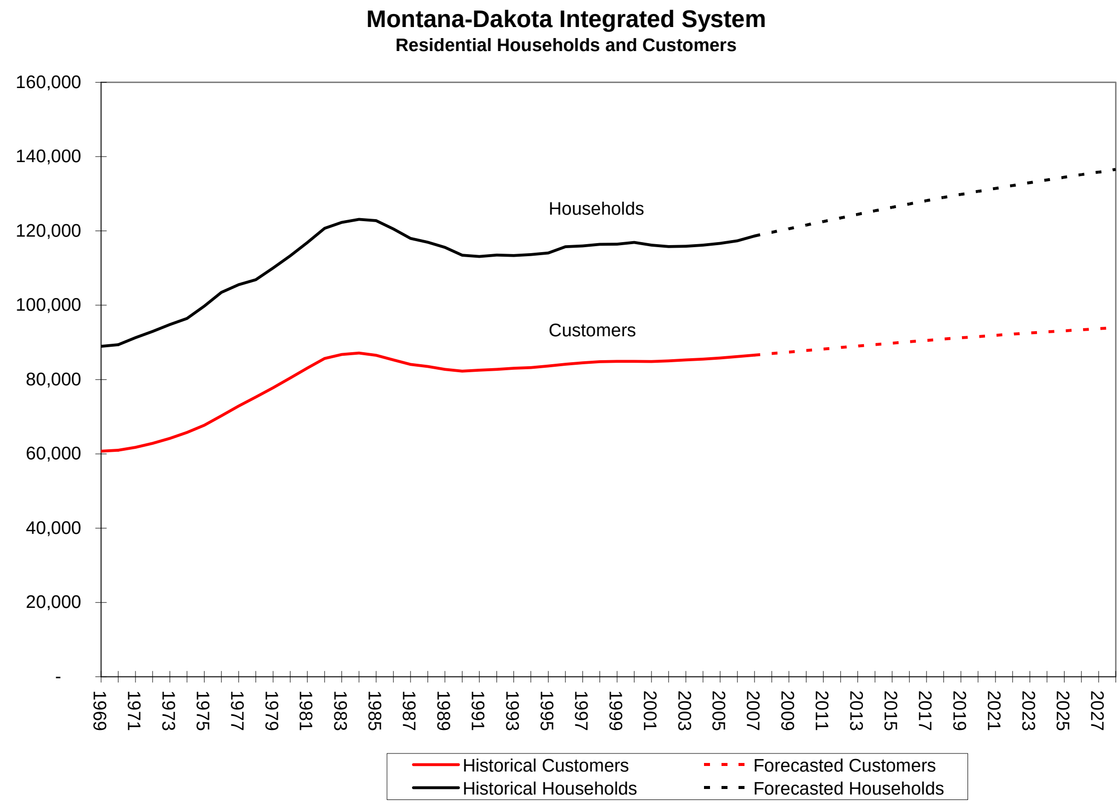
The model for the number of customers (bills) is as follows:

$$\ln(res\_bills_t) = a + b^{hhld} \times \ln(hholds_t) + e_t$$

In this equation, *a* and b^{hhld} are estimated parameters; e_t is the error term, the dependent variable is the natural log of the number of bills and the only explanatory variable is the natural log of the number of households.

The Personal Consumption Expenditure Deflator was used to place residential electricity prices, residential natural gas prices, and personal income per household into real dollar terms for both the historical and forecasted time periods. See Appendix B-5 for the Personal Consumption Expenditure Deflator.

Historical and forecasted customers (bills) and households are plotted on the chart below while the values are given in Appendix B-6.



1.2. Small Commercial & Industrial

Small commercial & industrial (SC&I) sales could potentially depend on variables such as the SC&I price of electricity, alternate fuel prices for SC&I customers (natural gas), employment, heating degree days, cooling degree days, and year. Higher electricity prices may result in less electricity use, while higher alternate fuel prices and higher employment as well as colder than normal winters (more heating degree days) and hotter than normal summers (more cooling degree days) may result in more electricity consumption. Historical and forecasted values for these variables are available and were tested for statistical significance in developing the SC&I econometric equation. The historical and forecasted values for these variables are given in Appendix B.

In contrast to the residential sales forecast, a single model is used to forecast small commercial & industrial (SCI) sales. The final model is as follows:

$$\ln(sci\_kwh_t) = a + b^{CDD} \times CDD_t + b^{HDD} \times HDD_t + b^{Emp} \times \ln(emp\_no\_farm\_mining_t) + e_t$$

where:

ln	= natural logarithm;
sci_kwh_t	= small commercial & industrial sales;
CDD_t	= cooling degree days;
HDD_t	= heating degree days; and
$emp\_no\_farm\_mining_t$	= total employment, excluding farm and mining.

In this equation, *a* and the *b*'s are estimated parameters; e_t is the error term (which is assumed to be serially correlated).

The Chained GDP (Gross Domestic Product) Deflator, whose values are given on Appendix B-7, was used to place natural gas prices into real dollar terms for both the historical and forecasted time periods.

Employment numbers are available from W&P for the historical time period from the U.S. Department of Commerce, Bureau of Economic Analysis. Employment projections for the Integrated System service territory counties are made by W&P. While actual historical growth in employment for the counties in Montana-Dakota's service territory was 1.58% per year for the four year time period of 2001-2005 and 2.36% per year for the two year time period of 2003-2005, W&P has projected that employment will grow at 1.33% per year for the next ten years and at 1.25% per year for the next twenty. Since recent actual growth in employment is much higher than what is now projected by W&P, it was decided that growth in employment for the sector would be allowed to increase at historical levels (2.36% per year) for the next five years and at 1.58% per year thereafter.

Historical employment as well as employment as forecasted by W&P and the revised employment forecast are given on Appendix B-8.

1.3. Large Commercial & Industrial

1.3.1. Tesoro Refinery

The sales forecast for the Tesoro Refinery in Mandan, ND is based on a linear regression of 1981 to 2007 actual historical sales. Information available from Montana-Dakota's field personnel who have contact with the Tesoro Refinery supports this forecast.

1.3.2. Westmoreland Coal

Westmoreland Coal currently operates three mines that are served on Montana-Dakota's electric system – one at Beulah, ND, one at the Coyote Power Station at Beulah, ND, and one at Savage, MT. The sales forecast for Westmoreland Coal is being held flat at a level that is roughly the average for the past five years.

1.3.3. Montana Oil Fields

Oil field sales are made up of two Montana oil fields: the Cedar Creek Anticline near Baker and the Poplar oil field near Poplar, MT. Sales at the Cedar Creek Anticline are further broken down into sales to Encore Acquisition and all other sales at the Cedar Creek Anticline which includes sales to Burlington Northern. Sales to Encore Acquisition account for more than 70% of all Montana Oil Field sales in total. In the forecast, the sales to Encore Acquisition and sales for Other Oil Field (the Poplar Oil Field plus the Cedar Creek Anticline sales that are not Encore Acquisition sales) are listed separately.

Historical sales for each of the three oil field customers individually are shown on the graph on Appendix A-7. Sales to the oil fields in total generally declined each year from 1986 to 1997. New equipment was added by Encore Acquisition and Burlington Northern causing sales to increase fairly significantly from 1999 through 2007. Encore has indicated that it has completed the special projects it was working on. New equipment was also added by Burlington Resources causing the Other Oil Field sales class to have some significant growth from 1998 to 2007 but the latest information available indicates that those special projects are now complete, no new wells are planned, and this is now considered a "producing field" rather than an "expanding field." However, when these forecasts were produced in the fall of 2008, oil prices were still quite high and activity in the Bakken Formation in western North Dakota and eastern Montana was booming.

The forecast methods are described below.

<u>Encore Acquisition</u>

Encore Acquisition operates oil wells in the Cedar Creek Anticline that are served by Montana-Dakota at twelve sites or metering points. The forecast for Encore Acquisition was based on a log-linear regression through 1988 to 2007 actual sales for these "customers."

Other Oil Fields

The majority of the sales at the Cedar Creek Anticline that are not to Encore Acquisition are to Burlington Resources. The forecast for Other Oil Field sales was based on a log-linear regression through 1988 to 2007 actual sales for 2008-2017 and at half that level of growth for 2018 to 2028.

1.3.4. Sabin Metals

The Sabin Metals plant in Williston, ND has been recycling petroleum and petrochemical catalysts used in chemical and petroleum manufacturing in order to isolate and refine the small amounts of gold, silver, platinum, and other precious metals contained in them at the old Dakota Catalyst plant in Williston, ND since mid-2001. Montana-Dakota's field personnel, through contact with management at Sabin Metals, estimates the load at Sabin Metals will experience increases from the addition of a new 1500 kW arc furnace in 2010 that will begin with a 50% load factor and ramp up to a load factor of 95% by the year 2015. The sales forecast for Sabin Metals reflects an expected value of 70% based on the estimated probability that this new furnace will be added.

1.3.5. Keystone XL Pipeline

The proposed Keystone XL Pipeline project is an expansion project of the Keystone Pipeline in partnership between TransCanada and ConocoPhillips. This pipeline will originate in Alberta, Canada and extend south to the Gulf Coast in Texas, crossing Montana-Dakota's service territory in the state of Montana near Baker. Keystone has secured firm, long-term contracts from shippers and will proceed with the necessary regulatory applications. Montana-Dakota is expecting to provide electric service to a pumping station in Montana on this pipeline. It is anticipated that this load will come on-line in June 2012.

1.3.6. General LC&I

General LC&I sales (sales to all other LC&I customers that are not to the Tesoro Refinery, Westmoreland Coal, Montana Oil Fields, Sabin Metals, or TransCanada Keystone Pipeline) could depend on variables such as the LC&I price of electricity, alternate fuel prices for LC&I customers (natural gas), heating degree days, cooling degree days, employment, and year. Higher electricity prices can result in less electricity use, while higher alternate fuel prices and higher employment as well as colder than normal winters (more heating degree days) and hotter than normal summers (more cooling degree days) could result in more electricity consumption. Historical and forecasted values for these variables are available and were tested for statistical significance in developing the General LC&I econometric equation.

As with SCI sales, general large commercial & industrial (LCI) sales are forecast using a single model. The final model is as follows:

$$\ln(lci\_kwh_t) = a + b^{CDD} \times CDD_t + b^{ElecP} \times \ln(lci\_p\_elec_t) + b^{yr} \times year + e_t$$

where:

ln	= natural logarithm;
lci_kwh_t	= large commercial & industrial sales;
CDD_t	= cooling degree days;
$lci\_p\_elec_t$	= the real LCI price of electricity; and
$year_t$	= year, which serves as a time trend variable.

In this equation, *a* and the *b*'s are estimated parameters; e_t is the error term (which is assumed to be serially correlated).

After the General LC&I sales are projected using the equation developed as outlined above, adjustments are made to the projected sales to reflect additional load growth that is expected due to the addition of several new General LC&I customers that are in the process of being added or that will be added in 2009 and 2010. Information regarding the specific LC&I customers that are expected to come on line is provided by Montana-Dakota's field personnel who have contact with and closely monitor these customers. Sales are added to the General LC&I sales sector in 2009 and 2010 for the following new loads:

- Medcenter One Nursing Home – Mandan, ND
- Bear Paw Energy Compressor Motors – Lignite, ND
- Enbridge Pipeline – Stanley, ND
- LC&I space heating loads

These loads total 17,000 MWh in 2009 and 29,400 MWh in 2010 and thereafter.

1.4. Street Lighting

Electric sales for the street lighting sector (public street and highway lighting) were forecasted based on the results of a linear regression analysis of actual 1989-2007 sales.

1.5. Miscellaneous

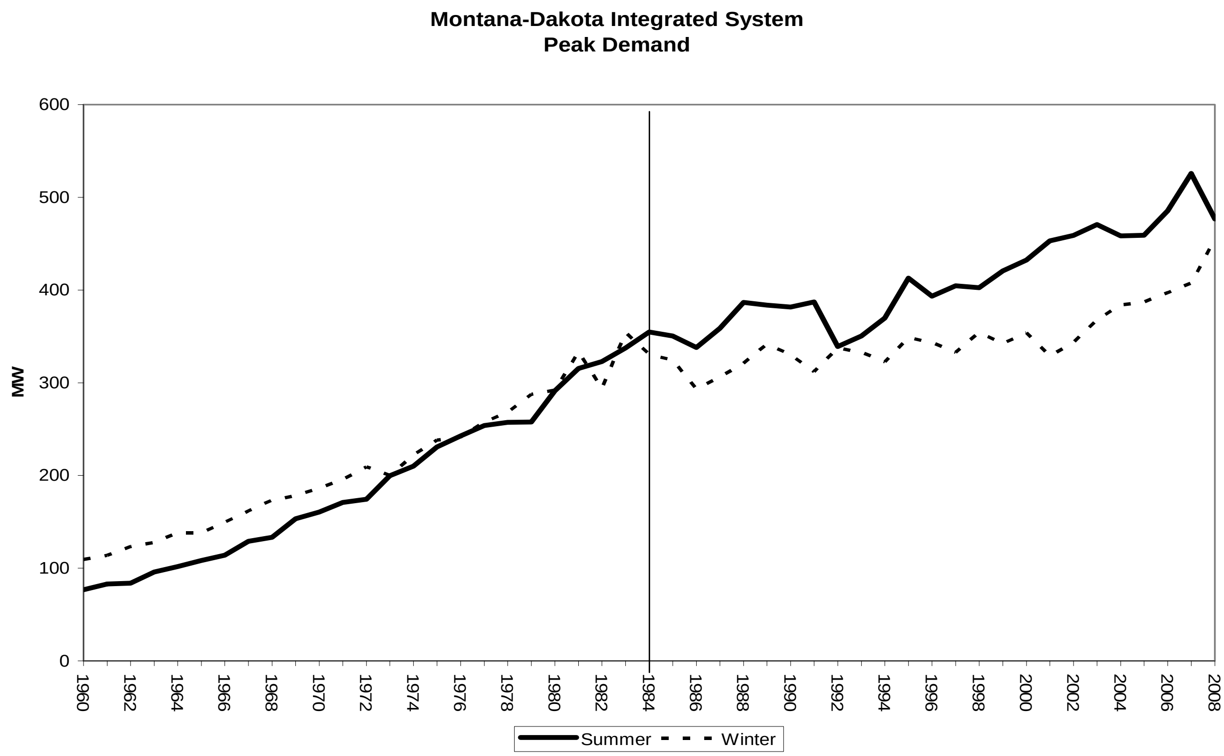
The miscellaneous sales sector is made up of sales for the following three end-uses:

1. Interdepartmental Sales – gas utility use of electricity
2. Other Public Sales – sales to government authorities which includes municipal pumping and some city sales (these sales are served under special contracts that are applicable only to public authorities)
3. Company Use - Montana-Dakota offices

The forecast for Interdepartmental Sales was based on a linear regression on actual 1989-2007 sales while the forecast for Other Public Sales was based on a linear regression on actual 1994-2007 sales. The forecast for Company Use was held constant at the actual 2007 level.

2. Forecast Methodology – Peak Demand

Integrated System historical peak demand is shown on the chart below.



Montana-Dakota was a winter peaking utility prior to 1984. From about 1973 to 1983, the spread between the winter and summer peaks began to narrow and in 1984 Montana-Dakota became a summer peaking utility. The difference between the summer and winter peaks has generally been widening since that time. From the Residential Energy Use Surveys conducted biennially by Montana-Dakota, it is known that air conditioning is becoming more prevalent over time and air conditioning load is driving much of the increase in summer peak demand.

The Integrated System peak demand forecast is developed on a total system basis; it is not disaggregated by sector. The summer peak demand forecast was developed through the use of an econometric model. Peak day temperature, annual cooling degree days, total system sales for the year including losses (annual requirements), and a time-trend variable (year) were used as the independent variables in the econometric model.

For peak day temperature, Montana-Dakota has available the historical hourly temperatures for three major load centers: Bismarck, ND; Williston, ND; and Miles City, MT. Weighted average temperatures for Bismarck (70%), Miles City (15%) and Williston (15%) at the time of the system peak were used as the peak day temperature. This weighting method has been tested and used in the company's short-term demand forecast as well as in other informal in-house analyses. The inclusion of cooling degree days in the model is based on the fact that Montana-Dakota is a summer peaking utility and that hotter summers create more hot days on which high peaks may be set and may also serve as a proxy for heat buildup on the peak day.

Any known customer load interruptions due to Interruptible Rate 39 and/or forced distribution outages that occurred at the time of the summer peak were added to the summer peak used in the analysis. The summer peak value thus represents the peak as it would have occurred had there not been any interruptions. Interruptions to the load at customers served on Interruptible Large Power Service Rate 39 typically occur at the time of the system peak. A forced distribution outage also occurred at the time of the system peak in the summer of 2002.

The summer peak demand model is as follows:

$$\begin{aligned}\ln(peak\_load_t) &= a + b^{CDD} \times CDD_t + b^{PTemp} \times peak\_temp_t \\ &\quad + b^{Sales} \times \ln(system\_kwh_t) + b^{yr} \times year_t + e_t\end{aligned}$$

where:

ln	= natural logarithm;
$peak\_load_t$	= summer peak demand;
CDD_t	= cooling degree days;
$peak\_temp_t$	= weighted average temp at time of peak;
$system\_kwh_t$	= annual energy requirements; and
$year_t$	= year, which serves as a time trend variable.

In this equation, *a* and the *b*'s are estimated parameters; e_t is the error term (which is assumed to be serially correlated).

The summer peak demand forecast that results from this econometric model reflects the load growth based on historical trends that Montana-Dakota has experienced. However, there are a couple of new loads that are expected to be added in the 2009 time frame. As mentioned in Section 1.3.6 above, the new loads that have been identified by Montana-Dakota's field personnel are the Medcenter One Nursing Home in Mandan, ND, a new motor at Enbridge Pipeline at Stanley, ND, and additional load at Bear Paw Energy in Lignite, ND. The incremental load resulting from the addition of these new loads, which will be added to summer peak as forecasted through the econometric model, amounts to 4.1 MW.

To calculate the winter peak demand forecast, the ratio of the 1997-2007 time period actual average winter peak demand to summer peak demand (80.0%) was used.

3. Forecast Results – Sales and Demand

The forecast methodology for both sales and demand as described in Sections 1 and 2 above results in the initial sales forecasts by sales class and the initial demand forecast. Reductions to the sales forecasts by class and to the demand forecast are made to reflect Demand-Side Management programs that are being implemented. Once these reductions are reflected in the sales forecasts, the total of the sales forecasts by class are adjusted by the loss factor to arrive at the final forecast of energy requirements.

3.1. Demand-Side Management (DSM) Reductions

As reflected in IRP's filed with the North Dakota and Montana Public Service Commissions, the following DSM programs have been or are expected to be implemented, and the reduction in energy and peak demand is reflected in the forecast:

- Conservation Programs
  - EnergyStar® Refrigerator rebates
  - EnergyStar® Freezer rebates
  - Refrigerator Round-up program
  - LED Exit Sign rebates
  - Commercial High-Efficiency Air Conditioner rebates
  - High-Efficiency Motor rebates

- Demand Response Programs
  - Interruptible Large Power Rates 38 & 39
  - Residential Air Conditioner Cycling
  - Commercial Air Conditioner Cycling

3.2. Losses

The sales forecasts reflect the energy delivered to Montana-Dakota's customers' meters. The total amount of electricity generated at the power plants to meet Montana-Dakota's customers' energy needs is greater than what is delivered to the meters and is called the 'Total Energy Requirements.' The difference between the sales and energy requirements reflects the losses that occur within the transmission and distribution system.

The total system losses can be calculated based on the percentage of the annual energy losses, which is defined as

$$\frac{TotalSystemLosses(MWh)}{TotalSystemLoad(MWh)} \quad x \quad 100$$

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

The percentage of the annual energy losses has varied from year to year, therefore, losses are averaged over a ten-year time period. The average value for the past ten years is 7.896%. Using this value for all future years, the total system hourly loads are calculated for each year during the study period.

3.3. Final Energy Requirements Forecast

The forecasted sales and system peak demand are first adjusted to reflect the effects of the DSM programs that are being implemented as explained in Section 3.1 and then adjusted for losses as outlined in Section 3.2, to calculate the total energy requirements and peak demand forecast. This is the amount of energy and capacity that needs to be generated or purchased to meet Montana-Dakota’s customers’ energy needs.

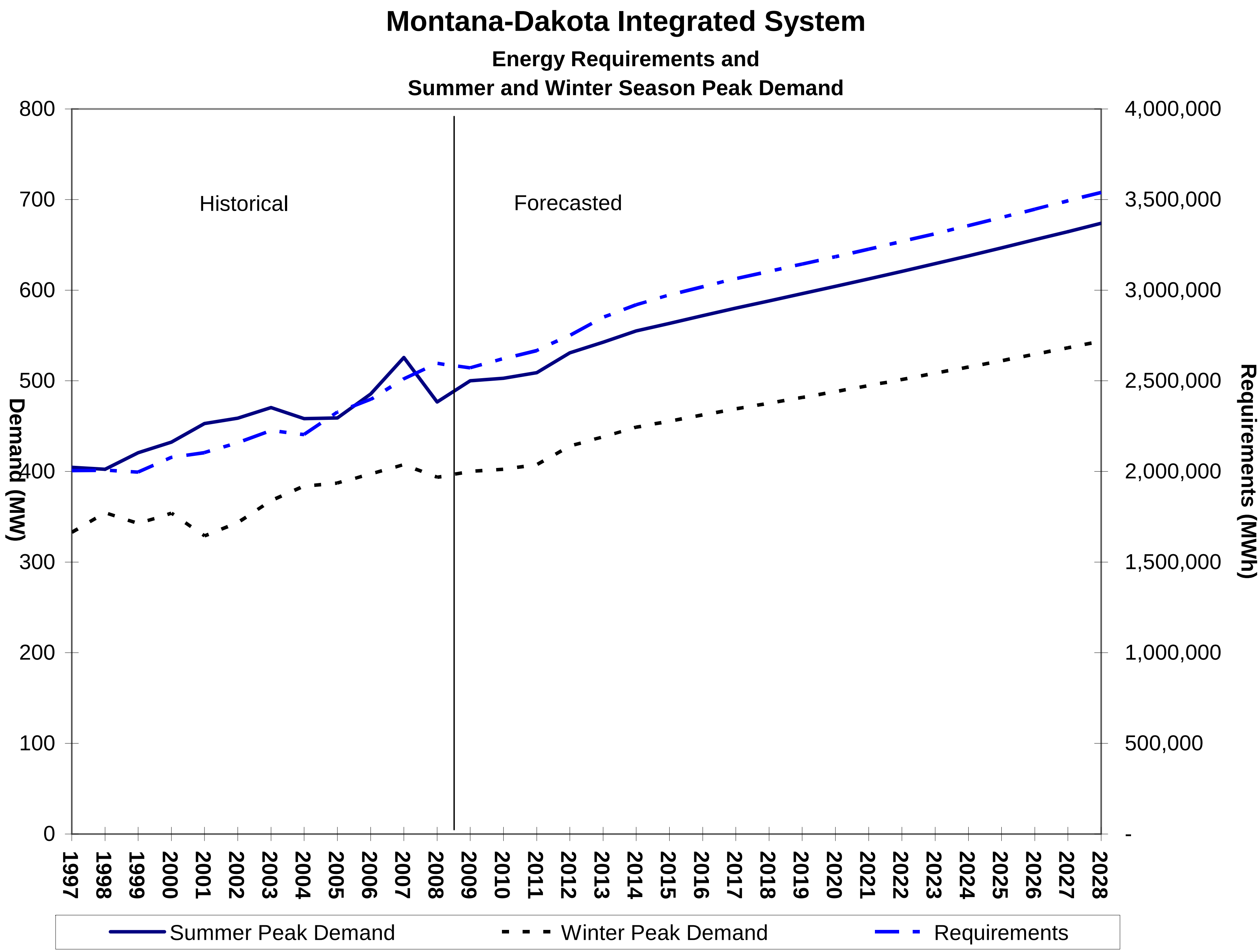
The final forecast results are presented on the following several pages. A table summarizing the Integrated System energy requirements and seasonal peak demand is given first, followed by a graph with historical and forecasted seasonal peak demand and energy requirements. A table summarizing historical and forecasted sales by sales sector is given next, followed by a graph of that table’s data. The next two pages of this section give historical and forecasted sales by end-use within the LC&I sales sector followed by a graph of the LC&I end-uses. The last page of this section is a table detailing the historical and forecasted residential sales, customers, and use per customer.

Refer to Appendices C-1 through C-5 for graphs of the historical and forecasted sales by sector.

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

	TOTAL ENERGY REQUIREMENTS		SUMMER PEAK - MW					WINTER PEAK */ AFTER DSM	
YEAR	MWh	%GROWTH	INTERRUPTIBLE LOADS NOT INTERRUPTED	Rate 38/39 INTRPT LOADS	CONSRVTN & DEMAND RESPONSE	PEAK DEMAND AFTER DSM	% CHG	MW	%GROWTH
1998	2,007,534					402.5		354.2	
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%				452.9	4.77%	328.9	-7.06%
2002	2,158,431	2.58%				458.8	1.30%	343.5	4.44%
2003	2,226,531	3.16%				470.5	2.55%	367.7	7.05%
2004	2,204,012	-1.01%				458.4	-2.57%	383.9	4.41%
2005	2,327,117	5.59%				459.1	0.15%	387.2	0.86%
2006	2,397,793	3.04%				485.5	5.75%	397.2	2.58%
2007	2,510,540	4.70%				525.6	8.26%	407.3	2.54%
2008	2,596,990	3.44%				476.6	-9.32%	455.0	11.71%
2009	2,571,064	-1.00%	515.9	9.6	6.3	500.0	4.91%	400.0	-12.09%
2010	2,623,027	2.02%	525.0	11.1	11.0	502.9	0.58%	402.3	0.58%
2011	2,666,898	1.67%	533.2	11.1	13.0	509.1	1.23%	407.3	1.23%
2012	2,750,872	3.15%	555.0	11.1	13.0	530.9	4.28%	428.0	5.08%
2013	2,849,843	3.60%	566.8	11.1	13.0	542.7	2.22%	438.2	2.38%
2014	2,918,996	2.43%	579.2	11.1	13.0	555.1	2.28%	448.9	2.46%
2015	2,974,139	1.89%	587.5	11.1	13.0	563.4	1.50%	455.6	1.48%
2016	3,018,569	1.49%	595.9	11.1	13.0	571.8	1.49%	462.3	1.48%
2017	3,063,902	1.50%	604.4	11.1	13.0	580.3	1.49%	469.1	1.47%
2018	3,103,483	1.29%	612.2	11.1	13.0	588.1	1.34%	475.3	1.33%
2019	3,143,697	1.30%	620.2	11.1	13.0	596.1	1.36%	481.7	1.35%
2020	3,184,640	1.30%	628.3	11.1	13.0	604.2	1.36%	488.2	1.35%
2021	3,226,322	1.31%	636.5	11.1	13.0	612.4	1.36%	494.8	1.34%
2022	3,268,816	1.32%	644.9	11.1	13.0	620.8	1.37%	501.5	1.36%
2023	3,312,089	1.32%	653.4	11.1	13.0	629.3	1.37%	508.3	1.36%
2024	3,356,092	1.33%	662.0	11.1	13.0	637.9	1.37%	515.2	1.35%
2025	3,400,924	1.34%	670.8	11.1	13.0	646.7	1.38%	522.2	1.37%
2026	3,446,391	1.34%	679.7	11.1	13.0	655.6	1.38%	529.3	1.36%
2027	3,492,606	1.34%	688.7	11.1	13.0	664.6	1.37%	536.5	1.36%
2028	3,539,500	1.34%	697.9	11.1	13.0	673.8	1.38%	543.9	1.37%

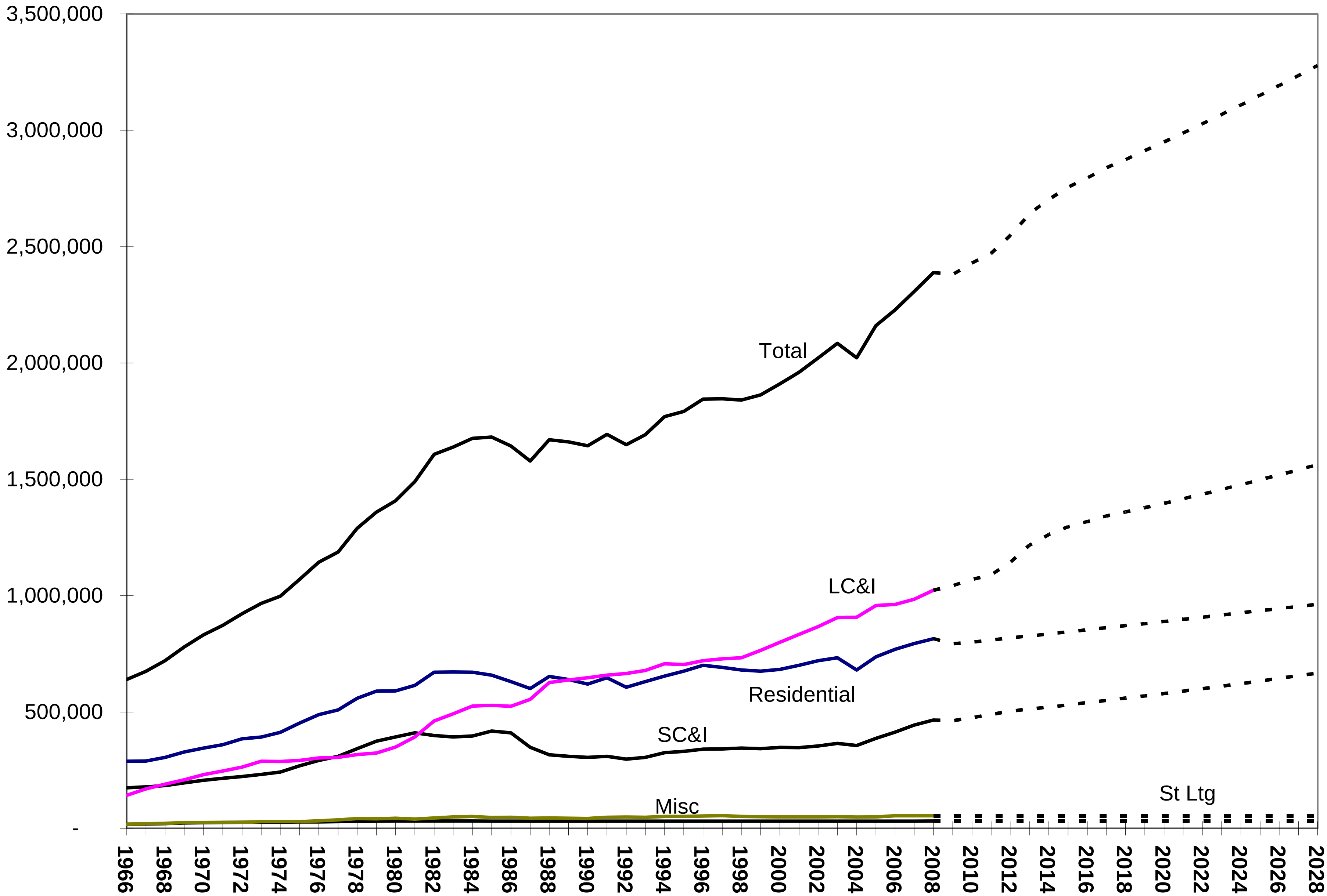
*/ Winter Peak is for Nov-Dec of current year and Jan-Apr of following year.


Montana-Dakota Integrated System
Energy Requirements and
Summer and Winter Season Peak Demand
Historical
Forecasted
Demand (MW)
Requirements (MWh)
0
100
200
300
400
500
600
700
800
-
500,000
1,000,000
1,500,000
2,000,000
2,500,000
3,000,000
3,500,000
4,000,000
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
Summer Peak Demand
Winter Peak Demand
Requirements

MONTANA-DAKOTA UTILITIES CO.
HISTORICAL AND FORECASTED ANNUAL SALES BY SECTOR
INTEGRATED SYSTEM
BILLING MONTH BASIS
REFLECTING DEMAND-SIDE PROGRAMS

	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
1998	680,290		345,012		733,236		30,848		51,342		1,840,728		2,007,534	
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	4.05%
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	1.28%
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	680,614	-7.15%	355,984	-2.54%	907,267	0.16%	30,555	-0.98%	48,062	-3.90%	2,022,482	-3.00%	2,204,012	-1.01%
2005	737,106	8.30%	386,746	8.64%	957,169	5.50%	30,376	-0.59%	49,328	2.63%	2,160,725	6.84%	2,327,117	5.59%
2006	768,952	4.32%	413,147	6.83%	962,186	0.52%	30,602	0.74%	53,472	8.40%	2,228,359	3.13%	2,397,793	3.04%
2007	793,914	3.25%	443,914	7.45%	984,672	2.34%	30,773	0.56%	53,954	0.90%	2,307,227	3.54%	2,510,540	4.70%
2008	814,895	2.64%	465,654	4.90%	1,023,079	3.90%	31,080	1.00%	53,705	-0.46%	2,388,413	3.52%	2,596,990	3.44%
2009	793,541	-2.62%	462,230	-0.74%	1,041,483	1.80%	30,781	-0.96%	52,665	-1.94%	2,380,700	-0.32%	2,568,680	-1.09%
2010	800,997	0.94%	475,269	2.82%	1,069,456	2.69%	30,785	0.01%	52,739	0.14%	2,429,246	2.04%	2,621,059	2.04%
2011	809,337	1.04%	489,061	2.90%	1,088,686	1.80%	30,789	0.01%	52,813	0.14%	2,470,686	1.71%	2,665,771	1.71%
2012	818,033	1.07%	503,261	2.90%	1,142,852	4.98%	30,794	0.02%	52,888	0.14%	2,547,828	3.12%	2,749,004	3.12%
2013	826,819	1.07%	512,229	1.78%	1,216,709	6.46%	30,798	0.01%	52,962	0.14%	2,639,517	3.60%	2,847,933	3.60%
2014	835,550	1.06%	521,358	1.78%	1,262,846	3.79%	30,802	0.01%	53,037	0.14%	2,703,593	2.43%	2,917,069	2.43%
2015	844,421	1.06%	530,647	1.78%	1,295,713	2.60%	30,806	0.01%	53,111	0.14%	2,754,698	1.89%	2,972,209	1.89%
2016	853,297	1.05%	540,102	1.78%	1,318,433	1.75%	30,810	0.01%	53,186	0.14%	2,795,828	1.49%	3,016,587	1.49%
2017	862,227	1.05%	549,726	1.78%	1,342,029	1.79%	30,815	0.02%	53,260	0.14%	2,838,057	1.51%	3,062,150	1.51%
2018	871,163	1.04%	559,520	1.78%	1,359,882	1.33%	30,819	0.01%	53,334	0.14%	2,874,718	1.29%	3,101,706	1.29%
2019	880,059	1.02%	569,488	1.78%	1,378,177	1.35%	30,823	0.01%	53,409	0.14%	2,911,956	1.30%	3,141,884	1.30%
2020	889,039	1.02%	579,632	1.78%	1,396,896	1.36%	30,827	0.01%	53,483	0.14%	2,949,877	1.30%	3,182,799	1.30%
2021	898,068	1.02%	589,955	1.78%	1,416,069	1.37%	30,831	0.01%	53,558	0.14%	2,988,481	1.31%	3,224,451	1.31%
2022	907,190	1.02%	600,461	1.78%	1,435,721	1.39%	30,836	0.02%	53,632	0.14%	3,027,840	1.32%	3,266,918	1.32%
2023	916,372	1.01%	611,156	1.78%	1,455,842	1.40%	30,840	0.01%	53,707	0.14%	3,067,917	1.32%	3,310,160	1.32%
2024	925,549	1.00%	622,040	1.78%	1,476,456	1.42%	30,844	0.01%	53,781	0.14%	3,108,670	1.33%	3,354,131	1.33%
2025	934,806	1.00%	633,116	1.78%	1,497,558	1.43%	30,848	0.01%	53,855	0.14%	3,150,183	1.34%	3,398,921	1.34%
2026	944,088	0.99%	644,391	1.78%	1,519,041	1.43%	30,852	0.01%	53,930	0.14%	3,192,302	1.34%	3,444,366	1.34%
2027	953,491	1.00%	655,864	1.78%	1,540,891	1.44%	30,857	0.02%	54,004	0.14%	3,235,107	1.34%	3,490,551	1.34%
2028	962,929	0.99%	667,543	1.78%	1,563,132	1.44%	30,861	0.01%	54,079	0.14%	3,278,544	1.34%	3,537,418	1.34%
1998-2008 AVG YEARLY GROWTH (10 YRS HIST)		1.79%		3.03%		3.28%		-0.03%		0.71%		2.59%		2.63%
2003-2008 AVG YEARLY GROWTH (5 YRS HIST)		3.00%		5.71%		2.49%		0.19%		2.26%		3.21%		3.46%
2009-2014 AVG YEARLY GROWTH (5 YEARS)		1.04%		2.44%		3.93%		0.01%		0.14%		2.58%		2.58%
2009-2019 AVG YEARLY GROWTH (10 YEARS)		1.04%		2.11%		2.84%		0.01%		0.14%		2.03%		2.03%
2009-2028 AVG YEARLY GROWTH (19 YEARS)		1.02%		1.95%		2.16%		0.01%		0.14%		1.70%		1.70%

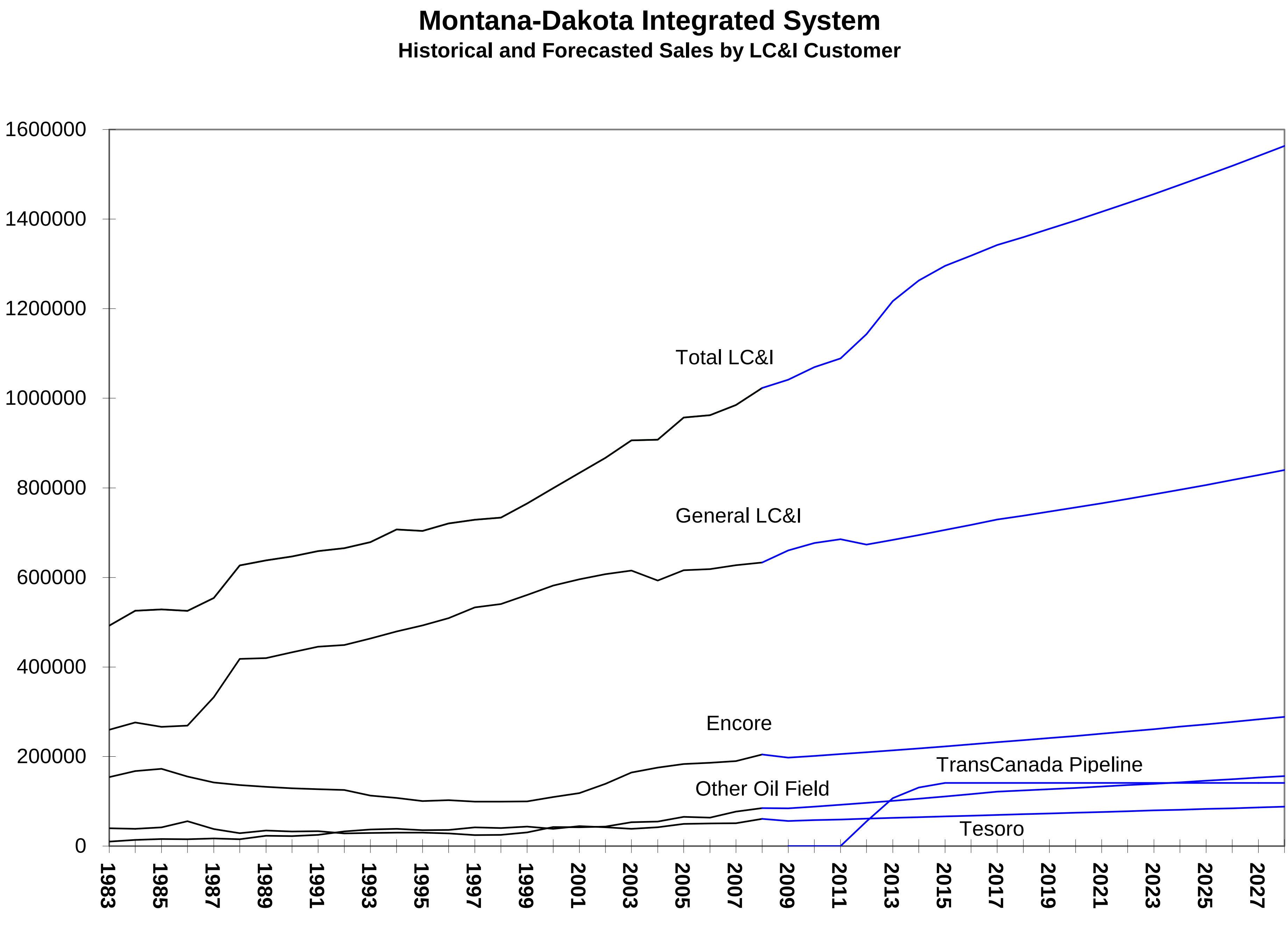
Integrated System Historical and Forecasted Sales by Class



MONTANA-DAKOTA UTILITIES CO.
HISTORICAL AND FORECASTED ANNUAL SALES BY LC&I END-USE
INTEGRATED SYSTEM
BILLING MONTH BASIS
REFLECTING DEMAND-SIDE PROGRAMS

	GENERAL LC&I 1/		TESORO REFINERY 2/		WESTMORELAND COAL 3/		ENCORE ACQUISITION 4/		OTHER OIL FIELD 5/		SABIN METALS 6/		TRANSCANADA PIPELINE		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	SALES(MWh)	%GROWTH
1998	540,627		40,444		28,047		99,203		24,915		-		-		733,236	
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	592,905	-3.61%	42,057	8.76%	29,498	7.81%	175,376	6.81%	54,951	3.38%	12,480	68.63%	-	-	907,267	0.16%
2005	615,993	3.89%	49,717	18.21%	28,563	-3.17%	183,284	4.51%	65,278	18.79%	14,334	14.86%	-	-	957,169	5.50%
2006	618,450	0.40%	50,341	1.26%	28,301	-0.92%	186,144	1.56%	63,390	-2.89%	15,560	8.55%	-	-	962,186	0.52%
2007	627,328	1.44%	50,909	1.13%	27,310	-3.50%	189,738	1.93%	76,887	21.29%	12,500	-19.67%	-	-	984,672	2.34%
2008	633,431	0.97%	60,953	19.73%	26,690	-2.27%	204,380	7.72%	84,788	10.28%	12,837	2.70%	-	-	1,023,079	3.90%
2009	660,253	4.23%	56,183	-7.83%	28,000	4.91%	197,481	-3.38%	84,236	-0.65%	15,330	19.42%	-	-	1,041,483	1.80%
2010	676,863	2.52%	57,857	2.98%	28,000	0.00%	201,470	2.02%	88,169	4.67%	17,097	11.53%	-	-	1,069,456	2.69%
2011	685,313	1.25%	59,530	2.89%	28,000	0.00%	205,539	2.02%	92,287	4.67%	18,017	5.38%	-	-	1,088,686	1.80%
2012	673,093	-1.78%	61,203	2.81%	28,000	0.00%	209,691	2.02%	96,597	4.67%	18,937	5.11%	55,331	-	1,142,852	4.98%
2013	683,593	1.56%	62,876	2.73%	28,000	0.00%	213,927	2.02%	101,108	4.67%	19,856	4.85%	107,349	94.01%	1,216,709	6.46%
2014	694,591	1.61%	64,549	2.66%	28,000	0.00%	218,248	2.02%	105,830	4.67%	20,776	4.63%	130,852	21.89%	1,262,846	3.79%
2015	705,853	1.62%	66,222	2.59%	28,000	0.00%	222,657	2.02%	110,772	4.67%	21,236	2.21%	140,973	7.73%	1,295,713	2.60%
2016	717,229	1.61%	67,895	2.53%	28,000	0.00%	227,155	2.02%	115,945	4.67%	21,236	0.00%	140,973	0.00%	1,318,433	1.75%
2017	729,150	1.66%	69,568	2.46%	28,000	0.00%	231,743	2.02%	121,359	4.67%	21,236	0.00%	140,973	0.00%	1,342,029	1.79%
2018	737,815	1.19%	71,241	2.40%	28,000	0.00%	236,424	2.02%	124,193	2.34%	21,236	0.00%	140,973	0.00%	1,359,882	1.33%
2019	746,761	1.21%	72,914	2.35%	28,000	0.00%	241,200	2.02%	127,093	2.34%	21,236	0.00%	140,973	0.00%	1,378,177	1.35%
2020	755,967	1.23%	74,587	2.29%	28,000	0.00%	246,072	2.02%	130,061	2.34%	21,236	0.00%	140,973	0.00%	1,396,896	1.36%
2021	765,459	1.26%	76,260	2.24%	28,000	0.00%	251,043	2.02%	133,098	2.34%	21,236	0.00%	140,973	0.00%	1,416,069	1.37%
2022	775,260	1.28%	77,933	2.19%	28,000	0.00%	256,114	2.02%	136,205	2.33%	21,236	0.00%	140,973	0.00%	1,435,721	1.39%
2023	785,353	1.30%	79,606	2.15%	28,000	0.00%	261,288	2.02%	139,386	2.34%	21,236	0.00%	140,973	0.00%	1,455,842	1.40%
2024	795,761	1.33%	81,279	2.10%	28,000	0.00%	266,566	2.02%	142,641	2.34%	21,236	0.00%	140,973	0.00%	1,476,456	1.42%
2025	806,476	1.35%	82,952	2.06%	28,000	0.00%	271,950	2.02%	145,971	2.33%	21,236	0.00%	140,973	0.00%	1,497,558	1.43%
2026	817,383	1.35%	84,625	2.02%	28,000	0.00%	277,444	2.02%	149,380	2.34%	21,236	0.00%	140,973	0.00%	1,519,041	1.43%
2027	828,468	1.36%	86,298	1.98%	28,000	0.00%	283,048	2.02%	152,868	2.33%	21,236	0.00%	140,973	0.00%	1,540,891	1.44%
2028	839,749	1.36%	87,971	1.94%	28,000	0.00%	288,766	2.02%	156,437	2.33%	21,236	0.00%	140,973	0.00%	1,563,132	1.44%
1998-2008 AVG YEARLY GROWTH (10 YRS HIST)		1.34%		3.43%		-0.35%		8.40%		11.63%		-		-		3.28%
2003-2008 AVG YEARLY GROWTH (5 YRS HIST)		0.92%		8.52%		-1.04%		3.92%		9.93%		8.45%		-		2.49%
2009-2014 AVG YEARLY GROWTH (5 YEARS)		1.02%		2.82%		0.00%		2.02%		4.67%		6.27%		-		3.93%
2009-2019 AVG YEARLY GROWTH (10 YEARS)		1.24%		2.64%		0.00%		2.02%		4.20%		3.31%		-		2.84%
2009-2028 AVG YEARLY GROWTH (19 YEARS)		1.27%		2.39%		0.00%		2.02%		3.31%		1.73%		-		2.16%

1/ GENERAL LARGE COMMERCIAL & INDUSTRIAL FORECAST WAS DEVELOPED FROM AN ECONOMETRIC FORECAST.
2/ TESORO REFINERY SALES ARE BASED ON A LINEAR REGRESSION OF 81-07 SALES.
3/ WESTMORELAND COAL IS HELD CONSTANT AT 2002 ACTUAL LEVELS.
4/ ENCORE ACQUISITION SALES FORECAST IS BASED ON AN EXPONENTIAL CURVE FIT THROUGH 88-07 ACTUAL SALES.
5/ OTHER OIL FIELDS SALES FORECAST IS BASED ON AN EXPONENTIAL CURVE FIT THROUGH 88-07 ACTUAL SALES AT POPLAR AND OTHER OIL FIELD (TOWN 714 LESS ENCORE).
6/ SABIN METALS EXPECTS TO ADD ANOTHER ARC FURNACE IN 2010.



Montana-Dakota Integrated System
Historical and Forecasted Sales by LC&I Customer
1600000
1400000
1200000
1000000
800000
600000
400000
200000
0
Total LC&I
General LC&I
Encore
TransCanada Pipeline
Other Oil Field
Tesoro
1983
1985
1987
1989
1991
1993
1995
1997
1999
2001
2003
2005
2007
2009
2011
2013
2015
2017
2019
2021
2023
2025
2027

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

YEAR	SALES (MWh)	%GROWTH	AVG CUSTS	CUST NO INC/(DEC)	AVG USE PER CUST (kWh/YR)	
1998	680,290		84,833		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	680,614	-7.15%	85,498	220	7,961	
2005	737,106	8.30%	85,791	293	8,592	
2006	768,952	4.32%	86,150	359	8,926	
2007	793,914	3.25%	86,575	425	9,170	
2008	814,895	2.64%	87,262	687	9,338	
2009	793,541	-2.62%	87,399	137	9,080	
2010	800,997	0.94%	87,803	404	9,123	
2011	809,337	1.04%	88,210	407	9,175	
2012	818,033	1.07%	88,622	412	9,231	
2013	826,819	1.07%	89,031	409	9,287	
2014	835,550	1.06%	89,416	385	9,345	
2015	844,421	1.06%	89,807	391	9,403	
2016	853,297	1.05%	90,183	376	9,462	
2017	862,227	1.05%	90,551	368	9,522	
2018	871,163	1.04%	90,905	354	9,583	
2019	880,059	1.02%	91,237	332	9,646	
2020	889,039	1.02%	91,566	329	9,709	
2021	898,068	1.02%	91,887	321	9,774	
2022	907,190	1.02%	92,207	320	9,839	
2023	916,372	1.01%	92,520	313	9,905	
2024	925,549	1.00%	92,817	297	9,972	
2025	934,806	1.00%	93,110	293	10,040	
2026	944,088	0.99%	93,392	282	10,109	
2027	953,491	1.00%	93,676	284	10,179	
2028	962,929	0.99%	93,950	274	10,249	

	SALES	**CUSTS**
1998-2008 AVG YEARLY GROWTH (10 YRS HIST)	1.79%	0.26%
2003-2008 AVG YEARLY GROWTH (5 YRS HIST)	3.00%	0.45%
2009-2014 AVG YEARLY GROWTH (5 YEARS)	1.04%	0.46%
2009-2019 AVG YEARLY GROWTH (10 YEARS)	1.04%	0.43%
2009-2028 AVG YEARLY GROWTH (19 YEARS)	1.02%	0.38%

*/ 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.

4. Forecast Uncertainty

Forecasting is a process permeated with uncertainty. The demand and energy projections produced by the econometric process described in the first four sections results in a forecast based solely on the information used as inputs to the equations. 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 considered. That uncertainty can be expressed by peak demand forecasts that reflect temperatures which correspond to higher confidence levels as well as high-growth and low-growth scenarios in energy forecasts.

4.1. Effect of Temperature on Peak Demand

The final forecast results given in Section 3 were developed assuming average temperatures at the time of the system peak. However, there are some shortcomings associated with this methodology. First, with an average temperature forecast, by definition actual peak demand would have a 50% probability of being lower than the forecast values and a 50% probability of exceeding forecast values (50/50 forecast). Second, there can be an appearance that peak demand is under forecasted when the actual temperature at the time of system peak exceeds average temperatures.

A study is conducted annually by Montana-Dakota's System Operations & Planning staff to establish the relationship between summer peak demand and temperature at the time of system peak. As part of the study, the Company's historical July and August demands and corresponding temperatures at times when the temperatures equaled or exceeded 85°F on Mondays through Thursdays are analyzed. The Fall 2008 study results indicated that each one degree increase in temperature at the time of summer peak would result in an increase of approximately 6.5 MW in summer peak demand.

Further statistical analysis of temperatures at the time of system peak for the years 1984 through 2008 (prior to 1984 the company was a winter peaking utility) provided the results shown in the following table:

Temperature Probability at Peak and Effect on Peak Demand

Probability	Weighted Average Temperature	Approximate Increase in Peak Demand (MW)
50.0%	97.1	0.0
75.0%	100.0	18.9
80.0%	100.8	24.1
85.0%	101.6	29.3
90.0%	102.7	36.4
95.0%	104.3	46.8
97.0%	105.3	53.3

As the table shows, there is a 90% probability that actual temperatures at the time of the system peak will not exceed 102.7°F. At this temperature, 36.4 MW of capacity in addition to that which was forecasted is needed to meet the system peak demand that may occur. This is called the 90/10 forecast and provides a peak demand forecast for extreme weather conditions. It represents a 90% probability that the actual peak demand will not exceed the forecast value and a 10% probability that the actual peak demand will be higher than the forecast value.

The following table summarizes the results of the 50/50 probability and 90/10 probability demand forecasts. The 2009 90/10 forecasted demand is calculated to be the 2009 50/50 forecasted demand plus 36.4 MW as shown in the table above. From that point, the growth rate for the 90/10 forecast scenario is assumed to be the same as that of the 50/50 forecast scenario.

Alternate Summer Peak Demand Forecast Comparison

Year	Base Forecast (97.1 degrees F) 50/50 Forecast (MW)	Growth Rate	Alternate Forecast (102.7 degrees F) 90/10 Forecast (MW) */
2009	500.0		536.4
2010	502.9	0.58%	539.5
2011	509.1	1.23%	546.2
2012	530.9	4.28%	569.6
2013	542.7	2.22%	582.3
2014	555.1	2.28%	595.6
2015	563.4	1.50%	604.5
2016	571.8	1.49%	613.5
2017	580.3	1.49%	622.6
2018	588.1	1.34%	631.0
2019	596.1	1.36%	639.6
2020	604.2	1.36%	648.3
2021	612.4	1.36%	657.1
2022	620.8	1.37%	666.1
2023	629.3	1.37%	675.2
2024	637.9	1.37%	684.4
2025	646.7	1.38%	693.8
2026	655.6	1.38%	703.3
2027	664.6	1.37%	713.0
2028	673.8	1.38%	722.9

*/ The growth rate for the 90/10 Forecast scenario is assumed to be the same as that of the 50/50 Forecast scenario.

4.2. High-Growth and Low-Growth Scenario Forecasts

Another approach to express uncertainty in this forecast was to simulate high-growth and low-growth scenarios which represent the corresponding 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 given on Appendix A-10 and graphed on Appendix A-11, 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% per year was assumed to occur during the 20-year forecast horizon. For the low-growth scenario, an average growth rate of 0.5% per year was assumed to occur during the 20-year forecast horizon.

Demand for each scenario was derived by applying the load factors calculated from the base forecast to the high-growth and low-growth scenario forecasted energy.

The results of the high-growth and low-growth scenarios for energy and demand are given below. The following two pages present the graphs of the numeric results.

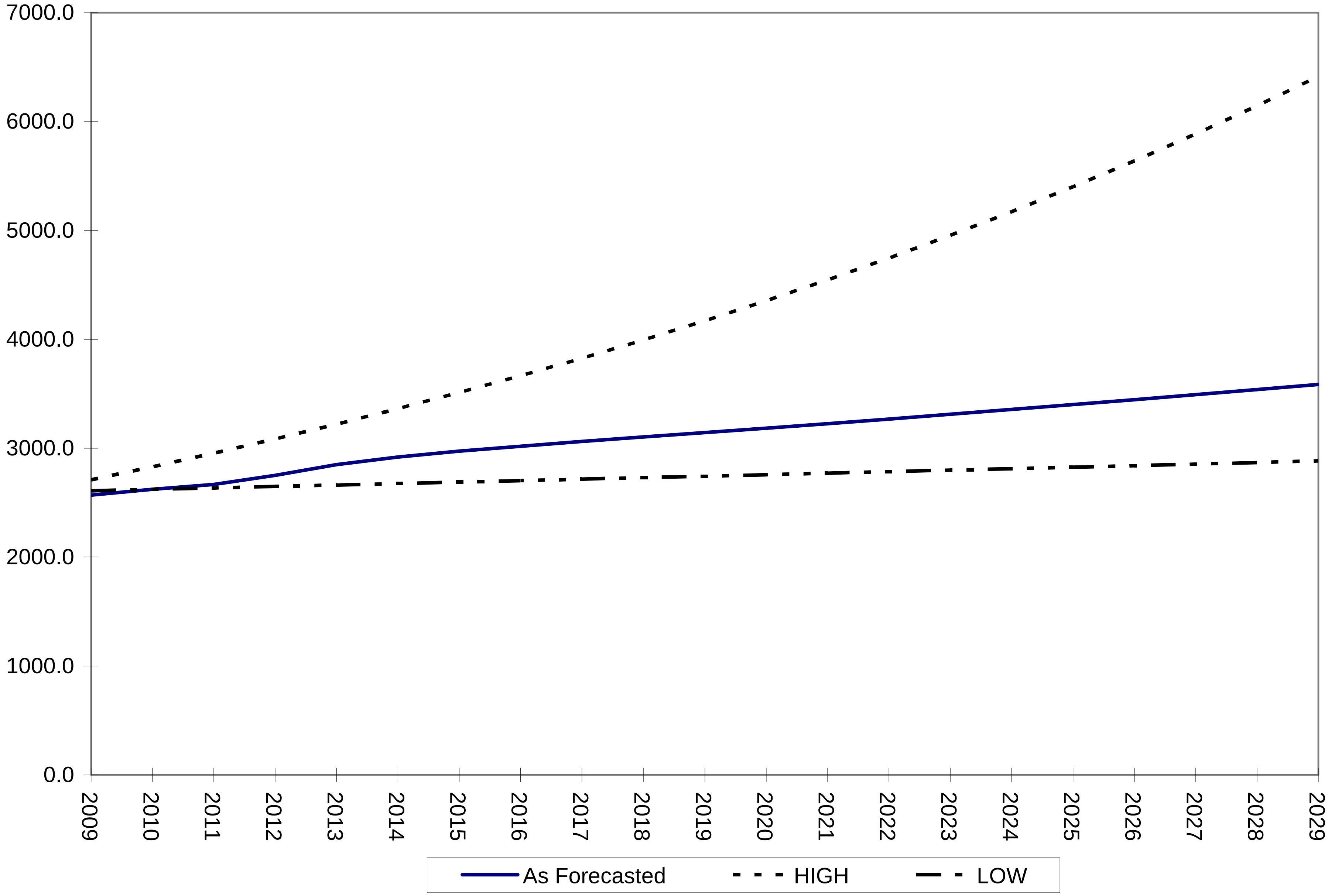
HIGH-GROWTH AND LOW-GROWTH SCENARIOS
TOTAL ANNUAL ENERGY (GWh) AND
SUMMER PEAK DEMAND (MW)

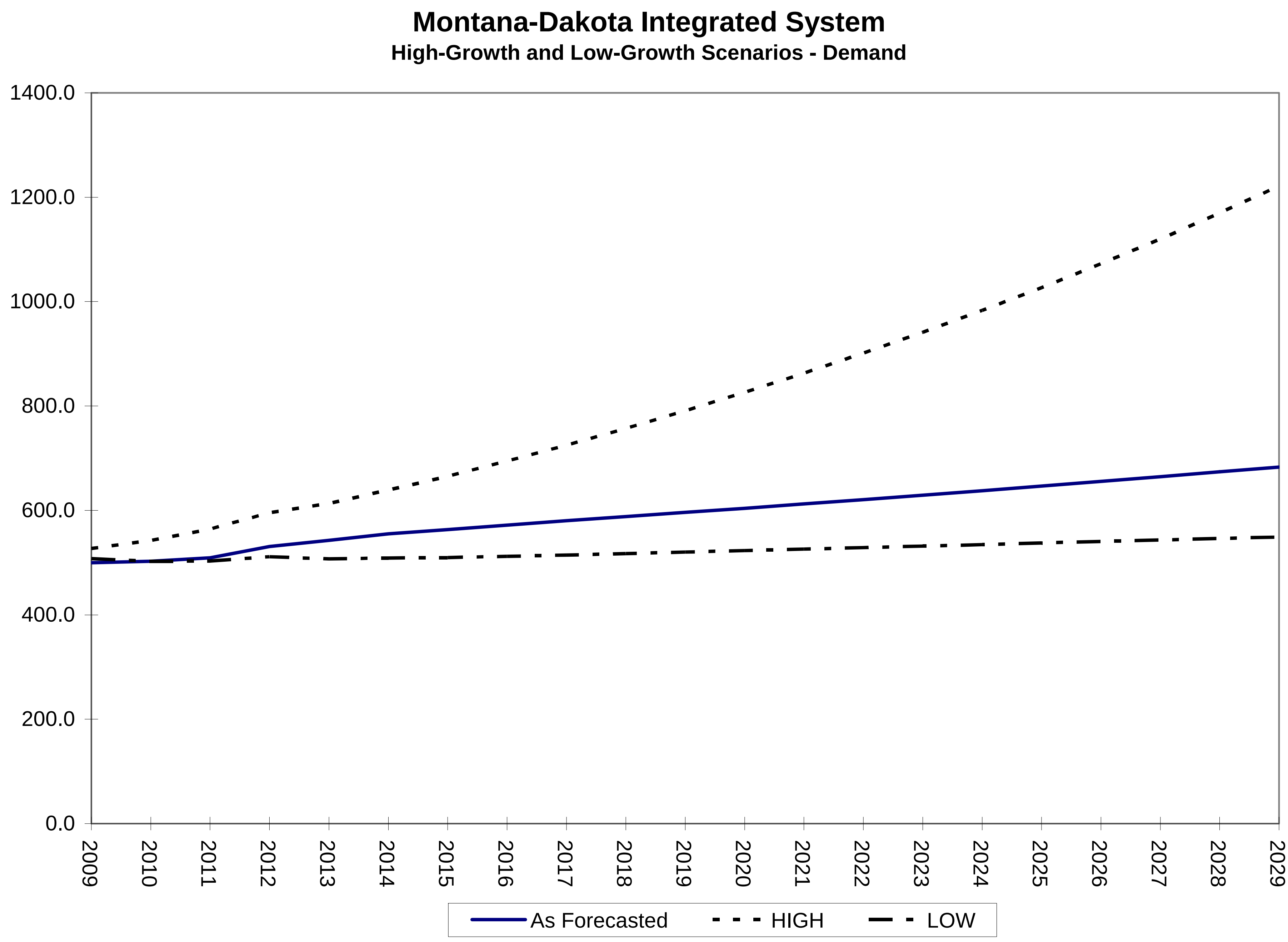
	ENERGY			DEMAND		
	Forecast	HIGH 1/	LOW 2/	Forecast	HIGH	LOW
2009	2571.1	2711.3	2610.0	500.0	527.3	507.6
2010	2623.0	2830.6	2623.0	502.9	542.7	502.9
2011	2666.9	2955.1	2636.2	509.1	564.1	503.2
2012	2750.9	3085.1	2649.3	530.9	595.4	511.3
2013	2849.8	3220.9	2662.6	542.7	613.4	507.0
2014	2919.0	3362.6	2675.9	555.1	639.5	508.9
2015	2974.1	3510.6	2689.3	563.4	665.0	509.4
2016	3018.6	3665.0	2702.7	571.8	694.2	512.0
2017	3063.9	3826.3	2716.2	580.3	724.7	514.5
2018	3103.5	3994.6	2729.8	588.1	757.0	517.3
2019	3143.7	4170.4	2743.5	596.1	790.8	520.2
2020	3184.6	4353.9	2757.2	604.2	826.0	523.1
2021	3226.3	4545.5	2771.0	612.4	862.8	526.0
2022	3268.8	4745.5	2784.8	620.8	901.2	528.9
2023	3312.1	4954.3	2798.7	629.3	941.3	531.8
2024	3356.1	5172.3	2812.7	637.9	983.1	534.6
2025	3400.9	5399.8	2826.8	646.7	1026.8	537.5
2026	3446.4	5637.4	2840.9	655.6	1072.4	540.4
2027	3492.6	5885.5	2855.1	664.6	1119.9	543.3
2028	3539.5	6144.4	2869.4	673.8	1169.7	546.2
2029	3587.0	6414.8	2883.8	683.1	1221.6	549.2

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).

Montana-Dakota Integrated System

High-Growth and Low-Growth Scenarios - Energy




Montana-Dakota Integrated System
High-Growth and Low-Growth Scenarios - Demand
1400.0
1200.0
1000.0
800.0
600.0
400.0
200.0
0.0
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
As Forecasted
HIGH
LOW

5. Allocations

Montana-Dakota's Integrated System consists of the service territories in Montana, North Dakota, and South Dakota. The forecasts developed by sector and in total as described up to this point are for Montana-Dakota's Integrated System in total. Montana-Dakota's Financial Forecasting Department requires forecasts of monthly peak demands by state, and monthly sales and energy requirements by sector and by state. Therefore, disaggregating the Integrated System forecast into state and monthly numbers is necessary.

5.1. Sales and Customer Allocations by State

Historical data indicates that each state's portion of the system demand and energy has not remained constant and no consistent trend has emerged. The portions (or ratios) of each sector within the three states also does not indicate any consistent trend. Since the most meaningful time period for Montana-Dakota financial forecasting is five years or less, it was decided to use the ratios from the most recent year (2007) for allocating energy and customers to the states by sales sector. The tables below show the percent of total electric sales and customers allocated to each state by customer class.

Percent of Sales by Sector Allocated to Each State

	ND	SD	MT
Residential	0.71634	0.07938	0.20429
SC&I	0.67491	0.07932	0.24577
MT Oil Fields	-	-	1.00000
Sabin Metals	1.00000	-	-
Westmoreland Coal	0.92134	-	0.07866
Tesoro Refinery	1.00000	-	-
General LC&I	0.75971	0.04617	0.19412
Street Lighting	0.68073	0.08572	0.23356
Other Public Sales	0.79693	0.05223	0.15084
Interdepartmental	0.53168	0.02152	0.44680
Company Use	0.91088	0.03697	0.05216

Percent of Customers by Sector Allocated to Each State

	ND	SD	MT
Residential	0.70980	0.07616	0.21404
SC&I	0.59742	0.11108	0.29150
General LC&I	0.69665	0.06550	0.23785
Street Lighting	0.79209	0.06342	0.14449
Other Public Sales	0.81538	0.06476	0.11986
Interdepartmental	0.56831	0.00546	0.42623

5.2. Sales and Customer Allocations by Month

The Financial Forecasting Department requires a calendar month forecast for each state. This is accomplished through a two-step process. First, monthly estimates of energy and customers by sector are determined by calculating the ratio of the monthly bill cycle value to the annual amount for the 15-year period 1993-2007. Results were averaged for each month for each sector for each state. These ratios were then applied to the annual amounts calculated as described in Section 5.1 to arrive at monthly billing-cycle sales. The allocation factors for billing-cycle sales for each state, month and sector are shown in Appendix A-8. Billing-month to calendar-month apportionment factors are then used to convert from billing-month to calendar-month sales. These apportionment factors are shown in Appendix A-9.

5.3. Peak Demand Allocations by Month

Allocating peak demand on a monthly basis consists of several steps:

1. Ratios of each monthly peak to the seasonal peak were calculated for the Integrated System for the period May 1993 through April 2008. (The summer season is May through October and the winter season is November through April of the next year.)
2. The ratios determined in Step 1 from each month were averaged to determine which month of the season was to be the peak month, second highest month, etc. Final results of this step indicate that July and December are the peak months for the summer and winter seasons, respectively, August and January have the second highest peaks for their respective seasons, etc. (See the table below which gives the monthly ranks for each month by season.)

Monthly Average of the Ratios of Monthly Peak To Seasonal Peak for the Integrated System (Number in Parenthesis is Rank)

Summer Season			**Winter Season**		
May	(5)	0.6881	November	(4)	0.9158
June	(3)	0.8981	December	(1)	0.9778
July	(1)	0.9771	January	(2)	0.9694
August	(2)	0.9646	February	(3)	0.9304
September	(4)	0.8263	March	(5)	0.8668
October	(6)	0.6754	April	(6)	0.8086

3. For each season, the monthly ratios determined in Step 1 for the May 1993 through April 2008 time period were sorted into rank sequence for each year of historical data and averaged across the years for each ranking. Applying the ranked average ratios from this step to the proper month according to the rank determined in Step 2 results in the monthly assignments given in the following table.

15-Year Average Monthly Ratios of Seasonal Peaks For the Integrated System

January	0.9635	July	1.0000
February	0.9318	August	0.9602
March	0.8611	September	0.8096
April	0.8080	October	0.6570
May	0.7011	November	0.9044
June	0.9017	December	1.0000

5.4. Peak Demand Allocation by Month and State

The methodology to allocate monthly demands to each state is essentially the same as described in Section 5.1 only demand is not allocated by sector. Therefore, only the 2007 monthly ratios by state were used. Appendix A-8 lists the monthly peak demand ratios for each state.

5.5. Annual Energy and Seasonal Peak Demand by State

Historical and forecasted sales by sector and in total are shown on the graphs on Appendices C-1 through C-8.

The forecasts of summer and winter peak demands and annual energy through the year 2028 for the states of Montana, North Dakota, and South Dakota are also given in Appendix C. The peak demand and annual energy for Montana, North Dakota, South Dakota, and the Integrated System are shown on Appendix C-9, C-10, C-11, and C-12. Appendices C-13, C-14, and C-15 graphically portray the tables in Appendices C-9 through C-12.

5.6. Sales Forecasts by Sector

The monthly forecasts for the ten year period 2009-2018, which result from the allocation method described above, are shown in Appendices D, E, F, and G for Montana, North Dakota, South Dakota, and the Integrated System, respectively.

APPENDIX A

Integrated System
Historical Data

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
2004	141,249,319	98,150,615	348,097,119	7,249,849	6,709,211	178,934	469,139	-	602,104,186
2005	150,705,819	102,045,511	364,489,268	7,232,015	6,481,903	194,114	454,825	-	631,603,455
2006	157,205,695	104,213,569	368,666,049	7,202,765	6,996,525	189,666	435,247	-	644,909,516
2007	162,186,142	109,101,052	385,230,122	7,187,164	6,827,828	197,773	430,092	-	671,160,173
2008	162,181,766	108,595,072	408,686,454	7,243,765	7,034,312	190,513	411,809	-	694,343,691

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
2004	482,828,358	224,924,291	532,079,391	20,632,572	32,251,096	238,077	5,030,082	-	1,297,983,867
2005	525,132,818	250,022,338	563,792,863	20,484,092	33,806,432	248,541	5,291,349	-	1,398,778,433
2006	550,070,624	274,727,542	564,963,429	20,772,430	35,894,619	238,213	7,203,891	-	1,453,870,748
2007	568,709,867	299,602,230	570,170,485	20,947,764	36,072,776	235,341	7,511,339	-	1,503,249,802
2008	585,608,722	320,093,226	583,501,829	21,200,739	35,709,163	242,421	7,356,084	-	1,553,712,184

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
2004	56,535,958	32,909,312	27,090,632	2,672,475	2,885,412	9,788	290,260	-	122,393,837
2005	61,267,370	34,678,560	28,886,389	2,660,320	2,535,633	10,026	305,636	-	130,343,934
2006	61,675,574	34,206,361	28,556,470	2,626,482	2,204,422	9,086	299,875	-	129,578,270
2007	63,017,590	35,210,997	29,271,378	2,637,764	2,364,117	9,526	304,850	-	132,816,222
2008	67,104,019	36,965,622	30,890,745	2,635,828	2,432,011	9,826	318,928	-	140,356,979

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
2004	680,613,635	355,984,218	907,267,142	30,554,896	41,845,719	426,799	5,789,481	-	2,022,481,890
2005	737,106,007	386,746,409	957,168,520	30,376,427	42,823,968	452,681	6,051,810	-	2,160,725,822
2006	768,951,893	413,147,472	962,185,948	30,601,677	45,095,566	436,965	7,939,013	-	2,228,358,534
2007	793,913,599	443,914,279	984,671,985	30,772,692	45,264,721	442,640	8,246,281	-	2,307,226,197
2008	814,894,507	465,653,920	1,023,079,028	31,080,332	45,175,486	442,760	8,086,821	-	2,388,412,854

MONTANA-DAKOTA UTILITIES CO.
INTEGRATED SYSTEM SEASONAL PEAKS AND PEAK MONTH LOAD FACTORS 1/
1960 THROUGH 2008

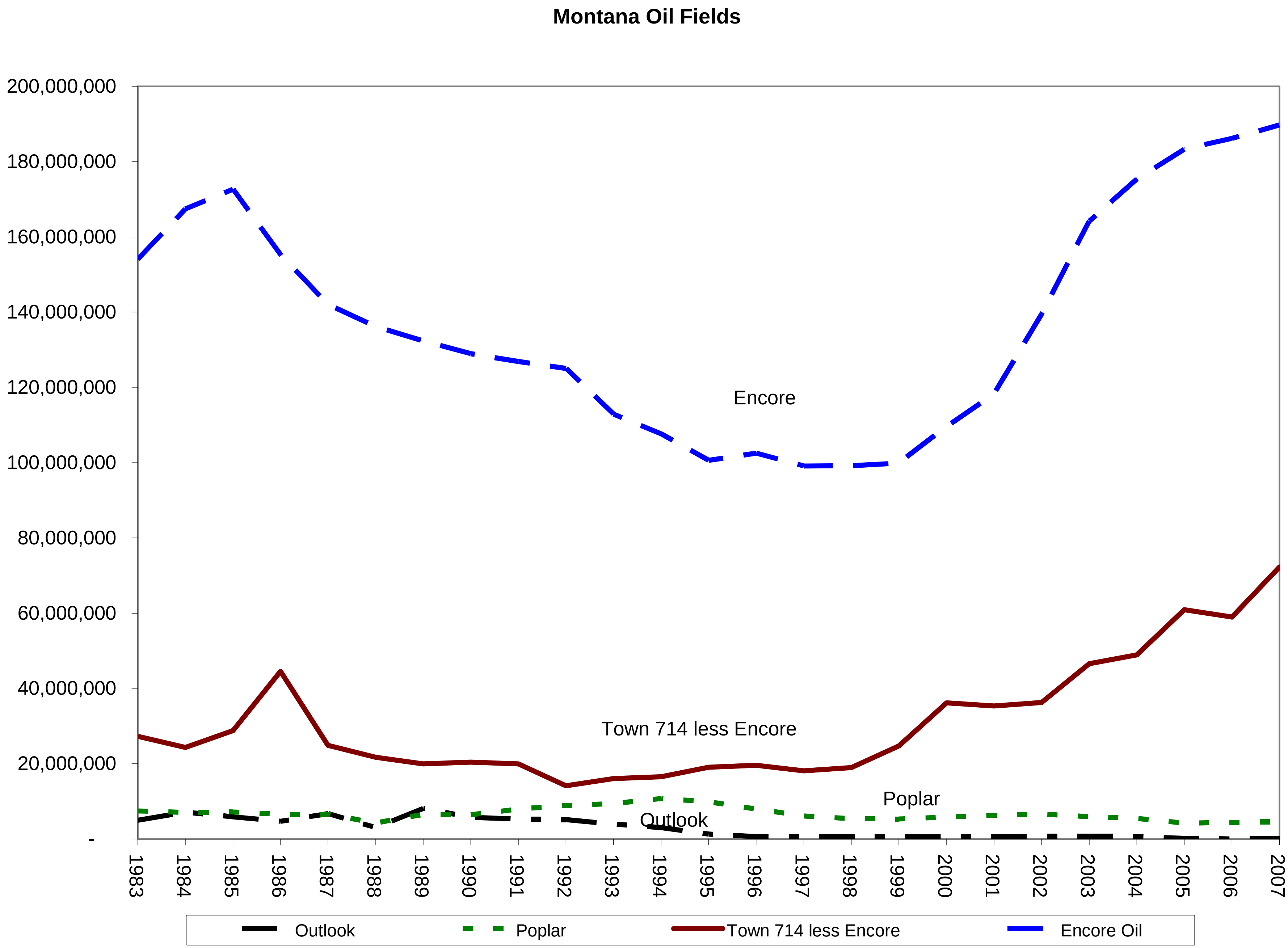
	SUMMER			WINTER			ANNUAL	
YEAR	MW	MONTH	LOAD FACTOR	MW	MONTH 2/	LOAD FACTOR	LOAD FACTOR	PEAK RATIO 3/
1960	76.7	AUG	70.7	109.3	DEC	58.8	50.9	1.425
1961	82.8	AUG	73.7	113.7	JAN	62.0	52.5	1.373
1962	83.8	AUG	76.4	123.2	JAN	65.4	53.7	1.470
1963	95.9	JUL	68.9	127.6	DEC	63.3	52.5	1.331
1964	101.8	AUG	68.2	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
2004	458.4	JUL	60.4	383.4	JAN	76.7	54.9	0.836
2005	459.1	JUL	65.9	387.2	DEC	76.8	57.9	0.843
2006	485.5	JUL	68.3	397.2	NOV	69.3	56.4	0.818
2007	525.6	JUL	66.3	407.3	JAN	80.5	54.5	0.775
2008	476.6	AUG	66.9	455.0	DEC	78.1	62.2	0.955

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.

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

	SUMMER				WINTER			
YEAR	ND	SD	MT	INT SYS	ND	SD	MT	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 *
2004	320.2	28.4	109.8	458.4	258.8	21.9	102.7	383.4 *
2005	311.6	27.7	119.8	459.1	265.0	21.8	100.4	387.2
2006	346.3	29.0	110.1	485.4	272.0	23.8	101.4	397.2
2007	365.8	31.6	128.3	525.7	293.0	25.3	89.0	407.3 *
2008	330.1	27.6	118.9	476.6	309.1	30.3	115.6	455.0

* WINTER PEAK IS IN THE FOLLOWING YEAR.


Montana Oil Fields
200,000,000
180,000,000
160,000,000
140,000,000
120,000,000
100,000,000
80,000,000
60,000,000
40,000,000
20,000,000
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1983
1984
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Encore
Town 714 less Encore
Poplar
Outlook
Outlook
Poplar
Town 714 less Encore
Encore Oil

BILLING CYCLE ALLOCATION FACTORS BY STATE

NORTH DAKOTA

SALES	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Residential	0.106982	0.090932	0.086134	0.076654	0.067447	0.069516	0.087022	0.097438	0.082569	0.069015	0.075353	0.090938
Small C&I	0.094860	0.085861	0.083824	0.077003	0.073493	0.075961	0.087396	0.094282	0.087280	0.074586	0.079065	0.086388
Large C&I	0.087229	0.081033	0.080571	0.078568	0.077748	0.081285	0.089011	0.092352	0.089054	0.081912	0.079698	0.081539
Street Lighting	0.092937	0.086804	0.084748	0.082131	0.079154	0.077514	0.076610	0.079119	0.081054	0.083530	0.086428	0.089971
Other Public Sales	0.084656	0.075336	0.081517	0.071648	0.077430	0.086799	0.100563	0.105268	0.093999	0.075703	0.070571	0.076509
Interdepartmental	0.103050	0.090804	0.090132	0.085745	0.079306	0.074245	0.074407	0.074199	0.075140	0.077718	0.082407	0.092848
Company Use	0.089478	0.082928	0.078557	0.079366	0.077560	0.084412	0.089603	0.096935	0.085154	0.071378	0.085747	0.078883
Tesoro Refinery	0.079128	0.069125	0.079589	0.082711	0.076700	0.092332	0.090820	0.091290	0.090915	0.084078	0.081310	0.082001
Westmoreland Coal	0.106780	0.096619	0.089384	0.089430	0.075415	0.075229	0.063762	0.066100	0.075153	0.082114	0.086710	0.093305
CUSTOMERS												
Residential	0.997344	0.997508	0.997742	0.997858	0.998595	1.000061	1.000692	1.001402	1.001696	1.002145	1.002525	1.002431
Small C&I	0.987148	0.985967	0.986288	0.993343	1.002531	1.008141	1.008726	1.011298	1.009907	1.003574	1.001259	1.001817
Large C&I	0.989996	0.993699	0.995610	0.999791	1.001583	1.000866	1.002061	1.002061	1.002061	1.004808	1.004091	1.003374
Street Lighting	1.002710	1.007145	1.006898	1.009855	1.010840	1.014782	0.982508	0.986943	0.989653	0.993841	0.995565	0.999261
Other Public Sales	0.994061	0.993904	0.995163	1.000983	1.009006	1.009163	1.008849	1.006961	1.003815	0.997994	0.992331	0.987769
PEAK DEMAND	0.6868	0.6787	0.6752	0.7000	0.6899	0.7038	0.6958	0.7018	0.6901	0.6740	0.6954	0.7092

SOUTH DAKOTA

SALES	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Residential	0.108881	0.093139	0.089046	0.079605	0.068883	0.068608	0.084137	0.094841	0.081198	0.067350	0.075021	0.089291
Small C&I	0.095225	0.085360	0.082947	0.076379	0.070404	0.073942	0.087285	0.100201	0.089593	0.074413	0.078462	0.085788
Large C&I	0.088421	0.079730	0.080457	0.078558	0.078257	0.077272	0.081538	0.091578	0.087877	0.086441	0.085074	0.084797
Street Lighting	0.084148	0.083094	0.083781	0.083459	0.083290	0.083443	0.083091	0.083180	0.083239	0.083663	0.083177	0.082435
Other Public Sales	0.083349	0.072680	0.075241	0.075728	0.074903	0.090394	0.104620	0.112020	0.090903	0.081857	0.068091	0.070214
Interdepartmental	0.146150	0.122797	0.104547	0.071352	0.055340	0.049908	0.049066	0.051605	0.058528	0.062347	0.102034	0.126326
Company Use	0.165835	0.161687	0.142129	0.095005	0.053403	0.059429	0.021496	0.047097	0.043050	0.038827	0.063025	0.109017
CUSTOMERS												
Residential	0.996366	0.995874	0.995739	0.997004	1.000419	1.002863	1.006952	1.006093	1.004570	1.001905	0.997520	0.994695
Small C&I	0.976246	0.974599	0.976528	0.992288	1.013600	1.023150	1.023009	1.021786	1.016517	0.999110	0.992335	0.990830
Large C&I	0.998168	0.998168	0.996875	0.998168	1.000754	1.003340	1.000754	0.998168	1.000754	1.002047	1.002047	1.000754
Street Lighting	0.997135	1.006304	1.013181	1.015473	1.017765	1.020057	0.990258	0.992550	0.992550	0.985673	0.983381	0.985673
Other Public Sales	0.943263	0.939593	0.941428	0.979966	1.055207	1.077229	1.084570	1.068053	1.046032	0.976296	0.948769	0.939593
PEAK DEMAND	0.0561	0.0578	0.0596	0.0578	0.0526	0.0543	0.0602	0.0500	0.0617	0.0633	0.0572	0.0554

MONTANA

SALES	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Residential	0.105545	0.089786	0.084390	0.075702	0.067554	0.069436	0.086818	0.103903	0.086052	0.068685	0.073851	0.088278
Small C&I	0.092296	0.085540	0.083281	0.077542	0.074199	0.074167	0.089422	0.100153	0.088848	0.074987	0.075407	0.084159
Large C&I	0.094840	0.083302	0.079923	0.081632	0.075123	0.077897	0.078615	0.082799	0.082551	0.086110	0.080020	0.097187
Street Lighting	0.086688	0.085316	0.083664	0.082433	0.083188	0.082206	0.081379	0.082331	0.082471	0.083066	0.083432	0.083826
Other Public Sales	0.079171	0.071587	0.067292	0.068776	0.073642	0.089062	0.107580	0.122708	0.104358	0.078693	0.068007	0.069125
Interdepartmental	0.108821	0.092742	0.090030	0.083731	0.076963	0.072452	0.073356	0.078712	0.075946	0.073403	0.080165	0.093678
Company Use	0.105179	0.112013	0.097400	0.083938	0.080812	0.064550	0.076322	0.085072	0.074108	0.063496	0.069742	0.087369
Oil Fields	0.090127	0.077579	0.084762	0.080767	0.080614	0.079925	0.081723	0.082518	0.082991	0.086068	0.084820	0.088104
Westmoreland Coal	0.117068	0.109093	0.103353	0.091402	0.079557	0.064531	0.060404	0.059308	0.057631	0.066638	0.084222	0.106793
CUSTOMERS												
Residential	1.001729	1.001528	1.000571	0.997433	0.997786	0.998202	0.998984	0.999471	0.999860	1.000544	1.001841	1.002051
Small C&I	0.982560	0.982335	0.983778	0.993543	1.007075	1.013017	1.015191	1.016447	1.013523	1.002296	0.996373	0.993862
Large C&I	0.979606	0.980969	0.982673	0.989831	1.006874	1.015054	1.020508	1.022212	1.013691	1.003124	0.994944	0.990513
Street Lighting	1.056008	1.060039	1.044924	1.044924	1.042909	1.038878	0.947183	0.951213	0.952221	0.952221	0.953229	0.956252
Other Public Sales	0.965198	0.961866	0.971862	0.995187	1.030729	1.036283	1.036283	1.034061	1.012958	0.996298	0.984080	0.975194
PEAK DEMAND	0.2571	0.2635	0.2652	0.2422	0.2575	0.2419	0.2440	0.2482	0.2482	0.2627	0.2474	0.2354

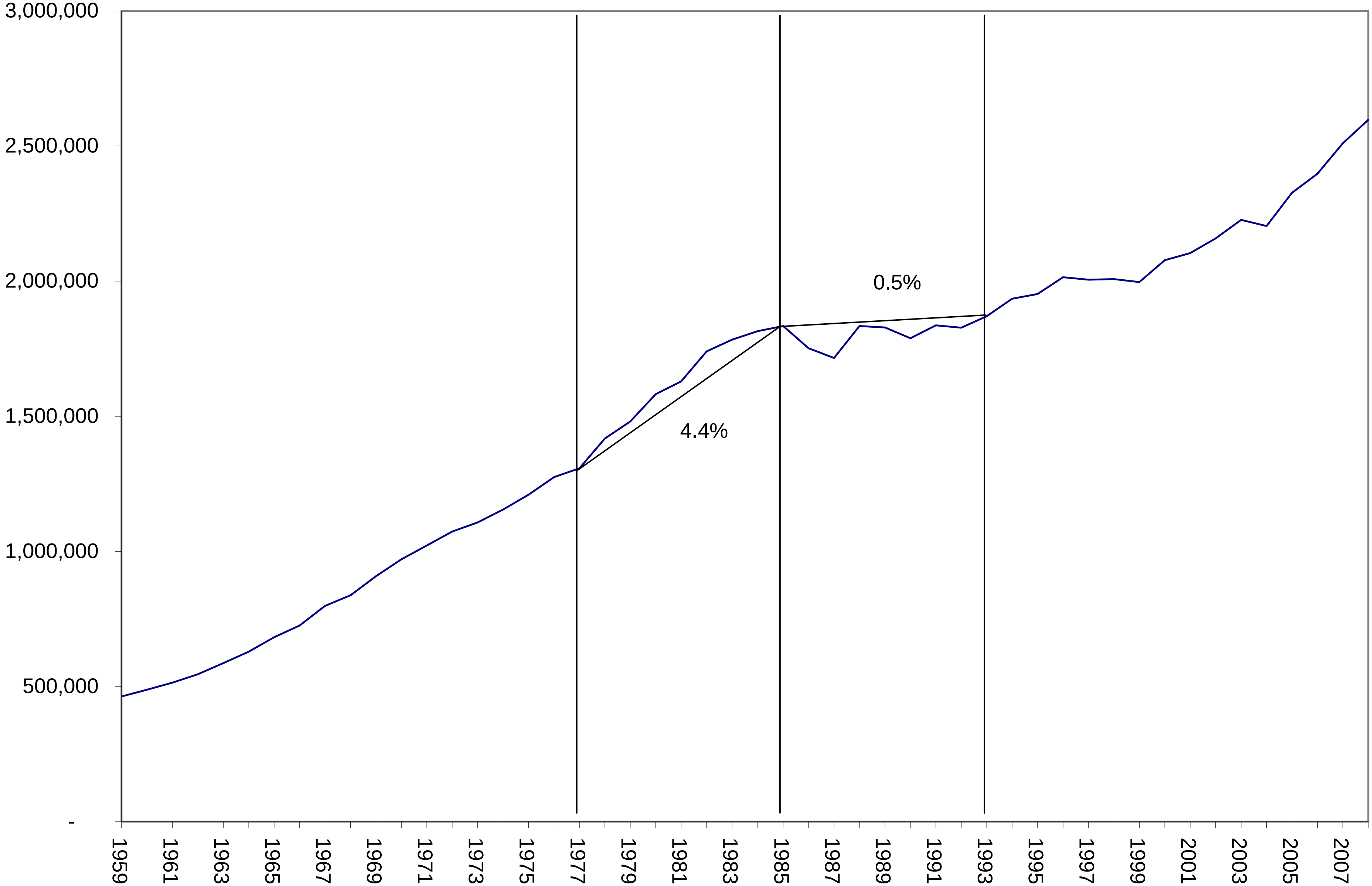
BILLING-MONTH TO CALENDAR-MONTH APPORTIONMENT FACTORS

Residential	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**
North Dakota	49.4%	47.0%	48.2%	47.7%	49.0%	49.8%	44.2%	50.8%	48.2%	48.3%	48.2%	49.2%
South Dakota	50.7%	50.9%	50.7%	52.2%	52.5%	53.4%	48.2%	54.1%	49.7%	50.9%	50.8%	51.7%
Montana	53.8%	51.8%	52.6%	52.2%	53.9%	55.3%	48.1%	56.8%	51.5%	52.8%	52.9%	52.7%
Small Commercial & Industrial												
North Dakota	48.0%	45.4%	43.3%	46.1%	47.4%	48.8%	44.0%	48.1%	46.1%	46.3%	47.7%	49.0%
South Dakota	52.0%	51.2%	52.4%	51.2%	51.9%	52.2%	46.4%	54.8%	48.7%	51.8%	52.4%	53.2%
Montana	50.9%	49.3%	49.9%	49.6%	48.7%	55.1%	46.3%	53.2%	48.4%	49.9%	49.5%	49.1%
Large Commercial & Industrial												
North Dakota	46.1%	42.8%	43.3%	43.1%	44.9%	45.7%	41.9%	44.2%	44.0%	43.3%	44.8%	46.4%
South Dakota	59.5%	56.5%	62.7%	61.7%	62.0%	63.6%	54.6%	68.0%	53.6%	62.4%	59.6%	57.4%
Montana	38.3%	30.2%	30.1%	26.0%	26.6%	29.0%	27.4%	29.9%	27.3%	26.9%	30.2%	34.0%
Street Lighting												
North Dakota	40.8%	39.4%	36.9%	37.9%	38.2%	40.0%	36.6%	38.1%	37.7%	37.7%	39.3%	41.5%
South Dakota	43.3%	44.9%	40.8%	42.7%	43.4%	44.4%	42.5%	42.6%	43.3%	42.7%	45.0%	45.8%
Montana	44.2%	44.7%	37.8%	40.8%	39.5%	43.2%	39.7%	38.9%	41.2%	39.8%	43.8%	43.2%
Other Public Sales												
North Dakota	45.5%	44.3%	42.1%	43.7%	43.3%	45.2%	42.5%	44.2%	43.8%	43.1%	46.1%	46.7%
South Dakota	65.8%	57.3%	73.0%	66.8%	64.2%	65.9%	55.9%	71.6%	54.0%	71.3%	61.8%	60.1%
Montana	52.2%	46.2%	52.6%	50.1%	51.3%	51.4%	44.5%	53.5%	45.9%	52.2%	52.8%	50.0%
Interdepartmental												
North Dakota	52.4%	48.4%	51.5%	49.0%	50.8%	52.5%	45.1%	52.9%	49.0%	50.0%	51.7%	48.9%
South Dakota	13.7%	12.8%	10.2%	10.8%	22.2%	13.6%	12.9%	12.7%	13.2%	13.4%	31.5%	12.5%
Montana	46.1%	43.2%	45.3%	44.9%	46.9%	46.6%	40.0%	52.6%	42.2%	45.6%	42.4%	39.4%
Company Use												
North Dakota	42.4%	38.8%	35.8%	35.2%	37.4%	38.0%	35.4%	35.8%	36.1%	37.4%	39.6%	41.9%
South Dakota	66.0%	70.3%	64.4%	67.6%	67.7%	68.2%	67.2%	66.3%	68.2%	66.6%	69.9%	70.8%
Montana	58.7%	58.0%	58.0%	60.8%	56.9%	59.5%	53.8%	57.5%	55.7%	56.4%	57.5%	60.9%

Integrated System
Historical Energy Requirements

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%
2004	2,204,012	-1.01%
2005	2,327,117	5.59%
2006	2,397,793	3.04%
2007	2,510,540	4.70%
2008	2,596,990	3.44%

Total Energy Requirements



APPENDIX B

Integrated System
Historical and Forecasted Exogenous Variables

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	7.387	7.372	5.276
2005	7.250	7.190	5.193
2006	7.500	7.351	5.396
2007	7.879	7.672	5.701
2008	7.792	7.598	5.734
2009	8.068	7.762	5.878
2010	8.386	7.980	6.124
2011	8.591	8.193	6.315
2012	9.251	8.877	6.982
2013	9.484	9.098	7.157
2014	9.719	9.328	7.332
2015	9.964	9.560	7.513
2016	10.208	9.801	7.704
2017	10.471	10.041	7.895
2018	10.821	10.357	8.181
2019	11.182	10.683	8.477
2020	11.555	11.019	8.784
2021	11.941	11.366	9.102
2022	12.340	11.724	9.431
2023	12.752	12.093	9.772
2024	13.178	12.473	10.125
2025	13.618	12.865	10.491
2026	14.073	13.270	10.870
2027	14.543	13.687	11.263
2028	15.028	14.118	11.670

SOURCES:
1967-2007: Historical prices calculated from Montana-Dakota Utilities Co., *Electric Operating Revenues Reports*
2008-2028: Forecasted prices

INTEGRATED SYSTEM NATURAL GAS PRICES
Historical and Forecasted Prices
$/Dk

YEAR	RESIDENTIAL PRICE	FIRM GENERAL
1979	$2.460	$2.140
1980	3.170	2.740
1981	3.560	3.100
1982	3.950	3.560
1983	5.070	4.700
1984	6.090	5.790
1985	5.160	4.870
1986	4.650	4.670
1987	5.290	4.890
1988	4.870	4.520
1989	4.400	4.060
1990	4.460	4.070
1991	4.570	4.200
1992	4.840	4.460
1993	5.050	4.690
1994	4.860	4.430
1995	4.380	3.910
1996	4.130	3.710
1997	4.540	4.090
1998	4.850	4.300
1999	5.080	4.540
2000	5.920	5.390
2001	7.420	6.870
2002	4.570	4.030
2003	6.830	6.290
2004	8.560	7.970
2005	10.490	9.840
2006	9.870	9.150
2007	7.780	7.090
2008	9.560	8.970
2009	10.517	9.886
2010	9.525	8.889
2011	10.166	9.525
2012	10.820	10.176
2013	11.200	10.556
2014	11.322	10.678
2015	11.401	10.757
2016	11.525	10.881
2017	11.606	10.962
2018	11.733	11.089
2019	11.990	11.342
2020	12.253	11.601
2021	12.522	11.866
2022	12.797	12.137
2023	13.078	12.414
2024	13.365	12.697
2025	13.658	12.987
2026	13.957	13.283
2027	14.263	13.586
2028	14.576	13.896

SOURCES:
1979-2007: CSBEPFL Rate Reporting Class Report
Gas Year-to-Date Report for Year-end
2008-2028: Forecasted prices

BISMARCK, NORTH DAKOTA
HEATING DEGREE DAYS (HDD)
AND
COOLING DEGREE DAYS(CDD)
(ANNUAL)

	HDD	CDD
1970	9,481	545
1971	9,280	423
1972	9,560	461
1973	8,516	411
1974	9,194	409
1975	9,039	433
1976	8,434	663
1977	8,636	367
1978	9,595	475
1979	9,998	365
1980	8,352	502
1981	7,685	441
1982	9,761	394
1983	8,706	658
1984	8,830	501
1985	9,590	297
1986	8,154	374
1987	7,314	532
1988	8,525	860
1989	9,086	672
1990	8,061	611
1991	8,052	709
1992	8,162	255
1993	9,144	217
1994	8,866	432
1995	9,027	522
1996	10,027	480
1997	8,450	609
1998	7,765	633
1999	7,710	457
2000	8,412	549
2001	8,039	668
2002	8,532	745
2003	8,493	737
2004	8,183	379
2005	7,792	555
2006	7,525	793
2007	8,345	666
NORMAL	8,802	471

Personal Income per Capita
Integrated System

Year	2004 $s
1969	13,149
1970	13,399
1971	14,025
1972	16,623
1973	21,449
1974	19,167
1975	18,372
1976	16,871
1977	16,734
1978	19,072
1979	18,628
1980	17,298
1981	20,656
1982	20,243
1983	19,792
1984	20,182
1985	19,219
1986	19,574
1987	19,493
1988	17,875
1989	19,390
1990	20,097
1991	20,057
1992	21,415
1993	21,786
1994	21,500
1995	21,222
1996	22,729
1997	22,267
1998	24,201
1999	24,357
2000	25,551
2001	26,249
2002	25,270
2003	27,731
2004	28,117
2005	29,359
2006	29,468
2007	29,748
2008	30,112
2009	30,489
2010	30,879
2011	31,273
2012	31,669
2013	32,067
2014	32,482
2015	32,894
2016	33,317
2017	33,745
2018	34,183
2019	34,638
2020	35,098
2021	35,566
2022	36,038
2023	36,513
2024	37,002
2025	37,495
2026	37,996
2027	38,498
2028	39,010

SOURCES:
1969-2005 U.S. Dept. of Commerce
2006-2028 Woods & Poole Economics

PERSONAL CONSUMPTION EXPENDITURE DEFLATOR

Year	Personal Consumption Expenditure Deflator (2004=100)	Inflation Rate
1969	23.30	--
1970	24.40	4.7%
1971	25.44	4.3%
1972	26.32	3.5%
1973	27.76	5.5%
1974	30.63	10.3%
1975	33.18	8.3%
1976	35.02	5.5%
1977	37.29	6.5%
1978	39.91	7.0%
1979	43.42	8.8%
1980	48.05	10.7%
1981	52.34	8.9%
1982	55.23	5.5%
1983	57.61	4.3%
1984	59.79	3.8%
1985	61.76	3.3%
1986	63.27	2.4%
1987	65.47	3.5%
1988	68.06	4.0%
1989	71.03	4.4%
1990	74.28	4.6%
1991	76.97	3.6%
1992	79.19	2.9%
1993	81.02	2.3%
1994	82.73	2.1%
1995	84.50	2.1%
1996	86.32	2.2%
1997	87.77	1.7%
1998	88.56	0.9%
1999	90.04	1.7%
2000	92.27	2.5%
2001	94.21	2.1%
2002	95.54	1.4%
2003	97.44	2.0%
2004	100.00	2.6%
2005	102.88	2.9%
2006	105.71	2.8%
2007	108.69	2.8%
2008	111.78	2.8%
2009	115.00	2.9%
2010	118.35	2.9%
2011	121.85	3.0%
2012	125.52	3.0%
2013	129.36	3.1%
2014	133.38	3.1%
2015	137.60	3.2%
2016	142.02	3.2%
2017	146.65	3.3%
2018	151.50	3.3%
2019	156.59	3.4%
2020	161.93	3.4%
2021	167.53	3.5%
2022	173.41	3.5%
2023	179.59	3.6%
2024	186.07	3.6%
2025	192.88	3.7%
2026	199.94	3.7%
2027	207.26	3.7%
2028	214.84	3.7%

SOURCES:
1969-2006 U.S. Department of Commerce
2007-2028 Woods & Poole Economics, Inc.

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	-0.86%	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	116,921	0.41%	84,914	-0.02%
2001	116,203	-0.61%	84,866	-0.06%
2002	115,823	-0.33%	85,012	0.17%
2003	115,875	0.04%	85,278	0.31%
2004	116,210	0.29%	85,498	0.26%
2005	116,683	0.41%	85,791	0.34%
2006	117,347	0.57%	86,150	0.42%
2007	118,639	1.10%	86,575	0.49%
2008	119,626	0.83%	86,993	0.48%
2009	120,586	0.80%	87,399	0.47%
2010	121,546	0.80%	87,803	0.46%
2011	122,518	0.80%	88,210	0.46%
2012	123,502	0.80%	88,622	0.47%
2013	124,485	0.80%	89,031	0.46%
2014	125,412	0.74%	89,416	0.43%
2015	126,356	0.75%	89,807	0.44%
2016	127,267	0.72%	90,183	0.42%
2017	128,162	0.70%	90,551	0.41%
2018	129,024	0.67%	90,905	0.39%
2019	129,835	0.63%	91,237	0.37%
2020	130,642	0.62%	91,566	0.36%
2021	131,431	0.60%	91,887	0.35%
2022	132,218	0.60%	92,207	0.35%
2023	132,991	0.58%	92,520	0.34%
2024	133,726	0.55%	92,817	0.32%
2025	134,454	0.54%	93,110	0.32%
2026	135,155	0.52%	93,392	0.30%
2027	135,863	0.52%	93,676	0.30%
2028	136,547	0.50%	93,950	0.29%

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

SOURCES:
Households
1970, 1980, 1985, 1990, 2000: U.S. Department of Commerce
All other years: Estimated and projected by Woods & Poole
Customers
1971-2007: Actuals from Montana-Dakota Utilities Co. Electric Operating Revenues Reports
2008-2028: Montana-Dakota forecast

GROSS DOMESTIC PRODUCT DEFLATOR

Year	GDP Deflator (2000=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	104.2	1.8%
2003	106.4	2.1%
2004	109.5	2.9%
2005	113.0	3.2%
2006	116.6	3.2%
2007	119.7	2.7%
2008	121.5	1.5%
2009	123.7	1.8%
2010	127.2	2.8%
2011	130.6	2.7%
2012	133.7	2.4%
2013	136.7	2.2%
2014	139.8	2.3%
2015	142.9	2.2%
2016	146.1	2.2%
2017	149.4	2.3%
2018	152.7	2.2%
2019	156.1	2.2%
2020	159.6	2.2%
2021	163.2	2.3%
2022	166.9	2.3%
2023	170.6	2.2%
2024	174.4	2.2%
2025	178.3	2.2%
2026	182.3	2.2%
2027	186.4	2.2%
2028	190.6	2.3%

SOURCES:
1969-2007 Actuals - U.S. Department of Commerce
2008-2012 GDP forecasted by The Conference Board
2013-2028 Estimates based on the 2008-2012 average yearly growth in GDP forecasted by The Conference Board.

INTEGRATED SYSTEM
EMPLOYMENT DATA
TOTAL EMPLOYMENT LESS FARM AND MINING EMPLOYMENT

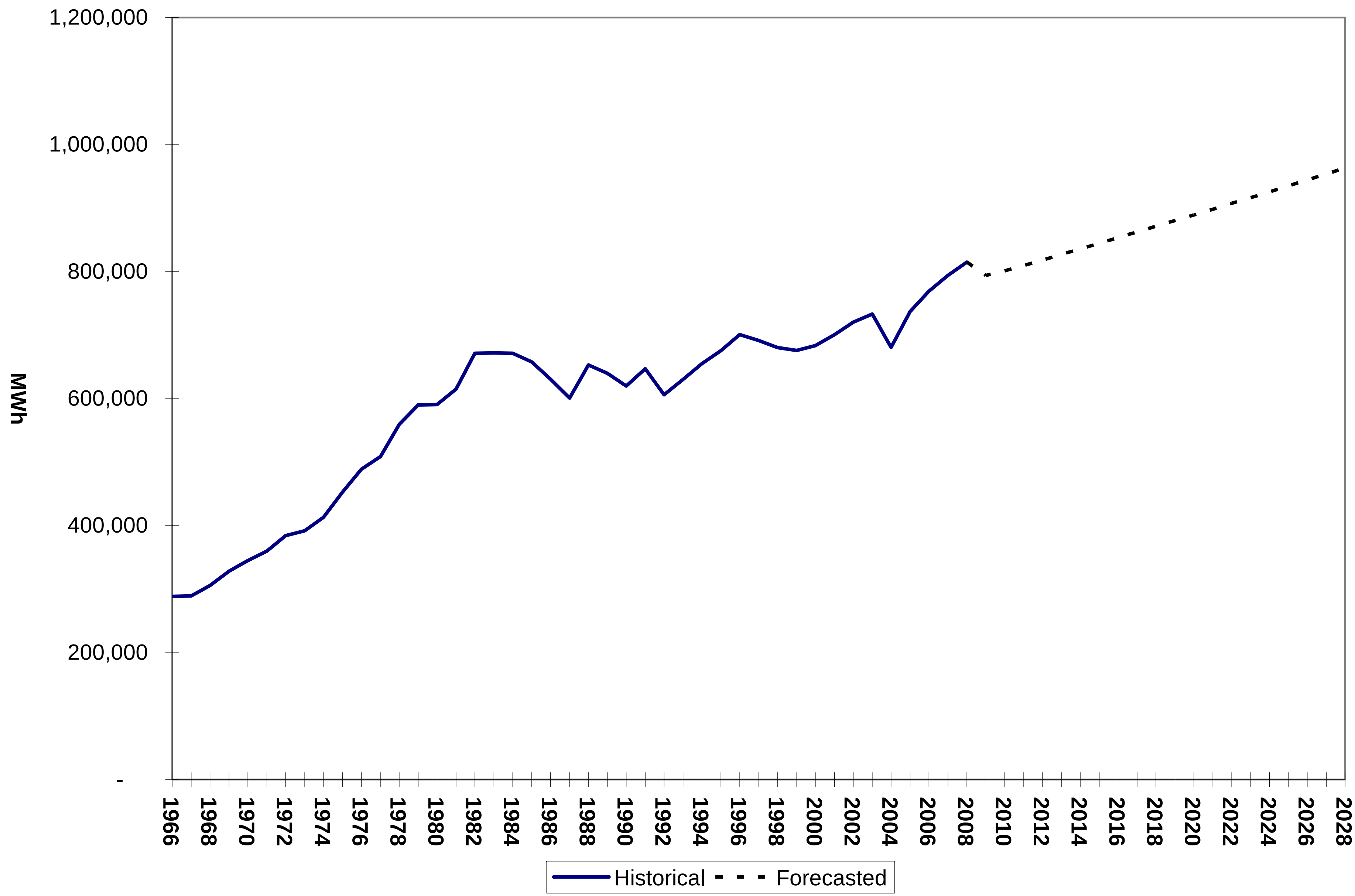
YEAR	NUMBER OF EMPLOYEES	GROWTH RATE	ADJUSTED EMPLOYMENT	GROWTH RATE
1969	93,205			
1970	94,447	1.33%		
1971	94,687	0.25%		
1972	97,706	3.19%		
1973	102,813	5.23%		
1974	106,581	3.66%		
1975	110,848	4.00%		
1976	115,446	4.15%		
1977	119,047	3.12%		
1978	125,818	5.69%		
1979	131,715	4.69%		
1980	136,239	3.43%		
1981	139,688	2.53%		
1982	144,872	3.71%		
1983	145,173	0.21%		
1984	142,357	-1.94%		
1985	138,452	-2.74%		
1986	134,123	-3.13%		
1987	133,468	-0.49%		
1988	134,029	0.42%		
1989	136,189	1.61%		
1990	138,420	1.64%		
1991	140,936	1.82%		
1992	142,003	0.76%		
1993	145,517	2.47%		
1994	152,664	4.91%		
1995	152,837	0.11%		
1996	155,126	1.50%		
1997	157,054	1.24%		
1998	160,783	2.37%		
1999	162,704	1.19%		
2000	165,058	1.45%		
2001	164,936	-0.07%		
2002	166,618	1.02%		
2003	167,629	0.61%		
2004	171,561	2.35%		
2005	175,635	2.37%		
2006	178,161	1.44%		
2007	180,684	1.42%		
2008	183,194	1.39%	184,948	2.36%
2009	185,711	1.37%	189,313	2.36%
2010	188,214	1.35%	193,781	2.36%
2011	190,727	1.34%	198,354	2.36%
2012	193,218	1.31%	203,035	2.36%
2013	195,725	1.30%	205,979	1.45%
2014	198,214	1.27%	208,966	1.45%
2015	200,728	1.27%	211,996	1.45%
2016	203,227	1.24%	215,070	1.45%
2017	205,724	1.23%	218,189	1.45%
2018	208,230	1.22%	221,353	1.45%
2019	210,725	1.20%	224,563	1.45%
2020	213,220	1.18%	227,819	1.45%
2021	215,711	1.17%	231,122	1.45%
2022	218,221	1.16%	234,473	1.45%
2023	220,708	1.14%	237,873	1.45%
2024	223,203	1.13%	241,322	1.45%
2025	225,705	1.12%	244,821	1.45%
2026	228,197	1.10%	248,371	1.45%
2027	230,696	1.10%	251,972	1.45%
2028	233,182	1.08%	255,626	1.45%

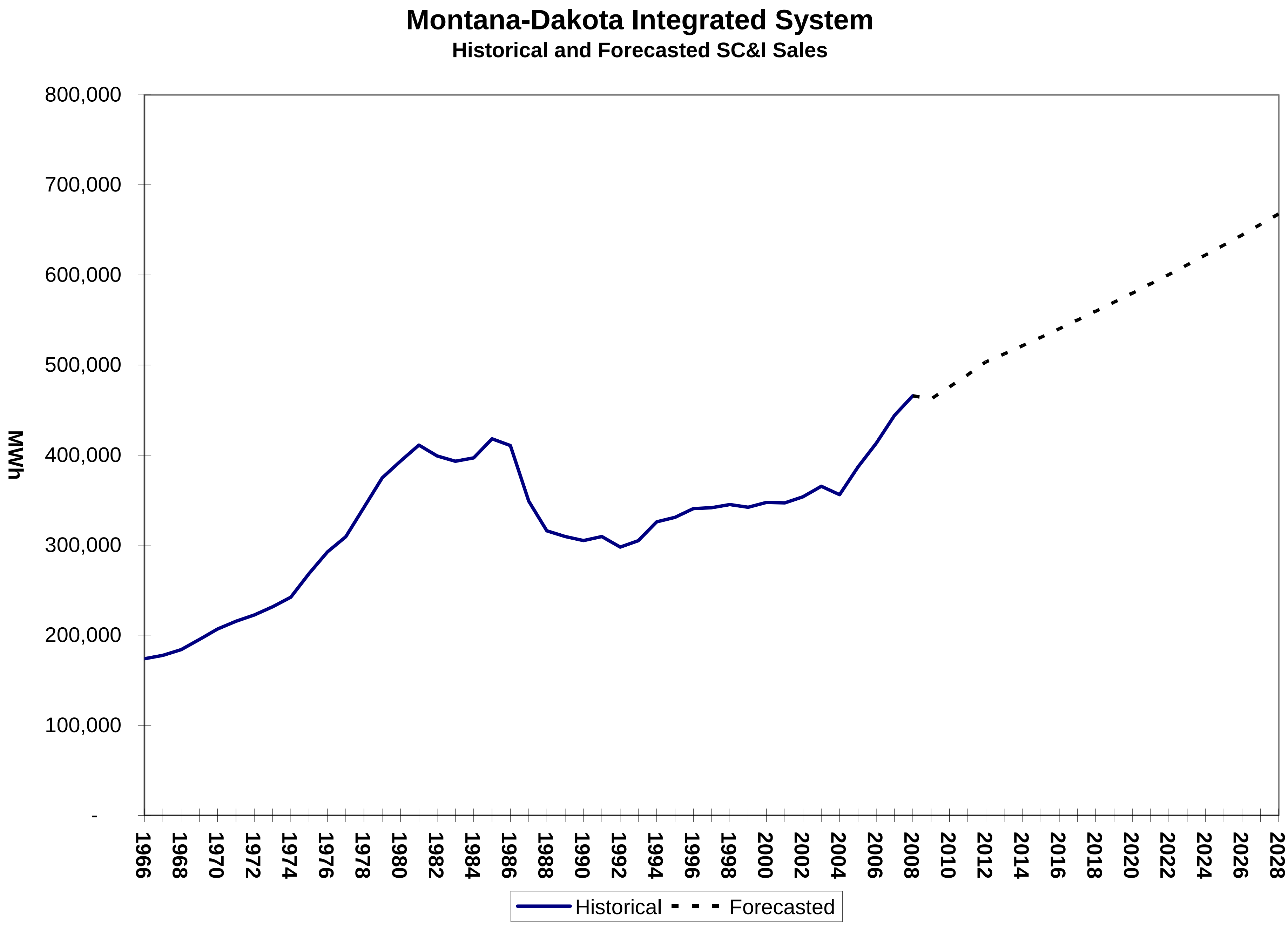
SOURCES:
Number of Employees
1969-2005: U.S. Department of Commerce
2006-2028: Woods & Poole Economics Inc.
Adjusted Employment
2008-2012: Employment growth set to 2-year actual historical growth for 2003-2005 (2.36%)
2013-2028: Employment growth set to 20-year actual historical log-linear growth for 1985-2005 (1.45%)

NOTE: The number of employees used for the forecast is the total employment less farming employment and mining employment (most farms are not served by Montana-Dakota and the mining sector is forecasted separately (oil fields and coal mining)).

APPENDIX C
Integrated System
Forecast Results

Montana-Dakota Integrated System
Historical and Forecasted Residential Sales

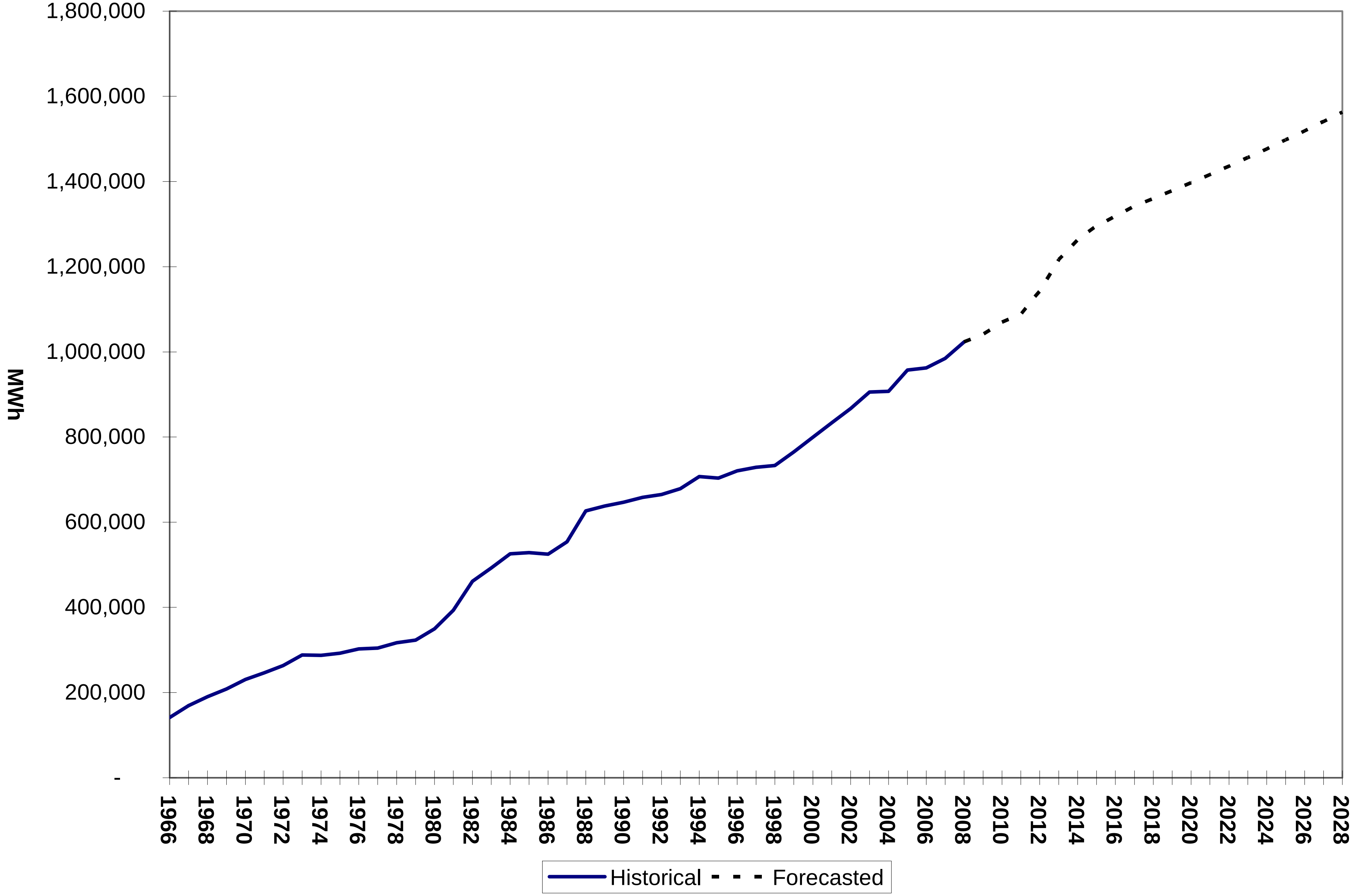


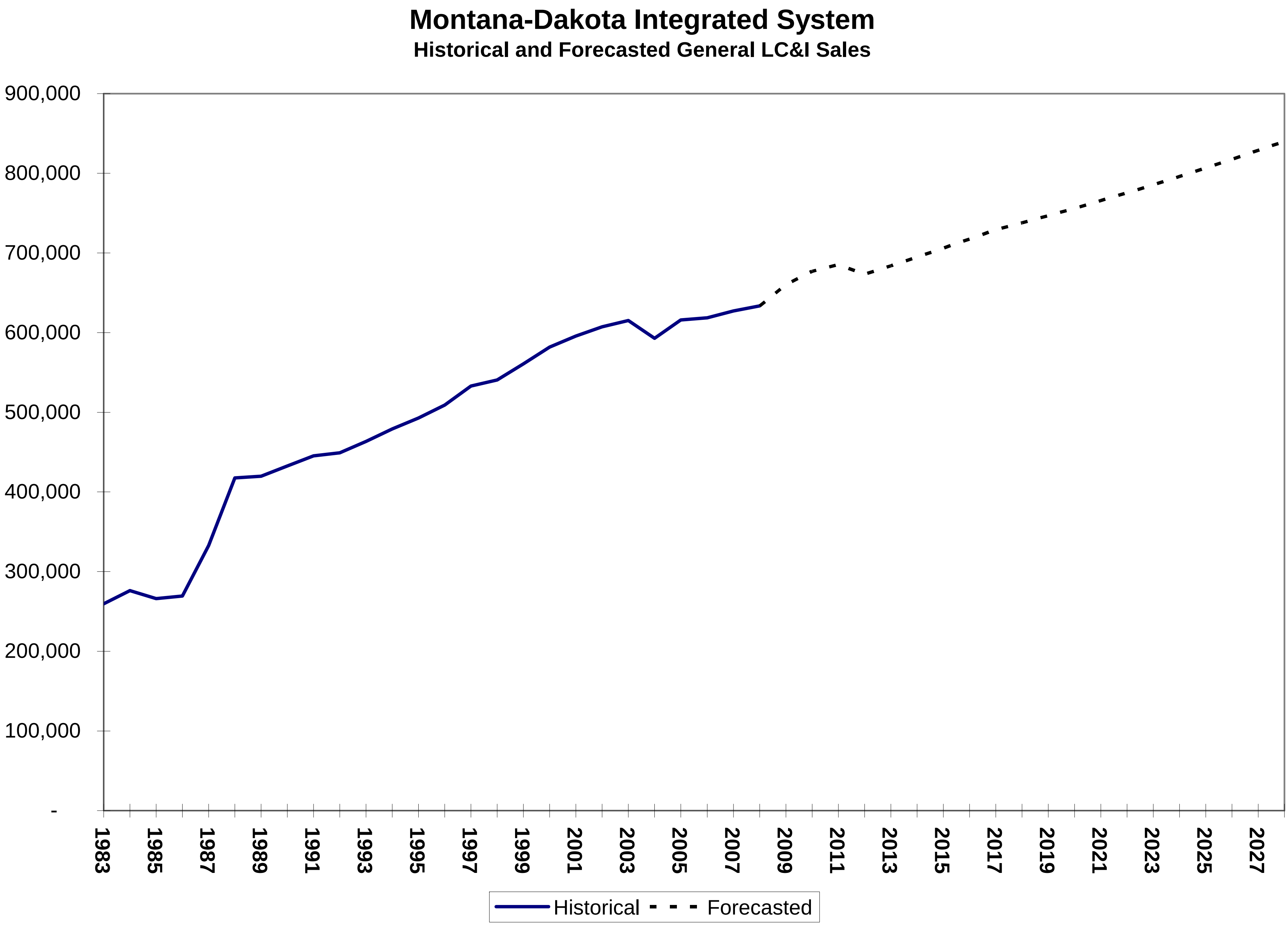


Montana-Dakota Integrated System
Historical and Forecasted SC&I Sales
MWh
800,000
700,000
600,000
500,000
400,000
300,000
200,000
100,000
-
1966
1968
1970
1972
1974
1976
1978
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
Historical
Forecasted

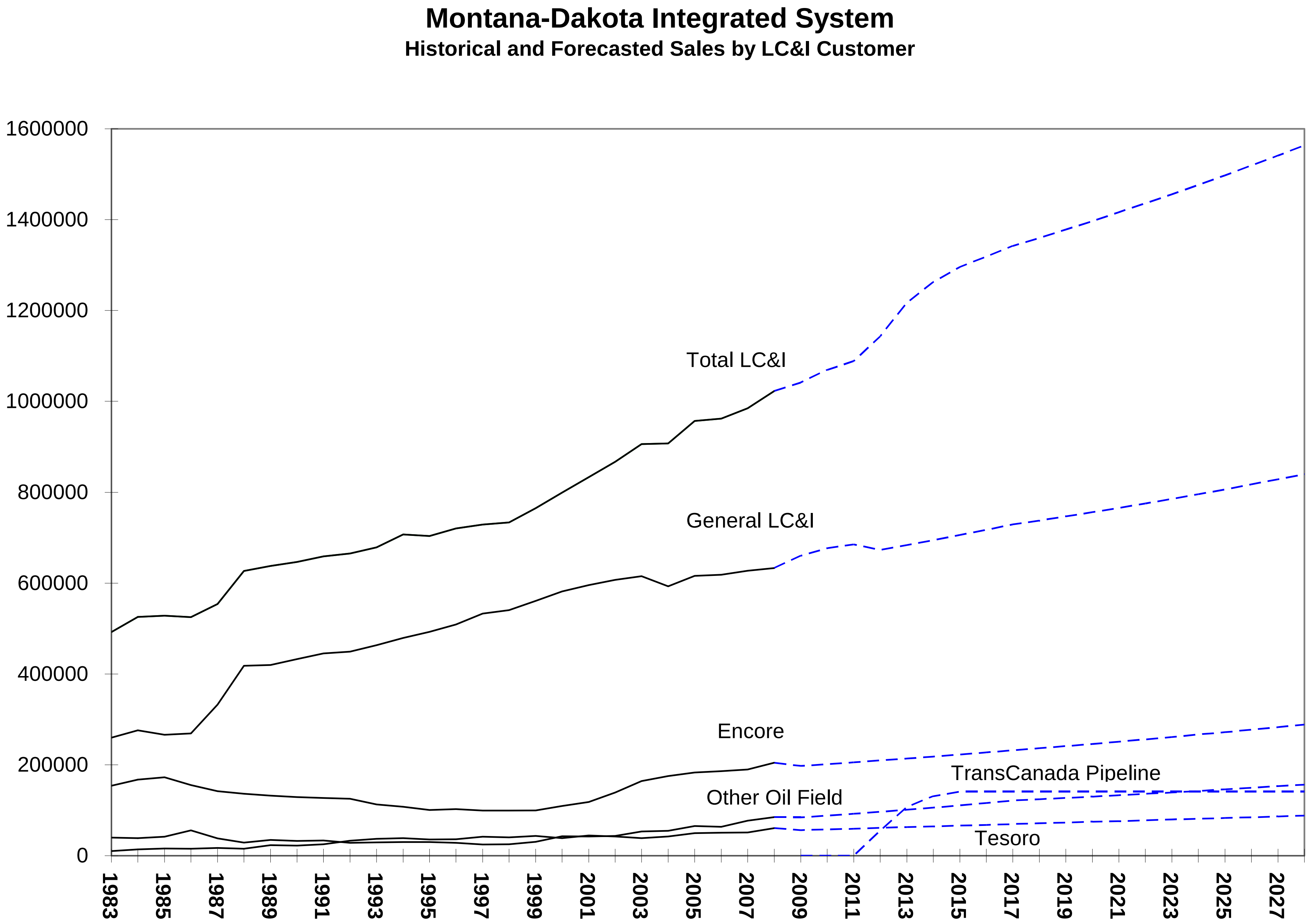
Montana-Dakota Integrated System

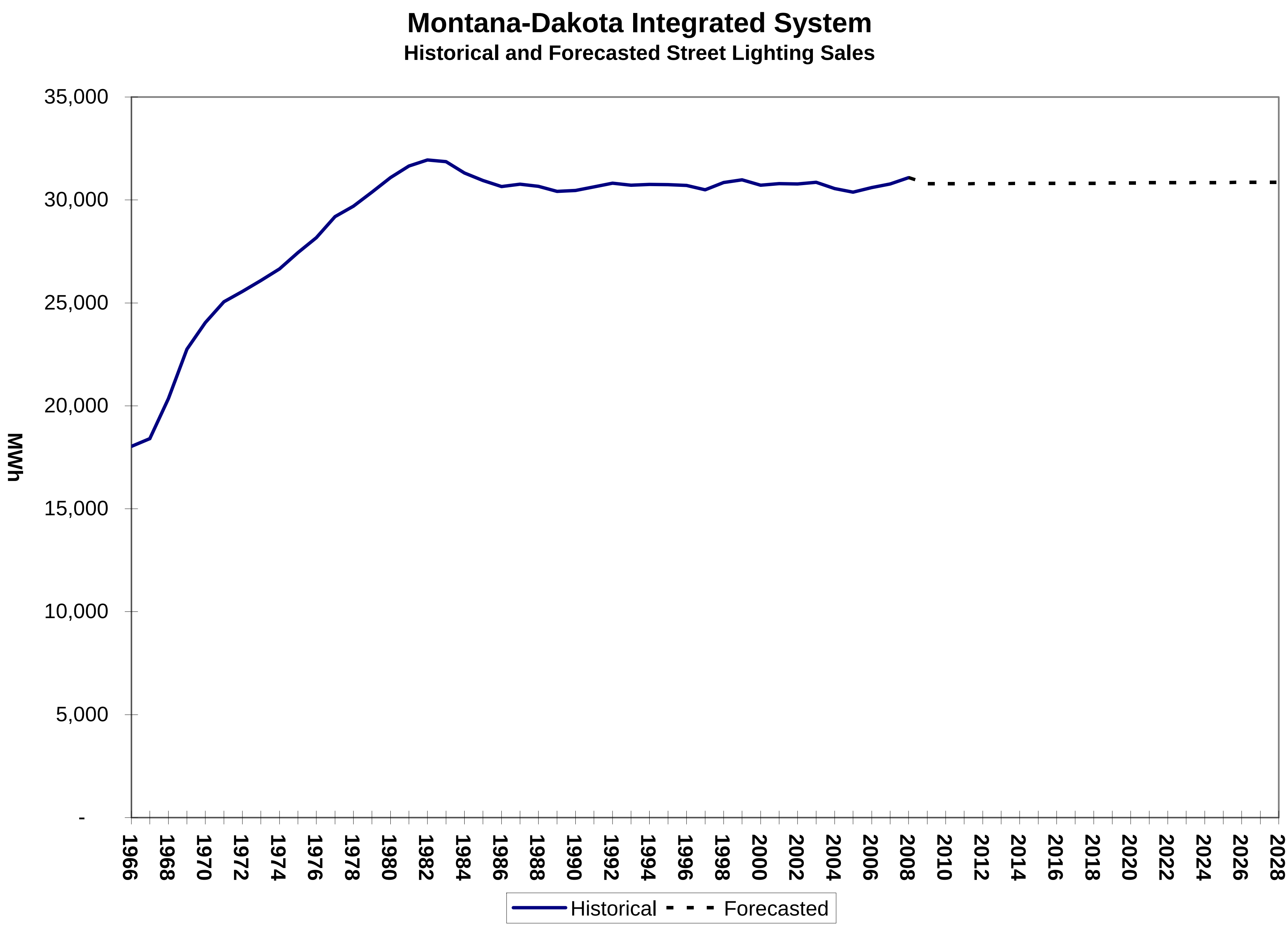
Historical and Forecasted LC&I Sales

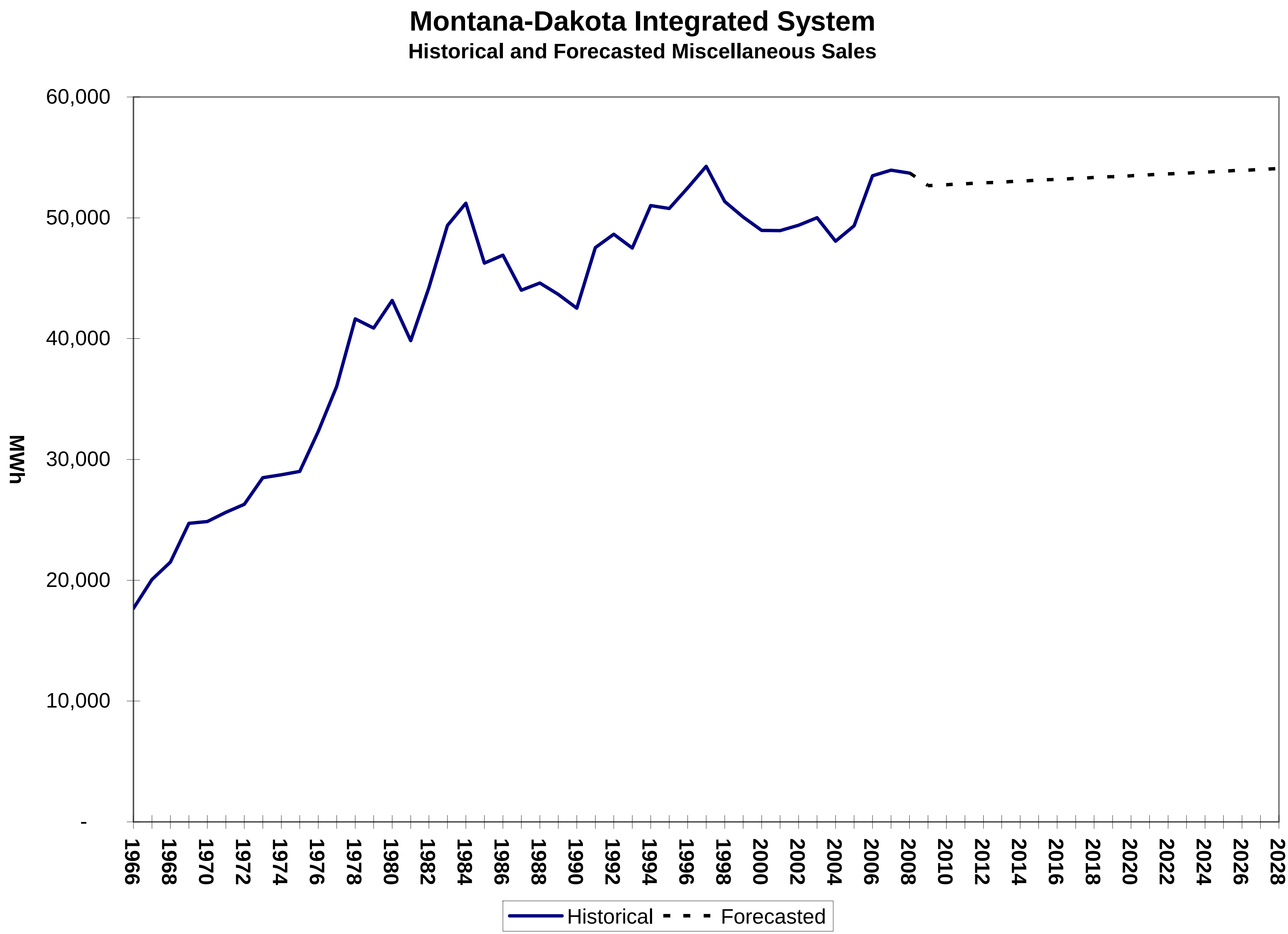


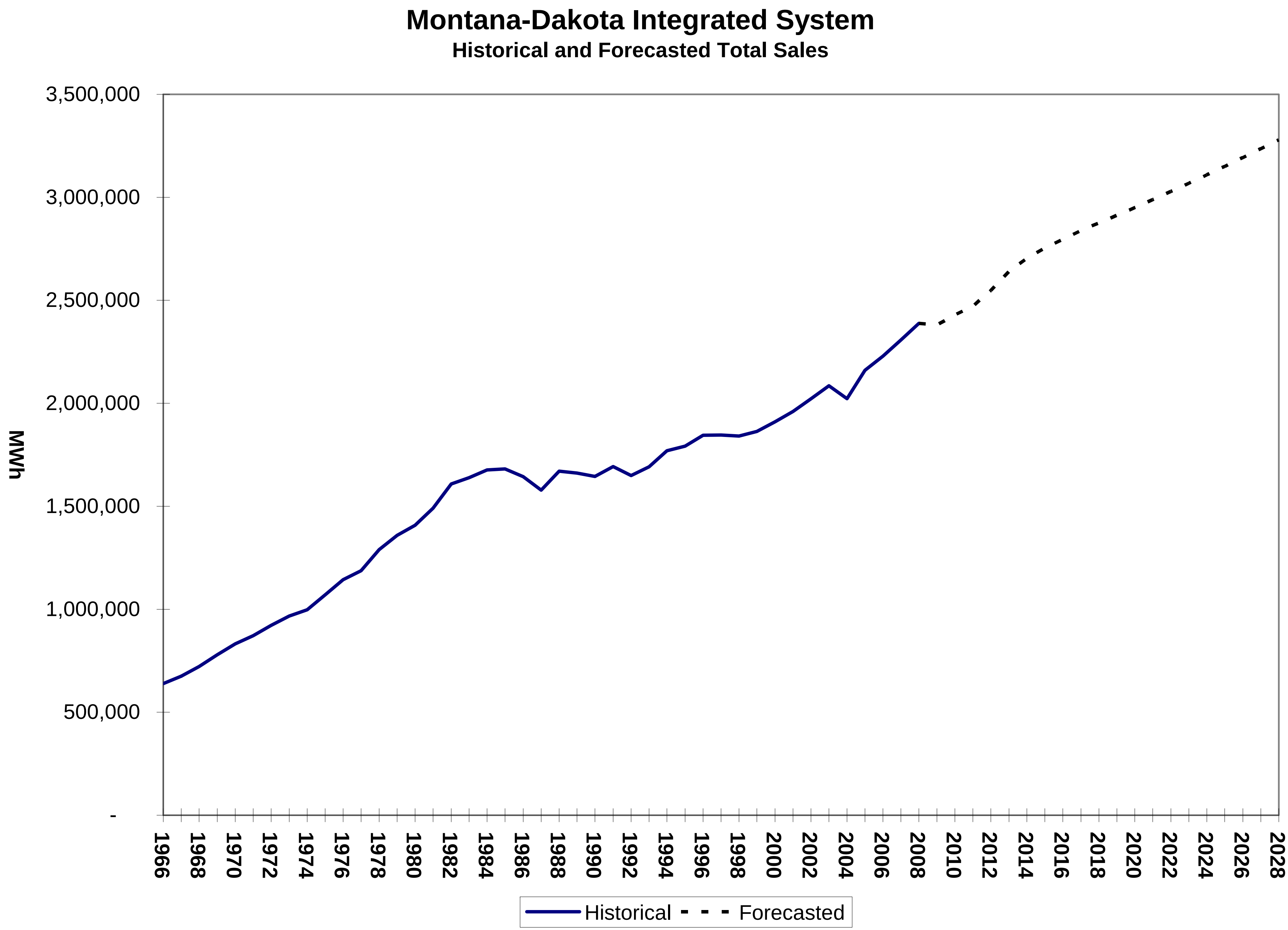


Montana-Dakota Integrated System
Historical and Forecasted General LC&I Sales
900,000
800,000
700,000
600,000
500,000
400,000
300,000
200,000
100,000
-
1983
1985
1987
1989
1991
1993
1995
1997
1999
2001
2003
2005
2007
2009
2011
2013
2015
2017
2019
2021
2023
2025
2027
Historical
Forecasted


Montana-Dakota Integrated System
Historical and Forecasted Sales by LC&I Customer
1600000
1400000
1200000
1000000
800000
600000
400000
200000
0
Total LC&I
General LC&I
Encore
TransCanada Pipeline
Other Oil Field
Tesoro
1983
1985
1987
1989
1991
1993
1995
1997
1999
2001
2003
2005
2007
2009
2011
2013
2015
2017
2019
2021
2023
2025
2027


Montana-Dakota Integrated System
Historical and Forecasted Street Lighting Sales
MWh
35,000
30,000
25,000
20,000
15,000
10,000
5,000
-
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
2026
2028
Historical
Forecasted


Montana-Dakota Integrated System
Historical and Forecasted Miscellaneous Sales
MWh
60,000
50,000
40,000
30,000
20,000
10,000
-
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
2026
2028
Historical
Forecasted


Montana-Dakota Integrated System
Historical and Forecasted Total Sales
MWh
3,500,000
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
2026
2028
Historical
Forecasted

MONTANA-DAKOTA UTILITIES CO.
FORECASTED ENERGY (GWh) AND SEASONAL DEMANDS (MW)
MONTANA

YEAR	SUMMER PEAK (MW)	SUMMER PEAK % CHG	SUMMER PEAK NET OF INT LOADS (MW)	SUMMER PEAK NET OF INT LOADS % CHG	WINTER PEAK (MW)	WINTER PEAK % CHG	ANNUAL ENERGY REQUIREMENTS (GWh)	ANNUAL ENERGY REQUIREMENTS % CHG	LOAD FACTOR (%) 1/
2009	122.0		122.0		94.2		758.4		70.77%
2010	122.7	0.57%	122.7	0.57%	94.7	0.53%	775.5	2.25%	72.15%
2011	124.3	1.30%	124.3	1.30%	95.9	1.27%	791.5	2.06%	72.69%
2012	141.9	14.16%	141.9	14.16%	113.1	17.94%	863.6	9.11%	69.47%
2013	147.6	4.02%	147.6	4.02%	118.4	4.69%	935.7	8.35%	72.17%
2014	153.8	4.20%	153.8	4.20%	124.2	4.90%	977.5	4.47%	72.55%
2015	155.8	1.30%	155.8	1.30%	125.8	1.29%	1,005.3	2.84%	73.66%
2016	157.9	1.35%	157.9	1.35%	127.3	1.19%	1,022.6	1.72%	73.93%
2017	160.0	1.33%	160.0	1.33%	128.9	1.26%	1,040.3	1.73%	74.02%
2018	161.9	1.19%	161.9	1.19%	130.4	1.16%	1,054.8	1.39%	74.37%
2019	163.8	1.17%	163.8	1.17%	131.9	1.15%	1,069.6	1.40%	74.54%
2020	165.8	1.22%	165.8	1.22%	133.4	1.14%	1,084.7	1.41%	74.68%
2021	167.8	1.21%	167.8	1.21%	135.0	1.20%	1,100.1	1.42%	74.64%
2022	169.9	1.25%	169.9	1.25%	136.6	1.19%	1,115.8	1.43%	74.97%
2023	171.9	1.18%	171.9	1.18%	138.2	1.17%	1,131.8	1.43%	75.16%
2024	174.0	1.22%	174.0	1.22%	139.8	1.16%	1,148.1	1.44%	75.32%
2025	176.2	1.26%	176.2	1.26%	141.4	1.14%	1,164.7	1.45%	75.25%
2026	178.3	1.19%	178.3	1.19%	143.1	1.20%	1,181.7	1.46%	75.66%
2027	180.5	1.23%	180.5	1.23%	144.8	1.19%	1,199.0	1.46%	75.83%
2028	182.8	1.27%	182.8	1.27%	146.5	1.17%	1,216.5	1.46%	75.97%

1/ Load Factor is calculated using demand net of interruptible loads.

MONTANA-DAKOTA UTILITIES CO.
FORECASTED ENERGY (GWh) AND SEASONAL DEMANDS (MW)
NORTH DAKOTA

	SUMMER PEAK		SUMMER PEAK NET OF INT LOADS		WINTER PEAK		ANNUAL ENERGY REQUIREMENTS		LOAD FACTOR
YEAR	(MW)	% CHG	(MW)	% CHG	(MW)	% CHG	(GWh)	% CHG	(%) 1/
2009	357.5		347.9		283.7		1,666.5		54.53%
2010	360.9	0.95%	349.8	0.55%	285.4	0.60%	1,698.9	1.94%	55.44%
2011	365.2	1.19%	354.1	1.23%	288.9	1.23%	1,724.5	1.51%	55.59%
2012	369.1	1.07%	358.0	1.10%	292.1	1.11%	1,735.0	0.61%	55.32%
2013	374.7	1.52%	363.6	1.56%	296.6	1.54%	1,759.8	1.43%	55.10%
2014	380.4	1.52%	369.3	1.57%	301.3	1.58%	1,785.1	1.44%	55.18%
2015	386.1	1.50%	375.0	1.54%	306.0	1.56%	1,810.3	1.41%	55.11%
2016	392.0	1.53%	380.9	1.57%	310.7	1.54%	1,835.3	1.38%	55.00%
2017	397.9	1.51%	386.8	1.55%	315.6	1.58%	1,860.7	1.38%	54.76%
2018	403.3	1.36%	392.2	1.40%	320.0	1.39%	1,883.8	1.24%	54.83%
2019	408.9	1.39%	397.8	1.43%	324.5	1.41%	1,907.1	1.24%	54.73%
2020	414.5	1.37%	403.4	1.41%	329.1	1.42%	1,930.9	1.25%	54.64%
2021	420.2	1.38%	409.1	1.41%	333.8	1.43%	1,955.1	1.25%	54.41%
2022	426.1	1.40%	415.0	1.44%	338.5	1.41%	1,979.7	1.26%	54.46%
2023	432.0	1.38%	420.9	1.42%	343.4	1.45%	2,004.7	1.26%	54.37%
2024	438.0	1.39%	426.9	1.43%	348.2	1.40%	2,030.2	1.27%	54.29%
2025	444.1	1.39%	433.0	1.43%	353.2	1.44%	2,056.1	1.28%	54.06%
2026	450.3	1.40%	439.2	1.43%	358.3	1.44%	2,082.3	1.27%	54.12%
2027	456.6	1.40%	445.5	1.43%	363.4	1.42%	2,108.9	1.28%	54.04%
2028	463.0	1.40%	451.9	1.44%	368.6	1.43%	2,135.8	1.28%	53.95%

1/ Load Factor is calculated using demand net of interruptible loads.

MONTANA-DAKOTA UTILITIES CO.
FORECASTED ENERGY (GWh) AND SEASONAL DEMANDS (MW)
SOUTH DAKOTA

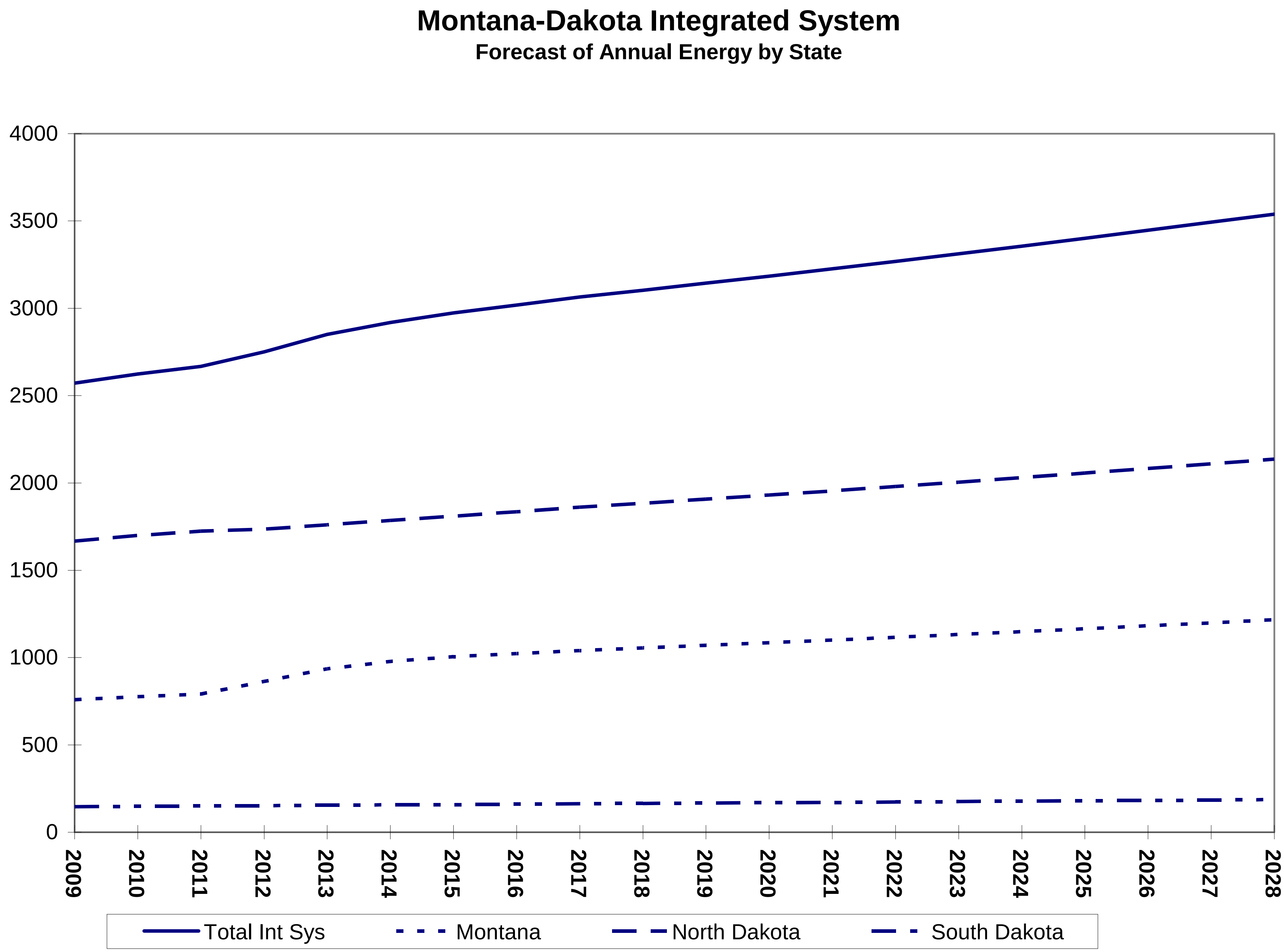
YEAR	SUMMER PEAK (MW)	SUMMER PEAK % CHG	SUMMER PEAK NET OF INT LOADS (MW)	SUMMER PEAK NET OF INT LOADS % CHG	WINTER PEAK (MW)	WINTER PEAK % CHG	ANNUAL ENERGY REQUIREMENTS (GWh)	ANNUAL ENERGY REQUIREMENTS % CHG	LOAD FACTOR (%) 1/
2009	30.2		30.2		22.2		146.1		55.07%
2010	30.4	0.66%	30.4	0.66%	22.3	0.45%	148.6	1.71%	55.80%
2011	30.7	0.99%	30.7	0.99%	22.6	1.35%	150.9	1.55%	56.11%
2012	31.0	0.98%	31.0	0.98%	22.9	1.33%	152.3	0.93%	56.08%
2013	31.5	1.61%	31.5	1.61%	23.2	1.31%	154.3	1.31%	55.77%
2014	32.0	1.59%	32.0	1.59%	23.6	1.72%	156.4	1.36%	55.79%
2015	32.5	1.56%	32.5	1.56%	23.9	1.27%	158.5	1.34%	55.67%
2016	33.0	1.54%	33.0	1.54%	24.3	1.67%	160.7	1.39%	55.59%
2017	33.5	1.52%	33.5	1.52%	24.7	1.65%	162.9	1.37%	55.36%
2018	34.0	1.49%	34.0	1.49%	25.0	1.21%	164.9	1.23%	55.37%
2019	34.5	1.47%	34.5	1.47%	25.4	1.60%	167.0	1.27%	55.26%
2020	35.0	1.45%	35.0	1.45%	25.7	1.18%	169.1	1.26%	55.15%
2021	35.5	1.43%	35.5	1.43%	26.1	1.56%	171.2	1.24%	54.90%
2022	36.0	1.41%	36.0	1.41%	26.5	1.53%	173.4	1.29%	54.98%
2023	36.5	1.39%	36.5	1.39%	26.9	1.51%	175.6	1.27%	54.92%
2024	37.0	1.37%	37.0	1.37%	27.2	1.12%	177.8	1.25%	54.86%
2025	37.5	1.35%	37.5	1.35%	27.6	1.47%	180.1	1.29%	54.68%
2026	38.1	1.60%	38.1	1.60%	28.0	1.45%	182.4	1.28%	54.65%
2027	38.6	1.31%	38.6	1.31%	28.4	1.43%	184.8	1.32%	54.65%
2028	39.2	1.55%	39.2	1.55%	28.8	1.41%	187.2	1.30%	54.51%

1/ Load Factor is calculated using demand net of interruptible loads.

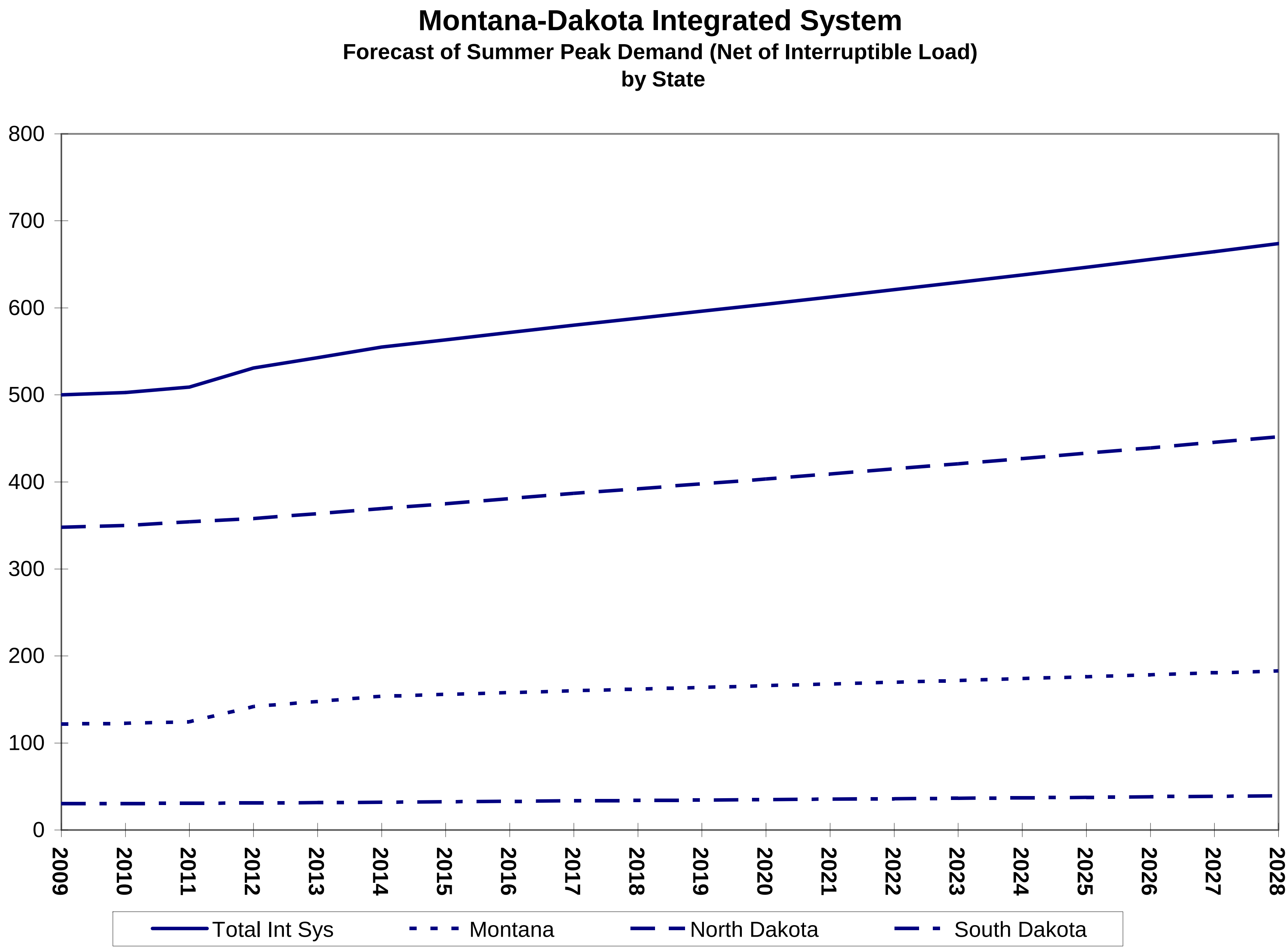
MONTANA-DAKOTA UTILITIES CO.
FORECASTED ENERGY (GWh) AND SEASONAL DEMANDS (MW)
INTEGRATED SYSTEM

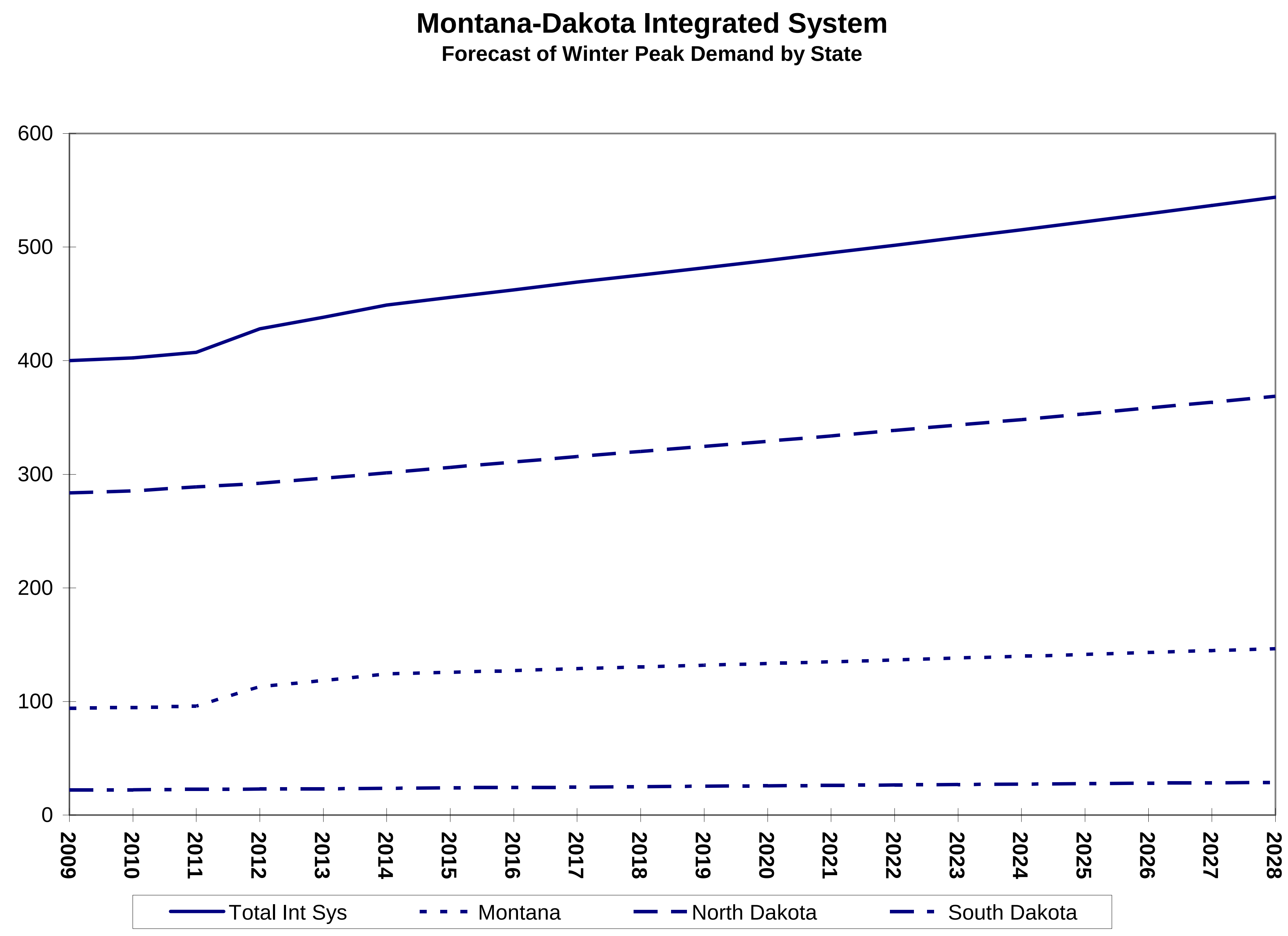
YEAR	SUMMER PEAK (MW)	SUMMER PEAK % CHG	SUMMER PEAK NET OF INT LOADS (MW)	SUMMER PEAK NET OF INT LOADS % CHG	WINTER PEAK (MW)	WINTER PEAK % CHG	ANNUAL ENERGY REQUIREMENTS (GWh)	ANNUAL ENERGY REQUIREMENTS % CHG	LOAD FACTOR (%) 1/
2009	509.7		500.1		400.1		2,571.1		58.53%
2010	514.0	0.84%	502.9	0.56%	402.4	0.57%	2,623.0	2.02%	59.54%
2011	520.2	1.21%	509.1	1.23%	407.4	1.24%	2,666.9	1.67%	59.80%
2012	542.0	4.19%	530.9	4.28%	428.1	5.08%	2,750.9	3.15%	59.15%
2013	553.8	2.18%	542.7	2.22%	438.2	2.36%	2,849.8	3.60%	59.78%
2014	566.2	2.24%	555.1	2.28%	449.1	2.49%	2,919.0	2.43%	60.03%
2015	574.4	1.45%	563.3	1.48%	455.7	1.47%	2,974.1	1.89%	60.27%
2016	582.9	1.48%	571.8	1.51%	462.3	1.45%	3,018.6	1.50%	60.26%
2017	591.4	1.46%	580.3	1.49%	469.2	1.49%	3,063.9	1.50%	60.11%
2018	599.2	1.32%	588.1	1.34%	475.4	1.32%	3,103.5	1.29%	60.24%
2019	607.2	1.34%	596.1	1.36%	481.8	1.35%	3,143.7	1.30%	60.20%
2020	615.3	1.33%	604.2	1.36%	488.2	1.33%	3,184.6	1.30%	60.17%
2021	623.5	1.33%	612.4	1.36%	494.9	1.37%	3,226.3	1.31%	59.98%
2022	632.0	1.36%	620.9	1.39%	501.6	1.35%	3,268.8	1.32%	60.10%
2023	640.4	1.33%	629.3	1.35%	508.5	1.38%	3,312.1	1.32%	60.08%
2024	649.0	1.34%	637.9	1.37%	515.2	1.32%	3,356.1	1.33%	60.06%
2025	657.8	1.36%	646.7	1.38%	522.2	1.36%	3,400.9	1.33%	59.87%
2026	666.7	1.35%	655.6	1.38%	529.4	1.38%	3,446.4	1.34%	60.01%
2027	675.7	1.35%	664.6	1.37%	536.6	1.36%	3,492.6	1.34%	59.99%
2028	685.0	1.38%	673.9	1.40%	543.9	1.36%	3,539.5	1.34%	59.96%

1/ Load Factor is calculated using demand net of interruptible loads.



Montana-Dakota Integrated System
Forecast of Annual Energy by State
4000
3500
3000
2500
2000
1500
1000
500
0
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
Total Int Sys
Montana
North Dakota
South Dakota


Montana-Dakota Integrated System
Forecast of Summer Peak Demand (Net of Interruptible Load)
by State
800
700
600
500
400
300
200
100
0
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
Total Int Sys
Montana
North Dakota
South Dakota


Montana-Dakota Integrated System
Forecast of Winter Peak Demand by State
600
500
400
300
200
100
0
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
Total Int Sys
Montana
North Dakota
South Dakota

APPENDIX D

Monthly Forecasts - Montana
(2009-2018)

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

MONTANA YEAR 2009

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	825.1	759.3	689.3	631.2	604.3	630.7	901.7	771.9	675.1	619.6	703.9	858.4	8,671.2
# of Residential Customers	18,739	18,735	18,718	18,659	18,665	18,673	18,688	18,697	18,704	18,717	18,741	18,745	18,707
Total Residential Sales - MWh	15,461	14,225	12,902	11,777	11,279	11,777	16,851	14,433	12,627	11,597	13,192	16,090	162,210
Use per Small Comm & Ind Customer - kWh	2,117.0	2,055.7	1,937.9	1,799.5	1,863.0	1,752.3	2,372.7	2,101.6	1,952.8	1,776.3	1,894.4	2,181.6	23,805.5
# of Small Comm & Ind Customers	4,698	4,696	4,703	4,750	4,815	4,843	4,854	4,860	4,846	4,792	4,764	4,752	4,781
Total Small Comm & Ind Sales - MWh	9,946	9,654	9,114	8,548	8,971	8,487	11,517	10,214	9,463	8,512	9,025	10,367	113,816
General Large Comm & Ind Sales	17,777	17,464	16,374	17,077	16,510	16,314	17,348	17,081	17,666	18,511	18,891	21,624	212,636
Encore Oil Sales	15,608	15,732	15,848	16,038	16,263	15,629	16,589	15,898	16,487	17,483	17,607	18,438	197,620
TransCanada Keystone Pipeline	-	-	-	-	-	-	-	-	-	-	-	-	-
Westmoreland Coal - MT Sales	232	236	212	195	170	137	136	127	132	163	209	254	2,203
Total Sales (Residential, SC&I and LC&I)	59,024	57,311	54,450	53,634	53,192	52,344	62,441	57,753	56,375	56,266	58,924	66,773	688,485
Other Public Sales	470	490	440	478	542	605	832	696	647	488	442	504	6,634
Street & Highway Lighting Sales	622	566	616	587	617	568	583	606	586	622	598	618	7,189
Interdepartmental Sales	19	18	17	16	14	13	16	13	15	14	16	21	192
Total Billed Sales - MWh	60,135	58,385	55,523	54,715	54,365	53,530	63,872	59,068	57,623	57,390	59,980	67,916	702,500
Company Use	46	45	40	34	32	29	37	34	29	29	36	41	432
Total Energy	60,181	58,430	55,563	54,749	54,397	53,559	63,909	59,102	57,652	57,419	60,016	67,957	702,932
Total Requirements (Energy + Losses)	64,932	63,043	59,950	59,072	58,693	57,788	68,955	63,768	62,205	61,952	64,754	73,322	758,434
# of Large Comm & Ind Customers	247	247	248	250	254	256	257	258	256	253	251	250	252
# of Other Public Customers	102	101	102	105	109	109	109	109	107	105	104	103	105
# of Street & Highway Lighting Customers	94	95	93	93	93	93	84	85	85	85	85	85	89
Peak Demand Net of DSM Programs	97.3	96.4	89.6	76.8	92.5	108.7	122.0	119.1	99.8	88.4	89.5	94.2	122.0

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

MONTANA YEAR 2010

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	829.5	763.4	692.9	634.5	607.3	632.7	905.4	774.8	677.4	622.8	707.6	863.1	8,712.3
# of Residential Customers	18,826	18,822	18,804	18,745	18,752	18,759	18,774	18,783	18,791	18,804	18,828	18,832	18,793
Total Residential Sales - MWh	15,617	14,368	13,030	11,893	11,389	11,869	16,998	14,554	12,729	11,711	13,323	16,253	163,734
Use per Small Comm & Ind Customer - kWh	2,160.3	2,097.2	1,977.0	1,835.8	1,901.0	1,787.4	2,420.9	2,144.3	1,992.3	1,812.0	1,932.9	2,226.1	24,287.9
# of Small Comm & Ind Customers	4,735	4,734	4,741	4,788	4,853	4,882	4,892	4,898	4,884	4,830	4,801	4,789	4,819
Total Small Comm & Ind Sales - MWh	10,229	9,928	9,373	8,790	9,226	8,726	11,843	10,503	9,730	8,752	9,280	10,661	117,041
General Large Comm & Ind Sales	18,378	18,054	16,927	17,655	17,068	16,861	17,920	17,642	18,258	19,136	19,530	22,290	219,722
Encore Oil Sales	15,924	16,050	16,168	16,361	16,590	15,944	16,924	16,219	16,820	17,836	17,963	18,810	201,609
TransCanada Keystone Pipeline	-	-	-	-	-	-	-	-	-	-	-	-	-
Westmoreland Coal - MT Sales	232	236	212	195	170	137	136	127	132	163	209	254	2,203
Total Sales (Residential, SC&I and LC&I)	60,380	58,636	55,710	54,894	54,443	53,538	63,821	59,045	57,669	57,598	60,305	68,268	704,309
Other Public Sales	471	491	441	479	542	606	833	698	648	489	443	505	6,646
Street & Highway Lighting Sales	622	567	616	587	617	568	583	606	586	622	598	618	7,190
Interdepartmental Sales	19	18	16	16	14	13	16	13	15	14	16	21	191
Total Billed Sales - MWh	61,492	59,712	56,783	55,976	55,616	54,725	65,253	60,362	58,918	58,723	61,362	69,412	718,336
Company Use	46	45	40	34	32	29	37	34	29	29	36	41	432
Total Energy	61,538	59,757	56,823	56,010	55,648	54,754	65,290	60,396	58,947	58,752	61,398	69,453	718,768
Total Requirements (Energy + Losses)	66,397	64,476	61,310	60,433	60,042	59,077	70,445	65,165	63,602	63,391	66,246	74,937	775,521
# of Large Comm & Ind Customers	248	249	249	251	255	257	259	259	257	254	252	251	253
# of Other Public Customers	102	101	102	105	109	109	109	109	107	105	104	103	105
# of Street & Highway Lighting Customers	94	95	93	93	93	93	84	85	85	85	85	85	89
Peak Demand Net of DSM Programs	99.0	98.1	91.2	78.0	94.1	109.2	122.7	119.6	100.0	90.0	90.0	94.7	122.7

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

MONTANA YEAR 2011

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	834.6	767.9	697.1	638.3	611.0	635.9	910.2	778.9	680.8	626.5	711.9	868.3	8,762.5
# of Residential Customers	18,913	18,909	18,891	18,832	18,839	18,847	18,861	18,871	18,878	18,891	18,915	18,919	18,881
Total Residential Sales - MWh	15,784	14,521	13,169	12,021	11,511	11,985	17,168	14,699	12,853	11,836	13,466	16,427	165,440
Use per Small Comm & Ind Customer - kWh	2,205.8	2,141.5	2,018.6	1,874.6	1,940.8	1,825.0	2,471.8	2,189.3	2,034.3	1,850.0	1,973.5	2,272.6	24,798.4
# of Small Comm & Ind Customers	4,772	4,771	4,778	4,825	4,891	4,920	4,930	4,936	4,922	4,868	4,839	4,827	4,857
Total Small Comm & Ind Sales - MWh	10,526	10,217	9,645	9,045	9,493	8,979	12,186	10,807	10,013	9,006	9,550	10,970	120,436
General Large Comm & Ind Sales	18,860	18,528	17,371	18,118	17,515	17,302	18,390	18,106	18,737	19,639	20,042	22,729	225,341
Encore Oil Sales	16,246	16,374	16,494	16,692	16,926	16,266	17,266	16,546	17,160	18,196	18,326	19,190	205,682
TransCanada Keystone Pipeline	-	-	-	-	-	-	-	-	-	-	-	-	-
Westmoreland Coal - MT Sales	232	236	212	195	170	137	136	127	132	163	209	254	2,203
Total Sales (Residential, SC&I and LC&I)	61,648	59,876	56,891	56,071	55,615	54,669	65,146	60,285	58,895	58,840	61,593	69,570	719,101
Other Public Sales	472	492	442	480	543	607	834	699	650	490	444	506	6,659
Street & Highway Lighting Sales	622	567	616	587	617	568	583	606	586	622	598	618	7,190
Interdepartmental Sales	19	18	16	16	14	13	16	13	15	14	16	21	191
Total Billed Sales - MWh	62,761	60,953	57,965	57,154	56,789	55,857	66,579	61,603	60,146	59,966	62,651	70,715	733,141
Company Use	46	45	40	34	32	29	37	34	29	29	36	41	432
Total Energy	62,807	60,998	58,005	57,188	56,821	55,886	66,616	61,637	60,175	59,995	62,687	70,756	733,573
Total Requirements (Energy + Losses)	67,767	65,815	62,586	61,704	61,307	60,299	71,876	66,503	64,927	64,733	67,637	76,343	791,497
# of Large Comm & Ind Customers	250	250	251	252	257	259	260	261	258	256	254	253	255
# of Other Public Customers	102	101	102	105	109	109	109	109	107	105	104	103	105
# of Street & Highway Lighting Customers	94	95	93	93	93	93	84	85	85	85	85	85	89
Peak Demand Net of DSM Programs	99.7	98.8	91.9	78.5	95.6	110.5	124.3	121.2	101.2	91.4	91.1	95.9	124.3

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

MONTANA YEAR 2012

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	839.6	772.6	701.3	642.2	614.7	639.8	915.8	783.6	685.0	630.3	716.3	873.5	8,815.5
# of Residential Customers	19,001	18,998	18,979	18,920	18,927	18,934	18,949	18,959	18,966	18,979	19,003	19,007	18,969
Total Residential Sales - MWh	15,953	14,677	13,310	12,150	11,635	12,114	17,353	14,857	12,992	11,963	13,611	16,603	167,218
Use per Small Comm & Ind Customer - kWh	2,252.7	2,187.0	2,061.5	1,914.2	1,982.0	1,864.0	2,524.6	2,235.7	2,077.8	1,889.9	2,015.8	2,307.8	25,313.8
# of Small Comm & Ind Customers	4,808	4,807	4,814	4,862	4,928	4,957	4,967	4,974	4,959	4,904	4,875	4,863	4,893
Total Small Comm & Ind Sales - MWh	10,831	10,513	9,924	9,307	9,768	9,240	12,540	11,121	10,304	9,268	9,827	11,223	123,865
General Large Comm & Ind Sales	19,022	18,687	17,521	18,273	17,666	17,452	18,550	18,262	18,898	19,808	20,215	23,092	227,450
Encore Oil Sales	16,574	16,705	16,827	17,029	17,268	16,595	17,615	16,880	17,506	18,564	18,696	19,578	209,837
TransCanada Keystone Pipeline	-	-	-	-	-	7,757	8,015	8,015	7,757	8,015	7,757	8,015	55,331
Westmoreland Coal - MT Sales	232	236	212	195	170	137	136	127	132	163	209	254	2,203
Total Sales (Residential, SC&I and LC&I)	62,612	60,818	57,794	56,954	56,507	63,295	74,209	69,262	67,589	67,781	70,315	78,765	785,903
Other Public Sales	473	493	443	481	544	608	836	700	651	491	445	507	6,672
Street & Highway Lighting Sales	622	567	616	587	617	568	583	606	586	622	598	618	7,190
Interdepartmental Sales	19	18	16	16	14	13	16	13	14	14	16	20	189
Total Billed Sales - MWh	63,726	61,896	58,869	58,038	57,682	64,484	75,644	70,581	68,840	68,908	71,374	79,910	799,954
Company Use	46	45	40	34	32	29	37	34	29	29	36	41	432
Total Energy	63,772	61,941	58,909	58,072	57,714	64,513	75,681	70,615	68,869	68,937	71,410	79,951	800,386
Total Requirements (Energy + Losses)	68,808	66,832	63,561	62,658	62,271	69,607	81,657	76,190	74,307	74,381	77,049	86,264	863,585
# of Large Comm & Ind Customers	251	251	252	254	258	260	261	262	260	257	255	254	256
# of Other Public Customers	102	101	102	105	109	109	109	109	107	105	104	103	105
# of Street & Highway Lighting Customers	94	95	93	93	93	93	84	85	85	85	85	85	89
Peak Demand Net of DSM Programs	100.9	100.0	93.0	79.5	96.6	127.9	141.9	138.7	118.6	108.6	108.3	113.1	141.9

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

MONTANA YEAR 2013

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	844.7	777.3	705.6	646.1	618.5	643.7	921.3	788.4	689.2	634.2	720.5	878.7	8,869.1
# of Residential Customers	19,089	19,085	19,067	19,007	19,014	19,022	19,037	19,046	19,054	19,067	19,091	19,095	19,056
Total Residential Sales - MWh	16,124	14,834	13,453	12,280	11,760	12,245	17,539	15,017	13,132	12,092	13,756	16,779	169,011
Use per Small Comm & Ind Customer - kWh	2,275.8	2,209.4	2,082.7	1,934.1	2,002.5	1,883.2	2,550.0	2,258.7	2,098.7	1,908.9	2,036.2	2,331.2	25,572.1
# of Small Comm & Ind Customers	4,844	4,843	4,850	4,898	4,965	4,994	5,005	5,011	4,997	4,941	4,912	4,900	4,930
Total Small Comm & Ind Sales - MWh	11,024	10,700	10,101	9,473	9,943	9,405	12,763	11,319	10,487	9,432	10,002	11,423	126,071
General Large Comm & Ind Sales	19,570	19,225	18,026	18,801	18,175	17,955	19,086	18,791	19,444	20,377	20,797	23,761	234,012
Encore Oil Sales	16,908	17,042	17,167	17,373	17,617	16,930	17,971	17,222	17,860	18,939	19,074	19,973	214,076
TransCanada Keystone Pipeline	8,015	7,239	8,015	7,757	8,015	9,576	9,895	9,895	9,576	9,895	9,576	9,895	107,349
Westmoreland Coal - MT Sales	232	236	212	195	170	137	136	127	132	163	209	254	2,203
Total Sales (Residential, SC&I and LC&I)	71,873	69,276	66,974	65,879	65,680	66,248	77,390	72,371	70,631	70,898	73,414	82,085	852,721
Other Public Sales	474	494	444	482	545	609	838	701	652	491	445	508	6,683
Street & Highway Lighting Sales	623	567	616	587	617	568	583	606	587	623	598	618	7,193
Interdepartmental Sales	18	17	16	15	14	13	16	13	14	14	16	20	186
Total Billed Sales - MWh	72,988	70,354	68,050	66,963	66,856	67,438	78,827	73,691	71,884	72,026	74,473	83,231	866,783
Company Use	46	45	40	34	32	29	37	34	29	29	36	41	432
Total Energy	73,034	70,399	68,090	66,997	66,888	67,467	78,864	73,725	71,913	72,055	74,509	83,272	867,215
Total Requirements (Energy + Losses)	78,801	75,958	73,467	72,287	72,169	72,795	85,091	79,546	77,591	77,745	80,393	89,848	935,691
# of Large Comm & Ind Customers	252	253	253	255	259	261	263	263	261	258	256	255	257
# of Other Public Customers	102	101	102	105	109	109	109	109	107	105	104	103	105
# of Street & Highway Lighting Customers	94	95	93	93	93	93	84	85	85	85	85	85	89
Peak Demand Net of DSM Programs	118.2	117.3	110.2	96.6	114.2	133.5	147.6	144.4	124.0	113.8	113.5	118.4	147.6

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

MONTANA YEAR 2014

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	849.9	782.1	709.9	650.1	622.3	647.8	927.1	793.4	693.5	638.1	725.0	884.2	8,924.3
# of Residential Customers	19,172	19,168	19,150	19,089	19,096	19,104	19,119	19,128	19,136	19,149	19,174	19,178	19,139
Total Residential Sales - MWh	16,294	14,991	13,595	12,410	11,884	12,375	17,725	15,176	13,271	12,219	13,901	16,957	170,798
Use per Small Comm & Ind Customer - kWh	2,299.7	2,232.7	2,104.6	1,954.2	2,023.3	1,902.6	2,576.8	2,282.2	2,120.8	1,929.1	2,057.6	2,355.6	25,839.7
# of Small Comm & Ind Customers	4,879	4,878	4,885	4,934	5,001	5,031	5,041	5,048	5,033	4,977	4,948	4,936	4,966
Total Small Comm & Ind Sales - MWh	11,220	10,891	10,281	9,642	10,119	9,572	12,990	11,521	10,674	9,601	10,181	11,627	128,318
General Large Comm & Ind Sales	20,145	19,789	18,554	19,351	18,708	18,482	19,647	19,343	20,014	20,975	21,406	24,460	240,878
Encore Oil Sales	17,250	17,386	17,514	17,724	17,972	17,272	18,334	17,569	18,221	19,322	19,459	20,377	218,400
TransCanada Keystone Pipeline	9,895	8,938	9,895	9,576	9,895	11,587	11,973	11,973	11,587	11,973	11,587	11,973	130,852
Westmoreland Coal - MT Sales	232	236	212	195	170	137	136	127	132	163	209	254	2,203
Total Sales (Residential, SC&I and LC&I)	75,036	72,231	70,051	68,898	68,748	69,425	80,805	75,709	73,899	74,253	76,743	85,648	891,448
Other Public Sales	475	494	444	482	546	610	839	703	653	492	446	509	6,693
Street & Highway Lighting Sales	623	567	616	587	617	568	583	606	587	623	598	618	7,193
Interdepartmental Sales	18	17	16	15	13	13	16	13	14	14	15	20	184
Total Billed Sales - MWh	76,152	73,309	71,127	69,982	69,924	70,616	82,243	77,031	75,153	75,382	77,802	86,795	905,518
Company Use	46	45	40	34	32	29	37	34	29	29	36	41	432
Total Energy	76,198	73,354	71,167	70,016	69,956	70,645	82,280	77,065	75,182	75,411	77,838	86,836	905,950
Total Requirements (Energy + Losses)	82,215	79,146	76,787	75,545	75,479	76,224	88,777	83,150	81,118	81,366	83,985	93,693	977,485
# of Large Comm & Ind Customers	254	254	255	256	261	263	264	265	263	260	258	257	259
# of Other Public Customers	102	101	102	105	109	109	109	109	107	105	104	103	105
# of Street & Highway Lighting Customers	94	95	93	93	93	93	84	85	85	85	85	85	89
Peak Demand Net of DSM Programs	123.6	122.7	115.5	101.6	119.5	139.5	153.8	150.6	129.8	119.4	119.2	124.2	153.8

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

MONTANA YEAR 2015

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	855.2	786.9	714.3	654.1	626.2	651.8	932.9	798.3	697.8	642.1	729.5	889.6	8,979.6
# of Residential Customers	19,255	19,252	19,233	19,173	19,180	19,188	19,203	19,212	19,220	19,233	19,258	19,262	19,222
Total Residential Sales - MWh	16,466	15,150	13,739	12,541	12,010	12,507	17,914	15,338	13,412	12,349	14,049	17,135	172,610
Use per Small Comm & Ind Customer - kWh	2,323.5	2,255.6	2,126.4	1,974.6	2,044.4	1,922.8	2,603.5	2,306.4	2,142.8	1,948.9	2,079.1	2,380.4	26,109.0
# of Small Comm & Ind Customers	4,915	4,914	4,921	4,970	5,038	5,067	5,078	5,084	5,070	5,014	4,984	4,971	5,002
Total Small Comm & Ind Sales - MWh	11,420	11,084	10,464	9,814	10,300	9,743	13,221	11,726	10,864	9,772	10,362	11,833	130,602
General Large Comm & Ind Sales	20,741	20,375	19,104	19,925	19,262	19,029	20,229	19,917	20,606	21,596	22,040	25,186	248,014
Encore Oil Sales	17,598	17,738	17,868	18,082	18,335	17,621	18,704	17,924	18,589	19,712	19,852	20,788	222,811
TransCanada Keystone Pipeline	11,973	10,814	11,973	11,587	11,973	11,587	11,973	11,973	11,587	11,973	11,587	11,973	140,973
Westmoreland Coal - MT Sales	232	236	212	195	170	137	136	127	132	163	209	254	2,203
Total Sales (Residential, SC&I and LC&I)	78,430	75,397	73,360	72,144	72,050	70,624	82,177	77,005	75,190	75,565	78,099	87,169	917,212
Other Public Sales	476	495	445	483	547	611	840	704	654	493	447	510	6,705
Street & Highway Lighting Sales	623	567	616	588	618	568	584	606	587	623	598	618	7,196
Interdepartmental Sales	18	17	15	15	13	12	15	13	14	13	15	20	180
Total Billed Sales - MWh	79,547	76,476	74,436	73,230	73,228	71,815	83,616	78,328	76,445	76,694	79,159	88,317	931,293
Company Use	46	45	40	34	32	29	37	34	29	29	36	41	432
Total Energy	79,593	76,521	74,476	73,264	73,260	71,844	83,653	78,362	76,474	76,723	79,195	88,358	931,725
Total Requirements (Energy + Losses)	85,878	82,564	80,357	79,049	79,044	77,517	90,258	84,549	82,512	82,781	85,449	95,335	1,005,293
# of Large Comm & Ind Customers	255	255	256	258	262	264	266	266	264	261	259	258	260
# of Other Public Customers	102	101	102	105	109	109	109	109	107	105	104	103	105
# of Street & Highway Lighting Customers	94	95	93	93	93	93	84	85	85	85	85	85	89
Peak Demand Net of DSM Programs	129.5	128.5	121.2	107.1	125.2	141.3	155.8	152.5	131.5	120.8	120.7	125.8	155.8

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

MONTANA YEAR 2016

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	860.5	791.9	718.9	658.2	630.1	656.0	938.8	803.3	702.3	646.1	734.1	895.2	9,036.2
# of Residential Customers	19,336	19,332	19,314	19,253	19,260	19,268	19,283	19,293	19,300	19,313	19,338	19,342	19,303
Total Residential Sales - MWh	16,639	15,309	13,884	12,673	12,136	12,639	18,102	15,499	13,554	12,478	14,196	17,314	174,423
Use per Small Comm & Ind Customer - kWh	2,348.1	2,280.1	2,148.9	1,995.6	2,066.3	1,943.3	2,631.4	2,331.0	2,165.5	1,969.9	2,101.2	2,405.9	26,387.9
# of Small Comm & Ind Customers	4,950	4,948	4,956	5,005	5,073	5,103	5,114	5,120	5,106	5,049	5,019	5,006	5,037
Total Small Comm & Ind Sales - MWh	11,623	11,282	10,650	9,988	10,483	9,917	13,457	11,935	11,057	9,946	10,546	12,044	132,927
General Large Comm & Ind Sales	21,358	20,981	19,673	20,518	19,836	19,596	20,834	20,512	21,221	22,239	22,696	25,940	255,408
Encore Oil Sales	17,954	18,096	18,229	18,448	18,706	17,977	19,082	18,286	18,965	20,110	20,253	21,208	227,314
TransCanada Keystone Pipeline	11,973	10,814	11,973	11,587	11,973	11,587	11,973	11,973	11,587	11,973	11,587	11,973	140,973
Westmoreland Coal - MT Sales	232	236	212	195	170	137	136	127	132	163	209	254	2,203
Total Sales (Residential, SC&I and LC&I)	79,779	76,718	74,621	73,409	73,304	71,853	83,584	78,332	76,516	76,909	79,487	88,733	933,247
Other Public Sales	477	497	446	484	548	612	842	705	655	494	448	510	6,718
Street & Highway Lighting Sales	623	567	616	588	618	569	584	606	587	623	598	618	7,197
Interdepartmental Sales	18	17	15	15	13	12	15	13	14	13	15	19	179
Total Billed Sales - MWh	80,897	77,799	75,698	74,496	74,483	73,046	85,025	79,656	77,772	78,039	80,548	89,880	947,341
Company Use	46	45	40	34	32	29	37	34	29	29	36	41	432
Total Energy	80,943	77,844	75,738	74,530	74,515	73,075	85,062	79,690	77,801	78,068	80,584	89,921	947,773
Total Requirements (Energy + Losses)	87,335	83,991	81,719	80,415	80,398	78,845	91,778	85,982	83,944	84,233	86,947	97,022	1,022,609
# of Large Comm & Ind Customers	256	257	257	259	263	266	267	267	265	262	260	259	262
# of Other Public Customers	102	101	102	105	109	109	109	109	107	105	104	103	105
# of Street & Highway Lighting Customers	94	95	93	93	93	93	84	85	85	85	85	85	89
Peak Demand Net of DSM Programs	131.1	130.1	122.7	108.4	126.7	143.1	157.9	154.5	133.2	122.3	122.2	127.3	157.9

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

MONTANA YEAR 2017

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	866.0	796.9	723.4	662.4	634.1	660.1	944.7	808.5	706.7	650.2	738.8	900.8	9,093.6
# of Residential Customers	19,415	19,411	19,393	19,332	19,339	19,347	19,362	19,371	19,379	19,392	19,417	19,421	19,382
Total Residential Sales - MWh	16,813	15,469	14,029	12,805	12,263	12,771	18,292	15,662	13,696	12,609	14,345	17,494	176,248
Use per Small Comm & Ind Customer - kWh	2,373.6	2,304.4	2,172.3	2,017.3	2,088.8	1,964.3	2,659.9	2,355.8	2,189.1	1,991.1	2,123.9	2,431.9	26,673.0
# of Small Comm & Ind Customers	4,984	4,983	4,990	5,040	5,108	5,138	5,149	5,156	5,141	5,084	5,054	5,041	5,072
Total Small Comm & Ind Sales - MWh	11,830	11,483	10,840	10,167	10,670	10,093	13,696	12,147	11,254	10,123	10,734	12,259	135,295
General Large Comm & Ind Sales	22,005	21,617	20,268	21,139	20,437	20,191	21,466	21,134	21,863	22,912	23,383	26,599	263,018
Encore Oil Sales	18,316	18,461	18,597	18,820	19,084	18,340	19,467	18,656	19,348	20,517	20,662	21,636	231,904
TransCanada Keystone Pipeline	11,973	10,814	11,973	11,587	11,973	11,587	11,973	11,973	11,587	11,973	11,587	11,973	140,973
Westmoreland Coal - MT Sales	232	236	212	195	170	137	136	127	132	163	209	254	2,203
Total Sales (Residential, SC&I and LC&I)	81,169	78,080	75,919	74,713	74,597	73,119	85,030	79,699	77,880	78,297	80,920	90,215	949,640
Other Public Sales	477	498	447	485	549	613	844	706	656	495	449	511	6,730
Street & Highway Lighting Sales	623	567	616	588	618	569	584	607	587	623	598	618	7,198
Interdepartmental Sales	18	17	15	15	13	12	15	13	14	13	15	19	179
Total Billed Sales - MWh	82,287	79,162	76,997	75,801	75,777	74,313	86,473	81,025	79,137	79,428	81,982	91,363	963,747
Company Use	46	45	40	34	32	29	37	34	29	29	36	41	432
Total Energy	82,333	79,207	77,037	75,835	75,809	74,342	86,510	81,059	79,166	79,457	82,018	91,404	964,179
Total Requirements (Energy + Losses)	88,834	85,462	83,120	81,823	81,794	80,212	93,341	87,459	85,417	85,731	88,495	98,622	1,040,310
# of Large Comm & Ind Customers	258	258	259	260	265	267	268	269	267	264	262	261	263
# of Other Public Customers	102	101	102	105	109	109	109	109	107	105	104	103	105
# of Street & Highway Lighting Customers	94	95	93	93	93	93	84	85	85	85	85	85	89
Peak Demand Net of DSM Programs	132.8	131.8	124.2	109.7	128.2	145.0	160.0	156.6	134.9	123.7	123.7	128.9	160.0

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

MONTANA YEAR 2018

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	871.5	802.0	728.1	666.7	638.2	664.4	950.9	813.7	711.3	654.4	743.5	906.4	9,152.0
# of Residential Customers	19,491	19,487	19,468	19,407	19,414	19,422	19,437	19,447	19,455	19,468	19,493	19,497	19,457
Total Residential Sales - MWh	16,987	15,629	14,174	12,938	12,390	12,904	18,482	15,825	13,838	12,740	14,493	17,673	178,073
Use per Small Comm & Ind Customer - kWh	2,399.6	2,329.5	2,196.1	2,039.2	2,111.5	1,985.5	2,688.5	2,381.7	2,213.1	2,012.7	2,146.8	2,458.0	26,962.8
# of Small Comm & Ind Customers	5,018	5,017	5,024	5,074	5,143	5,174	5,185	5,191	5,176	5,119	5,089	5,076	5,107
Total Small Comm & Ind Sales - MWh	12,041	11,687	11,033	10,347	10,860	10,273	13,940	12,364	11,455	10,303	10,925	12,477	137,704
General Large Comm & Ind Sales	22,383	21,989	20,617	21,502	20,788	20,537	21,835	21,498	22,239	23,305	23,785	27,058	267,540
Encore Oil Sales	18,686	18,835	18,973	19,200	19,469	18,710	19,860	19,032	19,738	20,931	21,079	22,074	236,587
TransCanada Keystone Pipeline	11,973	10,814	11,973	11,587	11,973	11,587	11,973	11,973	11,587	11,973	11,587	11,973	140,973
Westmoreland Coal - MT Sales	232	236	212	195	170	137	136	127	132	163	209	254	2,203
Total Sales (Residential, SC&I and LC&I)	82,302	79,190	76,982	75,769	75,650	74,148	86,226	80,819	78,989	79,415	82,078	91,509	963,079
Other Public Sales	478	499	448	486	550	614	845	708	658	496	449	512	6,743
Street & Highway Lighting Sales	623	567	616	588	618	569	584	607	587	623	598	618	7,198
Interdepartmental Sales	17	16	15	15	13	12	15	12	13	13	15	19	175
Total Billed Sales - MWh	83,420	80,272	78,061	76,858	76,831	75,343	87,670	82,146	80,247	80,547	83,140	92,658	977,195
Company Use	46	45	40	34	32	29	37	34	29	29	36	41	432
Total Energy	83,466	80,317	78,101	76,892	76,863	75,372	87,707	82,180	80,276	80,576	83,176	92,699	977,627
Total Requirements (Energy + Losses)	90,057	86,659	84,268	82,964	82,932	81,324	94,632	88,668	86,615	86,939	89,744	100,019	1,054,821
# of Large Comm & Ind Customers	259	259	260	262	266	268	270	270	268	265	263	262	264
# of Other Public Customers	102	101	102	105	109	109	109	109	107	105	104	103	105
# of Street & Highway Lighting Customers	94	95	93	93	93	93	84	85	85	85	85	85	89
Peak Demand Net of DSM Programs	134.4	133.5	125.8	111.1	129.7	146.7	161.9	158.4	136.5	125.1	125.1	130.4	161.9

APPENDIX E

Monthly Forecasts - North Dakota
(2009-2018)

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

NORTH DAKOTA YEAR 2009

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	891.0	824.9	746.2	672.1	633.6	670.8	896.6	801.2	695.1	658.8	766.4	911.5	9,168.4
# of Residential Customers	61,871	61,881	61,896	61,903	61,948	62,039	62,079	62,123	62,141	62,169	62,192	62,186	62,036
Total Residential Sales - MWh	55,126	51,046	46,187	41,606	39,250	41,617	55,658	49,774	43,196	40,957	47,665	56,685	568,766
Use per Small Comm & Ind Customer - kWh	2,848.7	2,685.7	2,680.0	2,446.1	2,404.0	2,441.2	2,975.7	2,806.4	2,571.1	2,466.6	2,660.7	2,889.7	31,875.1
# of Small Comm & Ind Customers	9,672	9,661	9,664	9,733	9,823	9,878	9,884	9,909	9,895	9,833	9,811	9,816	9,798
Total Small Comm & Ind Sales - MWh	27,553	25,947	25,900	23,808	23,615	24,114	29,412	27,808	25,441	24,254	26,105	28,366	312,320
General Large Comm & Ind Sales	41,016	40,783	39,930	39,964	40,149	40,852	46,351	45,432	42,828	41,242	41,080	42,672	502,297
Sabin Metals Sales	1,253	1,286	1,332	1,353	1,345	1,279	1,385	1,332	1,320	1,355	1,067	1,094	15,401
Tesoro Refinery Sales	4,059	4,158	4,538	4,579	4,745	4,955	5,232	5,110	4,906	4,725	4,659	4,580	56,246
Westmoreland Coal - ND Sales	2,552	2,424	2,302	2,186	1,959	1,743	1,709	1,805	2,003	2,203	2,352	2,560	25,798
Total Sales (Residential, SC&I and LC&I)	131,558	125,643	120,188	113,495	111,062	114,560	139,746	131,261	119,694	114,735	122,927	135,956	1,480,828
Other Public Sales	2,787	2,673	2,752	2,589	2,914	3,165	3,658	3,502	2,995	2,650	2,585	2,782	35,052
Street & Highway Lighting Sales	1,869	1,758	1,773	1,702	1,675	1,562	1,649	1,666	1,718	1,802	1,882	1,898	20,954
Interdepartmental Sales	22	22	20	19	18	16	18	16	18	19	20	24	232
Total Billed Sales - MWh	136,236	130,096	124,733	117,805	115,669	119,303	145,071	136,445	124,425	119,206	127,414	140,660	1,537,066
Company Use	629	592	589	604	606	631	695	698	609	591	637	629	7,510
Total Energy	136,865	130,688	125,322	118,409	116,275	119,934	145,766	137,143	125,034	119,797	128,051	141,289	1,544,576
Total Requirements (Energy + Losses)	147,672	141,008	135,218	127,758	125,457	129,404	157,276	147,972	134,907	129,257	138,162	152,446	1,666,537
# of Large Comm & Ind Customers	731	734	735	738	740	739	740	740	740	742	741	741	738
# of Other Public Customers	712	712	713	717	723	723	723	722	719	715	711	708	717
# of Street & Highway Lighting Customers	490	492	492	494	494	496	480	482	484	486	487	488	489
Peak Demand Net of DSM Programs	260.1	248.5	228.3	221.8	247.9	316.1	347.9	336.3	277.1	227.1	251.5	283.7	347.9

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

NORTH DAKOTA YEAR 2010

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	895.8	829.4	750.2	675.6	636.9	673.0	900.1	804.2	697.5	662.3	770.5	916.5	9,212.0
# of Residential Customers	62,157	62,167	62,182	62,189	62,235	62,326	62,365	62,410	62,428	62,456	62,480	62,474	62,322
Total Residential Sales - MWh	55,681	51,559	46,648	42,016	39,636	41,946	56,136	50,190	43,542	41,362	48,141	57,258	574,112
Use per Small Comm & Ind Customer - kWh	2,906.1	2,739.9	2,733.8	2,495.2	2,452.1	2,489.9	3,035.2	2,862.1	2,622.3	2,516.1	2,714.5	2,948.1	32,514.6
# of Small Comm & Ind Customers	9,749	9,737	9,741	9,810	9,901	9,956	9,962	9,988	9,974	9,911	9,888	9,894	9,876
Total Small Comm & Ind Sales - MWh	28,331	26,678	26,630	24,478	24,279	24,789	30,237	28,587	26,155	24,937	26,841	29,168	321,112
General Large Comm & Ind Sales	42,060	41,821	40,946	40,981	41,170	41,877	47,487	46,543	43,907	42,293	42,126	43,468	514,679
Sabin Metals Sales	1,398	1,434	1,486	1,509	1,500	1,426	1,545	1,485	1,472	1,511	1,191	1,177	17,134
Tesoro Refinery Sales	4,179	4,281	4,673	4,715	4,887	5,103	5,388	5,262	5,052	4,866	4,798	4,714	57,918
Westmoreland Coal - ND Sales	2,552	2,424	2,302	2,186	1,959	1,743	1,709	1,805	2,003	2,203	2,352	2,560	25,798
Total Sales (Residential, SC&I and LC&I)	134,201	128,197	122,685	115,885	113,431	116,884	142,502	133,872	122,132	117,172	125,449	138,345	1,510,753
Other Public Sales	2,791	2,678	2,757	2,594	2,919	3,171	3,664	3,508	3,000	2,655	2,590	2,787	35,114
Street & Highway Lighting Sales	1,870	1,758	1,773	1,702	1,675	1,562	1,649	1,667	1,718	1,802	1,882	1,898	20,956
Interdepartmental Sales	22	22	20	19	18	16	18	16	18	19	19	23	230
Total Billed Sales - MWh	138,884	132,655	127,235	120,200	118,043	121,633	147,833	139,063	126,868	121,648	129,940	143,053	1,567,053
Company Use	629	592	589	604	606	631	695	698	609	591	637	629	7,510
Total Energy	139,513	133,247	127,824	120,804	118,649	122,264	148,528	139,761	127,477	122,239	130,577	143,682	1,574,563
Total Requirements (Energy + Losses)	150,529	143,768	137,917	130,343	128,017	131,917	160,255	150,796	137,542	131,891	140,887	155,027	1,698,889
# of Large Comm & Ind Customers	735	738	739	742	744	743	744	744	744	746	746	745	743
# of Other Public Customers	712	712	713	717	723	723	723	722	719	715	711	708	717
# of Street & Highway Lighting Customers	490	492	492	494	494	496	480	482	484	486	487	488	489
Peak Demand Net of DSM Programs	264.3	252.5	232.0	225.3	251.8	317.6	349.8	338.2	277.9	230.8	252.9	285.4	349.8

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

NORTH DAKOTA YEAR 2011

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	901.2	834.3	754.7	679.7	640.7	676.4	904.9	808.4	701.0	666.2	775.1	922.0	9,264.9
# of Residential Customers	62,445	62,456	62,470	62,478	62,524	62,616	62,655	62,699	62,718	62,746	62,770	62,764	62,612
Total Residential Sales - MWh	56,276	52,109	47,146	42,465	40,060	42,354	56,696	50,687	43,968	41,804	48,655	57,871	580,089
Use per Small Comm & Ind Customer - kWh	2,967.4	2,797.6	2,791.5	2,547.6	2,503.9	2,542.1	3,099.1	2,922.7	2,677.4	2,569.0	2,771.5	3,010.2	33,199.0
# of Small Comm & Ind Customers	9,825	9,813	9,817	9,887	9,978	10,034	10,040	10,065	10,052	9,989	9,966	9,971	9,953
Total Small Comm & Ind Sales - MWh	29,154	27,453	27,404	25,188	24,984	25,508	31,115	29,417	26,914	25,661	27,620	30,014	330,432
General Large Comm & Ind Sales	42,586	42,345	41,458	41,493	41,684	42,398	48,079	47,122	44,454	42,822	42,653	43,376	520,470
Sabin Metals Sales	1,473	1,511	1,566	1,591	1,580	1,503	1,628	1,565	1,551	1,592	1,255	1,239	18,054
Tesoro Refinery Sales	4,300	4,405	4,809	4,852	5,028	5,250	5,543	5,413	5,198	5,006	4,937	4,849	59,590
Westmoreland Coal - ND Sales	2,552	2,424	2,302	2,186	1,959	1,743	1,709	1,805	2,003	2,203	2,352	2,560	25,798
Total Sales (Residential, SC&I and LC&I)	136,341	130,247	124,685	117,775	115,295	118,755	144,769	136,009	124,088	119,088	127,472	139,909	1,534,432
Other Public Sales	2,797	2,683	2,761	2,598	2,924	3,176	3,671	3,514	3,006	2,659	2,594	2,792	35,175
Street & Highway Lighting Sales	1,870	1,758	1,773	1,702	1,675	1,563	1,650	1,667	1,719	1,803	1,882	1,898	20,960
Interdepartmental Sales	22	22	20	19	18	16	18	16	18	19	19	23	230
Total Billed Sales - MWh	141,030	134,710	129,239	122,094	119,912	123,510	150,108	141,206	128,831	123,569	131,967	144,622	1,590,797
Company Use	629	592	589	604	606	631	695	698	609	591	637	629	7,510
Total Energy	141,659	135,302	129,828	122,698	120,518	124,141	150,803	141,904	129,440	124,160	132,604	145,251	1,598,307
Total Requirements (Energy + Losses)	152,844	145,985	140,079	132,386	130,034	133,943	162,710	153,109	139,661	133,964	143,074	156,720	1,724,509
# of Large Comm & Ind Customers	739	742	744	747	748	747	748	748	748	750	750	749	747
# of Other Public Customers	712	712	713	717	723	723	723	722	719	715	711	708	717
# of Street & Highway Lighting Customers	490	492	492	494	494	496	480	482	484	486	487	488	489
Peak Demand Net of DSM Programs	266.2	254.4	233.7	226.9	255.8	321.5	354.1	342.4	281.2	234.4	256.0	288.9	354.1

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

NORTH DAKOTA YEAR 2012

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	906.6	839.4	759.2	683.8	644.6	680.5	910.4	813.3	705.3	670.3	779.8	927.6	9,321.0
# of Residential Customers	62,737	62,747	62,762	62,769	62,815	62,907	62,947	62,992	63,010	63,039	63,062	63,057	62,904
Total Residential Sales - MWh	56,880	52,669	47,652	42,921	40,489	42,811	57,307	51,233	44,442	42,253	49,177	58,491	586,323
Use per Small Comm & Ind Customer - kWh	3,030.6	2,857.0	2,851.0	2,601.9	2,557.2	2,596.3	3,165.0	2,984.7	2,734.5	2,623.8	2,830.6	3,056.9	33,888.6
# of Small Comm & Ind Customers	9,899	9,888	9,891	9,962	10,054	10,110	10,116	10,142	10,128	10,064	10,041	10,047	10,029
Total Small Comm & Ind Sales - MWh	30,000	28,250	28,199	25,920	25,710	26,249	32,018	30,271	27,695	26,406	28,422	30,712	339,852
General Large Comm & Ind Sales	41,828	41,591	40,719	40,754	40,941	41,641	47,219	46,280	43,661	42,059	41,893	43,291	511,877
Sabin Metals Sales	1,548	1,588	1,646	1,672	1,661	1,580	1,710	1,645	1,631	1,673	1,319	1,300	18,973
Tesoro Refinery Sales	4,421	4,529	4,944	4,988	5,169	5,397	5,699	5,566	5,344	5,147	5,076	4,984	61,264
Westmoreland Coal - ND Sales	2,552	2,424	2,302	2,186	1,959	1,743	1,709	1,805	2,003	2,203	2,352	2,560	25,798
Total Sales (Residential, SC&I and LC&I)	137,229	131,051	125,462	118,441	115,929	119,420	145,661	136,800	124,776	119,741	128,239	141,338	1,544,086
Other Public Sales	2,802	2,688	2,767	2,603	2,930	3,183	3,678	3,521	3,011	2,665	2,600	2,797	35,245
Street & Highway Lighting Sales	1,870	1,759	1,774	1,703	1,675	1,563	1,650	1,667	1,719	1,803	1,883	1,898	20,964
Interdepartmental Sales	21	21	19	19	18	16	18	16	18	19	19	23	227
Total Billed Sales - MWh	141,922	135,519	130,022	122,766	120,552	124,182	151,007	142,004	129,524	124,228	132,741	146,056	1,600,522
Company Use	629	592	589	604	606	631	695	698	609	591	637	629	7,510
Total Energy	142,551	136,111	130,611	123,370	121,158	124,813	151,702	142,702	130,133	124,819	133,378	146,685	1,608,032
Total Requirements (Energy + Losses)	153,807	146,858	140,924	133,111	130,725	134,668	163,680	153,970	140,408	134,675	143,909	158,267	1,735,002
# of Large Comm & Ind Customers	743	746	747	750	751	751	752	752	752	754	753	753	750
# of Other Public Customers	712	712	713	717	723	723	723	722	719	715	711	708	717
# of Street & Highway Lighting Customers	490	492	492	494	494	496	480	482	484	486	487	488	489
Peak Demand Net of DSM Programs	269.5	257.5	236.6	229.7	258.5	325.0	358.0	346.2	284.3	236.9	258.8	292.1	358.0

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

NORTH DAKOTA YEAR 2013

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	912.1	844.5	763.9	688.0	648.5	684.7	916.0	818.3	709.6	674.3	784.5	933.1	9,377.7
# of Residential Customers	63,026	63,037	63,052	63,059	63,106	63,198	63,238	63,283	63,301	63,330	63,354	63,348	63,194
Total Residential Sales - MWh	57,489	53,233	48,163	43,382	40,924	43,273	57,925	51,786	44,921	42,706	49,704	59,113	592,617
Use per Small Comm & Ind Customer - kWh	3,061.4	2,886.4	2,880.0	2,628.5	2,583.3	2,623.0	3,197.5	3,015.3	2,762.6	2,650.7	2,859.5	3,088.0	34,235.3
# of Small Comm & Ind Customers	9,974	9,962	9,966	10,037	10,130	10,186	10,192	10,218	10,204	10,140	10,117	10,123	10,104
Total Small Comm & Ind Sales - MWh	30,534	28,754	28,702	26,382	26,169	26,718	32,589	30,811	28,190	26,878	28,929	31,260	345,916
General Large Comm & Ind Sales	42,479	42,238	41,353	41,389	41,580	42,291	47,958	47,004	44,342	42,715	42,547	43,975	519,871
Sabin Metals Sales	1,623	1,666	1,726	1,753	1,742	1,656	1,794	1,725	1,710	1,755	1,383	1,362	19,895
Tesoro Refinery Sales	4,542	4,653	5,079	5,125	5,310	5,545	5,855	5,718	5,490	5,287	5,214	5,118	62,936
Westmoreland Coal - ND Sales	2,552	2,424	2,302	2,186	1,959	1,743	1,709	1,805	2,003	2,203	2,352	2,560	25,798
Total Sales (Residential, SC&I and LC&I)	139,219	132,968	127,325	120,217	117,684	121,225	147,829	138,849	126,656	121,544	130,129	143,388	1,567,032
Other Public Sales	2,806	2,693	2,772	2,607	2,935	3,188	3,684	3,527	3,016	2,669	2,604	2,802	35,303
Street & Highway Lighting Sales	1,870	1,759	1,774	1,703	1,675	1,563	1,650	1,667	1,719	1,803	1,883	1,899	20,965
Interdepartmental Sales	21	21	19	19	18	16	18	16	17	18	19	23	225
Total Billed Sales - MWh	143,916	137,441	131,890	124,546	122,312	125,992	153,181	144,059	131,408	126,034	134,635	148,112	1,623,525
Company Use	629	592	589	604	606	631	695	698	609	591	637	629	7,510
Total Energy	144,545	138,033	132,479	125,150	122,918	126,623	153,876	144,757	132,017	126,625	135,272	148,741	1,631,035
Total Requirements (Energy + Losses)	155,958	148,932	142,939	135,032	132,623	136,621	166,026	156,187	142,441	136,623	145,953	160,485	1,759,820
# of Large Comm & Ind Customers	747	750	751	754	756	755	756	756	756	758	758	757	755
# of Other Public Customers	712	712	713	717	723	723	723	722	719	715	711	708	717
# of Street & Highway Lighting Customers	490	492	492	494	494	496	480	482	484	486	487	488	489
Peak Demand Net of DSM Programs	272.5	260.3	239.2	232.3	262.4	330.1	363.6	351.6	288.8	240.4	262.8	296.6	363.6

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

NORTH DAKOTA YEAR 2014

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	917.8	849.7	768.6	692.2	652.5	689.0	921.7	823.4	714.1	678.5	789.4	938.9	9,435.9
# of Residential Customers	63,299	63,309	63,324	63,332	63,378	63,471	63,511	63,557	63,575	63,604	63,628	63,622	63,468
Total Residential Sales - MWh	58,095	53,794	48,671	43,839	41,356	43,732	58,538	52,334	45,396	43,157	50,228	59,737	598,875
Use per Small Comm & Ind Customer - kWh	3,093.3	2,916.4	2,910.4	2,656.1	2,610.5	2,650.2	3,231.0	3,046.7	2,791.5	2,678.3	2,889.6	3,120.5	34,593.5
# of Small Comm & Ind Customers	10,047	10,035	10,038	10,110	10,203	10,261	10,266	10,293	10,278	10,214	10,190	10,196	10,178
Total Small Comm & Ind Sales - MWh	31,078	29,266	29,214	26,853	26,635	27,194	33,170	31,360	28,691	27,356	29,445	31,816	352,078
General Large Comm & Ind Sales	43,161	42,917	42,019	42,054	42,248	42,972	48,731	47,762	45,055	43,401	43,230	44,685	528,235
Sabin Metals Sales	1,698	1,742	1,806	1,834	1,823	1,733	1,877	1,805	1,789	1,836	1,447	1,404	20,794
Tesoro Refinery Sales	4,663	4,777	5,214	5,261	5,452	5,692	6,011	5,870	5,636	5,428	5,353	5,253	64,610
Westmoreland Coal - ND Sales	2,552	2,424	2,302	2,186	1,959	1,743	1,709	1,805	2,003	2,203	2,352	2,560	25,798
Total Sales (Residential, SC&I and LC&I)	141,247	134,920	129,226	122,027	119,473	123,065	150,035	140,936	128,570	123,381	132,055	145,455	1,590,389
Other Public Sales	2,812	2,698	2,777	2,612	2,940	3,194	3,690	3,533	3,022	2,674	2,609	2,807	35,368
Street & Highway Lighting Sales	1,871	1,759	1,774	1,703	1,676	1,563	1,650	1,668	1,719	1,803	1,883	1,899	20,968
Interdepartmental Sales	21	21	19	18	17	15	17	16	17	18	18	22	219
Total Billed Sales - MWh	145,951	139,398	133,796	126,360	124,106	127,837	155,392	146,153	133,328	127,876	136,565	150,183	1,646,944
Company Use	629	592	589	604	606	631	695	698	609	591	637	629	7,510
Total Energy	146,580	139,990	134,385	126,964	124,712	128,468	156,087	146,851	133,937	128,467	137,202	150,812	1,654,454
Total Requirements (Energy + Losses)	158,154	151,044	144,996	136,989	134,559	138,612	168,412	158,446	144,513	138,611	148,035	162,720	1,785,091
# of Large Comm & Ind Customers	751	754	755	758	760	759	760	760	760	762	762	761	759
# of Other Public Customers	712	712	713	717	723	723	723	722	719	715	711	708	717
# of Street & Highway Lighting Customers	490	492	492	494	494	496	480	482	484	486	487	488	489
Peak Demand Net of DSM Programs	276.7	264.4	242.9	235.9	266.3	335.3	369.3	357.1	293.4	244.1	266.9	301.3	369.3

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

NORTH DAKOTA YEAR 2015

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	923.5	855.0	773.3	696.5	656.6	693.3	927.4	828.6	718.5	682.7	794.3	944.7	9,494.5
# of Residential Customers	63,576	63,586	63,601	63,608	63,655	63,749	63,789	63,834	63,853	63,882	63,906	63,900	63,745
Total Residential Sales - MWh	58,711	54,364	49,186	44,303	41,794	44,198	59,161	52,892	45,880	43,614	50,761	60,367	605,229
Use per Small Comm & Ind Customer - kWh	3,125.7	2,947.0	2,940.8	2,684.0	2,637.6	2,678.1	3,264.7	3,078.7	2,820.8	2,706.5	2,919.6	3,153.3	34,955.9
# of Small Comm & Ind Customers	10,120	10,108	10,111	10,183	10,278	10,335	10,341	10,368	10,353	10,288	10,265	10,270	10,252
Total Small Comm & Ind Sales - MWh	31,632	29,788	29,734	27,331	27,110	27,679	33,761	31,920	29,204	27,844	29,969	32,384	358,356
General Large Comm & Ind Sales	43,861	43,612	42,699	42,735	42,932	43,668	49,523	48,538	45,785	44,104	43,930	45,406	536,793
Sabin Metals Sales	1,736	1,781	1,846	1,875	1,863	1,772	1,919	1,845	1,829	1,877	1,479	1,416	21,238
Tesoro Refinery Sales	4,784	4,901	5,349	5,397	5,593	5,840	6,166	6,022	5,783	5,570	5,492	5,387	66,284
Westmoreland Coal - ND Sales	2,552	2,424	2,302	2,186	1,959	1,743	1,709	1,805	2,003	2,203	2,352	2,560	25,798
Total Sales (Residential, SC&I and LC&I)	143,276	136,870	131,116	123,827	121,251	124,899	152,238	143,022	130,484	125,212	133,983	147,520	1,613,697
Other Public Sales	2,817	2,702	2,781	2,617	2,945	3,199	3,697	3,539	3,027	2,679	2,614	2,812	35,429
Street & Highway Lighting Sales	1,871	1,759	1,774	1,703	1,676	1,564	1,651	1,668	1,720	1,804	1,883	1,899	20,972
Interdepartmental Sales	20	21	19	18	17	15	17	15	17	18	18	22	217
Total Billed Sales - MWh	147,984	141,352	135,690	128,165	125,889	129,677	157,603	148,244	135,248	129,713	138,498	152,253	1,670,315
Company Use	629	592	589	604	606	631	695	698	609	591	637	629	7,510
Total Energy	148,613	141,944	136,279	128,769	126,495	130,308	158,298	148,942	135,857	130,304	139,135	152,882	1,677,825
Total Requirements (Energy + Losses)	160,347	153,152	147,039	138,937	136,483	140,597	170,797	160,702	146,584	140,593	150,121	164,953	1,810,305
# of Large Comm & Ind Customers	755	758	759	763	764	763	764	764	764	766	766	765	763
# of Other Public Customers	712	712	713	717	723	723	723	722	719	715	711	708	717
# of Street & Highway Lighting Customers	490	492	492	494	494	496	480	482	484	486	487	488	489
Peak Demand Net of DSM Programs	281.1	268.5	246.8	239.6	270.4	340.6	375.0	362.7	298.0	247.7	271.1	306.0	375.0

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

NORTH DAKOTA YEAR 2016

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	929.3	860.3	778.2	700.9	660.7	697.7	933.3	833.8	723.1	687.0	799.3	950.6	9,554.4
# of Residential Customers	63,842	63,852	63,867	63,875	63,922	64,016	64,056	64,102	64,120	64,149	64,173	64,167	64,012
Total Residential Sales - MWh	59,327	54,935	49,703	44,769	42,233	44,664	59,784	53,450	46,364	44,072	51,294	60,999	611,592
Use per Small Comm & Ind Customer - kWh	3,159.3	2,978.6	2,972.3	2,712.7	2,666.0	2,706.8	3,299.7	3,111.5	2,850.9	2,735.3	2,950.9	3,186.7	35,329.8
# of Small Comm & Ind Customers	10,191	10,179	10,182	10,255	10,350	10,408	10,414	10,441	10,426	10,361	10,337	10,343	10,324
Total Small Comm & Ind Sales - MWh	32,196	30,319	30,264	27,819	27,593	28,173	34,363	32,488	29,724	28,340	30,503	32,960	364,742
General Large Comm & Ind Sales	44,567	44,314	43,386	43,424	43,624	44,372	50,322	49,322	46,523	44,814	44,637	46,148	545,453
Sabin Metals Sales	1,736	1,781	1,846	1,875	1,863	1,772	1,919	1,845	1,829	1,877	1,479	1,416	21,238
Tesoro Refinery Sales	4,904	5,024	5,485	5,534	5,735	5,988	6,322	6,175	5,928	5,710	5,631	5,522	67,958
Westmoreland Coal - ND Sales	2,552	2,424	2,302	2,186	1,959	1,743	1,709	1,805	2,003	2,203	2,352	2,560	25,798
Total Sales (Residential, SC&I and LC&I)	145,282	138,797	132,986	125,607	123,007	126,711	154,418	145,085	132,371	127,016	135,896	149,605	1,636,780
Other Public Sales	2,822	2,707	2,786	2,622	2,951	3,205	3,703	3,546	3,033	2,684	2,618	2,817	35,494
Street & Highway Lighting Sales	1,871	1,759	1,774	1,704	1,676	1,564	1,651	1,668	1,720	1,804	1,884	1,899	20,974
Interdepartmental Sales	20	20	18	18	17	15	17	15	17	18	18	22	215
Total Billed Sales - MWh	149,995	143,283	137,564	129,951	127,651	131,495	159,789	150,314	137,141	131,522	140,416	154,343	1,693,463
Company Use	629	592	589	604	606	631	695	698	609	591	637	629	7,510
Total Energy	150,624	143,875	138,153	130,555	128,257	132,126	160,484	151,012	137,750	132,113	141,053	154,972	1,700,973
Total Requirements (Energy + Losses)	162,517	155,235	149,061	140,864	138,384	142,559	173,156	162,936	148,627	142,545	152,190	167,208	1,835,282
# of Large Comm & Ind Customers	759	761	763	766	768	767	768	768	768	770	769	769	766
# of Other Public Customers	712	712	713	717	723	723	723	722	719	715	711	708	717
# of Street & Highway Lighting Customers	490	492	492	494	494	496	480	482	484	486	487	488	489
Peak Demand Net of DSM Programs	285.5	272.7	250.6	243.3	274.4	345.9	380.9	368.4	302.7	251.5	275.4	310.7	380.9

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

NORTH DAKOTA YEAR 2017

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	935.2	865.8	783.1	705.3	664.9	702.2	939.2	839.2	727.7	691.4	804.4	956.6	9,615.0
# of Residential Customers	64,102	64,113	64,128	64,135	64,183	64,277	64,318	64,363	64,382	64,411	64,435	64,429	64,273
Total Residential Sales - MWh	59,947	55,509	50,222	45,237	42,675	45,134	60,411	54,011	46,850	44,532	51,829	61,632	617,987
Use per Small Comm & Ind Customer - kWh	3,193.3	3,010.7	3,004.3	2,741.8	2,694.6	2,736.1	3,335.5	3,145.3	2,881.5	2,764.8	2,982.7	3,221.1	35,710.7
# of Small Comm & Ind Customers	10,262	10,250	10,253	10,327	10,422	10,480	10,486	10,513	10,499	10,433	10,409	10,415	10,396
Total Small Comm & Ind Sales - MWh	32,769	30,859	30,803	28,314	28,084	28,675	34,976	33,067	30,253	28,845	31,047	33,547	371,239
General Large Comm & Ind Sales	45,307	45,050	44,107	44,144	44,348	45,110	51,160	50,143	47,296	45,558	45,378	46,809	554,410
Sabin Metals Sales	1,736	1,781	1,846	1,875	1,863	1,772	1,919	1,845	1,829	1,877	1,479	1,416	21,238
Tesoro Refinery Sales	5,025	5,148	5,619	5,670	5,875	6,135	6,478	6,327	6,075	5,851	5,770	5,657	69,630
Westmoreland Coal - ND Sales	2,552	2,424	2,302	2,186	1,959	1,743	1,709	1,805	2,003	2,203	2,352	2,560	25,798
Total Sales (Residential, SC&I and LC&I)	147,336	140,771	134,899	127,426	124,804	128,568	156,652	147,198	134,306	128,866	137,855	151,621	1,660,301
Other Public Sales	2,827	2,712	2,791	2,626	2,956	3,211	3,710	3,552	3,038	2,688	2,623	2,822	35,556
Street & Highway Lighting Sales	1,872	1,760	1,775	1,704	1,676	1,564	1,651	1,668	1,720	1,804	1,884	1,899	20,977
Interdepartmental Sales	20	20	18	18	17	15	17	15	17	18	18	22	215
Total Billed Sales - MWh	152,055	145,263	139,483	131,774	129,453	133,358	162,030	152,433	139,081	133,376	142,380	156,364	1,717,049
Company Use	629	592	589	604	606	631	695	698	609	591	637	629	7,510
Total Energy	152,684	145,855	140,072	132,378	130,059	133,989	162,725	153,131	139,690	133,967	143,017	156,993	1,724,559
Total Requirements (Energy + Losses)	164,740	157,372	151,132	142,831	140,328	144,569	175,574	165,222	150,720	144,545	154,310	169,389	1,860,732
# of Large Comm & Ind Customers	763	766	767	770	772	771	772	772	772	774	774	773	771
# of Other Public Customers	712	712	713	717	723	723	723	722	719	715	711	708	717
# of Street & Highway Lighting Customers	490	492	492	494	494	496	480	482	484	486	487	488	489
Peak Demand Net of DSM Programs	289.9	277.0	254.5	247.1	278.5	351.3	386.8	374.1	307.5	255.2	279.6	315.6	386.8

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

NORTH DAKOTA YEAR 2018

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	941.2	871.3	788.2	709.9	669.2	706.7	945.3	844.6	732.4	695.8	809.5	962.6	9,710.1
# of Residential Customers	64,353	64,363	64,378	64,386	64,434	64,528	64,569	64,615	64,634	64,663	64,687	64,681	64,524
Total Residential Sales - MWh	60,567	56,083	50,742	45,705	43,116	45,603	61,039	54,573	47,338	44,993	52,365	62,265	626,537
Use per Small Comm & Ind Customer - kWh	3,228.2	3,043.5	3,037.1	2,771.9	2,724.2	2,765.9	3,371.6	3,179.6	2,913.2	2,795.1	3,015.3	3,256.3	36,100.9
# of Small Comm & Ind Customers	10,332	10,320	10,323	10,397	10,493	10,552	10,558	10,585	10,570	10,504	10,480	10,486	10,467
Total Small Comm & Ind Sales - MWh	33,353	31,409	31,352	28,819	28,585	29,186	35,598	33,657	30,793	29,359	31,600	34,145	377,856
General Large Comm & Ind Sales	45,845	45,585	44,631	44,669	44,875	45,646	51,769	50,740	47,857	46,098	45,917	47,369	561,001
Sabin Metals Sales	1,736	1,781	1,846	1,875	1,863	1,772	1,919	1,845	1,829	1,877	1,479	1,416	21,238
Tesoro Refinery Sales	5,146	5,272	5,754	5,806	6,017	6,283	6,634	6,479	6,221	5,992	5,908	5,791	71,303
Westmoreland Coal - ND Sales	2,552	2,424	2,302	2,186	1,959	1,743	1,709	1,805	2,003	2,203	2,352	2,560	25,798
Total Sales (Residential, SC&I and LC&I)	149,199	142,554	136,627	129,060	126,415	130,232	158,667	149,099	136,041	130,522	139,621	153,546	1,681,582
Other Public Sales	2,832	2,717	2,796	2,631	2,961	3,217	3,717	3,558	3,044	2,693	2,628	2,827	35,621
Street & Highway Lighting Sales	1,872	1,760	1,775	1,704	1,677	1,564	1,651	1,668	1,720	1,804	1,884	1,900	20,979
Interdepartmental Sales	20	20	18	18	17	15	17	15	16	17	18	21	212
Total Billed Sales - MWh	153,923	147,051	141,216	133,413	131,070	135,028	164,052	154,340	140,821	135,036	144,151	158,294	1,738,394
Company Use	629	592	589	604	606	631	695	698	609	591	637	629	7,510
Total Energy	154,552	147,643	141,805	134,017	131,676	135,659	164,747	155,038	141,430	135,627	144,788	158,923	1,745,904
Total Requirements (Energy + Losses)	166,755	159,301	153,002	144,599	142,073	146,371	177,755	167,280	152,597	146,336	156,220	171,471	1,883,760
# of Large Comm & Ind Customers	767	770	771	775	776	775	776	776	776	778	778	777	775
# of Other Public Customers	712	712	713	717	723	723	723	722	719	715	711	708	717
# of Street & Highway Lighting Customers	490	492	492	494	494	496	480	482	484	486	487	488	489
Peak Demand Net of DSM Programs	294.4	281.3	258.5	251.0	282.3	356.3	392.2	379.3	311.8	258.7	283.6	320.0	392.2

APPENDIX F

Monthly Forecasts – South Dakota
(2009-2018)

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

SOUTH DAKOTA YEAR 2009

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	961.3	864.4	812.9	705.1	656.4	683.0	890.4	787.3	706.6	672.8	788.7	942.2	9,469.3
# of Residential Customers	6,632	6,629	6,628	6,636	6,659	6,675	6,703	6,697	6,687	6,669	6,640	6,621	6,656
Total Residential Sales - MWh	6,375	5,730	5,388	4,679	4,371	4,559	5,968	5,273	4,725	4,487	5,237	6,238	63,031
Use per Small Comm & Ind Customer - kWh	1,843.2	1,757.9	1,619.4	1,496.1	1,438.0	1,490.9	2,000.9	1,750.5	1,673.0	1,550.5	1,683.1	1,851.0	20,151.2
# of Small Comm & Ind Customers	1,779	1,776	1,779	1,808	1,847	1,864	1,864	1,862	1,852	1,820	1,808	1,805	1,822
Total Small Comm & Ind Sales - MWh	3,279	3,122	2,881	2,705	2,656	2,779	3,730	3,260	3,098	2,822	3,043	3,341	36,716
General Large Comm & Ind Sales	2,457	2,588	2,385	2,389	2,397	2,203	3,008	2,306	2,881	2,530	2,524	2,741	30,408
Total Sales (Residential, SC&I and LC&I)	12,111	11,440	10,654	9,773	9,424	9,541	12,705	10,839	10,704	9,839	10,804	12,320	130,155
Other Public Sales	161	198	163	168	199	205	290	186	230	150	156	191	2,297
Street & Highway Lighting Sales	224	211	225	222	222	215	219	221	219	225	220	214	2,637
Interdepartmental Sales	1	1	1	1	1	-	-	-	1	1	1	1	9
Total Billed Sales - MWh	12,497	11,850	11,043	10,164	9,846	9,961	13,214	11,246	11,154	10,215	11,181	12,726	135,098
Company Use	52	42	35	20	17	10	12	14	12	17	29	43	303
Total Energy	12,549	11,892	11,078	10,184	9,863	9,971	13,226	11,260	11,166	10,232	11,210	12,769	135,401
Total Requirements (Energy + Losses)	13,540	12,831	11,953	10,988	10,642	10,759	14,271	12,149	12,048	11,040	12,095	13,777	146,093
# of Large Comm & Ind Customers	69	69	69	69	69	70	69	69	69	70	70	69	69
# of Other Public Customers	54	53	54	56	60	61	62	61	60	56	54	53	57
# of Street & Highway Lighting Customers	39	39	40	40	40	40	39	39	39	39	38	39	39
Peak Demand Net of DSM Programs	21.2	21.2	20.2	18.3	18.9	24.5	30.2	24.0	24.9	21.4	20.7	22.2	30.2

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

SOUTH DAKOTA YEAR 2010

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	966.5	869.1	817.2	708.6	659.7	685.1	893.7	790.1	708.9	676.3	793.2	947.2	9,513.7
# of Residential Customers	6,663	6,659	6,659	6,667	6,690	6,706	6,734	6,728	6,718	6,700	6,670	6,652	6,687
Total Residential Sales - MWh	6,440	5,788	5,442	4,724	4,414	4,594	6,018	5,316	4,762	4,532	5,291	6,301	63,620
Use per Small Comm & Ind Customer - kWh	1,880.5	1,793.2	1,652.4	1,526.8	1,467.3	1,520.7	2,040.8	1,786.5	1,706.4	1,581.4	1,717.2	1,888.8	20,558.6
# of Small Comm & Ind Customers	1,793	1,790	1,793	1,822	1,861	1,879	1,879	1,876	1,867	1,835	1,822	1,819	1,836
Total Small Comm & Ind Sales - MWh	3,372	3,210	2,963	2,782	2,731	2,857	3,835	3,352	3,186	2,902	3,129	3,436	37,753
General Large Comm & Ind Sales	2,518	2,652	2,443	2,447	2,455	2,254	3,077	2,357	2,950	2,592	2,587	2,787	31,118
Total Sales (Residential, SC&I and LC&I)	12,329	11,649	10,847	9,953	9,600	9,705	12,930	11,024	10,898	10,025	11,006	12,523	132,490
Other Public Sales	161	198	163	168	199	206	291	186	230	151	157	191	2,301
Street & Highway Lighting Sales	224	211	225	222	222	215	220	222	219	225	220	214	2,639
Interdepartmental Sales	1	1	1	1	1	-	-	-	1	1	1	1	9
Total Billed Sales - MWh	12,715	12,059	11,236	10,344	10,022	10,126	13,441	11,432	11,348	10,402	11,384	12,929	137,439
Company Use	52	42	35	20	17	10	12	14	12	17	29	43	303
Total Energy	12,767	12,101	11,271	10,364	10,039	10,136	13,453	11,446	11,360	10,419	11,413	12,972	137,742
Total Requirements (Energy + Losses)	13,775	13,057	12,161	11,182	10,831	10,937	14,515	12,350	12,257	11,242	12,314	13,996	148,617
# of Large Comm & Ind Customers	70	70	70	70	70	70	70	70	70	70	70	70	70
# of Other Public Customers	54	53	54	56	60	61	62	61	60	56	54	53	57
# of Street & Highway Lighting Customers	39	39	40	40	40	40	39	39	39	39	38	39	39
Peak Demand Net of DSM Programs	21.6	21.6	20.5	18.7	19.3	24.6	30.4	24.1	25.0	21.7	20.8	22.3	30.4

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

SOUTH DAKOTA YEAR 2011

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	972.1	874.4	822.2	713.0	663.7	688.6	898.5	794.4	712.5	680.4	797.9	953.1	9,568.7
# of Residential Customers	6,694	6,690	6,689	6,698	6,721	6,737	6,765	6,759	6,749	6,731	6,701	6,682	6,718
Total Residential Sales - MWh	6,508	5,850	5,500	4,775	4,461	4,639	6,079	5,369	4,809	4,580	5,347	6,369	64,282
Use per Small Comm & Ind Customer - kWh	1,920.8	1,831.4	1,687.2	1,559.3	1,497.7	1,553.2	2,084.2	1,823.5	1,742.5	1,614.8	1,753.7	1,927.9	20,992.7
# of Small Comm & Ind Customers	1,807	1,804	1,807	1,836	1,876	1,893	1,893	1,891	1,881	1,849	1,836	1,834	1,851
Total Small Comm & Ind Sales - MWh	3,471	3,304	3,049	2,863	2,810	2,940	3,945	3,448	3,278	2,986	3,220	3,536	38,849
General Large Comm & Ind Sales	2,550	2,686	2,474	2,478	2,486	2,282	3,116	2,387	2,986	2,625	2,619	2,771	31,460
Total Sales (Residential, SC&I and LC&I)	12,528	11,839	11,022	10,116	9,757	9,861	13,140	11,204	11,073	10,190	11,185	12,675	134,591
Other Public Sales	162	198	164	169	199	206	291	187	231	151	157	191	2,306
Street & Highway Lighting Sales	224	211	225	222	222	215	220	222	219	226	221	214	2,641
Interdepartmental Sales	1	1	1	1	1	-	-	-	1	1	1	1	9
Total Billed Sales - MWh	12,915	12,249	11,412	10,508	10,179	10,282	13,651	11,613	11,524	10,568	11,564	13,081	139,547
Company Use	52	42	35	20	17	10	12	14	12	17	29	43	303
Total Energy	12,967	12,291	11,447	10,528	10,196	10,292	13,663	11,627	11,536	10,585	11,593	13,124	139,850
Total Requirements (Energy + Losses)	13,991	13,262	12,351	11,359	11,001	11,105	14,742	12,545	12,447	11,421	12,508	14,160	150,892
# of Large Comm & Ind Customers	70	70	70	70	70	70	70	70	70	70	70	70	70
# of Other Public Customers	54	53	54	56	60	61	62	61	60	56	54	53	57
# of Street & Highway Lighting Customers	39	39	40	40	40	40	39	39	39	39	38	39	39
Peak Demand Net of DSM Programs	21.8	21.7	20.7	18.8	19.6	24.8	30.7	24.3	25.1	22.1	21.1	22.6	30.7

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

SOUTH DAKOTA YEAR 2012

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	978.1	879.4	827.0	717.3	667.8	692.8	904.1	799.0	716.9	684.5	802.5	958.7	9,626.2
# of Residential Customers	6,725	6,722	6,721	6,729	6,752	6,769	6,796	6,791	6,780	6,762	6,733	6,714	6,750
Total Residential Sales - MWh	6,578	5,912	5,559	4,826	4,509	4,690	6,145	5,426	4,861	4,629	5,404	6,437	64,972
Use per Small Comm & Ind Customer - kWh	1,962.0	1,870.6	1,722.6	1,592.3	1,529.9	1,585.5	2,129.2	1,862.6	1,779.7	1,649.4	1,791.2	1,958.2	21,429.6
# of Small Comm & Ind Customers	1,820	1,817	1,821	1,850	1,890	1,908	1,907	1,905	1,895	1,863	1,850	1,847	1,864
Total Small Comm & Ind Sales - MWh	3,571	3,399	3,137	2,946	2,892	3,025	4,060	3,548	3,373	3,073	3,314	3,617	39,954
General Large Comm & Ind Sales	2,504	2,638	2,430	2,434	2,441	2,241	3,060	2,344	2,933	2,578	2,572	2,776	30,951
Total Sales (Residential, SC&I and LC&I)	12,652	11,948	11,125	10,206	9,842	9,956	13,265	11,318	11,167	10,279	11,289	12,829	135,877
Other Public Sales	162	199	164	169	200	207	292	187	231	151	157	192	2,311
Street & Highway Lighting Sales	224	211	225	222	222	215	220	222	219	226	221	214	2,641
Interdepartmental Sales	1	1	1	1	1	-	-	-	1	1	1	1	9
Total Billed Sales - MWh	13,039	12,359	11,515	10,598	10,265	10,378	13,777	11,727	11,618	10,657	11,668	13,236	140,838
Company Use	52	42	35	20	17	10	12	14	12	17	29	43	303
Total Energy	13,091	12,401	11,550	10,618	10,282	10,388	13,789	11,741	11,630	10,674	11,697	13,279	141,141
Total Requirements (Energy + Losses)	14,125	13,380	12,462	11,456	11,093	11,209	14,878	12,668	12,548	11,517	12,621	14,328	152,285
# of Large Comm & Ind Customers	70	70	70	70	71	71	71	70	71	71	71	71	71
# of Other Public Customers	54	53	54	56	60	61	62	61	60	56	54	53	57
# of Street & Highway Lighting Customers	39	39	40	40	40	40	39	39	39	39	38	39	39
Peak Demand Net of DSM Programs	22.1	22.0	20.9	19.0	19.8	25.1	31.0	24.6	25.4	22.3	21.3	22.9	31.0

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

SOUTH DAKOTA YEAR 2013

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	984.1	884.9	832.1	721.7	671.8	697.0	909.4	804.0	721.2	688.6	807.4	964.5	9,684.8
# of Residential Customers	6,756	6,753	6,752	6,760	6,783	6,800	6,828	6,822	6,812	6,794	6,764	6,745	6,781
Total Residential Sales - MWh	6,649	5,976	5,619	4,878	4,557	4,740	6,210	5,485	4,913	4,679	5,462	6,506	65,670
Use per Small Comm & Ind Customer - kWh	1,981.9	1,889.0	1,739.9	1,608.8	1,546.0	1,602.6	2,150.1	1,880.9	1,797.7	1,666.4	1,809.4	1,977.9	21,647.1
# of Small Comm & Ind Customers	1,834	1,831	1,835	1,864	1,904	1,922	1,922	1,920	1,910	1,877	1,864	1,861	1,879
Total Small Comm & Ind Sales - MWh	3,635	3,459	3,193	2,999	2,944	3,080	4,132	3,611	3,434	3,128	3,373	3,681	40,668
General Large Comm & Ind Sales	2,543	2,679	2,468	2,472	2,479	2,276	3,108	2,381	2,979	2,618	2,612	2,820	31,435
Total Sales (Residential, SC&I and LC&I)	12,826	12,113	11,279	10,349	9,980	10,096	13,450	11,477	11,326	10,424	11,446	13,006	137,773
Other Public Sales	162	199	164	169	200	207	292	187	231	152	158	192	2,313
Street & Highway Lighting Sales	224	211	225	222	222	215	220	222	219	226	221	214	2,641
Interdepartmental Sales	1	1	1	1	-	-	-	-	1	1	1	1	8
Total Billed Sales - MWh	13,213	12,524	11,669	10,741	10,402	10,518	13,962	11,886	11,777	10,803	11,826	13,413	142,735
Company Use	52	42	35	20	17	10	12	14	12	17	29	43	303
Total Energy	13,265	12,566	11,704	10,761	10,419	10,528	13,974	11,900	11,789	10,820	11,855	13,456	143,038
Total Requirements (Energy + Losses)	14,313	13,558	12,628	11,611	11,241	11,360	15,077	12,840	12,720	11,674	12,791	14,519	154,332
# of Large Comm & Ind Customers	71	71	71	71	71	71	71	71	71	71	71	71	71
# of Other Public Customers	54	53	54	56	60	61	62	61	60	56	54	53	57
# of Street & Highway Lighting Customers	39	39	40	40	40	40	39	39	39	39	38	39	39
Peak Demand Net of DSM Programs	22.3	22.2	21.2	19.3	20.1	25.5	31.5	25.0	25.8	22.6	21.7	23.2	31.5

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

SOUTH DAKOTA YEAR 2014

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	990.2	890.4	837.3	726.0	676.0	701.5	915.4	809.1	725.9	692.9	812.5	970.4	9,745.5
# of Residential Customers	6,785	6,782	6,781	6,790	6,813	6,829	6,857	6,851	6,841	6,823	6,793	6,774	6,810
Total Residential Sales - MWh	6,719	6,039	5,678	4,929	4,606	4,791	6,277	5,543	4,966	4,728	5,520	6,574	66,366
Use per Small Comm & Ind Customer - kWh	2,002.6	1,909.3	1,758.5	1,625.0	1,561.8	1,618.9	2,172.7	1,900.9	1,816.3	1,683.7	1,827.9	1,998.3	21,872.4
# of Small Comm & Ind Customers	1,847	1,844	1,848	1,878	1,918	1,936	1,936	1,934	1,924	1,891	1,878	1,875	1,892
Total Small Comm & Ind Sales - MWh	3,699	3,521	3,250	3,052	2,996	3,134	4,206	3,676	3,495	3,184	3,433	3,747	41,392
General Large Comm & Ind Sales	2,584	2,722	2,507	2,511	2,520	2,313	3,158	2,420	3,027	2,660	2,654	2,865	31,941
Total Sales (Residential, SC&I and LC&I)	13,001	12,281	11,434	10,492	10,122	10,238	13,641	11,639	11,488	10,571	11,606	13,185	139,699
Other Public Sales	162	199	165	170	201	207	293	188	233	152	158	193	2,321
Street & Highway Lighting Sales	224	211	225	222	222	215	220	222	219	226	221	214	2,641
Interdepartmental Sales	1	1	1	1	-	-	-	-	1	1	1	1	8
Total Billed Sales - MWh	13,388	12,692	11,825	10,885	10,545	10,660	14,154	12,049	11,941	10,950	11,986	13,593	144,669
Company Use	52	42	35	20	17	10	12	14	12	17	29	43	303
Total Energy	13,440	12,734	11,860	10,905	10,562	10,670	14,166	12,063	11,953	10,967	12,015	13,636	144,972
Total Requirements (Energy + Losses)	14,501	13,740	12,797	11,766	11,396	11,513	15,285	13,016	12,896	11,833	12,964	14,713	156,420
# of Large Comm & Ind Customers	71	71	71	71	71	72	71	71	71	71	71	71	71
# of Other Public Customers	54	53	54	56	60	61	62	61	60	56	54	53	57
# of Street & Highway Lighting Customers	39	39	40	40	40	40	39	39	39	39	38	39	39
Peak Demand Net of DSM Programs	22.6	22.6	21.5	19.6	20.4	25.9	32.0	25.3	26.2	23.0	22.0	23.6	32.0

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

SOUTH DAKOTA YEAR 2015

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	996.3	896.0	842.4	730.7	680.2	705.9	921.0	814.1	730.4	697.3	817.5	976.4	9,806.1
# of Residential Customers	6,815	6,811	6,811	6,819	6,843	6,859	6,887	6,881	6,871	6,853	6,823	6,803	6,840
Total Residential Sales - MWh	6,790	6,103	5,738	4,982	4,655	4,842	6,343	5,602	5,019	4,779	5,578	6,643	67,070
Use per Small Comm & Ind Customer - kWh	2,023.0	1,928.8	1,777.4	1,642.4	1,578.0	1,636.0	2,195.6	1,921.1	1,835.2	1,701.6	1,846.6	2,018.4	22,100.7
# of Small Comm & Ind Customers	1,861	1,858	1,861	1,891	1,932	1,950	1,950	1,948	1,938	1,904	1,892	1,889	1,906
Total Small Comm & Ind Sales - MWh	3,765	3,584	3,308	3,106	3,049	3,190	4,281	3,742	3,557	3,240	3,494	3,813	42,128
General Large Comm & Ind Sales	2,626	2,766	2,548	2,553	2,561	2,351	3,210	2,460	3,076	2,704	2,698	2,913	32,466
Total Sales (Residential, SC&I and LC&I)	13,180	12,452	11,593	10,641	10,265	10,383	13,834	11,804	11,652	10,722	11,769	13,368	141,664
Other Public Sales	163	200	165	170	201	207	293	188	233	152	158	193	2,323
Street & Highway Lighting Sales	224	211	225	222	222	215	220	222	219	226	221	214	2,641
Interdepartmental Sales	1	1	1	1	-	-	-	-	1	1	1	1	8
Total Billed Sales - MWh	13,568	12,864	11,984	11,034	10,688	10,805	14,347	12,214	12,105	11,101	12,149	13,776	146,636
Company Use	52	42	35	20	17	10	12	14	12	17	29	43	303
Total Energy	13,620	12,906	12,019	11,054	10,705	10,815	14,359	12,228	12,117	11,118	12,178	13,819	146,939
Total Requirements (Energy + Losses)	14,696	13,925	12,968	11,927	11,550	11,669	15,493	13,194	13,073	11,996	13,140	14,910	158,541
# of Large Comm & Ind Customers	72	72	71	72	72	72	72	72	72	72	72	72	72
# of Other Public Customers	54	53	54	56	60	61	62	61	60	56	54	53	57
# of Street & Highway Lighting Customers	39	39	40	40	40	40	39	39	39	39	38	39	39
Peak Demand Net of DSM Programs	23.0	22.9	21.8	19.9	20.7	26.3	32.5	25.7	26.6	23.3	22.3	23.9	32.5

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

SOUTH DAKOTA YEAR 2016

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	1,002.6	901.5	847.9	735.2	684.4	710.3	926.8	819.3	734.9	701.6	822.6	982.5	9,867.5
# of Residential Customers	6,843	6,840	6,839	6,848	6,871	6,888	6,916	6,910	6,900	6,881	6,851	6,832	6,868
Total Residential Sales - MWh	6,861	6,167	5,799	5,034	4,703	4,893	6,410	5,661	5,071	4,828	5,636	6,713	67,772
Use per Small Comm & Ind Customer - kWh	2,044.7	1,949.7	1,795.6	1,659.7	1,594.3	1,653.4	2,218.6	1,942.0	1,855.8	1,719.4	1,867.1	2,040.4	22,337.1
# of Small Comm & Ind Customers	1,874	1,871	1,875	1,905	1,946	1,964	1,964	1,961	1,951	1,918	1,905	1,902	1,920
Total Small Comm & Ind Sales - MWh	3,832	3,648	3,367	3,162	3,103	3,247	4,357	3,808	3,621	3,298	3,557	3,881	42,880
General Large Comm & Ind Sales	2,669	2,811	2,589	2,594	2,602	2,389	3,262	2,500	3,126	2,747	2,741	2,960	32,990
Total Sales (Residential, SC&I and LC&I)	13,361	12,625	11,754	10,790	10,408	10,529	14,029	11,969	11,818	10,872	11,933	13,553	143,642
Other Public Sales	163	200	165	170	201	207	294	188	233	152	158	193	2,324
Street & Highway Lighting Sales	224	211	225	222	222	215	220	222	219	226	221	214	2,641
Interdepartmental Sales	1	1	1	1	-	-	-	-	1	1	1	1	8
Total Billed Sales - MWh	13,749	13,037	12,145	11,183	10,831	10,951	14,543	12,379	12,271	11,251	12,313	13,961	148,615
Company Use	52	42	35	20	17	10	12	14	12	17	29	43	303
Total Energy	13,801	13,079	12,180	11,203	10,848	10,961	14,555	12,393	12,283	11,268	12,342	14,004	148,918
Total Requirements (Energy + Losses)	14,891	14,112	13,142	12,088	11,704	11,827	15,704	13,372	13,253	12,158	13,317	15,110	160,678
# of Large Comm & Ind Customers	72	72	72	72	72	72	72	72	72	72	72	72	72
# of Other Public Customers	54	53	54	56	60	61	62	61	60	56	54	53	57
# of Street & Highway Lighting Customers	39	39	40	40	40	40	39	39	39	39	38	39	39
Peak Demand Net of DSM Programs	23.4	23.3	22.2	20.2	21.0	26.7	33.0	26.1	27.1	23.7	22.7	24.3	33.0

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

SOUTH DAKOTA YEAR 2017

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	1,009.0	907.3	853.1	739.7	688.8	714.8	932.8	824.6	739.7	706.0	828.0	988.7	9,930.5
# of Residential Customers	6,871	6,868	6,867	6,876	6,899	6,916	6,944	6,938	6,928	6,910	6,879	6,860	6,896
Total Residential Sales - MWh	6,933	6,232	5,859	5,086	4,752	4,944	6,478	5,721	5,125	4,879	5,696	6,783	68,484
Use per Small Comm & Ind Customer - kWh	2,066.7	1,970.7	1,815.0	1,677.7	1,612.4	1,671.0	2,243.5	1,962.7	1,875.1	1,737.9	1,886.8	2,062.6	22,578.2
# of Small Comm & Ind Customers	1,887	1,884	1,888	1,918	1,959	1,978	1,977	1,975	1,965	1,931	1,918	1,915	1,933
Total Small Comm & Ind Sales - MWh	3,900	3,713	3,427	3,218	3,159	3,305	4,435	3,876	3,685	3,356	3,619	3,950	43,642
General Large Comm & Ind Sales	2,713	2,858	2,633	2,637	2,645	2,429	3,317	2,542	3,177	2,793	2,787	3,001	33,532
Total Sales (Residential, SC&I and LC&I)	13,545	12,802	11,918	10,941	10,556	10,678	14,230	12,139	11,987	11,027	12,101	13,733	145,658
Other Public Sales	163	200	165	171	202	208	294	189	234	153	159	194	2,332
Street & Highway Lighting Sales	224	211	225	222	222	215	220	222	219	226	221	214	2,641
Interdepartmental Sales	1	1	1	1	-	-	-	-	1	1	1	1	8
Total Billed Sales - MWh	13,933	13,214	12,309	11,335	10,980	11,101	14,744	12,550	12,441	11,407	12,482	14,142	150,639
Company Use	52	42	35	20	17	10	12	14	12	17	29	43	303
Total Energy	13,985	13,256	12,344	11,355	10,997	11,111	14,756	12,564	12,453	11,424	12,511	14,185	150,942
Total Requirements (Energy + Losses)	15,089	14,303	13,319	12,252	11,865	11,989	15,921	13,556	13,436	12,326	13,499	15,305	162,860
# of Large Comm & Ind Customers	72	72	72	72	72	73	72	72	72	73	73	72	72
# of Other Public Customers	54	53	54	56	60	61	62	61	60	56	54	53	57
# of Street & Highway Lighting Customers	39	39	40	40	40	40	39	39	39	39	38	39	39
Peak Demand Net of DSM Programs	23.7	23.6	22.5	20.5	21.3	27.1	33.5	26.6	27.5	24.0	23.0	24.7	33.5

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

SOUTH DAKOTA YEAR 2018

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	1,015.3	913.1	858.6	744.5	693.3	719.5	938.7	829.9	744.5	710.7	833.3	994.8	9,994.2
# of Residential Customers	6,898	6,895	6,894	6,903	6,926	6,943	6,971	6,965	6,955	6,936	6,906	6,887	6,923
Total Residential Sales - MWh	7,004	6,296	5,920	5,139	4,802	4,996	6,544	5,780	5,178	4,930	5,755	6,852	69,192
Use per Small Comm & Ind Customer - kWh	2,089.4	1,992.0	1,835.7	1,696.4	1,629.3	1,689.7	2,267.4	1,983.6	1,895.7	1,757.1	1,907.7	2,085.5	22,825.7
# of Small Comm & Ind Customers	1,900	1,897	1,900	1,931	1,973	1,991	1,991	1,989	1,978	1,944	1,931	1,928	1,946
Total Small Comm & Ind Sales - MWh	3,970	3,779	3,488	3,276	3,215	3,364	4,514	3,945	3,750	3,416	3,684	4,021	44,421
General Large Comm & Ind Sales	2,746	2,892	2,664	2,669	2,677	2,458	3,356	2,572	3,215	2,826	2,821	3,037	33,933
Total Sales (Residential, SC&I and LC&I)	13,719	12,966	12,071	11,084	10,694	10,818	14,414	12,297	12,143	11,171	12,259	13,909	147,546
Other Public Sales	164	201	166	171	202	208	294	189	234	153	159	194	2,335
Street & Highway Lighting Sales	225	211	225	222	222	216	220	222	219	226	221	214	2,643
Interdepartmental Sales	1	1	1	1	-	-	-	-	-	1	1	1	7
Total Billed Sales - MWh	14,109	13,379	12,463	11,478	11,118	11,242	14,928	12,708	12,596	11,551	12,640	14,318	152,531
Company Use	52	42	35	20	17	10	12	14	12	17	29	43	303
Total Energy	14,161	13,421	12,498	11,498	11,135	11,252	14,940	12,722	12,608	11,568	12,669	14,361	152,834
Total Requirements (Energy + Losses)	15,279	14,481	13,485	12,406	12,014	12,141	16,120	13,727	13,603	12,482	13,669	15,495	164,902
# of Large Comm & Ind Customers	73	73	73	73	73	73	73	73	73	73	73	73	73
# of Other Public Customers	54	53	54	56	60	61	62	61	60	56	54	53	57
# of Street & Highway Lighting Customers	39	39	40	40	40	40	39	39	39	39	38	39	39
Peak Demand Net of DSM Programs	24.1	24.0	22.9	20.8	21.6	27.5	34.0	26.9	27.9	24.4	23.4	25.0	34.0

APPENDIX G

Monthly Forecasts – Integrated System
(2009-2018)

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

INTEGRATED SYSTEM YEAR 2009

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	882.2	813.8	739.1	665.9	629.1	663.2	897.2	793.9	691.7	651.5	754.7	902.5	9,084.9
# of Residential Customers	87,242	87,245	87,242	87,198	87,272	87,387	87,470	87,517	87,532	87,555	87,573	87,552	87,399
Total Residential Sales - MWh	76,962	71,001	64,477	58,061	54,900	57,953	78,477	69,479	60,549	57,041	66,094	79,013	794,008
Use per Small Comm & Ind Customer - kWh	2,525.1	2,400.2	2,347.0	2,152.1	2,137.8	2,133.2	2,690.0	2,482.2	2,290.3	2,164.0	2,330.0	2,569.7	28,220.4
# of Small Comm & Ind Customers	16,149	16,133	16,146	16,291	16,485	16,585	16,602	16,631	16,593	16,445	16,383	16,373	16,401
Total Small Comm & Ind Sales - MWh	40,777	38,722	37,894	35,060	35,241	35,379	44,659	41,282	38,003	35,587	38,172	42,073	462,852
General Large Comm & Ind Sales	61,250	60,835	58,689	59,429	59,056	59,369	66,706	64,819	63,374	62,283	62,495	67,037	745,340
Sabin Metals Sales	1,253	1,286	1,332	1,353	1,345	1,279	1,385	1,332	1,320	1,355	1,067	1,094	15,401
Encore Oil Sales	15,608	15,732	15,848	16,038	16,263	15,629	16,589	15,898	16,487	17,483	17,607	18,438	197,620
Tesoro Refinery Sales	4,059	4,158	4,538	4,579	4,745	4,955	5,232	5,110	4,906	4,725	4,659	4,580	56,246
TransCanada Keystone Pipeline	-	-	-	-	-	-	-	-	-	-	-	-	-
Westmoreland Coal Sales	2,784	2,660	2,514	2,381	2,129	1,880	1,845	1,932	2,135	2,366	2,561	2,814	28,001
Total Sales (Residential, SC&I and LC&I)	202,693	194,394	185,292	176,902	173,679	176,445	214,892	199,853	186,774	180,840	192,655	215,049	2,299,468
Other Public Sales	3,418	3,361	3,355	3,235	3,655	3,975	4,780	4,384	3,872	3,288	3,183	3,477	43,983
Street & Highway Lighting Sales	2,715	2,535	2,614	2,511	2,514	2,345	2,451	2,493	2,523	2,649	2,700	2,730	30,780
Interdepartmental Sales	42	41	38	36	33	29	34	29	34	34	37	46	433
Total Billed Sales - MWh	208,868	200,331	191,299	182,684	179,881	182,794	222,157	206,759	193,203	186,811	198,575	221,302	2,374,664
Company Use	727	679	664	658	655	670	744	746	650	637	702	713	8,245
Total Energy	209,595	201,010	191,963	183,342	180,536	183,464	222,901	207,505	193,853	187,448	199,277	222,015	2,382,909
Total Requirements (Energy + Losses)	226,144	216,882	207,121	197,818	194,792	197,951	240,502	223,889	209,160	202,249	215,011	239,545	2,571,064
# of Large Comm & Ind Customers	1,047	1,050	1,052	1,057	1,063	1,065	1,066	1,067	1,065	1,065	1,062	1,060	1,060
# of Other Public Customers	868	866	869	878	892	893	894	892	886	876	869	864	879
# of Street & Highway Lighting Customers	623	626	625	627	627	629	603	606	608	610	610	612	617
Peak Demand Net of DSM Programs	378.6	366.1	338.1	316.9	359.3	449.3	500.1	479.4	401.8	336.9	361.7	400.1	500.1

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

INTEGRATED SYSTEM YEAR 2010

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	886.9	818.2	743.0	669.3	632.3	665.3	900.8	796.8	694.1	654.9	758.8	907.4	9,128.0
# of Residential Customers	87,646	87,648	87,645	87,601	87,677	87,791	87,873	87,921	87,937	87,960	87,978	87,958	87,803
Total Residential Sales - MWh	77,737	71,714	65,119	58,633	55,439	58,409	79,152	70,059	61,034	57,604	66,754	79,811	801,466
Use per Small Comm & Ind Customer - kWh	2,576.2	2,448.6	2,394.2	2,195.5	2,180.8	2,175.8	2,744.0	2,532.0	2,336.1	2,207.5	2,377.2	2,621.8	28,788.4
# of Small Comm & Ind Customers	16,277	16,261	16,275	16,420	16,615	16,717	16,733	16,762	16,725	16,576	16,511	16,502	16,531
Total Small Comm & Ind Sales - MWh	41,932	39,816	38,966	36,050	36,235	36,373	45,915	42,441	39,071	36,591	39,250	43,265	475,905
General Large Comm & Ind Sales	62,956	62,527	60,316	61,083	60,693	60,992	68,484	66,542	65,115	64,021	64,243	68,545	765,519
Sabin Metals Sales	1,398	1,434	1,486	1,509	1,500	1,426	1,545	1,485	1,472	1,511	1,191	1,177	17,134
Encore Oil Sales	15,924	16,050	16,168	16,361	16,590	15,944	16,924	16,219	16,820	17,836	17,963	18,810	201,609
Tesoro Refinery Sales	4,179	4,281	4,673	4,715	4,887	5,103	5,388	5,262	5,052	4,866	4,798	4,714	57,918
TransCanada Keystone Pipeline	-	-	-	-	-	-	-	-	-	-	-	-	-
Westmoreland Coal Sales	2,784	2,660	2,514	2,381	2,129	1,880	1,845	1,932	2,135	2,366	2,561	2,814	28,001
Total Sales (Residential, SC&I and LC&I)	206,910	198,482	189,242	180,732	177,473	180,127	219,253	203,941	190,699	184,795	196,760	219,136	2,347,552
Other Public Sales	3,423	3,367	3,361	3,241	3,660	3,983	4,788	4,392	3,878	3,295	3,190	3,483	44,061
Street & Highway Lighting Sales	2,716	2,536	2,614	2,511	2,514	2,345	2,452	2,495	2,523	2,649	2,700	2,730	30,785
Interdepartmental Sales	42	41	37	36	33	29	34	29	34	34	36	45	430
Total Billed Sales - MWh	213,091	204,426	195,254	186,520	183,680	186,484	226,527	210,857	197,134	190,773	202,686	225,394	2,422,828
Company Use	727	679	664	658	655	670	744	746	650	637	702	713	8,245
Total Energy	213,818	205,105	195,918	187,178	184,335	187,154	227,271	211,603	197,784	191,410	203,388	226,107	2,431,073
Total Requirements (Energy + Losses)	230,701	221,301	211,388	201,958	198,890	201,931	245,215	228,311	213,401	206,524	219,447	243,960	2,623,027
# of Large Comm & Ind Customers	1,053	1,057	1,058	1,063	1,069	1,070	1,073	1,073	1,071	1,070	1,068	1,066	1,066
# of Other Public Customers	868	866	869	878	892	893	894	892	886	876	869	864	879
# of Street & Highway Lighting Customers	623	626	625	627	627	629	603	606	608	610	610	612	617
Peak Demand Net of DSM Programs	384.9	372.2	343.7	322.0	365.2	451.4	502.9	481.9	402.9	342.5	363.7	402.4	502.9

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

INTEGRATED SYSTEM YEAR 2011

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	892.3	823.1	747.5	673.4	636.1	668.7	905.5	801.0	697.6	658.8	763.3	912.9	9,180.5
# of Residential Customers	88,052	88,055	88,050	88,008	88,084	88,200	88,281	88,329	88,345	88,368	88,386	88,365	88,210
Total Residential Sales - MWh	78,567	72,479	65,814	59,261	56,032	58,978	79,942	70,755	61,630	58,219	67,467	80,666	809,811
Use per Small Comm & Ind Customer - kWh	2,630.5	2,500.3	2,444.7	2,241.7	2,226.7	2,221.6	2,801.7	2,585.3	2,385.3	2,253.9	2,427.1	2,676.8	29,394.3
# of Small Comm & Ind Customers	16,404	16,388	16,402	16,548	16,745	16,847	16,863	16,892	16,855	16,706	16,641	16,632	16,660
Total Small Comm & Ind Sales - MWh	43,151	40,974	40,098	37,096	37,286	37,427	47,246	43,671	40,204	37,653	40,390	44,520	489,716
General Large Comm & Ind Sales	63,996	63,559	61,303	62,089	61,685	61,982	69,585	67,615	66,178	65,086	65,314	68,876	777,270
Sabin Metals Sales	1,473	1,511	1,566	1,591	1,580	1,503	1,628	1,565	1,551	1,592	1,255	1,239	18,054
Encore Oil Sales	16,246	16,374	16,494	16,692	16,926	16,266	17,266	16,546	17,160	18,196	18,326	19,190	205,682
Tesoro Refinery Sales	4,300	4,405	4,809	4,852	5,028	5,250	5,543	5,413	5,198	5,006	4,937	4,849	59,590
TransCanada Keystone Pipeline	-	-	-	-	-	-	-	-	-	-	-	-	-
Westmoreland Coal Sales	2,784	2,660	2,514	2,381	2,129	1,880	1,845	1,932	2,135	2,366	2,561	2,814	28,001
Total Sales (Residential, SC&I and LC&I)	210,517	201,962	192,598	183,962	180,666	183,286	223,055	207,498	194,056	188,118	200,250	222,154	2,388,124
Other Public Sales	3,431	3,373	3,367	3,247	3,666	3,989	4,796	4,400	3,887	3,300	3,195	3,489	44,140
Street & Highway Lighting Sales	2,716	2,536	2,614	2,511	2,514	2,346	2,453	2,495	2,524	2,651	2,701	2,730	30,791
Interdepartmental Sales	42	41	37	36	33	29	34	29	34	34	36	45	430
Total Billed Sales - MWh	216,706	207,912	198,616	189,756	186,879	189,650	230,338	214,422	200,501	194,103	206,182	228,418	2,463,485
Company Use	727	679	664	658	655	670	744	746	650	637	702	713	8,245
Total Energy	217,433	208,591	199,280	190,414	187,534	190,320	231,082	215,168	201,151	194,740	206,884	229,131	2,471,730
Total Requirements (Energy + Losses)	234,602	225,062	215,016	205,449	202,342	205,347	249,328	232,157	217,035	210,118	223,219	247,223	2,666,898
# of Large Comm & Ind Customers	1,059	1,062	1,065	1,069	1,075	1,076	1,078	1,079	1,076	1,076	1,074	1,072	1,072
# of Other Public Customers	868	866	869	878	892	893	894	892	886	876	869	864	879
# of Street & Highway Lighting Customers	623	626	625	627	627	629	603	606	608	610	610	612	617
Peak Demand Net of DSM Programs	387.7	374.9	346.3	324.2	371.0	456.8	509.1	487.9	407.5	347.9	368.2	407.4	509.1

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

INTEGRATED SYSTEM YEAR 2012

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	897.7	828.1	752.0	677.4	640.0	672.8	911.1	805.9	701.9	662.8	767.9	918.4	9,236.0
# of Residential Customers	88,463	88,467	88,462	88,418	88,494	88,610	88,692	88,742	88,756	88,780	88,798	88,778	88,622
Total Residential Sales - MWh	79,410	73,257	66,520	59,897	56,633	59,615	80,804	71,516	62,295	58,844	68,191	81,530	818,513
Use per Small Comm & Ind Customer - kWh	2,686.6	2,553.4	2,496.7	2,289.4	2,274.1	2,268.8	2,861.6	2,640.2	2,436.2	2,302.1	2,479.0	2,718.4	30,005.2
# of Small Comm & Ind Customers	16,527	16,512	16,526	16,674	16,872	16,975	16,990	17,021	16,982	16,831	16,766	16,757	16,786
Total Small Comm & Ind Sales - MWh	44,402	42,162	41,260	38,173	38,369	38,514	48,618	44,939	41,371	38,747	41,563	45,552	503,670
General Large Comm & Ind Sales	63,354	62,916	60,670	61,461	61,048	61,334	68,829	66,886	65,493	64,445	64,680	69,159	770,277
Sabin Metals Sales	1,548	1,588	1,646	1,672	1,661	1,580	1,710	1,645	1,631	1,673	1,319	1,300	18,973
Encore Oil Sales	16,574	16,705	16,827	17,029	17,268	16,595	17,615	16,880	17,506	18,564	18,696	19,578	209,837
Tesoro Refinery Sales	4,421	4,529	4,944	4,988	5,169	5,397	5,699	5,566	5,344	5,147	5,076	4,984	61,264
TransCanada Keystone Pipeline	-	-	-	-	-	7,757	8,015	8,015	7,757	8,015	7,757	8,015	55,331
Westmoreland Coal Sales	2,784	2,660	2,514	2,381	2,129	1,880	1,845	1,932	2,135	2,366	2,561	2,814	28,001
Total Sales (Residential, SC&I and LC&I)	212,493	203,817	194,381	185,601	182,277	192,672	233,135	217,380	203,532	197,801	209,843	232,932	2,465,866
Other Public Sales	3,437	3,380	3,374	3,253	3,674	3,998	4,806	4,408	3,893	3,307	3,202	3,496	44,228
Street & Highway Lighting Sales	2,716	2,537	2,615	2,512	2,514	2,346	2,453	2,495	2,524	2,651	2,702	2,730	30,795
Interdepartmental Sales	41	40	36	36	33	29	34	29	33	34	36	44	425
Total Billed Sales - MWh	218,687	209,774	200,406	191,402	188,498	199,045	240,428	224,312	209,982	203,793	215,783	239,202	2,541,314
Company Use	727	679	664	658	655	670	744	746	650	637	702	713	8,245
Total Energy	219,414	210,453	201,070	192,060	189,153	199,715	241,172	225,058	210,632	204,430	216,485	239,915	2,549,559
Total Requirements (Energy + Losses)	236,740	227,070	216,947	207,225	204,089	215,484	260,215	242,828	227,263	220,573	233,579	258,859	2,750,872
# of Large Comm & Ind Customers	1,064	1,067	1,069	1,074	1,080	1,082	1,084	1,084	1,083	1,082	1,079	1,078	1,077
# of Other Public Customers	868	866	869	878	892	893	894	892	886	876	869	864	879
# of Street & Highway Lighting Customers	623	626	625	627	627	629	603	606	608	610	610	612	617
Peak Demand Net of DSM Programs	392.5	379.5	350.5	328.2	374.9	478.0	530.9	509.5	428.3	367.8	388.4	428.1	530.9

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

INTEGRATED SYSTEM YEAR 2013

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	903.1	833.1	756.5	681.6	643.9	676.9	916.6	810.8	706.2	666.8	772.6	923.9	9,292.2
# of Residential Customers	88,871	88,875	88,871	88,826	88,903	89,020	89,103	89,151	89,167	89,191	89,209	89,188	89,031
Total Residential Sales - MWh	80,261	74,042	67,234	60,540	57,241	60,258	81,673	72,288	62,966	59,476	68,921	82,397	827,298
Use per Small Comm & Ind Customer - kWh	2,714.0	2,579.5	2,522.1	2,312.9	2,297.5	2,292.3	2,890.6	2,667.2	2,461.0	2,325.6	2,504.2	2,746.0	30,311.7
# of Small Comm & Ind Customers	16,652	16,636	16,651	16,799	16,999	17,102	17,119	17,149	17,111	16,958	16,893	16,884	16,913
Total Small Comm & Ind Sales - MWh	45,193	42,913	41,996	38,854	39,055	39,203	49,484	45,740	42,110	39,438	42,304	46,364	512,654
General Large Comm & Ind Sales	64,592	64,142	61,847	62,662	62,234	62,522	70,152	68,176	66,766	65,710	65,956	70,556	785,317
Sabin Metals Sales	1,623	1,666	1,726	1,753	1,742	1,656	1,794	1,725	1,710	1,755	1,383	1,362	19,895
Encore Oil Sales	16,908	17,042	17,167	17,373	17,617	16,930	17,971	17,222	17,860	18,939	19,074	19,973	214,076
Tesoro Refinery Sales	4,542	4,653	5,079	5,125	5,310	5,545	5,855	5,718	5,490	5,287	5,214	5,118	62,936
TransCanada Keystone Pipeline	8,015	7,239	8,015	7,757	8,015	9,576	9,895	9,895	9,576	9,895	9,576	9,895	107,349
Westmoreland Coal Sales	2,784	2,660	2,514	2,381	2,129	1,880	1,845	1,932	2,135	2,366	2,561	2,814	28,001
Total Sales (Residential, SC&I and LC&I)	223,918	214,357	205,578	196,445	193,343	197,570	238,669	222,697	208,613	202,866	214,989	238,479	2,557,526
Other Public Sales	3,442	3,386	3,380	3,258	3,680	4,004	4,814	4,415	3,899	3,312	3,207	3,502	44,299
Street & Highway Lighting Sales	2,717	2,537	2,615	2,512	2,514	2,346	2,453	2,495	2,525	2,652	2,702	2,731	30,799
Interdepartmental Sales	40	39	36	35	32	29	34	29	32	33	36	44	419
Total Billed Sales - MWh	230,117	220,319	211,609	202,250	199,569	203,949	245,970	229,636	215,069	208,863	220,934	244,756	2,633,043
Company Use	727	679	664	658	655	670	744	746	650	637	702	713	8,245
Total Energy	230,844	220,998	212,273	202,908	200,224	204,619	246,714	230,382	215,719	209,500	221,636	245,469	2,641,288
Total Requirements (Energy + Losses)	249,072	238,448	229,034	218,930	216,033	220,776	266,194	248,573	232,752	226,042	239,137	264,852	2,849,843
# of Large Comm & Ind Customers	1,070	1,074	1,075	1,080	1,086	1,087	1,090	1,090	1,088	1,087	1,085	1,083	1,083
# of Other Public Customers	868	866	869	878	892	893	894	892	886	876	869	864	879
# of Street & Highway Lighting Customers	623	626	625	627	627	629	603	606	608	610	610	612	617
Peak Demand Net of DSM Programs	413.0	399.8	370.6	348.2	396.7	489.1	542.7	521.0	438.6	376.8	398.0	438.2	542.7

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

INTEGRATED SYSTEM YEAR 2014

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	908.7	838.3	761.2	685.8	647.9	681.2	922.4	815.9	710.6	671.0	777.4	929.6	9,350.0
# of Residential Customers	89,256	89,259	89,255	89,211	89,287	89,404	89,487	89,536	89,552	89,576	89,595	89,574	89,416
Total Residential Sales - MWh	81,107	74,823	67,943	61,178	57,846	60,898	82,539	73,053	63,633	60,103	69,648	83,267	836,039
Use per Small Comm & Ind Customer - kWh	2,742.3	2,606.6	2,548.8	2,337.0	2,321.5	2,316.0	2,920.9	2,695.0	2,486.8	2,349.9	2,530.5	2,774.7	30,628.7
# of Small Comm & Ind Customers	16,773	16,757	16,771	16,922	17,122	17,228	17,243	17,275	17,235	17,082	17,016	17,007	17,036
Total Small Comm & Ind Sales - MWh	45,997	43,678	42,745	39,547	39,749	39,900	50,366	46,556	42,859	40,141	43,059	47,190	521,787
General Large Comm & Ind Sales	65,890	65,428	63,080	63,916	63,476	63,767	71,536	69,525	68,097	67,036	67,290	72,010	801,053
Sabin Metals Sales	1,698	1,742	1,806	1,834	1,823	1,733	1,877	1,805	1,789	1,836	1,447	1,404	20,794
Encore Oil Sales	17,250	17,386	17,514	17,724	17,972	17,272	18,334	17,569	18,221	19,322	19,459	20,377	218,400
Tesoro Refinery Sales	4,663	4,777	5,214	5,261	5,452	5,692	6,011	5,870	5,636	5,428	5,353	5,253	64,610
TransCanada Keystone Pipeline	9,895	8,938	9,895	9,576	9,895	11,587	11,973	11,973	11,587	11,973	11,587	11,973	130,852
Westmoreland Coal Sales	2,784	2,660	2,514	2,381	2,129	1,880	1,845	1,932	2,135	2,366	2,561	2,814	28,001
Total Sales (Residential, SC&I and LC&I)	229,284	219,432	210,711	201,417	198,342	202,729	244,481	228,284	213,957	208,205	220,404	244,288	2,621,536
Other Public Sales	3,449	3,391	3,386	3,264	3,687	4,011	4,822	4,424	3,908	3,318	3,213	3,509	44,382
Street & Highway Lighting Sales	2,718	2,537	2,615	2,512	2,515	2,346	2,453	2,496	2,525	2,652	2,702	2,731	30,802
Interdepartmental Sales	40	39	36	34	30	28	33	29	32	33	34	43	411
Total Billed Sales - MWh	235,491	225,399	216,748	207,227	204,574	209,114	251,789	235,233	220,422	214,208	226,353	250,571	2,697,131
Company Use	727	679	664	658	655	670	744	746	650	637	702	713	8,245
Total Energy	236,218	226,078	217,412	207,885	205,229	209,784	252,533	235,979	221,072	214,845	227,055	251,284	2,705,376
Total Requirements (Energy + Losses)	254,870	243,930	234,580	224,300	221,434	226,349	272,474	254,612	238,527	231,810	244,984	271,126	2,918,996
# of Large Comm & Ind Customers	1,076	1,079	1,081	1,085	1,092	1,094	1,095	1,096	1,094	1,093	1,091	1,089	1,089
# of Other Public Customers	868	866	869	878	892	893	894	892	886	876	869	864	879
# of Street & Highway Lighting Customers	623	626	625	627	627	629	603	606	608	610	610	612	617
Peak Demand Net of DSM Programs	422.9	409.7	379.9	357.1	406.2	500.7	555.1	533.0	449.4	386.5	408.1	449.1	555.1

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

INTEGRATED SYSTEM YEAR 2015

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	914.3	843.5	765.9	690.0	651.9	685.4	928.1	821.0	715.0	675.1	782.2	935.3	9,408.0
# of Residential Customers	89,646	89,649	89,645	89,600	89,678	89,796	89,879	89,927	89,944	89,968	89,987	89,965	89,807
Total Residential Sales - MWh	81,966	75,616	68,662	61,826	58,459	61,547	83,417	73,832	64,311	60,741	70,387	84,144	844,909
Use per Small Comm & Ind Customer - kWh	2,770.9	2,633.7	2,575.4	2,361.6	2,345.6	2,340.5	2,951.4	2,723.4	2,512.8	2,374.5	2,556.7	2,803.9	30,949.0
# of Small Comm & Ind Customers	16,896	16,880	16,893	17,044	17,248	17,352	17,369	17,400	17,361	17,206	17,141	17,130	17,160
Total Small Comm & Ind Sales - MWh	46,817	44,456	43,506	40,251	40,458	40,612	51,263	47,387	43,624	40,856	43,825	48,030	531,085
General Large Comm & Ind Sales	67,228	66,753	64,351	65,213	64,755	65,048	72,962	70,915	69,468	68,404	68,668	73,505	817,272
Sabin Metals Sales	1,736	1,781	1,846	1,875	1,863	1,772	1,919	1,845	1,829	1,877	1,479	1,416	21,238
Encore Oil Sales	17,598	17,738	17,868	18,082	18,335	17,621	18,704	17,924	18,589	19,712	19,852	20,788	222,811
Tesoro Refinery Sales	4,784	4,901	5,349	5,397	5,593	5,840	6,166	6,022	5,783	5,570	5,492	5,387	66,284
TransCanada Keystone Pipeline	11,973	10,814	11,973	11,587	11,973	11,587	11,973	11,973	11,587	11,973	11,587	11,973	140,973
Westmoreland Coal Sales	2,784	2,660	2,514	2,381	2,129	1,880	1,845	1,932	2,135	2,366	2,561	2,814	28,001
Total Sales (Residential, SC&I and LC&I)	234,886	224,719	216,069	206,612	203,565	205,907	248,249	231,831	217,326	211,499	223,851	248,057	2,672,573
Other Public Sales	3,456	3,397	3,391	3,270	3,693	4,017	4,830	4,431	3,914	3,324	3,219	3,515	44,457
Street & Highway Lighting Sales	2,718	2,537	2,615	2,513	2,516	2,347	2,455	2,496	2,526	2,653	2,702	2,731	30,809
Interdepartmental Sales	39	39	35	34	30	27	32	28	32	32	34	43	405
Total Billed Sales - MWh	241,099	230,692	222,110	212,429	209,804	212,298	255,566	238,786	223,798	217,508	229,806	254,346	2,748,244
Company Use	727	679	664	658	655	670	744	746	650	637	702	713	8,245
Total Energy	241,826	231,371	222,774	213,087	210,459	212,968	256,310	239,532	224,448	218,145	230,508	255,059	2,756,489
Total Requirements (Energy + Losses)	260,921	249,641	240,364	229,913	227,077	229,783	276,548	258,445	242,169	235,370	248,710	275,198	2,974,139
# of Large Comm & Ind Customers	1,082	1,085	1,086	1,093	1,098	1,099	1,102	1,102	1,100	1,099	1,097	1,095	1,095
# of Other Public Customers	868	866	869	878	892	893	894	892	886	876	869	864	879
# of Street & Highway Lighting Customers	623	626	625	627	627	629	603	606	608	610	610	612	617
Peak Demand Net of DSM Programs	433.6	419.9	389.8	366.6	416.3	508.2	563.3	540.9	456.1	391.8	414.1	455.7	563.3

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

INTEGRATED SYSTEM YEAR 2016

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	920.1	848.8	770.8	694.4	656.0	689.7	934.0	826.2	719.5	679.4	787.1	941.2	9,467.3
# of Residential Customers	90,021	90,024	90,020	89,976	90,053	90,172	90,255	90,305	90,320	90,343	90,362	90,341	90,183
Total Residential Sales - MWh	82,826	76,410	69,385	62,476	59,072	62,196	84,295	74,610	64,989	61,377	71,125	85,025	853,787
Use per Small Comm & Ind Customer - kWh	2,800.5	2,662.0	2,602.8	2,386.8	2,370.8	2,365.5	2,982.9	2,752.6	2,539.7	2,399.8	2,584.2	2,833.8	31,279.9
# of Small Comm & Ind Customers	17,015	16,998	17,013	17,165	17,369	17,475	17,492	17,522	17,483	17,328	17,261	17,251	17,281
Total Small Comm & Ind Sales - MWh	47,651	45,249	44,281	40,969	41,178	41,337	52,177	48,230	44,401	41,584	44,606	48,885	540,548
General Large Comm & Ind Sales	68,594	68,106	65,648	66,536	66,062	66,357	74,418	72,334	70,871	69,800	70,074	75,048	833,850
Sabin Metals Sales	1,736	1,781	1,846	1,875	1,863	1,772	1,919	1,845	1,829	1,877	1,479	1,416	21,238
Encore Oil Sales	17,954	18,096	18,229	18,448	18,706	17,977	19,082	18,286	18,965	20,110	20,253	21,208	227,314
Tesoro Refinery Sales	4,904	5,024	5,485	5,534	5,735	5,988	6,322	6,175	5,928	5,710	5,631	5,522	67,958
TransCanada Keystone Pipeline	11,973	10,814	11,973	11,587	11,973	11,587	11,973	11,973	11,587	11,973	11,587	11,973	140,973
Westmoreland Coal Sales	2,784	2,660	2,514	2,381	2,129	1,880	1,845	1,932	2,135	2,366	2,561	2,814	28,001
Total Sales (Residential, SC&I and LC&I)	238,422	228,140	219,361	209,806	206,718	209,094	252,031	235,386	220,705	214,797	227,316	251,891	2,713,669
Other Public Sales	3,462	3,404	3,397	3,276	3,700	4,024	4,839	4,439	3,921	3,330	3,224	3,520	44,536
Street & Highway Lighting Sales	2,718	2,537	2,615	2,514	2,516	2,348	2,455	2,496	2,526	2,653	2,703	2,731	30,812
Interdepartmental Sales	39	38	34	34	30	27	32	28	32	32	34	42	402
Total Billed Sales - MWh	244,641	234,119	225,407	215,630	212,964	215,493	259,357	242,349	227,184	220,812	233,277	258,184	2,789,419
Company Use	727	679	664	658	655	670	744	746	650	637	702	713	8,245
Total Energy	245,368	234,798	226,071	216,288	213,619	216,163	260,101	243,095	227,834	221,449	233,979	258,897	2,797,664
Total Requirements (Energy + Losses)	264,743	253,338	243,922	233,367	230,486	233,231	280,638	262,290	245,824	238,936	252,454	279,340	3,018,569
# of Large Comm & Ind Customers	1,087	1,090	1,092	1,097	1,103	1,105	1,107	1,107	1,105	1,104	1,101	1,100	1,100
# of Other Public Customers	868	866	869	878	892	893	894	892	886	876	869	864	879
# of Street & Highway Lighting Customers	623	626	625	627	627	629	603	606	608	610	610	612	617
Peak Demand Net of DSM Programs	440.0	426.1	395.5	371.9	422.1	515.7	571.8	549.0	463.0	397.5	420.3	462.3	571.8

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

INTEGRATED SYSTEM YEAR 2017

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	925.9	854.2	775.6	698.8	660.1	694.2	939.9	831.5	724.1	683.7	792.1	947.1	9,527.4
# of Residential Customers	90,388	90,392	90,388	90,343	90,421	90,540	90,624	90,672	90,689	90,713	90,731	90,710	90,551
Total Residential Sales - MWh	83,692	77,209	70,109	63,128	59,690	62,849	85,180	75,394	65,671	62,019	71,869	85,908	862,719
Use per Small Comm & Ind Customer - kWh	2,830.7	2,690.6	2,630.9	2,412.4	2,396.5	2,391.0	3,015.4	2,782.2	2,567.0	2,425.7	2,612.1	2,864.3	31,617.5
# of Small Comm & Ind Customers	17,133	17,117	17,131	17,285	17,489	17,596	17,612	17,644	17,605	17,448	17,381	17,371	17,401
Total Small Comm & Ind Sales - MWh	48,499	46,055	45,070	41,699	41,912	42,073	53,107	49,089	45,191	42,324	45,400	49,756	550,175
General Large Comm & Ind Sales	70,025	69,525	67,008	67,920	67,430	67,730	75,943	73,819	72,337	71,263	71,548	76,409	850,959
Sabin Metals Sales	1,736	1,781	1,846	1,875	1,863	1,772	1,919	1,845	1,829	1,877	1,479	1,416	21,238
Encore Oil Sales	18,316	18,461	18,597	18,820	19,084	18,340	19,467	18,656	19,348	20,517	20,662	21,636	231,904
Tesoro Refinery Sales	5,025	5,148	5,619	5,670	5,875	6,135	6,478	6,327	6,075	5,851	5,770	5,657	69,630
TransCanada Keystone Pipeline	11,973	10,814	11,973	11,587	11,973	11,587	11,973	11,973	11,587	11,973	11,587	11,973	140,973
Westmoreland Coal Sales	2,784	2,660	2,514	2,381	2,129	1,880	1,845	1,932	2,135	2,366	2,561	2,814	28,001
Total Sales (Residential, SC&I and LC&I)	242,050	231,653	222,736	213,080	209,956	212,366	255,912	239,036	224,173	218,190	230,876	255,569	2,755,599
Other Public Sales	3,467	3,410	3,403	3,282	3,707	4,032	4,848	4,447	3,928	3,336	3,231	3,527	44,618
Street & Highway Lighting Sales	2,719	2,538	2,616	2,514	2,516	2,348	2,455	2,497	2,526	2,653	2,703	2,731	30,816
Interdepartmental Sales	39	38	34	34	30	27	32	28	32	32	34	42	402
Total Billed Sales - MWh	248,275	237,639	228,789	218,910	216,209	218,773	263,247	246,008	230,659	224,211	236,844	261,869	2,831,435
Company Use	727	679	664	658	655	670	744	746	650	637	702	713	8,245
Total Energy	249,002	238,318	229,453	219,568	216,864	219,443	263,991	246,754	231,309	224,848	237,546	262,582	2,839,680
Total Requirements (Energy + Losses)	268,663	257,137	247,571	236,906	233,987	236,770	284,836	266,237	249,573	242,602	256,304	283,316	3,063,902
# of Large Comm & Ind Customers	1,093	1,096	1,098	1,102	1,109	1,111	1,112	1,113	1,111	1,111	1,109	1,106	1,106
# of Other Public Customers	868	866	869	878	892	893	894	892	886	876	869	864	879
# of Street & Highway Lighting Customers	623	626	625	627	627	629	603	606	608	610	610	612	617
Peak Demand Net of DSM Programs	446.4	432.4	401.2	377.3	428.0	523.4	580.3	557.3	469.9	402.9	426.3	469.2	580.3

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

INTEGRATED SYSTEM YEAR 2018

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	931.8	859.6	780.6	703.3	664.4	698.7	946.0	836.9	728.8	688.1	797.2	953.0	9,588.6
# of Residential Customers	90,742	90,745	90,740	90,696	90,774	90,893	90,977	91,027	91,044	91,067	91,086	91,065	90,905
Total Residential Sales - MWh	84,557	78,007	70,835	63,782	60,308	63,503	86,064	76,178	66,354	62,662	72,612	86,789	871,652
Use per Small Comm & Ind Customer - kWh	2,861.7	2,719.9	2,659.8	2,438.9	2,422.6	2,417.0	3,047.9	2,812.6	2,595.2	2,452.2	2,640.5	2,895.5	31,962.5
# of Small Comm & Ind Customers	17,250	17,234	17,247	17,402	17,609	17,717	17,734	17,765	17,724	17,567	17,500	17,490	17,520
Total Small Comm & Ind Sales - MWh	49,364	46,875	45,873	42,442	42,659	42,823	54,052	49,965	45,997	43,078	46,209	50,643	559,980
General Large Comm & Ind Sales	70,974	70,466	67,912	68,840	68,340	68,641	76,960	74,810	73,312	72,229	72,523	77,464	862,473
Sabin Metals Sales	1,736	1,781	1,846	1,875	1,863	1,772	1,919	1,845	1,829	1,877	1,479	1,416	21,238
Encore Oil Sales	18,686	18,835	18,973	19,200	19,469	18,710	19,860	19,032	19,738	20,931	21,079	22,074	236,587
Tesoro Refinery Sales	5,146	5,272	5,754	5,806	6,017	6,283	6,634	6,479	6,221	5,992	5,908	5,791	71,303
TransCanada Keystone Pipeline	11,973	10,814	11,973	11,587	11,973	11,587	11,973	11,973	11,587	11,973	11,587	11,973	140,973
Westmoreland Coal Sales	2,784	2,660	2,514	2,381	2,129	1,880	1,845	1,932	2,135	2,366	2,561	2,814	28,001
Total Sales (Residential, SC&I and LC&I)	245,220	234,710	225,680	215,913	212,758	215,199	259,307	242,215	227,173	221,108	233,958	258,964	2,792,207
Other Public Sales	3,474	3,417	3,410	3,288	3,713	4,039	4,856	4,455	3,936	3,342	3,236	3,533	44,699
Street & Highway Lighting Sales	2,720	2,538	2,616	2,514	2,517	2,349	2,455	2,497	2,526	2,653	2,703	2,732	30,820
Interdepartmental Sales	38	37	34	34	30	27	32	27	29	31	34	41	394
Total Billed Sales - MWh	251,452	240,702	231,740	221,749	219,018	221,614	266,650	249,194	233,664	227,134	239,931	265,270	2,868,120
Company Use	727	679	664	658	655	670	744	746	650	637	702	713	8,245
Total Energy	252,179	241,381	232,404	222,407	219,673	222,284	267,394	249,940	234,314	227,771	240,633	265,983	2,876,365
Total Requirements (Energy + Losses)	272,091	260,441	250,755	239,969	237,019	239,836	288,507	269,675	252,815	245,757	259,633	286,985	3,103,483
# of Large Comm & Ind Customers	1,099	1,102	1,104	1,110	1,115	1,116	1,119	1,119	1,117	1,116	1,114	1,112	1,112
# of Other Public Customers	868	866	869	878	892	893	894	892	886	876	869	864	879
# of Street & Highway Lighting Customers	623	626	625	627	627	629	603	606	608	610	610	612	617
Peak Demand Net of DSM Programs	452.9	438.8	407.2	382.9	433.6	530.5	588.1	564.6	476.2	408.2	432.1	475.4	588.1

Attachment B

DEMAND-SIDE ANALYSIS DOCUMENTATION

Demand-Side Analysis

TABLE OF CONTENTS

DEMAND-SIDE ANALYSIS

Overview

With the demand for electricity growing Montana-Dakota recognizes the value Demand-Side Management (DSM) can play in meeting our customers future energy requirements. Montana-Dakota developed a list of potential DSM programs that would be best suited for the Company's load shape. Potential programs were selected through a joint effort between Montana-Dakota and the IRP Public Advisory Group (PAG). However, the implementation of DSM programs cannot be done without cost consideration to the utility, its customers/ratepayers, and its shareholders. Interests need to be balanced to achieve results at an affordable cost to both the utility and its customers.

Contained in this Attachment is a detailed discussion of Montana-Dakota's demand-side analysis. The DSM program analysis and DSM Model spreadsheets are included in the Appendices for the base case and for the sensitivity analysis of high and low participation rates.

Potential DSM Programs

Montana-Dakota explored the feasibility of offering twelve DSM programs to its customers. Current programs were also included as well as a program that uses rate design as a tool to promote DSM. The following programs were evaluated:

Residential Programs

1. Promote a direct-control central air conditioner cycling program through the use of a controllable thermostat with no cash incentive other than the thermostat valued at $300 installed.
2. Promote a direct-control central air conditioner cycling program through the use of a controllable thermostat with a $25 cash incentive and a thermostat valued at $300 installed.
3. Promote ENERGY STAR® residential central air conditioners through the use of a $175/ton cash incentive for replacement of a customer's central air conditioner with the purchase of a new ENERGY STAR® central air conditioner with a Seasonal Energy Efficiency Ratio (SEER) of 15 or greater.

4. Promote ENERGY STAR® appliances to residential customers where they would receive a direct incentive from the dealer of $15 for each ENERGY STAR® appliance purchased.
5. Promote a refrigerator round-up program, whereby customers are offered a cash incentive of $35 in exchange for the Company removing the customer's second refrigerator.
6. Promote a residential lighting program, whereby customers are offered free compact fluorescent light bulbs.
7. Promote a residential new home construction bundle that includes a central air conditioner, compact fluorescent light bulbs, and ENERGY STAR® appliances.

Commercial Programs

1. Promote the Interruptible Demand Response rate in North Dakota and Montana and implement that rate in South Dakota.
2. Promote high-efficiency motors with a cash incentive of $0.15 per kWh saved for the purchase of a high-efficiency motor or variable speed drive installation on an existing motor.
3. Promote commercial high-efficiency air conditioners through an incentive of $100 per ton of cooling. All commercial cooling applications are included except for central plant chillers.
4. Promote a high-efficiency lighting program to commercial customers that provides a cash incentive of $0.20 per watt saved for replacing and retrofitting existing lighting systems.
5. Promote a direct-control demand response program for irrigation that would control irrigation pumping load during peak periods and offer a cash incentive of $6 per kW to participating customers.

DSM Methodology

In order to balance all interests and achieve cost-effective DSM for the utility and its customers/ratepayers, a cost-benefit analysis from different perspectives was performed on potential DSM measures. The perspectives or "tests" are not intended to be used individually or in isolation, but they must be compared to each other. This multi-perspective approach will allow consideration for tradeoffs between the various tests. However, the impacts measured from the Ratepayer Test will determine if a program is feasible. Once a program is determined feasible, all other test results are considered to determine if a program is to be implemented. Therefore, even if a program is feasible it may not be implemented due to tradeoffs with other tests and other identified factors.

Benefit/Cost Analysis

Montana-Dakota used a Microsoft Excel spreadsheet-based model (Montana-Dakota DSM Model) to run a benefit/cost analysis for each considered DSM program. The basic function of this evaluation tool is to calculate each DSM program's benefits and costs over the projected life on a discounted cash flow basis to determine its cost effectiveness on a stand alone basis. The programs were evaluated using four different cost-effectiveness tests:

- *Participant Test* considers the economic impact of a program on the participating customers.
- *Utility Test* considers the impact on the utility.
- *Societal Cost Test* considers the impact on both the participating and non-participating customers as well as including environmental externalities.
- *Ratepayer Test* includes all quantifiable benefits and costs of a given program and its impact on all ratepayers.

The following section explains the process of evaluating the programs from each of the four perspectives:

Participant Test

The Participant Test is a measure of the quantifiable benefits and costs brought about by a customer's participation in a DSM program. For purposes of evaluating the merits of a particular DSM program, quantifiable benefits include any incentives received by a participant and the reduction in a participant's electric bill through reduced energy and/or demand. Quantifiable costs include any costs the customer incurs in order to participate in a DSM program, such as increased appliance costs or the availability of a back-up fuel source. The merits of the DSM program are evaluated on the NPV of the annual benefits and costs over the years in the analysis horizon. The NPV determination is based on the utility discount rate and assumes the cash flows occur at the end of the year.

The following represents a simplified look at the equations used to evaluate the participant net benefit:

Net Benefit = Total Annual Benefits – Total Annual Costs

where:

Total Annual Benefits =Energy Savings (kWh) + Demand Savings (kW) + Incentive + Other Savings

Total Annual Costs = Direct Costs + Other Costs

A benefit/cost ratio greater than one for the Participant Test indicates the DSM program will result in savings to the participant over the life of the program.

Utility Test

The Utility Test is a measure of the quantifiable benefits and costs the utility incurs as a result of customer participation in a DSM program. For purposes of evaluating the merits of a particular DSM program, quantifiable benefits include any reduction in purchased power costs due to decreased customer energy and demand, along with a reduction in variable operation and maintenance costs. Quantifiable costs to the utility include incentive and administrative costs, along with the loss of electric margin due to reduced sales. The merits of the DSM program are evaluated on the NPV of the annual benefits and costs over the years in the analysis horizon. The NPV determination is based on the utility discount rate and assumes the cash flows occur at the end of the year. The following represents a simplified look at the equations used to evaluate the utility net benefit:

Net Benefit = Annual Cost of Energy Saved – Annual Project Costs

where:

Annual Cost of Energy Saved = Energy Savings (kWh) + Peak Demand Savings (kW)* + O&M Savings*

**kWh & kW savings include losses and reserve requirement savings*

Annual Project Costs = Total Project Costs + Lost Margin

A benefit/cost ratio greater than one for the Utility Test indicates the cost of energy saved is greater than the cost of saving the energy.

Societal Cost Test

The Societal Cost Test measures the net costs of a DSM program as a resource option based on the total costs of the program (both the participants' costs and the utility's costs). This test also includes a factor for environmental externalities. This test is a summation of the benefit and cost terms in the Participant Test and the Ratepayer Test. The merits of the DSM program are evaluated on the NPV of the annual benefits and costs over the years in the analysis horizon. The NPV determination is based on the utility discount rate and assumes the cash flows occur at the end of the year. The annual costs are discounted at the utility discount rate. The following represents a simplified look at the equations used to evaluate the total cost net benefit:

Net Benefit = Annual Cost of Energy Saved – Annual Project Costs

where:

*Annual Cost of Energy Saved = Energy Savings (kWh) * + Demand Savings (kW) * + O&M Savings + Avoided Environmental Damage*

**kWh & kW savings include losses and reserve requirement savings*

Annual Project Costs = Total Project Costs

A benefit/cost ratio greater than one for the Societal Cost Test indicates the DSM program is beneficial to both the utility and its ratepayers on a societal cost basis.

Ratepayer Test

The Ratepayer Test is a measure of the quantifiable benefits and costs placed on ratepayers due to changes in the utility's revenues and operating costs as a result of the DSM program. The Ratepayer test includes the same benefits and costs as the Utility Test, except the quantifiable costs exclude lost margin. The merits of the DSM program are evaluated on the NPV of the annual benefits and costs over the years in the analysis horizon. The NPV determination is based on the utility discount rate and assumes the cash flows occur at the end of the year. The annual costs are discounted at the utility discount rate. The following represents a simplified look at the equations used to evaluate the ratepayer net benefit:

Net Benefit = Annual Cost of Energy Saved – Annual Project Costs

where:

*Annual Cost of Energy Saved = Energy Savings (kWh) * + Demand Savings (kW) * + O&M Savings*

**kWh & kW savings include losses and reserve requirement savings*

Annual Project Costs = Total Project Costs

A benefit/cost ratio greater than one for the Ratepayer Test indicates the DSM program will reduce overall rates.

Montana-Dakota evaluated each program's feasibility based on the results of the Ratepayer Test. If the benefit/cost ratio for the Ratepayers Tests were greater than one, the DSM program(s) are considered feasible and will be further evaluated.

DSM Model Input Data

Montana-Dakota's DSM Model is dependent on the input data to determine the cost-benefit of each program. Recent Company operational and financial data is used for the general model data inputs and estimated supply cost avoidance is used based on marginal energy costs and capacity costs of adding the next supply resource including reserve requirements and losses. Program specific data is also used for each program being evaluated. The operational, financial, and program data inputs used for each program model run are provided in Appendix A and the sources of this data are summarized below in Table B-1.

As shown in Table B-1, inputs for avoided system energy costs and capacity costs due to the specific DSM measure are utilized. Avoided energy costs are based on system marginal energy cost as of June 2009. The System Marginal Energy cost avoided is the same regardless of the strategic focus of the DSM measure. However, there are two different system demand costs used in the analysis called "Peak Shaving Demand Costs" and "Conservation Demand Costs." The avoided capacity related costs are applied to specific DSM programs depending on the strategic focus of the program being analyzed. For example, the "System Peak Shaving Demand Cost" would apply to programs that are primarily peak shaving in nature. As shown in Table B-1, the demand cost avoidance for this measure would be the levelized cost of a new combustion turbine. The "System Conservation Demand Cost" is based on the cost avoidance of additional base load capacity which is levelized on the cost for Big Stone Unit II used in the supply-side and integration analysis and would apply to all DSM programs that have a strategic conservation focus.

The underlying demand-side resource program designs and evaluation criteria, cost information and other assumptions that are particular to the programs studied are provided for each program in Appendix A. A summary list of sources for energy savings calculations, program cost, participant cost, and participation rate estimates for each DSM program is contained below in Table B-2.

2009 Input Data Summary
Demand-Side Management Model
Table B-1

Input Data Description	Information Source
Retail Rate	System Average retail rate for customer class based
System Marginal Energy Costs	System Marginal energy costs as of June 2009
Retail Demand Cost	Seasonal demand cost based on program availability
System Peak Shaving Demand Costs	Demand Cost is based on estimated levelized cost of combustion turbine
System Conservation Demand Costs	Demand cost is based on estimated levelized cost of Big Stone II-Base Load
MAPP Reserve Margin	Current Required capacity reserve margin
Variable O&M	Montana-Dakota historical information
Environmental Damage Factor	$30 ton Carbon Cost
Total Sales by Class	2006 total sales for customer class based on program availability
Total Customers	2006 total sales for customer class based on program availability
Growth and Escalation Factors	Projected based on consumer indexes and forecasted escalation rates
Utility Discount Rate	Montana-Dakota's capital structure of incremental WACC 2008
Societal Discount Rate	Equal to 30 year T-Bill rate average for the 52 weeks ending June 1, 2009
General Input Data Year	2009
Project Analysis Year	Year program will be implemented
Effective Tax Rate	Avg. of Montana-Dakota's current state and local tax rate for integrated system
System Demand Line Loss Factor	Historical demand line loss factor for integrated electric system
System Energy Line Loss Factor	Historical energy line loss factor for integrated electric system
Direct Utility Project Costs	Total direct cost to the utility caused by implementing the DSM program
Administrative Costs	Total projected administrative costs including general admin and marketing costs of the DSM program
Direct Operating Costs	Direct operating cost estimated for the specific DSM program
Incentive Costs	Total annual cost of the incentive paid to the program participant
Direct Participant Project Costs	Direct costs that the participant is required to pay to participate in the DSM program
Other Participant Project Costs	Other costs or savings (neg) to the particpant for participating in the DSM program
Project Life	Based on the estimated useful life of the energy saving equipment
Avg. Energy Reduction	Avg. energy reduction (kWh) caused by the DSM program
Avg. Demand Reduction	Avg. demand reduction (kW) caused by the DSM program
Number of Participants	Total projected participation by customers, kW load target, or equipment saturation

DSM Program Analysis Data Source
Table B-2

DSM Program	Energy Calulation & Customer Cost Data	Program Cost Data	Participation Rate Estimate
Interruptible Rate-Demand Response Only	500 kW Model	OA&MCE	Potential Customers- Customer Reps
Residential A/C cycling (No Incentive)	Industry Data, EPRI, Venfor Info	Pricing of turnkey program provided by Honeywell	End Use Survey, Vendor Data
Residential A/C cycling (With Incentive)	Industry Data, EPRI, Venfor Info	Pricing of turnkey program provided by Honeywell	End Use Survey, Vendor Data
High Efficiency Residential AC	Energy Star, Industry Data, EPRI	OA&MCE	Customer End Use Survey,Estimate
Residental appliances (Refrigerators & Freezers)	Energy Star, AHAM, WAPA, DSM Guide	OA&MCE	End Use Survey, Energy Star. AHAM
Refrigerator Round-Up	WAPA DSM Guide	OA&MCE	End Use Survey, Industry Data
Residential Lighting (Various delivery Methods)	Energy Star DOE 2004	OA&MCE	Estimated
Commercial Lighting	Industry Data, IES	OA&MCE	Xenergy Survey, Estimate
High Efficiency A/C commerical	Energy Star, Industry Data, EPRI	OA&MCE	Estimated
Commercial High Efficiency Motors	Motor Master Program - DOE & AEE for LF	OA&MCE	Estimated
Residential New Construction Bundle	Energy Star, AHAM, WAPA, DSM Guide	OA&MCE	Estimated, New Service Line Report
Irrigation Demand Response- Direct Control	Industry Data, Vendor Info	Pricing from M2M Communications	Estimated

AHAM - Association of Home Appliance Manufactures

EPRI - Electric Power Research Institute

IES - Illuminatin Engineering Society

OA&MCE - Operating Administration & Marketing Cost Estimate

WAPA-Western Area Power Associatin 1992 DSM Guide

DOE - Department of Energy

AEE - Association of Energy En

DSM Model Results

<u>Base Case Scenario</u>

Based on the methodology and data inputs discussed above a base case scenario was developed for all DSM programs. The complete DSM Model runs for each program are contained in Appendix A, and a summary of the cost-benefit ratios are shown in Table B-3.

DSM Program Cost Benefit Summary

(Base Case)

Table B-3

DSM Program	**Customer Segment**	**Program Objective**	**B/C Ration**	**Rate Payer B/C Ratio**	**Societal B/C Ratio**	**Participant B/C Ratio**
Interruptible Rate-Demand Response Only	CI	PC	6.52	6.67	5.83	3.6
Residential A/C cycling (No Incentive)	R	PC	1.96	2.07	3.88	INF
Residential A/C cycling (With Incentive)	R	PC	1.49	1.57	3.1	INF
High Efficiency Residential AC	R	SC	5.71	7.43	15.14	1.75
Residental appliances (Refrigerators & Freezers)	R	SC	2.4	3.06	5.66	2.91
Refrigerator Round-Up	R	SC	4.1	7.8	20.58	INF
Residential Lighting (Various delivery Methods)	R	SC	9.35	22.31	38.35	INF
Commercial Lighting	CI	SC	8.65	16.16	4.37	1.1
High Efficiency A/C commerical	CI	SC	6.37	7.35	13.14	1.94
Commercial High Efficiency Motors	CI	SC	4.81	7.75	3.49	1.18
Residential New Construction Bundle	R	SC	7.11	10.62	17.3	2.1
Irrigation Demand Response- Direct Control	C	PC	1.49	1.49	2.85	INF

PC - Peak Clipping
C - Commercial
INF- Infinity as participant has no cost participation amount

SLG - Strategic Load Growth
R- Residential

SC- Strategic Conservation
I - Industrial

Sensitivity Analysis

One of the most significant variables affecting the viability of the programs are the customer participation estimates. In order to quantify the effect of reduced or increased participation in the programs as compared to the base case, a sensitivity analysis was performed for all programs assuming participation rates higher than the base case and participation rates lower than the base case.

Sensitivity A is an analysis assuming the participation rate in all DSM programs doubles over the base case. A summary of the cost-benefit ratios are shown in Table B-4.

DSM Program Cost Benefit Summary
(High Participation - Sensitivity A)
Table B-4

DSM Program	Customer Segment	Program Objective	Utility B/C Ration	Rate Payer B/C Ratio	Societal B/C Ratio	Participant B/C Ratio
Interruptible Rate-Demand Response Only	CI	PC	6.66	6.82	5.89	3.60
Residential A/C cycling (No Incentive)	R	PC	2.27	2.40	4.50	INF
Residential A/C cycling (With Incentive)	R	PC	1.67	1.75	3.49	INF
High Efficiency Residential AC	R	SC	5.87	7.71	15.74	1.75
Residental appliances (Refrigerators & Freezers)	R	SC	3.46	5.00	9.19	2.91
Refrigerator Round-Up	R	SC	4.10	7.81	20.61	INF
Residential Lighting (Various delivery Methods)	R	SC	0.83	2.48	4.27	INF
Commercial Lighting	CI	SC	8.69	16.29	4.38	1.10
High Efficiency A/C commerical	CI	SC	6.65	7.72	13.77	1.94
Commercial High Efficiency Motors	CI	SC	4.99	8.25	3.54	1.18
Residential New Construction Bundle	R	SC	7.26	10.95	17.77	2.10
Irrigation Demand Response- Direct Control	C	PC	1.41	1.41	2.68	INF

PC - Peak Clipping　　SLG - Strategic Load Growth　　SC- Strategic Conservation
C - Commercial　　R- Residential　　I - Industrial

INF- Infinity as participant has no cost participation amount

Sensitivity B is an analysis assuming the participation rate in all DSM programs is reduced by fifty percent of the base case. A summary of the cost-benefit ratios are shown in Table B-5.

DSM Program Cost Benefit Summary
(Low Participation - Sensitivity B)
Table B-5

DSM Program	Customer Segment	Program Objective	Utility B/C Ration	Rate Payer B/C Ratio	Societal B/C Ratio	Participant B/C Ratio
Interruptible Rate-Demand Response Only	CI	PC	4.77	4.85	4.92	3.53
Residential A/C cycling (No Incentive)	R	PC	1.54	1.62	3.03	INF
Residential A/C cycling (With Incentive	R	PC	1.24	1.29	2.53	INF
High Efficiency Residential AC	R	SC	5.42	6.94	14.08	1.75
Residental appliances (Refrigerators & Freezers)	R	SC	1.50	1.73	3.21	2.91
Refrigerator Round-Up	R	SC	3.22	5.13	11.89	INF
Residential Lighting (Various delivery Methods)	R	SC	7.49	14.00	24.06	INF
Commercial Lighting	CI	SC	8.58	15.91	4.36	1.10
High Efficiency A/C commerical	CI	SC	5.89	6.72	12.06	1.94
Commercial High Efficiency Motors	CI	SC	4.47	6.92	3.39	1.18
Residential New Construction Bundle	R	SC	6.84	10.01	16.44	2.10
Irrigation Demand Response- Direct Control	C	PC	1.40	1.40	2.67	INF

PC - Peak Clipping
SLG - Strategic Load Growth
SC- Strategic Conservation
C - Commercial
R- Residential
I - Industrial
INF- Infinity as participant has no cost participation amount

As indicated by the sensitivity analysis, there were no significant changes in the feasibility of any of the programs in Sensitivity A (High Participation) or Sensitivity B (Low Participation).

Feasible DSM Programs

Based on the Ratepayer Test, the following twelve programs have been identified as feasible DSM programs:

1. Residential air conditioner cycling program (with no cash incentive)
2. Residential air conditioner cycling program (with cash incentive)
3. ENERGY STAR® appliance rebates
4. ENERGY STAR® residential air conditioner rebates
5. Refrigerator round-up program
6. Interruptible Demand Response rates
7. High-efficiency commercial motor rebates
8. High-efficiency commercial air conditioner rebates
9. Commercial lighting retrofit rebates
10. Residential new construction bundle rebates
11. Residential lighting program
12. Irrigation direct-control demand response program

Currently Offered DSM Programs

Montana-Dakota currently offers five DSM programs in addition to the ENERGY STAR® Partnership, which is an indirect program used to promote conservation, education, and consumer awareness. This portfolio of DSM programs (identified as cost beneficial in prior IRPs) was re-evaluated in this IRP along with enhancements to certain programs as described below.

ENERGY STAR® Partnership

Montana-Dakota applied to become an ENERGY STAR® partner in January 2006 and received partnership status in May 2006. Montana-Dakota continues to use the ENERGY STAR® partnership to promote conservation in its marketing efforts is also continuing to explore additional partnerships with ENEGRY STAR® on national campaigns such as the "Change a Light" program.

ENERGY STAR® Residential Central Air Conditioner Rebates

This program, which offers a $175 per ton incentive to residential customers for installing a central air conditioner with a 15 SEER or higher, was implemented in June 2006. Participation in this program has been lower than expected. Montana-Dakota has decreased the assumed participation level for this program in the benefit/cost analysis, and the program is still feasible.

ENERGY STAR® Appliance Rebates

This program, which offers a $10 incentive to participants for installing an ENERGY STAR® refrigerator or freezer, was implemented in January 2008. Participation in this program has been significantly lower than expected, which Montana-Dakota attributes to a reluctance of the participant to take the time to complete an application for the offered incentive. Montana-Dakota has decreased the assumed participation level in the benefit/cost model and has raised the incentive to $15 for each qualifying ENERGY STAR® appliances. Montana-Dakota is planning to work with participating dealers to offer point-of-purchase incentives to the participants with reimbursement going to the dealers.

Refrigerator Round-Up Program

This program offers residential customers a $35 incentive, free pickup, and recycling of an older refrigerator in operation at their home. Montana-Dakota implemented this program in Montana in August 2008 on a one-time basis for collection. Participation was significantly lower than expected, and program costs per participant were almost twice as much as had been expected. While the program remains cost effective even with the higher operating cost, Montana-Dakota is planning to restructure the delivery of this program in 2010 and will make the program available on a continual basis with pickup and delivery handled by a third-party vendor.

Commercial Lighting Retrofit Rebates

This program, which offers a $0.20 per watt incentive for replacing existing T-12 lighting with new, higher-efficiency lighting, was implemented in September 2006. The average rebate is $8.00 for the most common type of fixture. The LED exit sign lighting program was added in January 2008. Participation in this program has exceeded projected participation levels. The program will continue to be offered with future customer participation projected to be higher than the level projected in the 2007 IRP. The incremental increased energy and demand savings due to expanding the program are included in the ”New DSM Package” in Table B-8.

Interruptible Demand Response Rates

Montana-Dakota offers a Demand Response Tariff in North Dakota and Montana to large commercial customers. The Interruptible Demand Response program modeled in this IRP is similar to the Montana Demand Response Rate Tariff, which offers a kW demand credit of $2.50 per billed kW of demand. Since the rate is currently in place, future customer participation in this program is expected to reach the level projected in the 2007 IRP.

2007-2008 Results from the Currently Offered DSM Programs

The DSM portfolio currently offered and described above has yielded approximately 6,000 kW of demand reduction and over 1,700,000 kWh of annual energy savings in each of the 2007 and 2008 program years. A summary of the 2007-2008 DSM actual results are shown below in Table B-6.

2007 - 2008 Results from the Currently Offered DSM Programs

Table B-6

	2007				2008			
Electric Program	Participants	Direct Expenses	kW	kWh	Participants	Direct Expenses	kW	kWh
Montana Refrigerator Round-Up	0	-	-	-	28	$6,471	39.6	32,648
Montana Lighting	9	$25,777	65.1	162,500	6	$4,138	20.0	76,676
North Dakota Lighting	37	$86,051	426	1,469,676	42	$119,720	590	1,531,090
South Dakota Lighting	3	$2,046	10	22,238	-	-	-	-
Montana Energy Star® Refigerator & Freezers	-	-	-	-	-	-	-	-
North Dakota Energy Star® Refigerator & Freezers	-	-	-	-	11	$110	1	792
South Dakota Energy Star® Refigerator & Freezers	-	-	-	-	2	$20	0	144
Montana Residential A/C	-	-	-	-	2	$788	2	1,080
North Dakota Residential A/C	37	$7,400	28	22,598	62	$27,483	48	38,400
South Dakota Residential A/C	-	-	-	-	1	$180	1	240
Interruptible Rate 39	1	$48,000	800	20,202	1	$48,000	800	3,600
IT Demand Response Rate 38	2	$180,000	4,670.0	71,370	2	$180,000	4,600	22,700
Total DSM Savings	**89**	**$349,274**	**5,999.1**	**1,768,584**	**157**	**$386,910**	**6,101.60**	**1,707,370**

New DSM Package

The Residential Lighting Program and the Residential New Construction Bundle programs were found feasible and determined appropriate to be included in the portfolio of DSM programs.

The demand-side analysis also showed higher expected customer participations, compared to those predicted in the 2007 IRP, for the Residential Air Conditioner Cycling and Commercial Lighting programs. The impact of the two new programs and the incremental customer participations of the other two are bundled in a "New DSM Package" shown in Table B-7. The "New DSM Package" is modeled as an additional resource option for the IRP.

The following two programs will not be implemented at this time, although the analysis showed they were feasible

- Residential Air Conditioner Cycling (with a cash incentive) - It was determined that the Residential Air Conditioner Cycling program would be initiated without a cash incentive to customers. However, as shown in the benefit/cost tests, the program is feasible with an incentive of $25 per participant if an incentive is ultimately determined to be necessary to reach anticipated participation levels.

- Irrigation Demand Response – This program was shown feasible in the analysis under the assumption that 75% of the irrigation loads are operated during system peak periods. If only 60% of those loads are operated during system peak periods, the benefits of the program will be significantly reduced and the program will not be cost effective. Further study is needed to confirm the amount of irrigation loads that will be operated during system peaks.

New DSM Package

Table B-7

Electric Program	Incremental kW	Incremental kWh	Installed $/kW	Installed $/kWh
Residential A/C Cycling (Increase)	2,766	4,994,566	$559.09	$0.310
Commercial Lighting (Increase)	4,460	89,200,000	$202.03	$0.010
Residential Lighting Program (New)	505	4,424,405	$129.71	$0.015
Residential New Construction Bundle (New)	391	4,561,921	$399.59	$0.034
TOTALS	**8122**	**103,180,892**	**$322.61**	**$0.092**

Summary of the Demand-Side Analysis Results

As a result of the demand-side analysis for this IRP, the following portfolio of DSM and conservation programs will continue as reflected in the current load forecast. New programs in the list below are considered in the integration process described in Appendix A.

1. Residential air conditioner cycling program (with no cash incentive)
2. ENERGY STAR® appliance rebates
3. ENERGY STAR® residential air conditioner rebates
4. Refrigerator round-up program
5. Interruptible Demand Response rates
6. High-efficiency commercial motor rebates
7. High-efficiency commercial air conditioner rebates
8. Commercial lighting retrofit rebates
9. Residential new construction bundle rebates
10. Residential lighting program

The DSM portfolio will benefit all customers as indicated by the Ratepayer Test results shown in this demand-side analysis. Table B-8 shows the estimated costs and potential reductions in energy and peak demand associated with the demand response programs, the conservation programs, and the total DSM portfolio recommended in this IRP. As shown in Table B-8, implementing this portfolio of ten programs will provide Montana-Dakota an estimated demand reduction of 22.7 MW and an estimated energy reduction of 170,810,314 KWh over the projected life of the programs. The DSM program cost is approximately $368/kW or $0.049/kWh over the projected life of the programs. The first year program costs are estimated at $1,403,167, with a total estimated cost of $5,391,212 over the two-year plan implementation period.

SUMMARY OF THE DSM PORTIFOLIO

Table B-8

Total DSM Program	2010	2011	IRP Totals	Project Life
Demand Response Programs Only				
Participants	1,202	6,503	7,705	10,008
kWh Saved	226,560	999,108	1,225,668	22,715,587
Annual kW Avoided *	2,374	8,632	11,006	15,106
Administrative Costs	$209	$209	$418	
Operating Costs	$898,067	$3,422,745	$4,320,812	
Incentive Costs	$30,000	$60,000	$90,000	
Total Costs	**$928,276**	**$3,482,954**	**$4,411,230**	**$6,411,145**
Total Demand Response Cost per kWh	$4.10	$3.49	$3.60	$0.28
Total Demand Response Cost per kW	$391.02	$403.49	$400.80	$424.41
Conservation Programs Only				
Participants	5748	5803	11551	17549
kWh Saved	3,697,940	3,755,483	7,453,423	148,094,726
Annual kW Avoided *	1,677	1,748	3,425	7,642
Administrative Costs	$88,774	$88,774	177548	-
Operating Costs	$7,853	$7,928	15781	-
Incentive Costs	$378,264	$408,389	786653	-
Total Costs	**$474,891**	**$505,091**	**$979,982**	**$1,962,573**
Total Demand Response Cost per kWh	$0.13	$0.13	$0.13	$0.01
Total Demand Response Cost per kW	$283.18	$288.95	$286.13	$256.81
Total Program				
Participants	6950	12306	19256	27557
kWh Saved	3,924,500	4,754,592	8,679,092	170,810,314
Annual kW Avoided *	4,051	10,380	14,431	22,748
Administrative Costs	$88,983	$88,983	177966	-
Operating Costs	$905,920	$3,430,673	4336593	-
Incentive Costs	$408,264	$468,389	876653	-
Total Costs	**$1,403,167**	**$3,988,045**	**$5,391,212**	**$8,373,720**
Total Cost Per kWh	**$0.36**	**$0.84**	**$0.62**	**$0.049**
Total Cost Per kW	**$346.38**	**$384.20**	**$373.59**	**$368.11**

Appendix A

Base Case

Inputs Data and Analysis Results

2009 Input Data Summary
Demand-Side Management Model

Table - B-1

Input Data Description	Information Source
Retail Rate	System Average retail rate for customer class based.
System Marginal Energy Costs	System Marginal energy costs as of June 2009
Retail Demand Cost	Seasonal demand cost based on program availability
System Peak Shaving Demand Costs	Demand Cost is based on estimated levelized cost of Combustion turbine
System Conservation Demand Costs	Demand cost is based on estimated levelized costs of Big Stone II - Base Load
MAPP Reserve Margin	Current required capacity reserve margin
Variable O&M	Montana-Dakota's historical information
Environmental Damage Factor	$30 / ton Carbon Cost
Total Sales By Class	2006 total sales for customer class based on program availability.
Total Customers	2006 total sales for customer class based on program availability.
Growth and Escalation Factors	Projected based on consumer indexes and forecasted escalation rates
Utility Discount Rate	Montana-Dakota's capital structure of incremental WACC 2008
Societal Discount Rate	Equal to the 30 year T-Bill rate average for the 52 weeks ending June 1, 2009
General Input Data Year	2009
Project Analysis Year	Year program will be implemented
Effective Tax Rate	Avg of Montana-Dakota's current state and local tax rate for integrated system
System Demand Line Loss Factor	Historical demand line loss factor for integrated electric system
System Energy Line Loss Factor	Historical energy line loss factor for integrated electric system
Direct Utility Project Costs	Total direct cost to the utility caused by implementing the DSM program
Administrative Costs	Total projected administrative costs including general admin and marketing costs of the DSM program
Direct Operating Costs	Direct operating cost estimated for the specific DSM program
Incentive Costs	Total annual cost of the incentive paid to the program participant
Direct Participant Project Costs	Direct costs that the participant is required to pay to participate in the DSM program
Other Participant Project Costs	Other costs or savings (neg) to the participant for participating in the DSM program
Project Life	Based on the estimated useful life of the energy saving equipment
Avg. Energy Reduction	Avg energy reduction (kWh) caused by the DSM program
Avg. Demand Reduction	Avg demand reduction (kW) caused by the DSM program
Number of Participants	Total projected participation by customers, kW load target, or equipment saturation

2009 Program Data Key Assumption Sources

Table B-2

DSM Program	Energy Calulation & Customer Cost Data	Program Cost Data	Participation Rate Estimate
Interruptible Rate - Demand Response Only	500 kW Model	Operating, Admin & Mkting Cost Estimate	Potential Customers - Customer Reps
Residential A/C Cycling (No Incentive)	Industry Data, EPRI, Vendor Info	Pricing of turnkey program provided by Honeywell	End Use Survey, Vendor Data
Residential A/C Cycling (With Incentive)	Industry Data, EPRI, Vendor Info	Pricing of turnkey program provided by Honeywell	End Use Survey, Vendor Data
High Efficiency Residential AC	Energy Star, Industry Data, EPRI	Operating, Admin & Mkting Cost Estimate	Customer End Use Survey, Estimate
Residential Appliances (Refrigerators & Freezers)	Energy Star, AHAM, WAPA DSM Guide	Operating, Admin & Mkting Cost Estimate	End Use Survey, Energy Star, AHAM
Refrigerator Round-Up	WAPA DSM Guide	Operating, Admin & Mkting Cost Estimate	End Use Survey, Industry Data
Residential Lighting (Various Delivery Methods)	Energy Star DOE 2004	Operating, Admin & Mkting Cost Estimate	Estimated
Commercial Lighting	Industry Data, IES	Operating, Admin & Mkting Cost Estimate	Xenergy Survey, Estimate
High Efficiency A/C Commercial	Energy Star, Industry Data, EPRI	Operating, Admin & Mkting Cost Estimate	Estimate
Commercial High Efficiency Motors	Motor Master Program - DOE & AEE for LF	Operating, Admin & Mkting Cost Estimate	Estimate
Residential New Construction Bundle	Energy Star, AHAM, WAPA DSM Guide	Operating, Admin & Mkting Cost Estimate	Estimated , New Service Line Report
Irrigation Demand Response - Direct Control	Industry Data, Vendor Info	Pricing from M2M Communications	Estimated

AHAM - Association of Home Appliance Manufacturers
EPRI - Electric Power Research Institute
IES - Illumination Engineering Society

WAPA - Western Area Power Association 1992 DSM Guide
DOE - Department of Energy
AEE - Association onf Energy Engineers

2009 DSM Program Summary

All Programs

DSM Program	Customer Segment	Program Objective	Utility B/C Ratio	Rate Payer B/C Ratio	Societal B/C Ratio	Participant B/C Ratio
Interruptible Rate - Demand Response Only	CI	PC	6.52	6.67	5.83	3.60
Residential A/C Cycling (No Incentive)	R	PC	1.96	2.07	3.88	INF
Residential A/C Cycling (With Incentive)	R	PC	1.49	1.57	3.10	INF
High Efficiency A/C Residential	R	SC	5.71	7.43	15.14	1.75
Residential Appliances (Refrigerators & Freezers)	R	SC	2.40	3.06	5.66	2.91
Refrigerator Round-Up	R	SC	4.10	7.80	20.58	INF
Residential Lighting (Various Delivery Methods)	R	SC	9.35	22.31	38.35	INF
Commercial Lighting	CI	SC	8.65	16.16	4.37	1.10
High Efficiency A/C Commercial	CI	SC	6.37	7.35	13.14	1.94
Commercial High Efficiency Motors	CI	SC	4.81	7.75	3.49	1.18
Residential New Construction Bundle	R	SC	7.11	10.62	17.30	2.10
Irrigation Demand Response - Direct Control	C	PC	1.49	1.49	2.85	INF

PC = Peak Clipping
SLG = Strategic Load Growth
SC = Strategic Conservation
C= Commercial
R= Residential
I = Industrial
INF= Infinity as participant has no cost participation amount

Demand Side Management

Total Program Summary

Total DSM Program	2010	2011	IRP Totals	Project Life
Demand Response Programs Only				
Particpants	1,202	6,503	7,705	10,008
kWH Saved	226,560	999,108	1,225,668	22,715,587
Annual kW Avoided *	2,374	8,632	11,006	15,106
Administrative Cost	$209	$209	$418	
Operating Cost	$898,067	$3,422,745	$4,320,812	
Incentive Cost	$30,000	$60,000	$90,000	
Total Cost	**$928,276**	**$3,482,954**	**$4,411,230**	**$6,411,145**
Total Demand Response Cost per kWh	*$4.10*	*$3.49*	*$3.60*	*$0.282*
Total Demand Response Cost per kW	*$391.02*	*$403.49*	*$400.80*	*$424.41*
Conservation Programs Only				
Particpants	5,748	5,803	11,551	17,549
kWH Saved	3,697,940	3,755,483	7,453,423	148,094,726
Annual kW Avoided *	1,677	1,748	3,425	7,642
Administrative Cost	$88,774	$88,774	$177,548	
Operating Cost	$7,853	$7,928	$15,781	
Incentive Cost	$378,264	$408,389	$786,653	
Total Cost	**$474,891**	**$505,091**	**$979,982**	**$1,962,573**
Total Conservation Cost per kWh	*$0.13*	*$0.13*	*$0.13*	*$0.013*
Total Conservation Cost per kW	*$283.18*	*$288.95*	*$286.13*	*$256.81*
Total Program				
Particpants	6,950	12,306	19,256	27,557
kWH Saved	3,924,500	4,754,592	8,679,092	170,810,314
Annual kW Avoided *	4,051	10,380	14,431	22,748
Administrative Cost	$88,983	$88,983	177,966	
Operating Cost	$905,920	$3,430,673	4,336,593	
Incentive Cost	$408,264	$468,389	876,653	
Total Cost	**$1,403,167**	**$3,988,045**	**$5,391,212**	**$8,373,720**
Total Cost Per kWh	***$0.36***	***$0.84***	***$0.62***	***$0.049***
Total Cost Per kW	***$346.38***	***$384.20***	***$373.59***	***$368.11***

**Includes Committed DSM resources which are included in the most recent load forecast.*

Demand Side Management

Incremental DSM Resources

Program	Incremental kW	Incremental kWh	Installed $ / kW	Installed $ / kWh
Residential AC Cycling (Increase)	2,766	4,994,566	$559.09	$0.310
Commercial Lighting (increase)	4,460	89,200,000	$202.03	$0.010
Residential Lighting Progam (New)	505	4,424,405	$129.71	$0.015
Residential New Construction Bundle (Ne	391	4,561,921	$399.59	$0.034
Totals	**8,122**	**103,180,892**	**$322.61**	**$0.092**

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

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

Project: **Total Program**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.04427
1a) Retail Rate Winter ($/kWh) =	$0.03858
Fuel Clause Adjustment (FCA)	$0.01132
Escalation Rate =	2.50%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.02795
Escalation Rate =	3.50%
3) Retail Summer Demand Rate ($/kW/season) =	$44.90
3a) Retail Winter Demand Rate ($/kW/season) =	$65.79
Escalation Rate =	2.50%
4) System Peak Shaving Demand Cost ($/kW/yr)	$107.77
MAPP Reserve Margin=	15.0%
Escalation Rate =	4.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	49.5%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	2,303,627,455
Growth Rate =	2.02%
8) Total Customers by class =	104,741
Growth Rate =	0.70%
9) Utility Discount Rate =	8.27%
10) Social Discount Rate(Tbill) =	3.99%
11) General Input Data Year =	2009
12) Project Analysis Year 1 =	2010
12a) Project Analysis Year 2 =	2011
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.90%
14b) System Energy Line loss factor	7.90%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$88,983
Direct Operating Costs =	$905,920
Incentive Costs =	$408,264
Total Utility Project Costs Year 1 =	**$1,403,167**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$88,983
Direct Operating Costs =	$3,430,673
Incentive Costs =	$468,389
Total Utility Project Costs Year 2 =	**$3,988,045**
15b) Total Utilty Cost Year 3 =	**$1,968,442**
15c) Total Utilty Cost Year 4 =	**$505,933**
15d) Total Utility Cost Year 5 =	**$508,133**
15e) Total Utility Operating Cost (Program Life) =	**$264,206**
Escalation Rate =	3.00%
16) Direct Participant Costs ($/Part.) =	$116,492
Escalation Rate =	3.00%
17a) Other Participant Costs (Annual $/Part.) =	$ 8,000
Escalation Rate =	3.00%
17b) Other Participant Savings (Annual $/Part.) =	$ 20,304
Escalation Rate =	0%
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	175.0
20a) Avg Winter kW/part Saved =	345.0
	0
21) Avg. Summer kWh/Part. Saved =	42,514
21a) Avg. Winter kWh/Part. Saved =	27,456
22) Number of Participants (First Year) =	6,950
22a) Number of Participants (Second Year) =	12,306
22a) Number of Participants (Third Year) =	8,151
22a) Number of Participants (Fourth Year) =	75
22a) Number of Participants (Fifth Year) =	75
	0
23) Incentive/Participant (All) =	$ 20,105

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Total Program**

Cost Summary

Program Promotion (Years)	5
Project Life (Years)	15
Total Progam Cost (Utility)	$8,373,720
Total Program Participants	27,557
Utility Cost per Participant (First Year) =	$201.89
Utility Cost per Participant (Program) =	$303.87
Total kW Reduction	22,748
Total Energy Reduction (kWh)	170,810,314
Societal Cost per kwh	$0.08

Test Results

	NPV	B/C
Utility Test	$28,231,164	3.95
Ratepayer Test	$29,708,522	4.67
Societal Cost Test	$54,511,296	4.76
Participant Test	$10,065,350	2.09

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: **Total Program**

		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)	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	2010	3,924,500	$0.0289	$0	4,051	$3,419.00	$1,077,912	$1,374,267	56,985	$1,431,252	($353,340
2	2011	8,679,092	$0.0299	0	14,431	$3,493.00	3,068,743	$3,959,145	136,201	4,095,347	(1,026,604
3	2012	12,889,387	$0.0310	0	20,333	$3,570.00	4,556,611	$1,968,442	197,651	2,166,093	2,390,518
4	2013	15,907,889	$0.0321	0	21,541	$3,648.00	5,268,449	$505,933	230,158	736,092	4,532,357
5	2014	18,926,392	$0.0332	0	22,748	$3,729.00	6,012,274	$508,133	261,511	769,644	5,242,630
6	2015	18,926,392	$0.0344	0	22,748	$3,811.00	6,153,108	$266,252	257,411	523,663	5,629,444
7	2016	18,926,392	$0.0356	0	22,748	$3,895.00	6,297,682	$268,323	253,074	521,397	5,776,285
8	2017	18,926,392	$0.0368	0	22,748	$3,982.00	6,446,098	$270,418	248,489	518,908	5,927,190
9	2018	18,926,392	$0.0381	0	22,748	$4,070.00	6,598,460	$272,539	243,647	516,186	6,082,274
10	2019	18,373,341	$0.0394	0	22,243	$4,161.00	6,489,824	$274,685	223,645	498,330	5,991,494
11	2020	3,280,829	$0.0408	0	16,206	$4,254.00	3,055,786	$276,857	63,376	340,233	2,715,553
12	2021	3,280,829	$0.0422	0	16,206	$4,350.00	3,126,025	$279,055	61,508	340,562	2,785,463
13	2022	3,280,829	$0.0437	0	16,206	$4,448.00	3,198,067	$281,279	59,565	340,843	2,857,224
14	2023	3,280,829	$0.0452	0	16,206	$4,548.00	3,271,959	$283,530	57,543	341,073	2,930,886
15	2024	3,280,829	$0.0468	0	16,206	$4,651.00	3,347,748	$285,808	55,441	341,248	3,006,500
16	2025	0	$0.0485	0	0	$4,756.00	0	0	0	0	0
Total =		170,810,314			277,369		$67,968,746	$11,074,666	$2,406,205	$13,480,871	$54,487,874
NPV =							37,793,128	8,130,328	1,431,636	9,561,964	28,231,164

Total NPV = $28,231,164
Benefit/Cost Ratio = 3.95

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(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: **Total 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)
2010	$113,529	$0	$964,383	$1,077,912	$1,374,267	$1,374,267	$0	($296,355)
2011	259,858	0	2,808,885	3,068,743	$3,959,145	3,959,145	0	(890,402)
2012	399,425	0	4,157,186	4,556,611	$1,968,442	1,968,442	0	2,588,170
2013	510,218	0	4,758,231	5,268,449	$505,933	505,933	0	4,762,515
2014	628,277	0	5,383,997	6,012,274	$508,133	508,133	0	5,504,141
2015	650,267	0	5,502,841	6,153,108	$264,206	264,206	0	5,888,901
2016	673,026	0	5,624,655	6,297,682	$264,206	264,206	0	6,033,475
2017	696,582	0	5,749,516	6,446,098	$264,206	264,206	0	6,181,892
2018	720,963	0	5,877,498	6,598,460	$264,206	264,206	0	6,334,254
2019	724,392	0	5,765,433	6,489,824	$264,206	264,206	0	6,225,618
2020	133,878	0	2,921,908	3,055,786	$264,206	264,206	0	2,791,580
2021	138,564	0	2,987,462	3,126,025	$264,206	264,206	0	2,861,819
2022	143,413	0	3,054,654	3,198,067	$264,206	264,206	0	2,933,861
2023	148,433	0	3,123,526	3,271,959	$264,206	264,206	0	3,007,753
2024	153,628	0	3,194,120	3,347,748	$264,206	264,206	0	3,083,542
2025	0	0	0	0	0	0	0	0
Total =	$6,094,453	$0	$61,874,295	$67,968,746	$10,957,980	$10,957,980		$57,010,764
NPV =	3,528,984	0	34,264,145	37,793,128	8,084,606	8,084,606		29,708,522

Total NPV = $29,708,522
Benefit/Cost Ratio = 4.67

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (A) + (B) + (C)
(E) = Total Utility Project Costs (15)
(F) = (E)
(G) = (D) - (F)

Table 3

Societal Cost Test

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

Company **Montana-Dakota Utilities Co.**
Project: **Total 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)
2010	$113,529	$0	$964,383	$549,573	$1,627,486	$1,374,267	$2,184,572	$399,437	$3,159,402	($1,531,916)
2011	$259,858	$0	$2,808,885	$1,611,537	4,680,280	$3,959,145	2,355,890	$843,961	5,471,074	(790,794)
2012	$399,425	$0	$4,157,186	$2,464,670	7,021,282	$1,968,442	2,401,570	$1,312,918	3,057,094	3,964,188
2013	$510,218	$0	$4,758,231	$2,935,194	8,203,643	$505,933	1,695,020	$0	2,200,954	6,002,689
2014	$628,277	$0	$5,383,997	$3,450,087	9,462,361	$508,133	1,696,371	$0	2,204,504	7,257,858
2015	$650,267	$0	$5,502,841	$3,636,830	9,789,938	$264,206	47,762	$0	311,968	9,477,969
2016	$673,026	$0	$5,624,655	$3,833,950	10,131,632	$264,206	49,195	$0	313,401	9,818,231
2017	$696,582	$0	$5,749,516	$4,042,033	10,488,131	$264,206	50,671	$0	314,877	10,173,254
2018	$720,963	$0	$5,877,498	$4,261,700	10,860,160	$264,206	52,191	$0	316,397	10,543,762
2019	$724,392	$0	$5,765,433	$4,317,282	10,807,106	$264,206	53,757	$0	317,963	10,489,143
2020	$133,878	$0	$2,921,908	$2,093,812	5,149,598	$264,206	55,369	$0	319,576	4,830,022
2021	$138,564	$0	$2,987,462	$2,206,197	5,332,223	$264,206	57,030	$0	321,237	5,010,986
2022	$143,413	$0	$3,054,654	$2,324,752	5,522,820	$264,206	58,741	$0	322,948	5,199,872
2023	$148,433	$0	$3,123,526	$2,449,820	5,721,779	$264,206	60,504	$0	324,710	5,397,069
2024	$153,628	$0	$3,194,120	$2,581,763	5,929,511	$264,206	62,319	$0	326,525	5,602,986
2025	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$6,094,453	$0	$61,874,295	$42,759,200	$110,727,950	$10,957,980	$10,880,962	$2,556,316	$19,282,630	$91,445,319
NPV =	3,528,984	0	34,264,145	31,212,110	69,005,239	8,084,606	8,532,679	2,123,342	14,493,943	54,511,296

Total NPV = $54,511,296
Benefit/Cost Ratio = 4.76

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) 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 a
directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Total 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 Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)		Direct Part. Costs (H)
2010	0.0659	$399,437	1,413,703	2,223,461	$0.057	$0.051	2,121	1,634	$230.00	$337.00	$838,649		$2,168,092
2011	0.1813	$843,961	3,573,168	4,470,476	$0.058	$0.052	9,745	3,629	$236.00	$346.00	$2,110,969		2,313,454
2012	0.1800	$1,312,918	5,212,485	6,733,194	$0.060	$0.054	13,201	5,643	$242.00	$354.00	$3,197,859		2,357,861
2013	0.1788	$0	6,144,985	8,598,194	$0.061	$0.055	13,574	6,389	$248.00	$363.00	$2,160,358		1,650,000
2014	0.1775	$0	7,077,485	10,463,194	$0.063	$0.056	13,947	7,135	$254.00	$372.00	$2,448,475		1,650,000
2015	0.1763	$0	7,077,485	10,463,194	$0.064	$0.058	13,947	7,135	$260.00	$381.00	$2,505,376		0
2016	0.1751	$0	7,077,485	10,463,194	$0.066	$0.059	13,947	7,135	$267.00	$391.00	$2,563,699		0
2017	0.1739	$0	7,077,485	10,463,194	$0.068	$0.061	13,947	7,135	$274.00	$401.00	$2,623,480		0
2018	0.1727	$0	7,077,485	10,463,194	$0.069	$0.062	13,947	7,135	$280.00	$411.00	$2,684,756		0
2019	0.1715	$0	6,906,632	10,121,488	$0.071	$0.064	13,791	6,823	$287.00	$421.00	$2,697,358		0
2020	0.1703	$0	2,244,132	796,488	$0.073	$0.065	11,926	3,093	$295.00	$432.00	$1,378,012		0
2021	0.1691	$0	2,244,132	796,488	$0.075	$0.067	11,926	3,093	$302.00	$442.00	$1,408,152		0
2022	0.1679	$0	2,244,132	796,488	$0.077	$0.069	11,926	3,093	$309.00	$453.00	$1,439,044		0
2023	0.1667	$0	2,244,132	796,488	$0.079	$0.071	11,926	3,093	$317.00	$465.00	$1,470,709		0
2024	0.1656	$0	2,244,132	796,488	$0.081	$0.072	11,926	3,093	$325.00	$476.00	$1,503,166		0
2025	0.1644	0	0	0	$0.083	$0.074	0	0	$333.00	$488.00	$0		0
			69,859,058	88,445,223							$31,030,062		$10,139,407
											$19,303,682		8,817,048

Total NPV = $10,065,350
Benefit/Cost Ratio = 2.09

(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 Participa
(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
(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

Integrated Electric System Cost-Effectiveness Analysis

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

Project: **Total Demand Response Program**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.04427
1a) Retail Rate Winter ($/kWh) =	$0.03858
Fuel Clause Adjustment (FCA)	$0.01132
Escalation Rate =	2.50%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.02795
Escalation Rate =	3.50%
3) Retail Summer Demand Rate ($/kW/season) =	$44.90
3a) Retail Winter Demand Rate ($/kW/season) =	$65.79
Escalation Rate =	2.50%
4) System Peak Shaving Demand Cost ($/kW/yr)	$107.77
MAPP Reserve Margin=	15.0%
Escalation Rate =	4.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	49.5%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	2,303,627,455
Growth Rate =	2.02%
8) Total Customers by class =	104,741
Growth Rate =	0.70%
9) Utility Discount Rate =	8.27%
10) Social Discount Rate(Tbill) =	3.99%
11) General Input Data Year =	2009
12) Project Analysis Year 1 =	2010
12a) Project Analysis Year 2 =	2011
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.90%
14b) System Energy Line loss factor	7.90%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$209
Direct Operating Costs =	$898,067
Incentive Costs =	$30,000
Total Utility Project Costs Year 1 =	**$928,276**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$209
Direct Operating Costs =	$3,422,745
Incentive Costs =	$60,000
Total Utility Project Costs Year 2 =	**$3,482,954**
15b) Total Utilty Cost Year 3 =	**$1,473,702**
15c) Total Utilty Cost Year 4 =	**$262,007**
15d) Total Utility Cost Year 5 =	**$264,206**
15e) Total Utility Operating Cost (Program Life) =	**$264,206**
Escalation Rate =	3.00%
16) Direct Participant Costs ($/Part.) =	$90,000
Escalation Rate =	3.00%
17a) Other Participant Costs (Annual $/Part.) =	$ 8,000
Escalation Rate =	3.00%
17b) Other Participant Savings (Annual $/Part.) =	$ 20,264
Escalation Rate =	0%
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	168.0
20a) Avg Winter kW/part Saved =	333.0
	0
21) Avg. Summer kWh/Part. Saved =	27,116
21a) Avg. Winter kWh/Part. Saved =	0
22) Number of Participants (First Year) =	1,202
22a) Number of Participants (Second Year) =	6,503
22a) Number of Participants (Third Year) =	2,303
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
	0
23) Incentive/Participant (All) =	$ 15,000

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Total Demand Response Program**

Cost Summary

Program Promotion (Years)	5
Project Life (Years)	15
Total Progam Cost (Utility)	$6,411,145
Total Program Participants	10,008
Utility Cost per Participant (First Year) =	$772.28
Utility Cost per Participant (Program) =	$640.60
Total kW Reduction	15,106
Total Energy Reduction (kWh)	22,715,587
Societal Cost per kwh	$0.32

Test Results

	NPV	B/C
Utility Test	$9,897,506	2.44
Ratepayer Test	$10,219,924	2.56
Societal Cost Test	$24,102,976	4.28
Participant Test	$8,184,890	8.57

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: **Total Demand Response Program**

		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)	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	2010	226,560	$0.0289	$0	2,374	$253.00	$307,148	$928,277	5,772	$934,049	($626,901
2	2011	1,225,668	$0.0299	0	11,006	$259.00	1,460,753	$3,482,955	33,139	3,516,094	(2,055,341
3	2012	1,635,643	$0.0310	0	15,106	$264.00	2,048,032	$1,473,702	42,570	1,516,272	531,760
4	2013	1,635,643	$0.0321	0	15,106	$270.00	2,093,635	$262,007	41,488	303,495	1,790,140
5	2014	1,635,643	$0.0332	0	15,106	$276.00	2,140,395	$264,206	40,368	304,574	1,835,821
6	2015	1,635,643	$0.0344	0	15,106	$282.00	2,188,343	$266,252	39,209	305,461	1,882,882
7	2016	1,635,643	$0.0356	0	15,106	$289.00	2,237,509	$268,323	38,009	306,332	1,931,177
8	2017	1,635,643	$0.0368	0	15,106	$295.00	2,287,923	$270,418	36,767	307,185	1,980,738
9	2018	1,635,643	$0.0381	0	15,106	$302.00	2,339,619	$272,539	35,482	308,021	2,031,598
10	2019	1,635,643	$0.0394	0	15,106	$308.00	2,392,627	$274,685	34,151	308,836	2,083,791
11	2020	1,635,643	$0.0408	0	15,106	$315.00	2,446,983	$276,857	32,775	309,631	2,137,351
12	2021	1,635,643	$0.0422	0	15,106	$322.00	2,502,720	$279,055	31,350	310,404	2,192,316
13	2022	1,635,643	$0.0437	0	15,106	$329.00	2,559,874	$281,279	29,875	311,154	2,248,720
14	2023	1,635,643	$0.0452	0	15,106	$337.00	2,618,481	$283,530	28,348	311,878	2,306,603
15	2024	1,635,643	$0.0468	0	15,106	$344.00	2,678,578	$285,808	26,768	312,576	2,366,002
16	2025	0	$0.0485	0	0	$352.00	0	0	0	0	0
Total =		22,715,587			209,758		$32,302,620	$9,169,893	$496,071	$9,665,962	$22,636,657
NPV =							16,755,110	6,580,908	276,697	6,857,605	9,897,506

Total NPV = $9,897,506
Benefit/Cost Ratio = 2.44

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(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: **Total Demand Response 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)
2010	$6,554	$0	$300,594	$307,148	$928,277	$928,277	$0	($621,129)
2011	36,697	0	1,424,055	1,460,753	$3,482,955	3,482,955	0	(2,022,202)
2012	50,686	0	1,997,346	2,048,032	$1,473,702	1,473,702	0	574,330
2013	52,460	0	2,041,174	2,093,635	$262,007	262,007	0	1,831,628
2014	54,297	0	2,086,099	2,140,395	$264,206	264,206	0	1,876,189
2015	56,197	0	2,132,146	2,188,343	$264,206	264,206	0	1,924,137
2016	58,164	0	2,179,345	2,237,509	$264,206	264,206	0	1,973,302
2017	60,200	0	2,227,724	2,287,923	$264,206	264,206	0	2,023,717
2018	62,307	0	2,277,312	2,339,619	$264,206	264,206	0	2,075,412
2019	64,487	0	2,328,140	2,392,627	$264,206	264,206	0	2,128,421
2020	66,744	0	2,380,239	2,446,983	$264,206	264,206	0	2,182,776
2021	69,080	0	2,433,640	2,502,720	$264,206	264,206	0	2,238,514
2022	71,498	0	2,488,376	2,559,874	$264,206	264,206	0	2,295,667
2023	74,001	0	2,544,480	2,618,481	$264,206	264,206	0	2,354,274
2024	76,591	0	2,601,987	2,678,578	$264,206	264,206	0	2,414,371
2025	0	0	0	0	0	0	0	0
Total =	$859,963	$0	$31,442,657	$32,302,620	$9,053,207	$9,053,207		$23,249,407
NPV =	439,203	0	16,315,907	16,755,110	6,535,186	6,535,186		10,219,924

Total NPV =	$10,219,924
Benefit/Cost Ratio =	2.56

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

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

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

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

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Cost Test

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

Company **Montana-Dakota Utilities Co.**
Project: **Total Demand Response 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)
2010	$6,554	$0	$300,594	$156,599	$463,747	$928,277	$196,480	$30,000	$1,094,757	($631,010)
2011	$36,697	$0	$1,424,055	$767,108	2,227,861	$3,482,955	312,436	$75,000	3,720,391	(1,492,530)
2012	$50,686	$0	$1,997,346	$1,107,780	3,155,812	$1,473,702	313,709	$120,000	1,667,411	1,488,401
2013	$52,460	$0	$2,041,174	$1,166,420	3,260,055	$262,007	45,020	$0	307,027	2,953,028
2014	$54,297	$0	$2,086,099	$1,228,246	3,368,641	$264,206	46,371	$0	310,577	3,058,064
2015	$56,197	$0	$2,132,146	$1,293,433	3,481,776	$264,206	47,762	$0	311,968	3,169,808
2016	$58,164	$0	$2,179,345	$1,362,168	3,599,676	$264,206	49,195	$0	313,401	3,286,275
2017	$60,200	$0	$2,227,724	$1,434,645	3,722,568	$264,206	50,671	$0	314,877	3,407,691
2018	$62,307	$0	$2,277,312	$1,511,072	3,850,691	$264,206	52,191	$0	316,397	3,534,294
2019	$64,487	$0	$2,328,140	$1,591,668	3,984,295	$264,206	53,757	$0	317,963	3,666,332
2020	$66,744	$0	$2,380,239	$1,676,662	4,123,645	$264,206	55,369	$0	319,576	3,804,069
2021	$69,080	$0	$2,433,640	$1,766,299	4,269,019	$264,206	57,030	$0	321,237	3,947,782
2022	$71,498	$0	$2,488,376	$1,860,834	4,420,708	$264,206	58,741	$0	322,948	4,097,760
2023	$74,001	$0	$2,544,480	$1,960,540	4,579,021	$264,206	60,504	$0	324,710	4,254,311
2024	$76,591	$0	$2,601,987	$2,065,703	4,744,281	$264,206	62,319	$0	326,525	4,417,756
2025	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$859,963	$0	$31,442,657	$20,949,177	$53,251,796	$9,053,207	$1,461,555	$225,000	$10,289,765	$42,962,031
NPV =	439,203	0	16,315,907	14,695,233	31,450,343	6,535,186	998,419	186,238	7,347,367	24,102,976

Total NPV = $24,102,976
Benefit/Cost Ratio = 4.28

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) 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 a directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Total Demand Response 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 Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)
2010	0.0114	$30,000	209,972	0	$0.057	$0.051	1,533	667	$92.00	$135.00	$202,470	$180,000
2011	0.0725	$75,000	1,135,930	0	$0.058	$0.052	8,533	1,667	$94.00	$138.00	$789,697	270,000
2012	0.0720	$120,000	1,515,888	0	$0.060	$0.054	11,333	2,667	$97.00	$142.00	$1,148,772	270,000
2013	0.0715	$0	1,515,888	0	$0.061	$0.055	11,333	2,667	$99.00	$145.00	$1,050,438	0
2014	0.0710	$0	1,515,888	0	$0.063	$0.056	11,333	2,667	$102.00	$149.00	$1,072,647	0
2015	0.0705	$0	1,515,888	0	$0.064	$0.058	11,333	2,667	$104.00	$153.00	$1,095,410	0
2016	0.0701	$0	1,515,888	0	$0.066	$0.059	11,333	2,667	$107.00	$156.00	$1,118,742	0
2017	0.0696	$0	1,515,888	0	$0.068	$0.061	11,333	2,667	$109.00	$160.00	$1,142,658	0
2018	0.0691	$0	1,515,888	0	$0.069	$0.062	11,333	2,667	$112.00	$164.00	$1,167,172	0
2019	0.0686	$0	1,515,888	0	$0.071	$0.064	11,333	2,667	$115.00	$168.00	$1,192,298	0
2020	0.0681	$0	1,515,888	0	$0.073	$0.065	11,333	2,667	$118.00	$173.00	$1,218,053	0
2021	0.0677	$0	1,515,888	0	$0.075	$0.067	11,333	2,667	$121.00	$177.00	$1,244,451	0
2022	0.0672	$0	1,515,888	0	$0.077	$0.069	11,333	2,667	$124.00	$181.00	$1,271,510	0
2023	0.0667	$0	1,515,888	0	$0.079	$0.071	11,333	2,667	$127.00	$186.00	$1,299,245	0
2024	0.0663	$0	1,515,888	0	$0.081	$0.072	11,333	2,667	$130.00	$191.00	$1,327,673	0
2025	0.0658	0	0	0	$0.083	$0.074	0	0	$133.00	$195.00	$0	0
			21,052,446	0							$16,341,236	$720,000
											$9,265,877	659,705

Total NPV = $8,184,890
Benefit/Cost Ratio = 8.57

(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 Participa
(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
(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

Integrated Electric System Cost-Effectiveness Analysis

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

Project: **Total Conservation Program**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.04427
1a) Retail Rate Winter ($/kWh) =	$0.03858
Fuel Clause Adjustment (FCA)	$0.01132
Escalation Rate =	2.50%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.02795
Escalation Rate =	3.50%
3) Retail Summer Demand Rate ($/kW/season) =	$44.90
3a) Retail Winter Demand Rate ($/kW/season) =	$65.79
Escalation Rate =	2.50%
4) System Peak Shaving Demand Cost ($/kW/yr)	$107.77
MAPP Reserve Margin=	15.0%
Escalation Rate =	4.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	49.5%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	2,303,627,455
Growth Rate =	2.02%
8) Total Customers by class =	104,741
Growth Rate =	0.70%
9) Utility Discount Rate =	8.27%
10) Social Discount Rate(Tbill) =	3.99%
11) General Input Data Year =	2009
12) Project Analysis Year 1 =	2010
12a) Project Analysis Year 2 =	2011
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.90%
14b) System Energy Line loss factor	7.90%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$88,774
Direct Operating Costs =	$7,853
Incentive Costs =	$378,264
Total Utility Project Costs Year 1 =	**$474,891**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$88,774
Direct Operating Costs =	$7,928
Incentive Costs =	$408,389
Total Utility Project Costs Year 2 =	**$505,091**
15b) Total Utilty Cost Year 3 =	**$494,739**
15c) Total Utilty Cost Year 4 =	**$243,926**
15d) Total Utility Cost Year 5 =	**$243,926**
15e) Total Utility Operating Cost (Program Life) =	**$0**
Escalation Rate =	3.00%
16) Direct Participant Costs ($/Part.) =	$26,492
Escalation Rate =	3.00%
17a) Other Participant Costs (Annual $/Part.) =	$ -
Escalation Rate =	3.00%
17b) Other Participant Savings (Annual $/Part.) =	$ 40
Escalation Rate =	0%
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	8.0
20a) Avg Winter kW/part Saved =	11.0
21) Avg. Summer kWh/Part. Saved =	15,398
21a) Avg. Winter kWh/Part. Saved =	27,456
22) Number of Participants (First Year) =	5,748
22a) Number of Participants (Second Year) =	5,803
22a) Number of Participants (Third Year) =	5,848
22a) Number of Participants (Fourth Year) =	75
22a) Number of Participants (Fifth Year) =	75
23) Incentive/Participant (All) =	$ 5,105

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Total Conservation Program**

Cost Summary

Program Promotion (Years)	5
Project Life (Years)	15
Total Progam Cost (Utility)	$1,962,573
Total Program Participants	17,549
Utility Cost per Participant (First Year) =	$82.62
Utility Cost per Participant (Program) =	$111.83
Total kW Reduction	7,642
Total Energy Reduction (kWh)	148,094,726
Societal Cost per kwh	$0.05

Test Results

	NPV	B/C
Utility Test	$18,333,657	7.78
Ratepayer Test	$19,488,597	13.58
Societal Cost Test	$30,408,319	5.25
Participant Test	$1,880,461	1.23

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: **Total Conservation Program**

		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)	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	2010	3,697,940	$0.0289	$0	1,677	$3,166.00	$770,764	$445,991	51,212	$497,203	$273,561
2	2011	7,453,423	$0.0299	0	3,425	$3,235.00	1,607,990	$476,191	103,062	579,253	1,028,738
3	2012	11,253,744	$0.0310	0	5,227	$3,305.00	2,508,579	$494,739	155,081	649,821	1,858,759
4	2013	14,272,246	$0.0321	0	6,435	$3,378.00	3,174,814	$243,926	188,671	432,597	2,742,217
5	2014	17,290,749	$0.0332	0	7,642	$3,452.00	3,871,879	$243,926	221,144	465,070	3,406,809
6	2015	17,290,749	$0.0344	0	7,642	$3,529.00	3,964,764	$0	218,202	218,202	3,746,562
7	2016	17,290,749	$0.0356	0	7,642	$3,607.00	4,060,173	$0	215,065	215,065	3,845,108
8	2017	17,290,749	$0.0368	0	7,642	$3,687.00	4,158,175	$0	211,723	211,723	3,946,452
9	2018	17,290,749	$0.0381	0	7,642	$3,769.00	4,258,842	$0	208,165	208,165	4,050,677
10	2019	16,737,698	$0.0394	0	7,137	$3,853.00	4,097,197	$0	189,494	189,494	3,907,704
11	2020	1,645,186	$0.0408	0	1,100	$3,939.00	608,803	$0	30,601	30,601	578,202
12	2021	1,645,186	$0.0422	0	1,100	$4,027.00	623,305	$0	30,158	30,158	593,147
13	2022	1,645,186	$0.0437	0	1,100	$4,118.00	638,193	$0	29,690	29,690	608,504
14	2023	1,645,186	$0.0452	0	1,100	$4,211.00	653,478	$0	29,195	29,195	624,283
15	2024	1,645,186	$0.0468	0	1,100	$4,306.00	669,170	$0	28,672	28,672	640,498
16	2025	0	$0.0485	0	0	$4,404.00	0	0	0	0	0
Total =		148,094,726			67,611		$35,666,126	$1,904,773	$1,910,135	$3,814,909	$31,851,221
NPV =							21,038,018	1,549,420	1,154,940	2,704,361	18,333,657

Total NPV = $18,333,657
Benefit/Cost Ratio = 7.78

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(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: **Total Conservation Program**

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)
2010	$106,975	$0	$663,790	$770,764	$445,991	$445,991	$0	$324,774
2011	223,161	0	1,384,829	1,607,990	$476,191	476,191	0	1,131,800
2012	348,738	0	2,159,841	2,508,579	$494,739	494,739	0	2,013,840
2013	457,758	0	2,717,056	3,174,814	$243,926	243,926	0	2,930,887
2014	573,981	0	3,297,898	3,871,879	$243,926	243,926	0	3,627,952
2015	594,070	0	3,370,694	3,964,764	$0	0	0	3,964,764
2016	614,863	0	3,445,310	4,060,173	$0	0	0	4,060,173
2017	636,383	0	3,521,792	4,158,175	$0	0	0	4,158,175
2018	658,656	0	3,600,186	4,258,842	$0	0	0	4,258,842
2019	659,904	0	3,437,293	4,097,197	$0	0	0	4,097,197
2020	67,134	0	541,669	608,803	$0	0	0	608,803
2021	69,483	0	553,822	623,305	$0	0	0	623,305
2022	71,915	0	566,278	638,193	$0	0	0	638,193
2023	74,432	0	579,046	653,478	$0	0	0	653,478
2024	77,037	0	592,133	669,170	$0	0	0	669,170
2025	0	0	0	0	0	0	0	0
Total =	$5,234,490	$0	$30,431,637	$35,666,126	$1,904,773	$1,904,773		$33,761,353
NPV =	3,089,782	0	17,948,237	21,038,018	1,549,420	1,549,420		19,488,597

Total NPV = $19,488,597
Benefit/Cost Ratio = 13.58

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (A) + (B) + (C)
(E) = Total Utility Project Costs (15)
(F) = (E)
(G) = (D) - (F)

Table 3

Societal Cost Test

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

Company **Montana-Dakota Utilities Co.**
Project: **Total Conservation 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)
2010	$106,975	$0	$663,790	$392,974	$1,163,739	$445,991	$1,988,092	$369,437	$2,064,645	($900,906)
2011	$223,161	$0	$1,384,829	$844,429	2,452,419	$476,191	2,043,454	$768,961	1,750,683	701,736
2012	$348,738	$0	$2,159,841	$1,356,890	3,865,470	$494,739	2,087,861	$1,192,918	1,389,683	2,475,787
2013	$457,758	$0	$2,717,056	$1,768,774	4,943,588	$243,926	1,650,000	$0	1,893,926	3,049,662
2014	$573,981	$0	$3,297,898	$2,221,841	6,093,720	$243,926	1,650,000	$0	1,893,926	4,199,794
2015	$594,070	$0	$3,370,694	$2,343,397	6,308,162	$0	0	$0	0	6,308,162
2016	$614,863	$0	$3,445,310	$2,471,783	6,531,956	$0	0	$0	0	6,531,956
2017	$636,383	$0	$3,521,792	$2,607,388	6,765,563	$0	0	$0	0	6,765,563
2018	$658,656	$0	$3,600,186	$2,750,627	7,009,469	$0	0	$0	0	7,009,469
2019	$659,904	$0	$3,437,293	$2,725,614	6,822,811	$0	0	$0	0	6,822,811
2020	$67,134	$0	$541,669	$417,149	1,025,953	$0	0	$0	0	1,025,953
2021	$69,483	$0	$553,822	$439,899	1,063,204	$0	0	$0	0	1,063,204
2022	$71,915	$0	$566,278	$463,918	1,102,112	$0	0	$0	0	1,102,112
2023	$74,432	$0	$579,046	$489,280	1,142,758	$0	0	$0	0	1,142,758
2024	$77,037	$0	$592,133	$516,060	1,185,230	$0	0	$0	0	1,185,230
2025	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$5,234,490	$0	$30,431,637	$21,810,023	$57,476,154	$1,904,773	$9,419,407	$2,331,316	$8,992,863	$48,483,291
NPV =	3,089,782	0	17,948,237	16,516,877	37,554,895	1,549,420	7,534,260	1,937,104	7,146,576	30,408,319

Total NPV = $30,408,319
Benefit/Cost Ratio = 5.25

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) 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 a
directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Total Conservation 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 Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)		Direct Part. Costs (H)
2010	0.0545	$369,437	1,203,731	2,223,461	$0.057	$0.051	587	967	$138.00	$202.00	$636,179		$1,988,092
2011	0.1088	$768,961	2,437,238	4,470,476	$0.058	$0.052	1,212	1,963	$142.00	$207.00	$1,321,273		2,043,454
2012	0.1080	$1,192,918	3,696,597	6,733,194	$0.060	$0.054	1,868	2,976	$145.00	$213.00	$2,049,087		2,087,861
2013	0.1072	$0	4,629,097	8,598,194	$0.061	$0.055	2,241	3,722	$149.00	$218.00	$1,109,919		1,650,000
2014	0.1065	$0	5,561,597	10,463,194	$0.063	$0.056	2,614	4,468	$152.00	$223.00	$1,375,828		1,650,000
2015	0.1058	$0	5,561,597	10,463,194	$0.064	$0.058	2,614	4,468	$156.00	$229.00	$1,409,966		0
2016	0.1050	$0	5,561,597	10,463,194	$0.066	$0.059	2,614	4,468	$160.00	$235.00	$1,444,957		0
2017	0.1043	$0	5,561,597	10,463,194	$0.068	$0.061	2,614	4,468	$164.00	$240.00	$1,480,822		0
2018	0.1036	$0	5,561,597	10,463,194	$0.069	$0.062	2,614	4,468	$168.00	$246.00	$1,517,584		0
2019	0.1029	$0	5,390,744	10,121,488	$0.071	$0.064	2,458	4,156	$172.00	$253.00	$1,505,060		0
2020	0.1021	$0	728,244	796,488	$0.073	$0.065	593	426	$177.00	$259.00	$159,959		0
2021	0.1014	$0	728,244	796,488	$0.075	$0.067	593	426	$181.00	$265.00	$163,700		0
2022	0.1007	$0	728,244	796,488	$0.077	$0.069	593	426	$186.00	$272.00	$167,534		0
2023	0.1000	$0	728,244	796,488	$0.079	$0.071	593	426	$190.00	$279.00	$171,464		0
2024	0.0993	$0	728,244	796,488	$0.081	$0.072	593	426	$195.00	$286.00	$175,493		0
2025	0.0986	0	0	0	$0.083	$0.074	0	0	$200.00	$293.00	$0		0
			48,806,612	88,445,223							$14,688,825		$9,419,407
											$10,037,804		8,157,343

Total NPV = $1,880,461
Benefit/Cost Ratio = 1.23

(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 Participa
(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
(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

Integrated Electric System Cost-Effectiveness Analysis

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

Project: **Interruptible Rate - Demand Response**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.04427
1a) Retail Rate Winter ($/kWh) =	$0.03858
Fuel Clause Adjustment (FCA)	$0.01132
Escalation Rate =	2.50%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.02795
Escalation Rate =	3.50%
3) Retail Summer Demand Rate ($/kW/season) =	$44.90
3a) Retail Winter Demand Rate ($/kW/season) =	$65.79
Escalation Rate =	2.50%
4) System Peak Shaving Demand Cost ($/kW/yr)	$107.77
MAPP Reserve Margin=	15.0%
Escalation Rate =	4.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	49.5%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	1,488,732,948
Growth Rate =	2.02%
8) Total Customers by class =	93
Growth Rate =	0.70%
9) Utility Discount Rate =	8.27%
10) Social Discount Rate(Tbill) =	3.99%
11) General Input Data Year =	2009
12) Project Analysis Year 1 =	2010
12a) Project Analysis Year 2 =	2011
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.90%
14b) System Energy Line loss factor	7.90%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$105
Direct Operating Costs =	$3,600
Incentive Costs =	$30,000
Total Utility Project Costs Year 1 =	**$33,705**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$105
Direct Operating Costs =	$3,600
Incentive Costs =	$60,000
Total Utility Project Costs Year 2 =	**$63,705**
15b) Total Utilty Cost Year 3 =	**$93,705**
15c) Total Utilty Cost Year 4 =	**$93,705**
15d) Total Utility Cost Year 5 =	**$93,705**
15e) Total Utility Operating Cost (Program Life) =	**$93,705**
Escalation Rate =	3.00%
16) Direct Participant Costs ($/Part.) =	$90,000
Escalation Rate =	3.00%
17a) Other Participant Costs (Annual $/Part.) =	$ 8,000
Escalation Rate =	3.00%
17b) Other Participant Savings (Annual $/Part.) =	$ 20,264
Escalation Rate =	0%
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	166.7
20a) Avg Winter kW/part Saved =	333.3
21) Avg. Summer kWh/Part. Saved =	26,986
21a) Avg. Winter kWh/Part. Saved =	0
22) Number of Participants (First Year) =	2
22a) Number of Participants (Second Year) =	3
22a) Number of Participants (Third Year) =	3
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 15,000

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Interruptible Rate - Demand Response**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$378,524
Total Program Participants	8
Utility Cost per Participant (First Year) =	$16,852.35
Utility Cost per Participant (Program) =	$47,315.44
Total kW Reduction	4,316
Total Energy Reduction (kWh)	3,232,086
Societal Cost per kwh	$0.47

Test Results

	NPV	B/C
Utility Test	$3,997,623	6.52
Ratepayer Test	$4,013,725	6.67
Societal Cost Test	$7,340,966	5.83
Participant Test	$2,805,427	3.60

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: **Interruptible Rate - Demand Response**

		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)	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	2010	58,236	$0.0289	$0	1,079	$126.63	$138,318	$33,705	803	$34,507	$103,811
2	2011	145,589	$0.0299	0	2,698	$129.39	353,392	$63,705	1,916	65,621	287,771
3	2012	232,943	$0.0310	0	4,316	$132.22	577,889	$93,705	2,917	96,622	481,267
4	2013	232,943	$0.0321	0	4,316	$135.12	590,664	$93,705	2,763	96,468	494,196
5	2014	232,943	$0.0332	0	4,316	$138.10	603,761	$93,705	2,604	96,308	507,452
6	2015	232,943	$0.0344	0	4,316	$141.15	617,188	$93,705	2,439	96,143	521,045
7	2016	232,943	$0.0356	0	4,316	$144.27	630,954	$93,705	2,268	95,973	534,981
8	2017	232,943	$0.0368	0	4,316	$147.47	645,066	$93,705	2,091	95,796	549,270
9	2018	232,943	$0.0381	0	4,316	$150.76	659,534	$93,705	1,908	95,613	563,921
10	2019	232,943	$0.0394	0	4,316	$154.12	674,367	$93,705	1,718	95,423	578,944
11	2020	232,943	$0.0408	0	4,316	$157.57	689,574	$93,705	1,522	95,227	594,347
12	2021	232,943	$0.0422	0	4,316	$161.10	705,164	$93,705	1,319	95,024	610,140
13	2022	232,943	$0.0437	0	4,316	$164.73	721,147	$93,705	1,109	94,814	626,333
14	2023	232,943	$0.0452	0	4,316	$168.44	737,533	$93,705	892	94,597	642,937
15	2024	232,943	$0.0468	0	4,316	$172.25	754,333	$93,705	667	94,372	659,961
16	2025	0	$0.0485	0	0	$176.15	0	0	0	0	0
Total =		3,232,086			59,885		$9,098,883	$1,315,571	$26,937	$1,342,508	$7,756,375
NPV =							4,721,724	707,999	16,101	724,100	3,997,623

Total NPV = $3,997,623
Benefit/Cost Ratio = 6.52

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(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: **Interruptible Rate - Demand Response**

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)
2010	$1,685	$0	$136,634	$138,318	$33,705	$33,705	$104,613
2011	4,359	0	349,033	353,392	$63,705	63,705	289,688
2012	7,219	0	570,670	577,889	$93,705	93,705	484,184
2013	7,471	0	583,193	590,664	$93,705	93,705	496,959
2014	7,733	0	596,028	603,761	$93,705	93,705	510,056
2015	8,003	0	609,185	617,188	$93,705	93,705	523,483
2016	8,284	0	622,670	630,954	$93,705	93,705	537,249
2017	8,573	0	636,493	645,066	$93,705	93,705	551,361
2018	8,873	0	650,661	659,534	$93,705	93,705	565,829
2019	9,184	0	665,183	674,367	$93,705	93,705	580,662
2020	9,506	0	680,068	689,574	$93,705	93,705	595,869
2021	9,838	0	695,326	705,164	$93,705	93,705	611,459
2022	10,183	0	710,964	721,147	$93,705	93,705	627,442
2023	10,539	0	726,994	737,533	$93,705	93,705	643,829
2024	10,908	0	743,425	754,333	$93,705	93,705	660,628
2025	0	0	0	0	0	0	0
Total =	$122,357	$0	$8,976,526	$9,098,883	$1,315,571	$1,315,571	$7,783,312
NPV =	62,504	0	4,659,220	4,721,724	707,999	707,999	4,013,725

Total NPV = $4,013,725
Benefit/Cost Ratio = 6.67

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (A) + (B) + (C)
(E) = Total Utility Project Costs (15)
(F) = (E)
(G) = (D) - (F)

Table 3

Societal Cost Test

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

Compar **Montana-Dakota Utilities Co.**
Project: **Interruptible Rate - Demand Response**

	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)
2010	$1,685	$0	$136,634	$70,522	$208,840	$33,705	$196,480	$30,000	$200,185	$8,655
2011	$4,359	$0	$349,033	$185,582	538,975	$63,705	312,436	$75,000	301,141	237,834
2012	$7,219	$0	$570,670	$312,580	890,469	$93,705	313,709	$120,000	287,414	603,055
2013	$7,471	$0	$583,193	$329,075	919,739	$93,705	45,020	$0	138,725	781,014
2014	$7,733	$0	$596,028	$346,463	950,224	$93,705	46,371	$0	140,076	810,148
2015	$8,003	$0	$609,185	$364,793	981,981	$93,705	47,762	$0	141,467	840,514
2016	$8,284	$0	$622,670	$384,117	1,015,070	$93,705	49,195	$0	142,900	872,171
2017	$8,573	$0	$636,493	$404,489	1,049,555	$93,705	50,671	$0	144,376	905,180
2018	$8,873	$0	$650,661	$425,968	1,085,503	$93,705	52,191	$0	145,896	939,607
2019	$9,184	$0	$665,183	$448,615	1,122,982	$93,705	53,757	$0	147,461	975,520
2020	$9,506	$0	$680,068	$472,493	1,162,067	$93,705	55,369	$0	149,074	1,012,993
2021	$9,838	$0	$695,326	$497,671	1,202,834	$93,705	57,030	$0	150,735	1,052,099
2022	$10,183	$0	$710,964	$524,219	1,245,366	$93,705	58,741	$0	152,446	1,092,920
2023	$10,539	$0	$726,994	$552,215	1,289,748	$93,705	60,504	$0	154,208	1,135,540
2024	$10,908	$0	$743,425	$581,737	1,336,069	$93,705	62,319	$0	156,023	1,180,046
2025	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$122,357	$0	$8,976,526	$5,900,537	$14,999,420	$1,315,571	$1,461,555	$225,000	$2,552,126	$12,447,295
NPV =	62,504	0	4,659,220	4,139,422	8,861,146	707,999	998,419	186,238	1,520,180	7,340,966

Total NPV = $7,340,966
Benefit/Cost Ratio = 5.83

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) 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 acc directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Interruptible Rate - Demand Response**

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 Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Costs: Direct Part. Costs (H)
2010	0.0214	$30,000	53,972	0	$0.057	$0.051	333	667	$46.02	$67.43	$133,901	$180,000
2011	0.0530	$75,000	134,930	0	$0.058	$0.052	833	1,667	$47.17	$69.12	$338,712	270,000
2012	0.0527	$120,000	215,888	0	$0.060	$0.054	1,333	2,667	$48.35	$70.85	$548,436	270,000
2013	0.0523	$0	215,888	0	$0.061	$0.055	1,333	2,667	$49.56	$72.62	$435,094	0
2014	0.0519	$0	215,888	0	$0.063	$0.056	1,333	2,667	$50.80	$74.44	$441,918	0
2015	0.0516	$0	215,888	0	$0.064	$0.058	1,333	2,667	$52.07	$76.30	$448,913	0
2016	0.0512	$0	215,888	0	$0.066	$0.059	1,333	2,667	$53.37	$78.20	$456,083	0
2017	0.0508	$0	215,888	0	$0.068	$0.061	1,333	2,667	$54.71	$80.16	$463,433	0
2018	0.0505	$0	215,888	0	$0.069	$0.062	1,333	2,667	$56.07	$82.16	$470,966	0
2019	0.0501	$0	215,888	0	$0.071	$0.064	1,333	2,667	$57.48	$84.22	$478,687	0
2020	0.0498	$0	215,888	0	$0.073	$0.065	1,333	2,667	$58.91	$86.32	$486,601	0
2021	0.0494	$0	215,888	0	$0.075	$0.067	1,333	2,667	$60.39	$88.48	$494,714	0
2022	0.0491	$0	215,888	0	$0.077	$0.069	1,333	2,667	$61.90	$90.69	$503,029	0
2023	0.0488	$0	215,888	0	$0.079	$0.071	1,333	2,667	$63.44	$92.96	$511,552	0
2024	0.0484	$0	215,888	0	$0.081	$0.072	1,333	2,667	$65.03	$95.28	$520,288	0
2025	0.0481	0	0	0	$0.083	$0.074	0	0	$66.65	$97.67	$0	0
			2,995,446	0							$6,732,325	$720,000
											$3,886,415	659,705

Total NPV = $2,805,427
Benefit/Cost Ratio = 3.60

(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 Participant
(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 F
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Interruptible Rate - Demand Response

Customer Class:	Commercial and Industrial	

Cost MDU

			$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Cost	$	3,600	$ 450	$ 3,600	$ 3,600	$ 3,600	$ 10,800
Incentive Costs	$	15,000	$ 15,000	$ 30,000	$ 60,000	$ 90,000	$ 180,000
Admin & Advertising	$	105	$ 39	$ 105	$ 105	$ 105	$ 314
Total Cost			**$ 15,489**	**$ 33,705**	**$ 63,705**	**$ 93,705**	**$ 191,114**

Notes

Admin & Advertising			Calculated
Operating Cost			Calculated
Incentive	$	2.50	per kW/month

Participant Costs (Incremental Cost Basis)

Estimated Average cost of inteconnection	$ 50,000	Average interconnection costs - Estimated
Estimated cost of Primary Service	$ 40,000	Cost for Transformer, Primary Metering, Switch Fuse
Total Cost	**$ 90,000**	
Other Partcipant Costs (Diesel @ 100 hrs of curtailment)	$ 8,000	

Participation Rate Calc

	% of Cust	Cust	
C& I Customers over 500 kW	100.00%	93	RA provided Query of CIS

		Total MW	
Participation Year 1	2	1.0	
Participation Year 2	3	1.5	
Participation Year 3	3	1.5	
Total Participantion Rate	**8**	**4.0**	This is in addtion to what we have currently

Energy Savings Calculation

IT Rate	Total conn kW	kW/Customer	Avg kW per event	Coincident Rate
Rate 38 - DR	500	500.0	500	100.0%

Avg Customer KWh Avoided @ 100 hrs		**26,986**	75% Customer LF
Primary Service Rate Savings per year	**$**	**20,264**	Included in other particapant savings

	Per Part	Proposed IT DR Rate	
Summer Demand Reduction	166.7	Summer kW	$ 8.254
Winter Demand Reduction	333.3	Winter kW	$ 5.254
Total Demand Reduction	**500**	Energy kWh	$ 0.03255
Summer Energy Reduction	26,986	Demand Credit kW	$ 2.50
Winter Energy Reduction	0		

Note:
MW of IT is the target not Customers
Incentive is equal to our lost Margin between ND Rate 30 Secondary and IT Rate

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

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

Project: **Air Conditioning Cycling - Res & Sm Comm**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.07212
1a) Retail Rate Winter ($/kWh) =	$0.06174
Fuel Clause Adjustment (FCA)	$0.01132
Escalation Rate =	2.50%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.02795
Escalation Rate =	3.50%
3) Retail Summer Demand Rate ($/kW/season) =	$44.90
3a) Retail Winter Demand Rate ($/kW/season) =	$65.79
Escalation Rate =	2.50%
4) System Peak Shaving Demand Cost ($/kW/yr)	$107.77
MAPP Reserve Margin=	15.0%
Escalation Rate =	4.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	49.5%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	814,894,507
Growth Rate =	2.02%
8) Total Customers by class =	87,692
Growth Rate =	0.70%
9) Utility Discount Rate =	8.27%
10) Social Discount Rate(Tbill) =	3.99%
11) General Input Data Year =	2009
12) Project Analysis Year 1 =	2010
12a) Project Analysis Year 2 =	2011
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.90%
14b) System Energy Line loss factor	7.90%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$105
Direct Operating Costs =	$894,467
Incentive Costs =	$0
Total Utility Project Costs Year 1 =	**$894,572**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$105
Direct Operating Costs =	$3,419,145
Incentive Costs =	$0
Total Utility Project Costs Year 2 =	**$3,419,250**
15b) Total Utilty Cost Year 3 =	**$1,379,998**
15c) Total Utilty Cost Year 4 =	**$168,302**
15d) Total Utility Cost Year 5 =	**$170,502**
15e) Total Utility Operating Cost (Program Life) =	**$170,502**
Escalation Rate =	1.20%
16) Direct Participant Costs ($/Part.) =	$0
Escalation Rate =	3.00%
17a) Other Participant Costs (Annual $/Part.) =	$ -
Escalation Rate =	3.00%
17b) Other Participant Savings (Annual $/Part.) =	$ -
Escalation Rate =	0%
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	1.0
20a) Avg Winter kW/part Saved =	0.0
21) Avg. Summer kWh/Part. Saved =	130
21a) Avg. Winter kWh/Part. Saved =	0
22) Number of Participants (First Year) =	1,200
22a) Number of Participants (Second Year) =	6,500
22a) Number of Participants (Third Year) =	2,300
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ -

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Air Conditioning Cycling - Res & Sm Comm**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$6,032,623
Total Program Participants	10,000
Utility Cost per Participant (First Year) =	$745.48
Utility Cost per Participant (Program) =	$603.26
Total kW Reduction	10,790
Total Energy Reduction (kWh)	19,483,503
Societal Cost per kwh	$0.30

Test Results

	NPV	B/C
Utility Test	$5,899,882	1.96
Ratepayer Test	$6,206,197	2.07
Societal Cost Test	$16,762,009	3.88
Participant Test	$5,379,462	#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: **Air Conditioning Cycling - Res & Sm Comm**

		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)	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	2010	168,324	$0.0289	$0	1,295	$126.63	$168,830	$894,572	4,970	$899,542	($730,712)
2	2011	1,080,079	$0.0299	0	8,308	$129.39	1,107,361	$3,419,250	31,223	3,450,473	(2,343,112)
3	2012	1,402,700	$0.0310	0	10,790	$132.22	1,470,143	$1,379,998	39,653	1,419,650	50,493
4	2013	1,402,700	$0.0321	0	10,790	$135.12	1,502,971	$168,302	38,725	207,027	1,295,944
5	2014	1,402,700	$0.0332	0	10,790	$138.10	1,536,634	$170,502	37,764	208,266	1,328,369
6	2015	1,402,700	$0.0344	0	10,790	$141.15	1,571,155	$172,548	36,770	209,318	1,361,838
7	2016	1,402,700	$0.0356	0	10,790	$144.27	1,606,555	$174,618	35,741	210,359	1,396,196
8	2017	1,402,700	$0.0368	0	10,790	$147.47	1,642,857	$176,714	34,676	211,390	1,431,468
9	2018	1,402,700	$0.0381	0	10,790	$150.76	1,680,084	$178,834	33,574	212,408	1,467,676
10	2019	1,402,700	$0.0394	0	10,790	$154.12	1,718,260	$180,980	32,433	213,413	1,504,847
11	2020	1,402,700	$0.0408	0	10,790	$157.57	1,757,409	$183,152	31,252	214,404	1,543,005
12	2021	1,402,700	$0.0422	0	10,790	$161.10	1,797,556	$185,350	30,030	215,380	1,582,176
13	2022	1,402,700	$0.0437	0	10,790	$164.73	1,838,727	$187,574	28,765	216,339	1,622,387
14	2023	1,402,700	$0.0452	0	10,790	$168.44	1,880,947	$189,825	27,456	217,281	1,663,666
15	2024	1,402,700	$0.0468	0	10,790	$172.25	1,924,245	$192,103	26,101	218,204	1,706,041
16	2025	0	$0.0485	0	0	$176.15	0	0	0	0	0
Total =		19,483,503			149,873		$23,203,736	$7,854,322	$469,133	$8,323,455	$14,880,281
NPV =							12,033,386	5,872,909	260,595	6,133,504	5,899,882

Total NPV = $5,899,882
Benefit/Cost Ratio = 1.96

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(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: **Air Conditioning Cycling - Res & Sm Comm**

	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)
2010	$4,869	$0	$163,960	$168,830	$894,572	$894,572	($725,743)
2011	32,338	0	1,075,022	1,107,361	$3,419,250	3,419,250	(2,311,890)
2012	43,468	0	1,426,675	1,470,143	$1,379,998	1,379,998	90,146
2013	44,989	0	1,457,982	1,502,971	$168,302	168,302	1,334,669
2014	46,564	0	1,490,071	1,536,634	$170,502	170,502	1,366,133
2015	48,194	0	1,522,962	1,571,155	$170,502	170,502	1,400,653
2016	49,880	0	1,556,675	1,606,555	$170,502	170,502	1,436,054
2017	51,626	0	1,591,231	1,642,857	$170,502	170,502	1,472,356
2018	53,433	0	1,626,651	1,680,084	$170,502	170,502	1,509,583
2019	55,303	0	1,662,957	1,718,260	$170,502	170,502	1,547,759
2020	57,239	0	1,700,170	1,757,409	$170,502	170,502	1,586,907
2021	59,242	0	1,738,314	1,797,556	$170,502	170,502	1,627,054
2022	61,316	0	1,777,411	1,838,727	$170,502	170,502	1,668,225
2023	63,462	0	1,817,486	1,880,947	$170,502	170,502	1,710,446
2024	65,683	0	1,858,562	1,924,245	$170,502	170,502	1,753,743
2025	0	0	0	0	0	0	0
Total =	$737,606	$0	$22,466,130	$23,203,736	$7,737,640	$7,737,640	$15,466,095
NPV =	376,699	0	11,656,687	12,033,386	5,827,189	5,827,189	6,206,197

Total NPV = $6,206,197
Benefit/Cost Ratio = 2.07

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (A) + (B) + (C)
(E) = Total Utility Project Costs (15)
(F) = (E)
(G) = (D) - (F)

Table 3

Societal Cost Test

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

Compar **Montana-Dakota Utilities Co.**
Project: **Air Conditioning Cycling - Res & Sm Comm**

	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)
2010	$4,869	$0	$163,960	$86,078	$254,907	$894,572	$0	$0	$894,572	($639,665)
2011	$32,338	$0	$1,075,022	$581,525	1,688,886	$3,419,250	0	$0	3,419,250	(1,730,364)
2012	$43,468	$0	$1,426,675	$795,200	2,265,343	$1,379,998	0	$0	1,379,998	885,346
2013	$44,989	$0	$1,457,982	$837,345	2,340,316	$168,302	0	$0	168,302	2,172,014
2014	$46,564	$0	$1,490,071	$881,783	2,418,418	$170,502	0	$0	170,502	2,247,916
2015	$48,194	$0	$1,522,962	$928,641	2,499,796	$170,502	0	$0	170,502	2,329,294
2016	$49,880	$0	$1,556,675	$978,051	2,584,606	$170,502	0	$0	170,502	2,414,105
2017	$51,626	$0	$1,591,231	$1,030,156	2,673,013	$170,502	0	$0	170,502	2,502,511
2018	$53,433	$0	$1,626,651	$1,085,104	2,765,188	$170,502	0	$0	170,502	2,594,687
2019	$55,303	$0	$1,662,957	$1,143,053	2,861,313	$170,502	0	$0	170,502	2,690,812
2020	$57,239	$0	$1,700,170	$1,204,169	2,961,578	$170,502	0	$0	170,502	2,791,077
2021	$59,242	$0	$1,738,314	$1,268,628	3,066,184	$170,502	0	$0	170,502	2,895,683
2022	$61,316	$0	$1,777,411	$1,336,615	3,175,342	$170,502	0	$0	170,502	3,004,840
2023	$63,462	$0	$1,817,486	$1,408,325	3,289,273	$170,502	0	$0	170,502	3,118,771
2024	$65,683	$0	$1,858,562	$1,483,966	3,408,211	$170,502	0	$0	170,502	3,237,710
2025	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$737,606	$0	$22,466,130	$15,048,640	$38,252,376	$7,737,640	$0	$0	$7,737,640	$30,514,736
NPV =	376,699	0	11,656,687	10,555,811	22,589,198	5,827,189	0	0	5,827,189	16,762,009

Total NPV = $16,762,009
Benefit/Cost Ratio = 3.88

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a)
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 ac
directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Air Conditioning Cycling - Res & Sm Comm**

		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 Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)
2010	0.0136	$0	156,000	0	$0.086	$0.075	1,200	0	$46.02	$67.43	$68,569	$0
2011	0.0866	$0	1,001,000	0	$0.088	$0.077	7,700	0	$47.17	$69.12	$450,984	0
2012	0.0860	$0	1,300,000	0	$0.090	$0.079	10,000	0	$48.35	$70.85	$600,336	0
2013	0.0854	$0	1,300,000	0	$0.092	$0.081	10,000	0	$49.56	$72.62	$615,345	0
2014	0.0848	$0	1,300,000	0	$0.094	$0.083	10,000	0	$50.80	$74.44	$630,728	0
2015	0.0842	$0	1,300,000	0	$0.097	$0.085	10,000	0	$52.07	$76.30	$646,497	0
2016	0.0836	$0	1,300,000	0	$0.099	$0.087	10,000	0	$53.37	$78.20	$662,659	0
2017	0.0830	$0	1,300,000	0	$0.102	$0.089	10,000	0	$54.71	$80.16	$679,226	0
2018	0.0825	$0	1,300,000	0	$0.104	$0.091	10,000	0	$56.07	$82.16	$696,206	0
2019	0.0819	$0	1,300,000	0	$0.107	$0.094	10,000	0	$57.48	$84.22	$713,611	0
2020	0.0813	$0	1,300,000	0	$0.109	$0.096	10,000	0	$58.91	$86.32	$731,452	0
2021	0.0808	$0	1,300,000	0	$0.112	$0.098	10,000	0	$60.39	$88.48	$749,738	0
2022	0.0802	$0	1,300,000	0	$0.115	$0.101	10,000	0	$61.90	$90.69	$768,481	0
2023	0.0796	$0	1,300,000	0	$0.118	$0.103	10,000	0	$63.44	$92.96	$787,693	0
2024	0.0791	$0	1,300,000	0	$0.121	$0.106	10,000	0	$65.03	$95.28	$807,386	0
2025	0.0785	0	0	0	$0.124	$0.108	0	0	$66.65	$97.67	$0	0
			18,057,000	0							$9,608,911	$0
											$5,379,462	0

Total NPV = $5,379,462
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 Participar
(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 F
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Honeywell - Demand Response 10 MW
Residential & Small Commercial

T-Stat no incentive

Project Cost	2009 Year 0	2010 Year 1	2011 Year 2	2012 Year 3	2013 Year 4	2014 Year 5	2015 Year 6	2016 Year 7	2017 Year 8	2018 Year 9	2019 Year 10	Total Cost
Residential Thermostat - Installed Cost	$0	$398,462	$2,390,769	$796,923	$60,260	$62,086	$63,968	$65,907	$67,904	$69,963	$72,084	$4,048,326
Residential DCU - Installed Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Commercial Thermostat Installed Cost	$0	$79,692	$199,231	$119,538	$6,696	$6,898	$7,108	$7,323	$7,545	$7,774	$8,009	$449,814
Commercial DCU - Installed Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Replacements due to failure (no warranty)	$0	$0	$0	$1,800	$5,347	$5,517	$5,693	$5,875	$6,063	$6,257	$6,457	$43,008
Network Software License Fee	$0	$6,800	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,800
Network Setup Fee	$0	$39,286	$0	$0	$0	$0	$0	$0	$0	$0	$0	$39,286
Communcation Fee (After implementation)	$0	$0	$0	$12,000	$36,000	$36,000	$36,000	$36,000	$36,000	$36,000	$36,000	$264,000
Program Administration & Network Fee	$0	$191,640	$287,460	$191,640	$0	$0	$0	$0	$0	$0	$0	$670,740
Marketing & Customer Outreach	$0	$156,008	$489,000	$258,096	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000	$1,323,104
Measurement & Verification	$0	$22,580	$52,686	$0	$0	$0	$0	$0	$0	$0	$0	$75,265
Customer Incentive	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Totals	**$0**	**$894,467**	**$3,419,145**	**$1,379,998**	**$168,302**	**$170,502**	**$172,769**	**$175,105**	**$177,512**	**$179,993**	**$182,550**	**$6,920,343**
											PV	**$5,306,299**

$/kW before Incentive	*$692*
Total $/kW	***$692***

Project Cost Data

Residential		**Sm Commerical**	
Total Points	9,000	Total Points	1,000
Residential t-stat installed	$384.53	Commercial Thermostat - Installed Cost	$407.26
Residential DCU	$215.00	Commercial DCU	$240.00
Precentage Residential	90%	Precentage Residential	10%
Precentage T-Stat	100%	Precentage T-Stat	100%
Pecentage DCU	0%	Pecentage DCU	0%
Points year 1 (2010)	1,000	Points year 1	200
Points year 2 (2011)	6,000	Points year 2	500
Points Year 3 (2012)	2,000	Points Year 3	300
Marketing Cost per unit installed year 1	$63.34	Cancellation Rate (Starting in Year 3)	3.0%
Marketing Cost per Unit Installed Yr 2 (Bugetary)	$103.52	New Install Rate (Starting in Year 3)	3.0%
Marketing Mobilization (one time Fee)	$80,000	Material cost Escallation Rate	3.0%
Program Admin & Network Communcations Fee (per month)	$23,955	Failure Rate	0.1%
Cancellation Rate (Starting in Year 3)	3.0%		
New Install Rate (Starting in Year 3)	3.0%		
Cancellation Costs T-Stat (implementation)	$80.00		
Cancellation Costs DCU (implementation)	$50.00		
Cost per turndown	$0.00		
Turndown Rate	0.0%		
Servcie Call Rate	$0.00		
Material cost Escallation Rate	3.0%		
Failure Rate	0.1%		
MDU Labor cost per hour (loaded)	$43.54		
Labor escalation rate	4.0%		
Hours to install T-Stat or DCU	2		
Internal annual Markteing Cost after implementation period	$60,000		
Sales Tax Rate on Equipment (T-stats or DCU)	5.5%		
Annual incentive Cost per participant (DCU)	$0		
One-time incentive Cost per participant (T-stat)	$0		

M & V Cost

Communcations per site	$0.00
Equipment & Installation Per site	$0.00
Initial M&V Analysis & Report	$75,265
Annual M&V Analysis & Report (Third Party)	30,000

Assumptions

Cancelaton Rate and New install rate are net zero
New Install /cancellation assumes only 50% of equipment will be new & 50% will be reinstalled equipment
No savings projection for Programable t_stat savings per customer
No savings projection for cycling kWh savings
1 point is equal to 1 kW
No MDU internal administrative costs (no added head count)
WACC 7.2%
Equipment life 10 yrs
Cancelation charge is only for installing the unit again somewhere else no removal charge
No addtionlal charge for turnddowns - Hwell's Cost
No service call charges - Included
M&V Cost based on quotes from Summit Blue
Advertising cost per Rena includes Radio, TV, & Direct Mail
Assumes sales tax on only T-stat or DCU at wieghted average sales tax cost
Material cost escallation assumed at forecated CPI

Energy Savings Calculation

Equipment	kw Conn	Annual kWh	Utilization Factor
3 Ton 10 SEER Unit	3.6	2,340	28%
Cycling Hours per Year		100 hrs	
Peak kW Reduced	**1.00**		

Av is 1 kW per particpant (Honeywell)
100 hrs of curtailment per year or 10% cycling rate
Utilization Factor is based on Honeywell realized kW redcction per partcipant

	Per Part
Summer Demand Reduction	1.00
Winter Demand Reduction	0.000
Summer Energy Reduction	130
Winter Energy Reduction	.

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

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

Project: **Air Conditioning Cycling w/incent - Res & Sm Comm**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.07212
1a) Retail Rate Winter ($/kWh) =	$0.06174
Fuel Clause Adjustment (FCA)	$0.01132
Escalation Rate =	2.50%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.02795
Escalation Rate =	3.50%
3) Retail Summer Demand Rate ($/kW/season) =	$44.90
3a) Retail Winter Demand Rate ($/kW/season) =	$65.79
Escalation Rate =	2.50%
4) System Peak Shaving Demand Cost ($/kW/yr)	$107.77
MAPP Reserve Margin=	15.0%
Escalation Rate =	4.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	49.5%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	814,894,507
Growth Rate =	2.02%
8) Total Customers by class =	87,692
Growth Rate =	0.70%
9) Utility Discount Rate =	8.27%
10) Social Discount Rate(Tbill) =	3.99%
11) General Input Data Year =	2009
12) Project Analysis Year 1 =	2010
12a) Project Analysis Year 2 =	2011
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.90%
14b) System Energy Line loss factor	7.90%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$105
Direct Operating Costs =	$894,467
Incentive Costs =	$30,000
Total Utility Project Costs Year 1 =	**$924,572**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$105
Direct Operating Costs =	$3,419,145
Incentive Costs =	$192,500
Total Utility Project Costs Year 2 =	**$3,611,750**
15b) Total Utilty Cost Year 3 =	**$1,629,998**
15c) Total Utilty Cost Year 4 =	**$418,302**
15d) Total Utility Cost Year 5 =	**$420,502**
15e) Total Utility Operating Cost (Program Life) =	**$420,502**
Escalation Rate =	1.20%
16) Direct Participant Costs ($/Part.) =	$0
Escalation Rate =	3.00%
17a) Other Participant Costs (Annual $/Part.) =	$ -
Escalation Rate =	3.00%
17b) Other Participant Savings (Annual $/Part.) =	$ -
Escalation Rate =	0%
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	1.0
20a) Avg Winter kW/part Saved =	0.0
21) Avg. Summer kWh/Part. Saved =	130
21a) Avg. Winter kWh/Part. Saved =	0
22) Number of Participants (First Year) =	1,200
22a) Number of Participants (Second Year) =	6,500
22a) Number of Participants (Third Year) =	2,300
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 25

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Air Conditioning Cycling w/incent - Res & Sm Comm**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$7,005,123
Total Program Participants	10,000
Utility Cost per Participant (First Year) =	$770.48
Utility Cost per Participant (Program) =	$700.51
Total kW Reduction	10,790
Total Energy Reduction (kWh)	19,483,503
Societal Cost per kwh	$0.37

Test Results

	NPV	B/C
Utility Test	$3,980,054	1.49
Ratepayer Test	$4,353,406	1.57
Societal Cost Test	$15,298,119	3.10
Participant Test	$5,800,525	#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: **Air Conditioning Cycling w/incent - Res & Sm Comm**

		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)	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	2010	168,324	$0.0289	$0	1,295	$126.63	$168,830	$924,572	4,970	$929,542	($760,712)
2	2011	1,080,079	$0.0299	0	8,308	$129.39	1,107,361	$3,611,750	31,223	3,642,973	(2,535,612)
3	2012	1,402,700	$0.0310	0	10,790	$132.22	1,470,143	$1,629,998	39,653	1,669,650	(199,507)
4	2013	1,402,700	$0.0321	0	10,790	$135.12	1,502,971	$418,302	38,725	457,027	1,045,944
5	2014	1,402,700	$0.0332	0	10,790	$138.10	1,536,634	$420,502	37,764	458,266	1,078,369
6	2015	1,402,700	$0.0344	0	10,790	$141.15	1,571,155	$425,548	36,770	462,318	1,108,838
7	2016	1,402,700	$0.0356	0	10,790	$144.27	1,606,555	$430,654	35,741	466,395	1,140,160
8	2017	1,402,700	$0.0368	0	10,790	$147.47	1,642,857	$435,822	34,676	470,498	1,172,359
9	2018	1,402,700	$0.0381	0	10,790	$150.76	1,680,084	$441,052	33,574	474,626	1,205,459
10	2019	1,402,700	$0.0394	0	10,790	$154.12	1,718,260	$446,345	32,433	478,778	1,239,483
11	2020	1,402,700	$0.0408	0	10,790	$157.57	1,757,409	$451,701	31,252	482,953	1,274,456
12	2021	1,402,700	$0.0422	0	10,790	$161.10	1,797,556	$457,121	30,030	487,151	1,310,405
13	2022	1,402,700	$0.0437	0	10,790	$164.73	1,838,727	$462,607	28,765	491,372	1,347,355
14	2023	1,402,700	$0.0452	0	10,790	$168.44	1,880,947	$468,158	27,456	495,614	1,385,333
15	2024	1,402,700	$0.0468	0	10,790	$172.25	1,924,245	$473,776	26,101	499,877	1,424,368
16	2025	0	$0.0485	0	0	$176.15	0	0	0	0	0
Total =		19,483,503			149,873		$23,203,736	$11,497,907	$469,133	$11,967,039	$11,236,696
NPV =							12,033,386	7,792,738	260,595	8,053,333	3,980,054

Total NPV = $3,980,054
Benefit/Cost Ratio = 1.49

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(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: **Air Conditioning Cycling w/incent - Res & Sm Comm**

	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)
2010	$4,869	$0	$163,960	$168,830	$924,572	$924,572	($755,743)
2011	32,338	0	1,075,022	1,107,361	$3,611,750	3,611,750	(2,504,390)
2012	43,468	0	1,426,675	1,470,143	$1,629,998	1,629,998	(159,854)
2013	44,989	0	1,457,982	1,502,971	$418,302	418,302	1,084,669
2014	46,564	0	1,490,071	1,536,634	$420,502	420,502	1,116,133
2015	48,194	0	1,522,962	1,571,155	$420,502	420,502	1,150,653
2016	49,880	0	1,556,675	1,606,555	$420,502	420,502	1,186,054
2017	51,626	0	1,591,231	1,642,857	$420,502	420,502	1,222,356
2018	53,433	0	1,626,651	1,680,084	$420,502	420,502	1,259,583
2019	55,303	0	1,662,957	1,718,260	$420,502	420,502	1,297,759
2020	57,239	0	1,700,170	1,757,409	$420,502	420,502	1,336,907
2021	59,242	0	1,738,314	1,797,556	$420,502	420,502	1,377,054
2022	61,316	0	1,777,411	1,838,727	$420,502	420,502	1,418,225
2023	63,462	0	1,817,486	1,880,947	$420,502	420,502	1,460,446
2024	65,683	0	1,858,562	1,924,245	$420,502	420,502	1,503,743
2025	0	0	0	0	0	0	0
Total =	$737,606	$0	$22,466,130	$23,203,736	$11,210,140	$11,210,140	$11,993,595
NPV =	376,699	0	11,656,687	12,033,386	7,679,980	7,679,980	4,353,406

Total NPV = $4,353,406

Benefit/Cost Ratio = 1.57

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

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

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

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

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Cost Test

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

Compar **Montana-Dakota Utilities Co.**
Project: **Air Conditioning Cycling w/incent - Res & Sm Comm**

	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)
2010	$4,869	$0	$163,960	$86,078	$254,907	$924,572	$0	$30,000	$894,572	($639,665)
2011	$32,338	$0	$1,075,022	$581,525	1,688,886	$3,611,750	0	$192,500	3,419,250	(1,730,364)
2012	$43,468	$0	$1,426,675	$795,200	2,265,343	$1,629,998	0	$250,000	1,379,998	885,346
2013	$44,989	$0	$1,457,982	$837,345	2,340,316	$418,302	0	$0	418,302	1,922,014
2014	$46,564	$0	$1,490,071	$881,783	2,418,418	$420,502	0	$0	420,502	1,997,916
2015	$48,194	$0	$1,522,962	$928,641	2,499,796	$420,502	0	$0	420,502	2,079,294
2016	$49,880	$0	$1,556,675	$978,051	2,584,606	$420,502	0	$0	420,502	2,164,105
2017	$51,626	$0	$1,591,231	$1,030,156	2,673,013	$420,502	0	$0	420,502	2,252,511
2018	$53,433	$0	$1,626,651	$1,085,104	2,765,188	$420,502	0	$0	420,502	2,344,687
2019	$55,303	$0	$1,662,957	$1,143,053	2,861,313	$420,502	0	$0	420,502	2,440,812
2020	$57,239	$0	$1,700,170	$1,204,169	2,961,578	$420,502	0	$0	420,502	2,541,077
2021	$59,242	$0	$1,738,314	$1,268,628	3,066,184	$420,502	0	$0	420,502	2,645,683
2022	$61,316	$0	$1,777,411	$1,336,615	3,175,342	$420,502	0	$0	420,502	2,754,840
2023	$63,462	$0	$1,817,486	$1,408,325	3,289,273	$420,502	0	$0	420,502	2,868,771
2024	$65,683	$0	$1,858,562	$1,483,966	3,408,211	$420,502	0	$0	420,502	2,987,710
2025	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$737,606	$0	$22,466,130	$15,048,640	$38,252,376	$11,210,140	$0	$472,500	$10,737,640	$27,514,736
NPV =	376,699	0	11,656,687	10,555,811	22,589,198	7,679,980	0	388,901	7,291,079	15,298,119

Total NPV = $15,298,119
Benefit/Cost Ratio = 3.10

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) 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 ac
directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Air Conditioning Cycling w/incent - Res & Sm Comm**

		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 Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)
2010	0.0136	$30,000	156,000	0	$0.086	$0.075	1,200	0	$46.02	$67.43	$98,569	$0
2011	0.0866	$192,500	1,001,000	0	$0.088	$0.077	7,700	0	$47.17	$69.12	$643,484	0
2012	0.0860	$250,000	1,300,000	0	$0.090	$0.079	10,000	0	$48.35	$70.85	$850,336	0
2013	0.0854	$0	1,300,000	0	$0.092	$0.081	10,000	0	$49.56	$72.62	$615,345	0
2014	0.0848	$0	1,300,000	0	$0.094	$0.083	10,000	0	$50.80	$74.44	$630,728	0
2015	0.0842	$0	1,300,000	0	$0.097	$0.085	10,000	0	$52.07	$76.30	$646,497	0
2016	0.0836	$0	1,300,000	0	$0.099	$0.087	10,000	0	$53.37	$78.20	$662,659	0
2017	0.0830	$0	1,300,000	0	$0.102	$0.089	10,000	0	$54.71	$80.16	$679,226	0
2018	0.0825	$0	1,300,000	0	$0.104	$0.091	10,000	0	$56.07	$82.16	$696,206	0
2019	0.0819	$0	1,300,000	0	$0.107	$0.094	10,000	0	$57.48	$84.22	$713,611	0
2020	0.0813	$0	1,300,000	0	$0.109	$0.096	10,000	0	$58.91	$86.32	$731,452	0
2021	0.0808	$0	1,300,000	0	$0.112	$0.098	10,000	0	$60.39	$88.48	$749,738	0
2022	0.0802	$0	1,300,000	0	$0.115	$0.101	10,000	0	$61.90	$90.69	$768,481	0
2023	0.0796	$0	1,300,000	0	$0.118	$0.103	10,000	0	$63.44	$92.96	$787,693	0
2024	0.0791	$0	1,300,000	0	$0.121	$0.106	10,000	0	$65.03	$95.28	$807,386	0
2025	0.0785	0	0	0	$0.124	$0.108	0	0	$66.65	$97.67	$0	0
			18,057,000	0							$10,081,411	$0
											$5,800,525	0

Total NPV = $5,800,525
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 Participar
(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 F
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Honeywell - Demand Response 10 MW

Residential & Small Commercial

T-Stat with $25 annual Incentive

Project Cost	2008 Year 0	2009 Year 1	2010 Year 2	2011 Year 3	2012 Year 4	2013 Year 5	2014 Year 6	2015 Year 7	2016 Year 8	2017 Year 9	2018 Year 10	Total Cost
Residential Thermostat - Installed Cost	$0	$398,462	$2,390,769	$796,923	$60,260	$62,086	$63,968	$65,907	$67,904	$69,963	$72,084	$4,048,326
Residential DCU - Installed Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Commercial Thermostat Installed Cost	$0	$79,692	$199,231	$119,538	$6,696	$6,898	$7,108	$7,323	$7,545	$7,774	$8,009	$449,814
Commercial DCU - Installed Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Replacements due to failure (no warranty)	$0	$0	$0	$1,800	$5,347	$5,517	$5,693	$5,875	$6,063	$6,257	$6,457	$43,008
Network Software License Fee	$0	$6,800	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,800
Network Setup Fee	$0	$39,286	$0	$0	$0	$0	$0	$0	$0	$0	$0	$39,286
Communcation Fee (After implementation)	$0	$0	$0	$12,000	$36,000	$36,000	$36,000	$36,000	$36,000	$36,000	$36,000	$264,000
Program Administration & Network Fee	$0	$191,640	$287,460	$191,640	$0	$0	$0	$0	$0	$0	$0	$670,740
Marketing & Customer Outreach	$0	$156,008	$489,000	$258,096	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000	$1,323,104
Measurement & Verification	$0	$22,580	$52,686	$0	$0	$0	$0	$0	$0	$0	$0	$75,265
Customer Incentive	$0	$30,000	$192,500	$250,000	$250,000	$250,000	$250,000	$250,000	$250,000	$250,000	$250,000	$2,222,500
Totals	**$0**	**$924,467**	**$3,611,645**	**$1,629,998**	**$418,302**	**$420,502**	**$422,769**	**$425,105**	**$427,512**	**$429,993**	**$432,550**	**$9,142,843**
											PV	**$6,691,109**

$/kW before Incentive	***$692***
Total $/kW	***$914***

Project Cost Data

Residential		**Sm Commerical**	
Total Points	9,000	Total Points	1,000
Residential t-stat installed	$384.53	Commercial Thermostat - Installed Cost	$407.26
Residential DCU	$215.00	Commercial DCU	$240.00
Precentage Residential	90%	Precentage Residential	10%
Precentage T-Stat	100%	Precentage T-Stat	100%
Pecentage DCU	0%	Pecentage DCU	0%
Points year 1 (2010)	1,000	Points year 1	200
Points year 2 (2011)	6,000	Points year 2	500
Points Year 3 (2012)	2,000	Points Year 3	300
Marketing Cost per unit installed year 1	$63.34	Cancellation Rate (Starting in Year 3)	3.0%
Marketing Cost per Unit Installed Yr 2 (Bugetary)	$103.52	New Install Rate (Starting in Year 3)	3.0%
Marketing Mobilization (one time Fee)	$80,000	Material cost Escallation Rate	3.0%
Program Admin & Network Communcations Fee (per month)	$23,955	Failure Rate	0.1%
Cancellation Rate (Starting in Year 3)	3.0%		
New Install Rate (Starting in Year 3)	3.0%		
Cancellation Costs T-Stat (implementation)	$80.00		
Cancellation Costs DCU (implementation)	$50.00		
Cost per turndown	$0.00		
Turndown Rate	0.0%		
Servcie Call Rate	$0.00		
Material cost Escallation Rate	3.0%		
Failure Rate	0.1%		
MDU Labor cost per hour (loaded)	$43.54		
Labor escalation rate	4.0%		
Hours to install T-Stat or DCU	2		
Internal annual Markteing Cost after implementation period	$60,000		
Sales Tax Rate on Equipment (T-stats or DCU)	5.5%		
Annual incentive Cost per participant (DCU)	$25		
One-time incentive Cost per participant (T-stat)	$0		
M & V Cost			
Communcations per site	$0.00		
Equipment & Installation Per site	$0.00		
Initial M&V Analysis & Report	$75,265		
Annual M&V Analysis & Report (Third Party)	30,000		

Assumptions

Cancelaton Rate and New install rate are net zero
New Install /cancellation assumes only 50% of equipment will be new & 50% will be reinstalled equipment
No savings projection for Programable t_stat savings per customer
No savings projection for cycling kWh savings
1 point is equal to 1 kW
No MDU internal administrative costs (no added head count)
WACC 7.2%
Equipment life 10 yrs
Cancelation charge is only for installing the unit again somewhere else no removal charge
No addtionlal charge for turnddowns - Hwell's Cost
No service call charges - Included
M&V Cost based on quotes from Summit Blue
Advertising cost per Rena includes Radio, TV, & Direct Mail
Assumes sales tax on only T-stat or DCU at wieghted average sales tax cost
Material cost escallation assumed at forecated CPI

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

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

Project: **Residential Air Conditioning**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.07212
1a) Retail Rate Winter ($/kWh) =	$0.06174
Fuel Clause Adjustment (FCA)	$0.01132
Escalation Rate =	2.50%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.02795
Escalation Rate =	3.50%
3) Retail Summer Demand Rate ($/kW/season) =	$0.00
3a) Retail Winter Demand Rate ($/kW/season) =	$0.00
Escalation Rate =	2.50%
4) System Conservation Demand Cost ($/kW/yr)	$336.77
MAPP Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	49.5%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	814,894,507
Growth Rate =	2.02%
8) Total Customers by class =	87,262
Growth Rate =	0.70%
9) Utility Discount Rate =	8.27%
10) Social Discount Rate(Tbill) =	3.99%
11) General Input Data Year =	2009
12) Project Analysis Year 1 =	2010
12a) Project Analysis Year 2 =	2011
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.90%
14b) System Energy Line loss factor	7.90%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$3,926
Direct Operating Costs =	$0
Incentive Costs =	$39,375
Total Utility Project Costs Year 1 =	**$43,301**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$3,926
Direct Operating Costs =	$0
Incentive Costs =	$52,500
Total Utility Project Costs Year 2 =	**$56,426**
15b) Total Utilty Cost Year 3 =	**$69,551**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
15e) Total Utility Operating Cost (Program Life) =	**$0**
Escalation Rate =	0.00%
16) Direct Participant Costs ($/Part.) =	$900
Escalation Rate =	3.00%
17a) Other Participant Costs (Annual $/Part.) =	$ -
Escalation Rate =	3.00%
17b) Other Participant Savings (Annual $/Part.) =	$ -
Escalation Rate =	0%
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	0.92
20a) Avg Winter kW/part Saved =	0.0
21) Avg. Summer kWh/Part. Saved =	720
21a) Avg. Winter kWh/Part. Saved =	0
22) Number of Participants (First Year) =	75
22a) Number of Participants (Second Year) =	100
22a) Number of Participants (Third Year) =	125
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 525

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

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

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$169,279
Total Program Participants	300
Utility Cost per Participant (First Year) =	$577.35
Utility Cost per Participant (Program) =	$564.26
Total kW Reduction	298
Total Energy Reduction (kWh)	3,224,052
Societal Cost per kwh	$0.04

Test Results

	NPV	B/C
Utility Test	$876,637	5.71
Ratepayer Test	$919,689	7.43
Societal Cost Test	$1,864,333	15.14
Participant Test	$185,049	1.75

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 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)	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	2010	58,266	$0.0289	$0	74	$395.70	$31,146	$43,301	1,720	$45,022	($13,876)
2	2011	135,954	$0.0299	0	174	$404.33	74,311	$56,426	3,930	60,357	13,955
3	2012	233,064	$0.0310	0	298	$413.18	130,269	$69,551	6,588	76,140	54,129
4	2013	233,064	$0.0321	0	298	$422.25	133,222	$0	6,434	6,434	126,788
5	2014	233,064	$0.0332	0	298	$431.54	136,251	$0	6,275	6,275	129,976
6	2015	233,064	$0.0344	0	298	$441.07	139,359	$0	6,109	6,109	133,249
7	2016	233,064	$0.0356	0	298	$450.83	142,547	$0	5,938	5,938	136,608
8	2017	233,064	$0.0368	0	298	$460.84	145,817	$0	5,762	5,762	140,055
9	2018	233,064	$0.0381	0	298	$471.10	149,172	$0	5,578	5,578	143,594
10	2019	233,064	$0.0394	0	298	$481.61	152,614	$0	5,389	5,389	147,225
11	2020	233,064	$0.0408	0	298	$492.39	156,145	$0	5,193	5,193	150,953
12	2021	233,064	$0.0422	0	298	$503.43	159,768	$0	4,990	4,990	154,778
13	2022	233,064	$0.0437	0	298	$514.76	163,484	$0	4,779	4,779	158,705
14	2023	233,064	$0.0452	0	298	$526.36	167,297	$0	4,562	4,562	162,735
15	2024	233,064	$0.0468	0	298	$538.26	171,209	$0	4,337	4,337	166,872
16	2025	0	$0.0485	0	0	$550.45	0	0	0	0	0
Total =		3,224,052			4,120		$2,052,611	$169,279	$77,585	$246,864	$1,805,747
NPV =							1,062,619	142,930	43,052	185,982	876,637

Total NPV = $876,637
Benefit/Cost Ratio = 5.71

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(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**

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)
2010	$1,686	$0	$29,461	$31,146	$43,301	$43,301	($12,155)
2011	4,071	0	70,241	74,311	$56,426	56,426	17,885
2012	7,222	0	123,047	130,269	$69,551	69,551	60,718
2013	7,475	0	125,747	133,222	$0	0	133,222
2014	7,737	0	128,514	136,251	$0	0	136,251
2015	8,008	0	131,351	139,359	$0	0	139,359
2016	8,288	0	134,259	142,547	$0	0	142,547
2017	8,578	0	137,239	145,817	$0	0	145,817
2018	8,878	0	140,294	149,172	$0	0	149,172
2019	9,189	0	143,425	152,614	$0	0	152,614
2020	9,510	0	146,635	156,145	$0	0	156,145
2021	9,843	0	149,925	159,768	$0	0	159,768
2022	10,188	0	153,297	163,484	$0	0	163,484
2023	10,544	0	156,753	167,297	$0	0	167,297
2024	10,913	0	160,296	171,209	$0	0	171,209
2025	0	0	0	0	0	0	0
Total =	$122,130	$0	$1,930,482	$2,052,611	$169,279	$169,279	$1,883,332
NPV =	62,288	0	1,000,331	1,062,619	142,930	142,930	919,689

Total NPV =	$919,689
Benefit/Cost Ratio =	7.43

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a)
x System Demand Cost (4)
(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)
(F) = (E)
(G) = (D) - (F)

Table 3

Societal Cost Test

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

Compar **Montana-Dakota Utilities Co.**
Project: **Residential 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)
2010	$1,686	$0	$29,461	$15,880	$47,026	$43,301	$67,500	$39,375	$71,426	($24,400)
2011	$4,071	$0	$70,241	$39,024	113,335	$56,426	90,000	$91,875	54,551	58,784
2012	$7,222	$0	$123,047	$70,462	200,731	$69,551	112,500	$157,500	24,551	176,180
2013	$7,475	$0	$125,747	$74,221	207,443	$0	0	$0	0	207,443
2014	$7,737	$0	$128,514	$78,186	214,437	$0	0	$0	0	214,437
2015	$8,008	$0	$131,351	$82,369	221,727	$0	0	$0	0	221,727
2016	$8,288	$0	$134,259	$86,781	229,327	$0	0	$0	0	229,327
2017	$8,578	$0	$137,239	$91,435	237,252	$0	0	$0	0	237,252
2018	$8,878	$0	$140,294	$96,345	245,517	$0	0	$0	0	245,517
2019	$9,189	$0	$143,425	$101,525	254,139	$0	0	$0	0	254,139
2020	$9,510	$0	$146,635	$106,990	263,135	$0	0	$0	0	263,135
2021	$9,843	$0	$149,925	$112,756	272,524	$0	0	$0	0	272,524
2022	$10,188	$0	$153,297	$118,841	282,325	$0	0	$0	0	282,325
2023	$10,544	$0	$156,753	$125,261	292,558	$0	0	$0	0	292,558
2024	$10,913	$0	$160,296	$132,035	303,245	$0	0	$0	0	303,245
2025	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$122,130	$0	$1,930,482	$1,332,111	$3,384,723	$169,279	$270,000	$288,750	$150,529	$3,234,194
NPV =	62,288	0	1,000,331	933,565	1,996,184	142,930	227,760	238,839	131,851	1,864,333

Total NPV = $1,864,333
Benefit/Cost Ratio = 15.14

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) 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 acc directly to the participant.

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

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 Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Costs: Direct Part. Costs (H)
2010	0.0009	$39,375	54,000	0	$0.086	$0.075	69	0	$0.00	$0.00	$43,993	$67,500
2011	0.0020	$91,875	126,000	0	$0.088	$0.077	161	0	$0.00	$0.00	$102,921	90,000
2012	0.0020	$157,500	216,000	0	$0.090	$0.079	276	0	$0.00	$0.00	$176,909	112,500
2013	0.0020	$0	216,000	0	$0.092	$0.081	276	0	$0.00	$0.00	$19,894	0
2014	0.0019	$0	216,000	0	$0.094	$0.083	276	0	$0.00	$0.00	$20,391	0
2015	0.0019	$0	216,000	0	$0.097	$0.085	276	0	$0.00	$0.00	$20,901	0
2016	0.0019	$0	216,000	0	$0.099	$0.087	276	0	$0.00	$0.00	$21,424	0
2017	0.0019	$0	216,000	0	$0.102	$0.089	276	0	$0.00	$0.00	$21,959	0
2018	0.0019	$0	216,000	0	$0.104	$0.091	276	0	$0.00	$0.00	$22,508	0
2019	0.0019	$0	216,000	0	$0.107	$0.094	276	0	$0.00	$0.00	$23,071	0
2020	0.0019	$0	216,000	0	$0.109	$0.096	276	0	$0.00	$0.00	$23,648	0
2021	0.0018	$0	216,000	0	$0.112	$0.098	276	0	$0.00	$0.00	$24,239	0
2022	0.0018	$0	216,000	0	$0.115	$0.101	276	0	$0.00	$0.00	$24,845	0
2023	0.0018	$0	216,000	0	$0.118	$0.103	276	0	$0.00	$0.00	$25,466	0
2024	0.0018	$0	216,000	0	$0.121	$0.106	276	0	$0.00	$0.00	$26,103	0
2025	0.0018	0	0	0	$0.124	$0.108	0	0	$0.00	$0.00	$0	0
			2,988,000	0							$598,273	$270,000
											$431,645	246,596

Total NPV = $185,049
Benefit/Cost Ratio = 1.75

(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 Participant
(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 F
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Residential High Efficiency A/C (Energy Star Rated)

Customer Class:	Residential

Cost MDU

		$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Costs	$ -	$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 525	$ 525	$ 39,375	$ 52,500	$ 65,625	$ 157,500
Admin & Advertising	$ 3,926	$ 31	$ 3,926	$ 3,926	$ 3,926	$ 11,779
Total Cost		**$ 556**	**$ 43,301**	**$ 56,426**	**$ 69,551**	**$ 169,279**

Notes

Admin & Advertising		Calculated
Operating Cost		Calculated
Incentive	$ 175	Per Ton

Participant Costs (Incremental Cost Basis)

Cost of STD Eff Model (13 SEER)	$ 1,400	Market Reasearch with local HVAC Dealers
Cost of High Efficiency Model (15 SEER)	$ 2,300	Market Reasearch with local HVAC Dealers
Increased cost of Higher Eff Model	**$ 900**	

Participation Rate Calc

	% of Cust	Cust	
Total Customers is Class	100.00%	86,151	
Total Customers With Central AC	50.64%	43,627	Per 2004 Customer Survey
Total Customers with Evap or Swamp Coolers	0.81%	698	Per 2004 Customer Survey

Total Available for program	44,325		
Total Estimated Saturation Percentage	0.8%		
Total Participants	**375**	0.44%	Of total Customer Base
Participation Year 1	75		
Participation Year 2	100		
Participation Year 3	125		

Energy Savings Calculation

Equipment	kw Conn	Annual kWh	Utilization Factor	
10 SEER Unit	3.8	2,160	67%	EPRI for Utilization Factor
15 SEER Unit	2.9	1,440		BismarckWeather Data used for cooling hrs
Energy Reduction	**0.92**	**720**		

	Per Part
Summer Demand Reduction	0.9
Winter Demand Reduction	0.0
Summer Energy Reduction	720
Winter Energy Reduction	0

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

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

Project: **Residential Energy Star Appliances**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.07212
1a) Retail Rate Winter ($/kWh) =	$0.06174
Fuel Clause Adjustment (FCA)	$0.01132
Escalation Rate =	2.50%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.02795
Escalation Rate =	3.50%
3) Retail Summer Demand Rate ($/kW/season) =	$0.00
3a) Retail Winter Demand Rate ($/kW/season) =	$0.00
Escalation Rate =	2.50%
4) System Conservation Demand Cost ($/kW/yr)	$336.77
MAPP Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	49.5%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	814,894,507
Growth Rate =	2.02%
8) Total Customers by class =	87,262
Growth Rate =	0.70%
9) Utility Discount Rate =	8.27%
10) Social Discount Rate(Tbill) =	3.99%
11) General Input Data Year =	2009
12) Project Analysis Year 1 =	2010
12a) Project Analysis Year 2 =	2011
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.90%
14b) System Energy Line loss factor	7.90%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$15,034
Direct Operating Costs =	$0
Incentive Costs =	$4,308
Total Utility Project Costs Year 1 =	**$19,341**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$15,034
Direct Operating Costs =	$0
Incentive Costs =	$4,308
Total Utility Project Costs Year 2 =	**$19,341**
15b) Total Utilty Cost Year 3 =	**$19,341**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
15e) Total Utility Operating Cost (Program Life) =	**$0**
Escalation Rate =	0.00%
16) Direct Participant Costs ($/Part.) =	$30
Escalation Rate =	3.00%
17a) Other Participant Costs (Annual $/Part.) =	$ -
Escalation Rate =	3.00%
17b) Other Participant Savings (Annual $/Part.) =	$ -
Escalation Rate =	0%
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	0.014
20a) Avg Winter kW/part Saved =	0.028
21) Avg. Summer kWh/Part. Saved =	24
21a) Avg. Winter kWh/Part. Saved =	48
22) Number of Participants (First Year) =	287
22a) Number of Participants (Second Year) =	287
22a) Number of Participants (Third Year) =	287
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 15

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

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

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$58,024
Total Program Participants	862
Utility Cost per Participant (First Year) =	$67.35
Utility Cost per Participant (Program) =	$67.35
Total kW Reduction	39
Total Energy Reduction (kWh)	937,006
Societal Cost per kwh	$0.05

Test Results

	NPV	B/C
Utility Test	$88,578	2.40
Ratepayer Test	$102,030	3.06
Societal Cost Test	$233,919	5.66
Participant Test	$45,731	2.91

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 Energy Star Appliances**

		Cost of Energy Saved						Project Cost			Cost of
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	Energy Saved Less Project Cost (J)
1	2010	22,310	$0.0289	$0	13	$395.70	$5,795	$19,341	587	$19,928	($14,133)
2	2011	44,619	$0.0299	0	26	$404.33	11,860	$19,341	1,177	20,519	(8,659)
3	2012	66,929	$0.0310	0	39	$413.18	18,205	$19,341	1,772	21,113	(2,908)
4	2013	66,929	$0.0321	0	39	$422.25	18,632	$0	1,777	1,777	16,855
5	2014	66,929	$0.0332	0	39	$431.54	19,070	$0	1,782	1,782	17,288
6	2015	66,929	$0.0344	0	39	$441.07	19,520	$0	1,787	1,787	17,733
7	2016	66,929	$0.0356	0	39	$450.83	19,981	$0	1,791	1,791	18,190
8	2017	66,929	$0.0368	0	39	$460.84	20,455	$0	1,795	1,795	18,660
9	2018	66,929	$0.0381	0	39	$471.10	20,942	$0	1,799	1,799	19,143
10	2019	66,929	$0.0394	0	39	$481.61	21,442	$0	1,802	1,802	19,640
11	2020	66,929	$0.0408	0	39	$492.39	21,955	$0	1,805	1,805	20,150
12	2021	66,929	$0.0422	0	39	$503.43	22,482	$0	1,807	1,807	20,675
13	2022	66,929	$0.0437	0	39	$514.76	23,023	$0	1,808	1,808	21,214
14	2023	66,929	$0.0452	0	39	$526.36	23,578	$0	1,809	1,809	21,769
15	2024	66,929	$0.0468	0	39	$538.26	24,149	$0	1,810	1,810	22,339
16	2025	0	$0.0485	0	0	$550.45	0	0	0	0	0
Total =		937,006			547		$291,088	$58,024	$25,108	$83,132	$207,956
NPV =							151,633	49,603	13,452	63,055	88,578

Total NPV =	$88,578
Benefit/Cost Ratio =	2.40

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(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 Energy Star Appliances**

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)
2010	$645	$0	$5,150	$5,795	$19,341	$19,341	($13,546)
2011	1,336	0	10,524	11,860	$19,341	19,341	(7,481)
2012	2,074	0	16,131	18,205	$19,341	19,341	(1,136)
2013	2,147	0	16,485	18,632	$0	0	18,632
2014	2,222	0	16,848	19,070	$0	0	19,070
2015	2,300	0	17,220	19,520	$0	0	19,520
2016	2,380	0	17,601	19,981	$0	0	19,981
2017	2,463	0	17,992	20,455	$0	0	20,455
2018	2,550	0	18,392	20,942	$0	0	20,942
2019	2,639	0	18,803	21,442	$0	0	21,442
2020	2,731	0	19,224	21,955	$0	0	21,955
2021	2,827	0	19,655	22,482	$0	0	22,482
2022	2,926	0	20,097	23,023	$0	0	23,023
2023	3,028	0	20,550	23,578	$0	0	23,578
2024	3,134	0	21,015	24,149	$0	0	24,149
2025	0	0	0	0	0	0	0
Total =	$35,400	$0	$255,688	$291,088	$58,024	$58,024	$233,064
NPV =	18,179	0	133,454	151,633	49,603	49,603	102,030

Total NPV = $102,030
Benefit/Cost Ratio = 3.06

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a)
x System Demand Cost (4)
(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)
(F) = (E)
(G) = (D) - (F)

Table 3

Societal Cost Test

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

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

	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)
2010	$645	$0	$5,150	$2,955	$8,750	$19,341	$8,615	$4,308	$23,649	($14,899)
2011	$1,336	$0	$10,524	$6,228	18,088	$19,341	8,615	$8,615	19,341	(1,253)
2012	$2,074	$0	$16,131	$9,847	28,053	$19,341	8,615	$12,923	15,034	13,019
2013	$2,147	$0	$16,485	$10,380	29,012	$0	0	$0	0	29,012
2014	$2,222	$0	$16,848	$10,943	30,013	$0	0	$0	0	30,013
2015	$2,300	$0	$17,220	$11,537	31,057	$0	0	$0	0	31,057
2016	$2,380	$0	$17,601	$12,164	32,146	$0	0	$0	0	32,146
2017	$2,463	$0	$17,992	$12,826	33,282	$0	0	$0	0	33,282
2018	$2,550	$0	$18,392	$13,526	34,468	$0	0	$0	0	34,468
2019	$2,639	$0	$18,803	$14,264	35,706	$0	0	$0	0	35,706
2020	$2,731	$0	$19,224	$15,043	36,998	$0	0	$0	0	36,998
2021	$2,827	$0	$19,655	$15,867	38,348	$0	0	$0	0	38,348
2022	$2,926	$0	$20,097	$16,736	39,758	$0	0	$0	0	39,758
2023	$3,028	$0	$20,550	$17,654	41,232	$0	0	$0	0	41,232
2024	$3,134	$0	$21,015	$18,623	42,772	$0	0	$0	0	42,772
2025	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$35,400	$0	$255,688	$188,594	$479,682	$58,024	$25,845	$25,845	$58,024	$421,658
NPV =	18,179	0	133,454	132,474	284,107	49,603	22,094	21,510	50,187	233,919

Total NPV = $233,919
Benefit/Cost Ratio = 5.66

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) 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 acc directly to the participant.

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

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 Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Costs: Direct Part. Costs (H)
2010	0.0033	$4,308	6,892	13,784	$0.086	$0.075	4	8	$0.00	$0.00	$5,929	$8,615
2011	0.0065	$8,615	13,784	27,568	$0.088	$0.077	8	16	$0.00	$0.00	$11,940	8,615
2012	0.0064	$12,923	20,676	41,352	$0.090	$0.079	12	24	$0.00	$0.00	$18,034	8,615
2013	0.0064	$0	20,676	41,352	$0.092	$0.081	12	24	$0.00	$0.00	$5,239	0
2014	0.0064	$0	20,676	41,352	$0.094	$0.083	12	24	$0.00	$0.00	$5,370	0
2015	0.0063	$0	20,676	41,352	$0.097	$0.085	12	24	$0.00	$0.00	$5,504	0
2016	0.0063	$0	20,676	41,352	$0.099	$0.087	12	24	$0.00	$0.00	$5,642	0
2017	0.0062	$0	20,676	41,352	$0.102	$0.089	12	24	$0.00	$0.00	$5,783	0
2018	0.0062	$0	20,676	41,352	$0.104	$0.091	12	24	$0.00	$0.00	$5,928	0
2019	0.0061	$0	20,676	41,352	$0.107	$0.094	12	24	$0.00	$0.00	$6,076	0
2020	0.0061	$0	20,676	41,352	$0.109	$0.096	12	24	$0.00	$0.00	$6,228	0
2021	0.0061	$0	20,676	41,352	$0.112	$0.098	12	24	$0.00	$0.00	$6,383	0
2022	0.0060	$0	20,676	41,352	$0.115	$0.101	12	24	$0.00	$0.00	$6,543	0
2023	0.0060	$0	20,676	41,352	$0.118	$0.103	12	24	$0.00	$0.00	$6,707	0
2024	0.0059	$0	20,676	41,352	$0.121	$0.106	12	24	$0.00	$0.00	$6,874	0
2025	0.0059	0	0	0	$0.124	$0.108	0	0	$0.00	$0.00	$0	0
			289,467	578,935							$108,180	$25,845
											$69,652	23,921

Total NPV = $45,731
Benefit/Cost Ratio = 2.91

(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 Participant
(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 F
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Energy Star Appliances Program

Customer Class:	Residential

Cost MDU

		$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Cost	$ -	$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 15	$ 15	$ 4,308	$ 4,308	$ 4,308	$ 12,923
Admin & Advertising	$ 15,034	$ 52	$ 15,034	$ 15,034	$ 15,034	$ 45,102
Total Cost		**$ 67**	**$ 19,341**	**$ 19,341**	**$ 19,341**	**$ 58,024**

Notes

Admin & Advertising	Calculated
Operating Cost	Calculated

Participant Costs (Incremental Cost Basis)

Avg Cost of Standard Efficiency Model	$ 1,070	Per Energy Star - DOE 2004
Avg Cost of Energy Star Model	$ 1,100	Per Energy Star - DOE 2004
Increased cost of Higher Eff Model	**$ 30**	Partial automatic defrost

Participation Rate Calc

	% of Cust	Cust
Total Customers is Class	100.00%	86,151

Total Customers Available for program	86,151		
Total Estimated Saturation Percentage	1.0%		
Total Participants	**862**	1.00%	Of total Customer Base
Participation Year 1	287		
Participation Year 2	287		
Participation Year 2	287		

Energy Savings Calculation Fridge

Refrigerators Data	kw Conn	Annual kWh	Utilization Factor	
Conventional	0.8	479	35%	18 Cu Ft Top Freezer ice maker
Energy Star	0.68	407	35%	As per survey results 88% for FF
Energy Savings	**0.12**	**72**		Energy Star - DOE 2004

	Per Part	
Summer Demand Reduction	0.014	Levelized for 4 months
Winter Demand Reduction	0.028	Levelized for 8 Months
Total Demand Reduction	**0.042**	**Total demand Reduction for Measure**
Summer Energy Reduction	24	
Winter Energy Reduction	48	

Energy Savings Calculation Freezer (inputs not used)

Freezer Data	kw Conn	Annual kWh	Utilization Factor	
Conventional Freezer	0.9	520	35%	22 Cu ft Chest Manual DF
Energy Star Freezer	0.8	468	35%	Energy Star -DOE 2004
Energy Savings	**0.10**	**52**		

	Per Part	
Summer Demand Reduction	0.012	Levelized for 4 months
Winter Demand Reduction	0.023	Levelized for 8 Months
Total Demand Reduction	**0.035**	**Total demand Reduction for Measure**
Summer Energy Reduction	17	
Winter Energy Reduction	35	

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

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

Project: **Refrigerator Round-up**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.07212
1a) Retail Rate Winter ($/kWh) =	$0.06174
Fuel Clause Adjustment (FCA)	$0.01132
Escalation Rate =	2.50%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.02795
Escalation Rate =	3.50%
3) Retail Summer Demand Rate ($/kW/season) =	$0.00
3a) Retail Winter Demand Rate ($/kW/season) =	$0.00
Escalation Rate =	2.50%
4) System Conservation Demand Cost ($/kW/yr)	$336.77
MAPP Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	49.5%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	814,894,507
Growth Rate =	2.02%
8) Total Customers by class =	87,262
Growth Rate =	0.70%
9) Utility Discount Rate =	8.27%
10) Social Discount Rate(Tbill) =	3.99%
11) General Input Data Year =	2009
12) Project Analysis Year 1 =	2010
12a) Project Analysis Year 2 =	2011
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.90%
14b) System Energy Line loss factor	7.90%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$13,088
Direct Operating Costs =	$7,853
Incentive Costs =	$3,665
Total Utility Project Costs Year 1 =	**$24,605**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$13,088
Direct Operating Costs =	$7,928
Incentive Costs =	$3,665
Total Utility Project Costs Year 2 =	**$24,680**
15b) Total Utilty Cost Year 3 =	**$24,680**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
15e) Total Utility Operating Cost (Program Life) =	**$0**
Escalation Rate =	0.00%
16) Direct Participant Costs ($/Part.) =	$0
Escalation Rate =	3.00%
17a) Other Participant Costs (Annual $/Part.) =	$ -
Escalation Rate =	3.00%
17b) Other Participant Savings (Annual $/Part.) =	$ -
Escalation Rate =	0%
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	0.120
20a) Avg Winter kW/part Saved =	0.240
21) Avg. Summer kWh/Part. Saved =	279
21a) Avg. Winter kWh/Part. Saved =	559
22) Number of Participants (First Year) =	105
22a) Number of Participants (Second Year) =	105
22a) Number of Participants (Third Year) =	105
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 35

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Refrigerator Round-up**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$73,965
Total Program Participants	314
Utility Cost per Participant (First Year) =	$235.00
Utility Cost per Participant (Program) =	$235.48
Total kW Reduction	122
Total Energy Reduction (kWh)	3,975,272
Societal Cost per kwh	$0.01

Test Results

	NPV	B/C
Utility Test	$373,052	4.10
Ratepayer Test	$430,122	7.80
Societal Cost Test	$879,659	20.58
Participant Test	$216,512	#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: **Refrigerator Round-up**

		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)	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	2010	94,649	$0.0289	$0	41	$395.70	$18,799	$24,605	2,489	$27,094	($8,295)
2	2011	189,299	$0.0299	0	81	$404.33	38,490	$24,680	4,996	29,676	8,815
3	2012	283,948	$0.0310	0	122	$413.18	59,110	$24,680	7,517	32,197	26,913
4	2013	283,948	$0.0321	0	122	$422.25	60,522	$0	7,540	7,540	52,983
5	2014	283,948	$0.0332	0	122	$431.54	61,973	$0	7,561	7,561	54,412
6	2015	283,948	$0.0344	0	122	$441.07	63,462	$0	7,581	7,581	55,881
7	2016	283,948	$0.0356	0	122	$450.83	64,993	$0	7,599	7,599	57,393
8	2017	283,948	$0.0368	0	122	$460.84	66,565	$0	7,616	7,616	58,949
9	2018	283,948	$0.0381	0	122	$471.10	68,180	$0	7,631	7,631	60,548
10	2019	283,948	$0.0394	0	122	$481.61	69,839	$0	7,644	7,644	62,194
11	2020	283,948	$0.0408	0	122	$492.39	71,543	$0	7,656	7,656	63,887
12	2021	283,948	$0.0422	0	122	$503.43	73,293	$0	7,665	7,665	65,629
13	2022	283,948	$0.0437	0	122	$514.76	75,092	$0	7,672	7,672	67,420
14	2023	283,948	$0.0452	0	122	$526.36	76,940	$0	7,676	7,676	69,263
15	2024	283,948	$0.0468	0	122	$538.26	78,838	$0	7,678	7,678	71,160
16	2025	0	$0.0485	0	0	$550.45	0	0	0	0	0
Total =		3,975,272			1,705		$947,639	$73,965	$106,522	$180,487	$767,152
NPV =							493,347	63,225	57,070	120,295	373,052

Total NPV = $373,052
Benefit/Cost Ratio = 4.10

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(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: **Refrigerator Round-up**

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)
	Decreases				Increases		
2010	$2,738	$0	$16,061	$18,799	$24,605	$24,605	($5,806)
2011	5,668	0	32,823	38,490	$24,680	24,680	13,810
2012	8,799	0	50,311	59,110	$24,680	24,680	34,430
2013	9,107	0	51,415	60,522	$0	0	60,522
2014	9,426	0	52,547	61,973	$0	0	61,973
2015	9,756	0	53,707	63,462	$0	0	63,462
2016	10,097	0	54,896	64,993	$0	0	64,993
2017	10,451	0	56,114	66,565	$0	0	66,565
2018	10,816	0	57,363	68,180	$0	0	68,180
2019	11,195	0	58,644	69,839	$0	0	69,839
2020	11,587	0	59,956	71,543	$0	0	71,543
2021	11,992	0	61,301	73,293	$0	0	73,293
2022	12,412	0	62,680	75,092	$0	0	75,092
2023	12,847	0	64,093	76,940	$0	0	76,940
2024	13,296	0	65,542	78,838	$0	0	78,838
2025	0	0	0	0	0	0	0
Total =	$150,187	$0	$797,452	$947,639	$73,965	$73,965	$873,674
NPV =	77,124	0	416,223	493,347	63,225	63,225	430,122

Total NPV = $430,122
Benefit/Cost Ratio = 7.80

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (A) + (B) + (C)
(E) = Total Utility Project Costs (15)
(F) = (E)
(G) = (D) - (F)

Table 3

Societal Cost Test

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

Compar **Montana-Dakota Utilities Co.**
Project: **Refrigerator Round-up**

	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)
2010	$2,738	$0	$16,061	$9,585	$28,384	$24,605	$0	$3,665	$20,940	$7,443
2011	$5,668	$0	$32,823	$20,213	58,704	$24,680	0	$7,329	17,351	41,353
2012	$8,799	$0	$50,311	$31,973	91,083	$24,680	0	$10,994	13,686	77,397
2013	$9,107	$0	$51,415	$33,719	94,241	$0	0	$0	0	94,241
2014	$9,426	$0	$52,547	$35,562	97,535	$0	0	$0	0	97,535
2015	$9,756	$0	$53,707	$37,510	100,972	$0	0	$0	0	100,972
2016	$10,097	$0	$54,896	$39,567	104,560	$0	0	$0	0	104,560
2017	$10,451	$0	$56,114	$41,740	108,304	$0	0	$0	0	108,304
2018	$10,816	$0	$57,363	$44,035	112,214	$0	0	$0	0	112,214
2019	$11,195	$0	$58,644	$46,459	116,298	$0	0	$0	0	116,298
2020	$11,587	$0	$59,956	$49,021	120,564	$0	0	$0	0	120,564
2021	$11,992	$0	$61,301	$51,727	125,020	$0	0	$0	0	125,020
2022	$12,412	$0	$62,680	$54,586	129,678	$0	0	$0	0	129,678
2023	$12,847	$0	$64,093	$57,607	134,547	$0	0	$0	0	134,547
2024	$13,296	$0	$65,542	$60,799	139,637	$0	0	$0	0	139,637
2025	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$150,187	$0	$797,452	$614,102	$1,561,741	$73,965	$0	$21,987	$51,978	$1,509,763
NPV =	77,124	0	416,223	431,238	924,585	63,225	0	18,299	44,926	879,659

Total NPV = $879,659
Benefit/Cost Ratio = 20.58

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) 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 acc
directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Refrigerator Round-up**

		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 Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)		Direct Part. Costs (H)
2010	0.0012	$3,665	29,240	58,480	$0.086	$0.075	13	25	$0.00	$0.00	$10,545		$0
2011	0.0024	$7,329	58,480	116,959	$0.088	$0.077	25	50	$0.00	$0.00	$21,433		0
2012	0.0024	$10,994	87,719	175,439	$0.090	$0.079	38	75	$0.00	$0.00	$32,679		0
2013	0.0023	$0	87,719	175,439	$0.092	$0.081	38	75	$0.00	$0.00	$22,227		0
2014	0.0023	$0	87,719	175,439	$0.094	$0.083	38	75	$0.00	$0.00	$22,783		0
2015	0.0023	$0	87,719	175,439	$0.097	$0.085	38	75	$0.00	$0.00	$23,353		0
2016	0.0023	$0	87,719	175,439	$0.099	$0.087	38	75	$0.00	$0.00	$23,936		0
2017	0.0023	$0	87,719	175,439	$0.102	$0.089	38	75	$0.00	$0.00	$24,535		0
2018	0.0023	$0	87,719	175,439	$0.104	$0.091	38	75	$0.00	$0.00	$25,148		0
2019	0.0022	$0	87,719	175,439	$0.107	$0.094	38	75	$0.00	$0.00	$25,777		0
2020	0.0022	$0	87,719	175,439	$0.109	$0.096	38	75	$0.00	$0.00	$26,421		0
2021	0.0022	$0	87,719	175,439	$0.112	$0.098	38	75	$0.00	$0.00	$27,082		0
2022	0.0022	$0	87,719	175,439	$0.115	$0.101	38	75	$0.00	$0.00	$27,759		0
2023	0.0022	$0	87,719	175,439	$0.118	$0.103	38	75	$0.00	$0.00	$28,453		0
2024	0.0022	$0	87,719	175,439	$0.121	$0.106	38	75	$0.00	$0.00	$29,164		0
2025	0.0021	0	0	0	$0.124	$0.108	0	0	$0.00	$0.00	$0		0
			1,228,073	2,456,146							$371,296		$0
											$216,512		0

Total NPV = $216,512
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 Participan
(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 F
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Refrigerator Round-Up Program

Customer Class:	Residential

Cost MDU

			$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Transport & Recycling (Operating)	$ 75		$ 25	$ 7,853	$ 7,928	$ 7,928	$ 23,708
Incentive Costs	$ 35		$ 35	$ 3,665	$ 3,665	$ 3,665	$ 10,994
Admin & Advertising	$ 125		$ 125	$ 13,088	$ 13,088	$ 13,088	$ 39,263
Total Cost	$ 235		**$ 185**	**$ 24,605**	**$ 24,680**	**$ 24,680**	**$ 73,965**

Notes

Operating Costs Calculated

Pick up and Recycling is estimated at loaded rate for 1.5 hr plus mileage & $20 recycling fee at Porter Bros $ 75

Participant Costs

None $ -

Participation Rate Calc

	% of Cust	Cust
Total Customers is Class	100.00%	86,151
Total Customers with 2 Refrigerators	34.03%	29,317
Total Customers with 3 or more Refrigerators	2.43%	2,093

Total Available for program	31,411		
Total Estimated Saturation Percentage	1.0%		
Total Partcipation	**314**	0.36%	Of total Customer Base
Participation Year 1	105		
Participation Year 2	105		
Participation Year 2	105		

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 88% for FF
Percentage of replacements		30%		UPA 1992 Study - Older Fridges
Replacement Savings	0.12	72		
Average Program Savings	1	838		
		Per Part		
Summer Demand Reduction		0.120	Levelized for 4 months	
Winter Demand Reduction		0.240	Levelized for 8 Months	
Total Demand Reduction		**0.359**	**Total demand Reduction for Measure**	
Summer Energy Reduction		279		
Winter Energy Reduction		559		
Total Energy Reduction		**838**		

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

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

Project: **Residential Lighting - Various Delivery Methods**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.07212
1a) Retail Rate Winter ($/kWh) =	$0.06174
Fuel Clause Adjustment (FCA)	$0.01132
Escalation Rate =	2.50%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.02795
Escalation Rate =	3.50%
3) Retail Summer Demand Rate ($/kW/season) =	$0.00
3a) Retail Winter Demand Rate ($/kW/season) =	$0.00
Escalation Rate =	2.50%
4) System Conservation Demand Cost ($/kW/yr)	$336.77
MAPP Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	49.5%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	814,894,507
Growth Rate =	2.02%
8) Total Customers by class =	87,262
Growth Rate =	0.70%
9) Utility Discount Rate =	8.27%
10) Social Discount Rate(Tbill) =	3.99%
11) General Input Data Year =	2009
12) Project Analysis Year 1 =	2010
12a) Project Analysis Year 2 =	2011
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.90%
14b) System Energy Line loss factor	7.90%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$13,088
Direct Operating Costs =	$0
Incentive Costs =	$8,750
Total Utility Project Costs Year 1 =	**$21,838**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$13,088
Direct Operating Costs =	$0
Incentive Costs =	$8,750
Total Utility Project Costs Year 2 =	**$21,838**
15b) Total Utilty Cost Year 3 =	**$21,838**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
15e) Total Utility Operating Cost (Program Life) =	**$0**
Escalation Rate =	0.00%
16) Direct Participant Costs ($/Part.) =	$0
Escalation Rate =	3.00%
17a) Other Participant Costs (Annual $/Part.) =	$ -
Escalation Rate =	3.00%
17b) Other Participant Savings (Annual $/Part.) =	$ -
Escalation Rate =	0%
18) Project Life (Years) =	9
20) Avg Summer kW/part. Saved =	0.010
20a) Avg Winter kW/part Saved =	0.021
21) Avg. Summer kWh/Part. Saved =	11
21a) Avg. Winter kWh/Part. Saved =	23
22) Number of Participants (First Year) =	5,000
22a) Number of Participants (Second Year) =	5,000
22a) Number of Participants (Third Year) =	5,000
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ -

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Residential Lighting - Various Delivery Methods**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	9
Total Progam Cost (Utility)	$65,514
Total Program Participants	15,000
Utility Cost per Participant (First Year) =	$4.37
Utility Cost per Participant (Program) =	$4.37
Total kW Reduction	505
Total Energy Reduction (kWh)	4,424,405
Societal Cost per kwh	$0.01

Test Results

	NPV	B/C
Utility Test	$1,115,855	9.35
Ratepayer Test	$1,193,535	22.31
Societal Cost Test	$2,091,681	38.35
Participant Test	$254,062	#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 Lighting - Various Delivery Methods**

		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)	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	2010	184,350	$0.0289	$0	168	$395.70	$71,952	$21,838	4,849	$26,687	$45,266
2	2011	368,700	$0.0299	0	337	$404.33	147,184	$21,838	9,730	31,568	115,616
3	2012	553,051	$0.0310	0	505	$413.18	225,823	$21,838	14,641	36,479	189,343
4	2013	553,051	$0.0321	0	505	$422.25	231,002	$0	14,685	14,685	216,316
5	2014	553,051	$0.0332	0	505	$431.54	236,316	$0	14,727	14,727	221,589
6	2015	553,051	$0.0344	0	505	$441.07	241,770	$0	14,766	14,766	227,004
7	2016	553,051	$0.0356	0	505	$450.83	247,366	$0	14,802	14,802	232,565
8	2017	553,051	$0.0368	0	505	$460.84	253,109	$0	14,834	14,834	238,275
9	2018	553,051	$0.0381	0	505	$471.10	259,003	$0	14,864	14,864	244,139
10	2019	0	$0.0394	0	0	$481.61	0	$0	0	0	0
11	2020	0	$0.0408	0	0	$492.39	0	$0	0	0	0
12	2021	0	$0.0422	0	0	$503.43	0	$0	0	0	0
13	2022	0	$0.0437	0	0	$514.76	0	$0	0	0	0
14	2023	0	$0.0452	0	0	$526.36	0	$0	0	0	0
15	2024	0	$0.0468	0	0	$538.26	0	$0	0	0	0
16	2025	0	$0.0485	0	0	$550.45	0	0	0	0	0
Total =		4,424,405			4,041		$1,913,526	$65,514	$117,898	$183,412	$1,730,115
NPV =							1,249,541	56,005	77,680	133,686	1,115,855

Total NPV = $1,115,855
Benefit/Cost Ratio = 9.35

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(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 Lighting - Various Delivery Methods**

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)
2010	$5,333	$0	$66,619	$71,952	$21,838	$21,838	$50,114
2011	11,039	0	136,145	147,184	$21,838	21,838	125,346
2012	17,138	0	208,684	225,823	$21,838	21,838	203,985
2013	17,738	0	213,264	231,002	$0	0	231,002
2014	18,359	0	217,957	236,316	$0	0	236,316
2015	19,002	0	222,769	241,770	$0	0	241,770
2016	19,667	0	227,700	247,366	$0	0	247,366
2017	20,355	0	232,755	253,109	$0	0	253,109
2018	21,067	0	237,936	259,003	$0	0	259,003
2019	0	0	0	0	$0	0	0
2020	0	0	0	0	$0	0	0
2021	0	0	0	0	$0	0	0
2022	0	0	0	0	$0	0	0
2023	0	0	0	0	$0	0	0
2024	0	0	0	0	$0	0	0
2025	0	0	0	0	0	0	0
Total =	$149,698	$0	$1,763,828	$1,913,526	$65,514	$65,514	$1,848,012
NPV =	97,251	0	1,152,289	1,249,541	56,005	56,005	1,193,535

Total NPV = $1,193,535

Benefit/Cost Ratio = 22.31

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

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

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

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

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Cost Test

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

Compar **Montana-Dakota Utilities Co.**
Project: **Residential Lighting - Various Delivery Methods**

	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)
2010	$5,333	$0	$66,619	$36,685	$108,637	$21,838	$0	$0	$21,838	$86,799
2011	$11,039	$0	$136,145	$77,293	224,477	$21,838	0	$0	21,838	202,639
2012	$17,138	$0	$208,684	$122,147	347,970	$21,838	0	$0	21,838	326,132
2013	$17,738	$0	$213,264	$128,697	359,699	$0	0	$0	0	359,699
2014	$18,359	$0	$217,957	$135,608	371,924	$0	0	$0	0	371,924
2015	$19,002	$0	$222,769	$142,900	384,670	$0	0	$0	0	384,670
2016	$19,667	$0	$227,700	$150,594	397,960	$0	0	$0	0	397,960
2017	$20,355	$0	$232,755	$158,713	411,822	$0	0	$0	0	411,822
2018	$21,067	$0	$237,936	$167,280	426,283	$0	0	$0	0	426,283
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
2022	$0	$0	$0	$0	0	$0	0	$0	0	0
2023	$0	$0	$0	$0	0	$0	0	$0	0	0
2024	$0	$0	$0	$0	0	$0	0	$0	0	0
2025	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$149,698	$0	$1,763,828	$1,119,917	$3,033,443	$65,514	$0	$0	$65,514	$2,967,929
NPV =	97,251	0	1,152,289	898,146	2,147,686	56,005	0	0	56,005	2,091,681

Total NPV = $2,091,681
Benefit/Cost Ratio = 38.35

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) 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 acc directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Lighting - Various Delivery Methods**

		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 Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)
2010	0.0569	$0	56,951	113,902	$0.086	$0.075	52	104	$0.00	$0.00	$13,401	$0
2011	0.1130	$0	113,902	227,804	$0.088	$0.077	104	208	$0.00	$0.00	$27,471	0
2012	0.1122	$0	170,853	341,706	$0.090	$0.079	156	312	$0.00	$0.00	$42,237	0
2013	0.1114	$0	170,853	341,706	$0.092	$0.081	156	312	$0.00	$0.00	$43,293	0
2014	0.1107	$0	170,853	341,706	$0.094	$0.083	156	312	$0.00	$0.00	$44,375	0
2015	0.1099	$0	170,853	341,706	$0.097	$0.085	156	312	$0.00	$0.00	$45,484	0
2016	0.1091	$0	170,853	341,706	$0.099	$0.087	156	312	$0.00	$0.00	$46,621	0
2017	0.1084	$0	170,853	341,706	$0.102	$0.089	156	312	$0.00	$0.00	$47,787	0
2018	0.1076	$0	170,853	341,706	$0.104	$0.091	156	312	$0.00	$0.00	$48,982	0
2019	0.1069	$0	0	0	$0.107	$0.094	0	0	$0.00	$0.00	$0	0
2020	0.1061	$0	0	0	$0.109	$0.096	0	0	$0.00	$0.00	$0	0
2021	0.1054	$0	0	0	$0.112	$0.098	0	0	$0.00	$0.00	$0	0
2022	0.1047	$0	0	0	$0.115	$0.101	0	0	$0.00	$0.00	$0	0
2023	0.1039	$0	0	0	$0.118	$0.103	0	0	$0.00	$0.00	$0	0
2024	0.1032	$0	0	0	$0.121	$0.106	0	0	$0.00	$0.00	$0	0
2025	0.1025	0	0	0	$0.124	$0.108	0	0	$0.00	$0.00	$0	0
			1,366,823	2,733,646							$359,650	$0
											$254,062	0

Total NPV = $254,062
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 Participan
(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 F
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Residential Lighting - Various Delivery Methods

Customer Class:	**Residential**

Cost MDU

			$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operationg Costs	$ -		$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 1.75		$ 2	$ 8,750	$ 8,750	$ 8,750	$ 26,250
Admin & Advertising	$13,088		$ 3	$ 13,088	$ 13,088	$ 13,088	$ 39,264
Total Cost	$ 13,089.67		**$ 4**	**$ 21,838**	**$ 21,838**	**$ 21,838**	**$ 65,514**

Notes

Participant Costs

None	$ -

Participation Rate Calc

	% of Cust	Cust
Total Customers is Class	100.00%	86,151

Total Available for program	86,151		
Total Estimated Saturation Percentage	17.4%		
Total Partcipation	**15,000**	17.41%	Of total Customer Base
Participation Year 1	5,000		
Participation Year 2	5,000		
Participation Year 2	5,000		

Energy Savings Calculation

Refrigerators Data	kw Conn	Annual kWh	Utilization Factor	
Standard 60 Watt bulb	0.06	65.7	100%	Energy Star Runtime Assumptions
13 w CFL	0.013	14.2	100%	
Savings	**0.05201**	**57.0**		
Percentage of replacements		60%		No customer installation factor
Average Program Savings	0.031	34.2		

	Per Part	
Summer Demand Reduction	0.010	Levelized for 4 months
Winter Demand Reduction	0.021	Levelized for 8 Months
Total Demand Reduction	**0.031**	**Total demand Reduction for Measure**
Summer Energy Reduction	11	
Winter Energy Reduction	23	
Total Energy Reduction	**34**	

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

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

Project: **Commercial Lighting Program**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.04427
1a) Retail Rate Winter ($/kWh) =	$0.03858
Fuel Clause Adjustment (FCA)	$0.01132
Escalation Rate =	2.50%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.02795
Escalation Rate =	3.50%
3) Retail Summer Demand Rate ($/kW/season) =	$44.90
3a) Retail Winter Demand Rate ($/kW/season) =	$65.79
Escalation Rate =	2.50%
4) System Conservation Demand Cost ($/kW/yr)	$336.77
MAPP Reserve Margin=	15.0%
Escalation Rate =	4.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	49.5%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	1,488,732,948
Growth Rate =	2.02%
8) Total Customers by class =	17,479
Growth Rate =	0.70%
9) Utility Discount Rate =	8.27%
10) Social Discount Rate(Tbill) =	3.99%
11) General Input Data Year =	2009
12) Project Analysis Year 1 =	2010
12a) Project Analysis Year 2 =	2011
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.90%
14b) System Energy Line loss factor	7.90%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$3,926
Direct Operating Costs =	$0
Incentive Costs =	$240,000
Total Utility Project Costs Year 1 =	**$243,926**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$3,926
Direct Operating Costs =	$0
Incentive Costs =	$240,000
Total Utility Project Costs Year 2 =	**$243,926**
15b) Total Utilty Cost Year 3 =	**$243,926**
15c) Total Utilty Cost Year 4 =	**$243,926**
15d) Total Utility Cost Year 5 =	**$243,926**
15e) Total Utility Operating Cost (Program Life) =	**$0**
Escalation Rate =	0.00%
16) Direct Participant Costs ($/Part.) =	$22,000
Escalation Rate =	3.00%
17a) Other Participant Costs (Annual $/Part.) =	$ -
Escalation Rate =	3.00%
17b) Other Participant Savings (Annual $/Part.) =	$ -
Escalation Rate =	0%
18) Project Life (Years) =	10
20) Avg Summer kW/part. Saved =	5.0
20a) Avg Winter kW/part Saved =	9.9
21) Avg. Summer kWh/Part. Saved =	12,433
21a) Avg. Winter kWh/Part. Saved =	24,867
22) Number of Participants (First Year) =	75
22a) Number of Participants (Second Year) =	75
22a) Number of Participants (Third Year) =	75
22a) Number of Participants (Fourth Year) =	75
22a) Number of Participants (Fifth Year) =	75
23) Incentive/Participant (All) =	$ 3,200

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Commercial Lighting Program**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	10
Total Progam Cost (Utility)	$1,219,632
Total Program Participants	375
Utility Cost per Participant (First Year) =	$3,252.35
Utility Cost per Participant (Program) =	$3,252.35
Total kW Reduction	6,037
Total Energy Reduction (kWh)	120,740,100
Societal Cost per kwh	$0.05

Test Results

	NPV	B/C
Utility Test	$13,821,566	8.65
Ratepayer Test	$14,661,336	16.16
Societal Cost Test	$21,288,099	4.37
Participant Test	$713,016	1.10

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 Lighting Program**

		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)	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	2010	3,018,503	$0.0289	$0	1,207	$395.70	$565,094	$243,926	36,544	$280,470	$284,624
2	2011	6,037,005	$0.0299	0	2,415	$404.33	1,157,140	$243,926	72,268	316,195	840,945
3	2012	9,055,508	$0.0310	0	3,622	$413.18	1,777,240	$243,926	107,087	351,013	1,426,226
4	2013	12,074,010	$0.0321	0	4,830	$422.25	2,426,537	$243,926	140,908	384,834	2,041,702
5	2014	15,092,513	$0.0332	0	6,037	$431.54	3,106,217	$243,926	173,633	417,559	2,688,658
6	2015	15,092,513	$0.0344	0	6,037	$441.07	3,181,258	$0	170,965	170,965	3,010,293
7	2016	15,092,513	$0.0356	0	6,037	$450.83	3,258,351	$0	168,123	168,123	3,090,228
8	2017	15,092,513	$0.0368	0	6,037	$460.84	3,337,553	$0	165,100	165,100	3,172,453
9	2018	15,092,513	$0.0381	0	6,037	$471.10	3,418,922	$0	161,886	161,886	3,257,036
10	2019	15,092,513	$0.0394	0	6,037	$481.61	3,502,520	$0	158,474	158,474	3,344,047
11	2020	0	$0.0408	0	0	$492.39	0	$0	0	0	0
12	2021	0	$0.0422	0	0	$503.43	0	$0	0	0	0
13	2022	0	$0.0437	0	0	$514.76	0	$0	0	0	0
14	2023	0	$0.0452	0	0	$526.36	0	$0	0	0	0
15	2024	0	$0.0468	0	0	$538.26	0	$0	0	0	0
16	2025	0	$0.0485	0	0	$550.45	0	0	0	0	0
Total =		120,740,100			48,296		$25,730,832	$1,219,632	$1,354,988	$2,574,620	$23,156,212
NPV =							15,628,372	967,036	839,770	1,806,806	13,821,566

Total NPV = $13,821,566
Benefit/Cost Ratio = 8.65

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(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 Lighting 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)
2010	$87,320	$0	$477,774	$565,094	$243,926	$243,926	$321,168
2011	180,752	0	976,388	1,157,140	$243,926	243,926	913,214
2012	280,618	0	1,496,622	1,777,240	$243,926	243,926	1,533,313
2013	387,253	0	2,039,284	2,426,537	$243,926	243,926	2,182,610
2014	501,009	0	2,605,208	3,106,217	$243,926	243,926	2,862,290
2015	518,544	0	2,662,714	3,181,258	$0	0	3,181,258
2016	536,693	0	2,721,658	3,258,351	$0	0	3,258,351
2017	555,477	0	2,782,076	3,337,553	$0	0	3,337,553
2018	574,919	0	2,844,003	3,418,922	$0	0	3,418,922
2019	595,041	0	2,907,479	3,502,520	$0	0	3,502,520
2020	0	0	0	0	$0	0	0
2021	0	0	0	0	$0	0	0
2022	0	0	0	0	$0	0	0
2023	0	0	0	0	$0	0	0
2024	0	0	0	0	$0	0	0
2025	0	0	0	0	0	0	0
Total =	$4,217,625	$0	$21,513,206	$25,730,832	$1,219,632	$1,219,632	$24,511,200
NPV =	2,548,354	0	13,080,018	15,628,372	967,036	967,036	14,661,336

Total NPV =	$14,661,336
Benefit/Cost Ratio =	16.16

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (A) + (B) + (C)
(E) = Total Utility Project Costs (15)
(F) = (E)
(G) = (D) - (F)

Table 3

Societal Cost Test

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

Compar **Montana-Dakota Utilities Co.**
Project: **Commercial Lighting 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)
2010	$87,320	$0	$477,774	$288,113	$853,208	$243,926	$1,650,000	$240,000	$1,653,926	($800,719)
2011	$180,752	$0	$976,388	$607,667	1,764,807	$243,926	1,650,000	$480,000	1,413,926	350,881
2012	$280,618	$0	$1,496,622	$961,309	2,738,549	$243,926	1,650,000	$720,000	1,173,926	1,564,622
2013	$387,253	$0	$2,039,284	$1,351,889	3,778,425	$243,926	1,650,000	$0	1,893,926	1,884,499
2014	$501,009	$0	$2,605,208	$1,782,473	4,888,690	$243,926	1,650,000	$0	1,893,926	2,994,764
2015	$518,544	$0	$2,662,714	$1,880,301	5,061,560	$0	0	$0	0	5,061,560
2016	$536,693	$0	$2,721,658	$1,983,644	5,241,995	$0	0	$0	0	5,241,995
2017	$555,477	$0	$2,782,076	$2,092,816	5,430,369	$0	0	$0	0	5,430,369
2018	$574,919	$0	$2,844,003	$2,208,154	5,627,077	$0	0	$0	0	5,627,077
2019	$595,041	$0	$2,907,479	$2,330,012	5,832,532	$0	0	$0	0	5,832,532
2020	$0	$0	$0	$0	0	$0	0	$0	0	0
2021	$0	$0	$0	$0	0	$0	0	$0	0	0
2022	$0	$0	$0	$0	0	$0	0	$0	0	0
2023	$0	$0	$0	$0	0	$0	0	$0	0	0
2024	$0	$0	$0	$0	0	$0	0	$0	0	0
2025	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$4,217,625	$0	$21,513,206	$15,486,379	$41,217,210	$1,219,632	$8,250,000	$1,440,000	$8,029,632	$33,187,579
NPV =	2,548,354	0	13,080,018	11,969,683	27,598,055	967,036	6,541,355	1,198,435	6,309,957	21,288,099

Total NPV = $21,288,099
Benefit/Cost Ratio = 4.37

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) 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 a directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial Lighting Program**

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 Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Costs: Direct Part. Costs (H)
2010	0.0043	$240,000	932,500	1,865,000	$0.057	$0.051	373	746	$46.02	$67.43	$455,996	$1,650,000
2011	0.0085	$480,000	1,865,000	3,730,000	$0.058	$0.052	746	1,492	$47.17	$69.12	$922,793	1,650,000
2012	0.0084	$720,000	2,797,500	5,595,000	$0.060	$0.054	1,119	2,238	$48.35	$70.85	$1,400,794	1,650,000
2013	0.0083	$0	3,730,000	7,460,000	$0.061	$0.055	1,492	2,984	$49.56	$72.62	$930,418	1,650,000
2014	0.0083	$0	4,662,500	9,325,000	$0.063	$0.056	1,865	3,730	$50.80	$74.44	$1,192,098	1,650,000
2015	0.0082	$0	4,662,500	9,325,000	$0.064	$0.058	1,865	3,730	$52.07	$76.30	$1,221,901	0
2016	0.0082	$0	4,662,500	9,325,000	$0.066	$0.059	1,865	3,730	$53.37	$78.20	$1,252,448	0
2017	0.0081	$0	4,662,500	9,325,000	$0.068	$0.061	1,865	3,730	$54.71	$80.16	$1,283,759	0
2018	0.0081	$0	4,662,500	9,325,000	$0.069	$0.062	1,865	3,730	$56.07	$82.16	$1,315,853	0
2019	0.0080	$0	4,662,500	9,325,000	$0.071	$0.064	1,865	3,730	$57.48	$84.22	$1,348,750	0
2020	0.0079	$0	0	0	$0.073	$0.065	0	0	$58.91	$86.32	$0	0
2021	0.0079	$0	0	0	$0.075	$0.067	0	0	$60.39	$88.48	$0	0
2022	0.0078	$0	0	0	$0.077	$0.069	0	0	$61.90	$90.69	$0	0
2023	0.0078	$0	0	0	$0.079	$0.071	0	0	$63.44	$92.96	$0	0
2024	0.0077	$0	0	0	$0.081	$0.072	0	0	$65.03	$95.28	$0	0
2025	0.0077	0	0	0	$0.083	$0.074	0	0	$66.65	$97.67	$0	0
			37,300,000	74,600,000							$11,324,810	$8,250,000
											$7,795,341	7,082,325

Total NPV = $713,016
Benefit/Cost Ratio = 1.10

(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 Participa
(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
(H) = Direct Participant Costs (16) x Participant (22
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

T-8 Lighting Retrofit (4 Lamp fixture model)

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	$ 3,200	$ 3,200	$ 240,000	$ 240,000	$ 240,000	$ 240,000	$ 240,000	$ 1,200,000
Admin & Advertising	$ 3,926	$ 52	$ 3,926	$ 3,926	$ 3,926	$ 3,926	$ 3,926	$ 19,632
Total Cost		**$ 3,252**	**$ 243,926**	**$ 243,926**	**$ 243,926**	**$ 243,926**	**$ 243,926**	**$ 1,219,632**

Notes

Admin & Advertising	Calculated	
Operating Cost	Calculated	
	$ 8.00	per fix

Participant Costs

Avg Cost per Fixture	$ 55.00	Average from existing rebates submitted
Fixtures per Participant	400	
Total Direct Cost per Part	**$ 22,000**	

Participation Rate Calc

	Cust	
Total Customers is Class	17,042	
Estimated fixtures per Customer	23	Derived from xenergy survey
Estimated fixtures on System	**391,966**	

Total fixtures Available for program	391,966
Estimated Conversion Percentage	2.2%
Part Rate of Light fixtures	8,625
Total Partcipants	**375**
Participation Year 1	75
Participation Year 2	75
Participation Year 3	75
Participation Year 4	75
Participation Year 5	75

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%**		

Average number of Fixtures per participant 400

Energy Reduced	Per Fixture	Per Part	
Summer Demand Reduction	0.0373	4.97	Levelized for 4 months
Winter Demand Reduction	0.0373	9.95	Levelized for 8 Months
Total Demand Reduction		**14.92**	**Total demand Reduction for Measure**
Summer Energy Reduction	31	12,433	
Winter Energy Reduction	62	24,867	

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

****** Actual Lighting program with be more comprehensive and include CFL, LED Exit Sighn, & MH, however incentive will follow the same $ per watt of savings**

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

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

Project: **Commercial Air Conditioning**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.04427
1a) Retail Rate Winter ($/kWh) =	$0.03858
Fuel Clause Adjustment (FCA)	$0.01132
Escalation Rate =	2.50%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.02795
Escalation Rate =	3.50%
3) Retail Summer Demand Rate ($/kW/season) =	$44.90
3a) Retail Winter Demand Rate ($/kW/season) =	$65.79
Escalation Rate =	2.50%
4) System Conservation Demand Cost ($/kW/yr)	$336.77
MAPP Reserve Margin=	15.0%
Escalation Rate =	4.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	49.5%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	1,488,732,948
Growth Rate =	2.02%
8) Total Customers by class =	17,479
Growth Rate =	0.70%
9) Utility Discount Rate =	8.27%
10) Social Discount Rate(Tbill) =	3.99%
11) General Input Data Year =	2009
12) Project Analysis Year 1 =	2010
12a) Project Analysis Year 2 =	2011
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.90%
14b) System Energy Line loss factor	7.90%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$2,094
Direct Operating Costs =	$0
Incentive Costs =	$20,000
Total Utility Project Costs Year 1 =	**$22,094**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$2,094
Direct Operating Costs =	$0
Incentive Costs =	$20,000
Total Utility Project Costs Year 2 =	**$22,094**
15b) Total Utilty Cost Year 3 =	**$22,094**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
15e) Total Utility Operating Cost (Program Life) =	**$0**
Escalation Rate =	0.00%
16) Direct Participant Costs ($/Part.) =	$1,000
Escalation Rate =	3.00%
17a) Other Participant Costs (Annual $/Part.) =	$ -
Escalation Rate =	3.00%
17b) Other Participant Savings (Annual $/Part.) =	$ -
Escalation Rate =	0%
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	0.9
20a) Avg Winter kW/part Saved =	0.0
21) Avg. Summer kWh/Part. Saved =	950
21a) Avg. Winter kWh/Part. Saved =	0
22) Number of Participants (First Year) =	40
22a) Number of Participants (Second Year) =	40
22a) Number of Participants (Third Year) =	40
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 500

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

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

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$66,282
Total Program Participants	120
Utility Cost per Participant (First Year) =	$552.35
Utility Cost per Participant (Program) =	$552.35
Total kW Reduction	112
Total Energy Reduction (kWh)	1,722,084
Societal Cost per kwh	$0.03

Test Results

	NPV	B/C
Utility Test	$351,253	6.37
Ratepayer Test	$359,944	7.35
Societal Cost Test	$720,988	13.14
Participant Test	$104,532	1.94

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 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)	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	2010	41,002	$0.0289	$0	37	$395.70	$15,973	$22,094	565	$22,659	($6,686)
2	2011	82,004	$0.0299	0	75	$404.33	32,674	$22,094	1,079	23,174	9,500
3	2012	123,006	$0.0310	0	112	$413.18	50,131	$22,094	1,541	23,635	26,496
4	2013	123,006	$0.0321	0	112	$422.25	51,281	$0	1,459	1,459	49,821
5	2014	123,006	$0.0332	0	112	$431.54	52,461	$0	1,375	1,375	51,086
6	2015	123,006	$0.0344	0	112	$441.07	53,671	$0	1,288	1,288	52,384
7	2016	123,006	$0.0356	0	112	$450.83	54,914	$0	1,198	1,198	53,716
8	2017	123,006	$0.0368	0	112	$460.84	56,189	$0	1,104	1,104	55,085
9	2018	123,006	$0.0381	0	112	$471.10	57,497	$0	1,007	1,007	56,490
10	2019	123,006	$0.0394	0	112	$481.61	58,840	$0	907	907	57,932
11	2020	123,006	$0.0408	0	112	$492.39	60,218	$0	804	804	59,414
12	2021	123,006	$0.0422	0	112	$503.43	61,632	$0	697	697	60,935
13	2022	123,006	$0.0437	0	112	$514.76	63,083	$0	586	586	62,497
14	2023	123,006	$0.0452	0	112	$526.36	64,572	$0	471	471	64,101
15	2024	123,006	$0.0468	0	112	$538.26	66,101	$0	352	352	65,749
16	2025	0	$0.0485	0	0	$550.45	0	0	0	0	0
Total =		1,722,084			1,569		$799,235	$66,282	$14,433	$80,715	$718,520
NPV =							416,606	56,662	8,690	65,353	351,253

Total NPV = $351,253
Benefit/Cost Ratio = 6.37

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(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 Air Conditioning**

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)
2010	$1,186	$0	$14,787	$15,973	$22,094	$22,094	($6,121)
2011	2,455	0	30,218	32,674	$22,094	22,094	10,579
2012	3,812	0	46,319	50,131	$22,094	22,094	28,037
2013	3,945	0	47,335	51,281	$0	0	51,281
2014	4,083	0	48,377	52,461	$0	0	52,461
2015	4,226	0	49,445	53,671	$0	0	53,671
2016	4,374	0	50,540	54,914	$0	0	54,914
2017	4,527	0	51,662	56,189	$0	0	56,189
2018	4,686	0	52,812	57,497	$0	0	57,497
2019	4,850	0	53,990	58,840	$0	0	58,840
2020	5,019	0	55,198	60,218	$0	0	60,218
2021	5,195	0	56,437	61,632	$0	0	61,632
2022	5,377	0	57,706	63,083	$0	0	63,083
2023	5,565	0	59,007	64,572	$0	0	64,572
2024	5,760	0	60,341	66,101	$0	0	66,101
2025	0	0	0	0	0	0	0
Total =	$65,061	$0	$734,174	$799,235	$66,282	$66,282	$732,953
NPV =	33,410	0	383,196	416,606	56,662	56,662	359,944

Total NPV = $359,944
Benefit/Cost Ratio = 7.35

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (A) + (B) + (C)
(E) = Total Utility Project Costs (15)
(F) = (E)
(G) = (D) - (F)

Table 3

Societal Cost Test

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

Compar **Montana-Dakota Utilities Co.**
Project: **Commercial 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)
2010	$1,186	$0	$14,787	$8,144	$24,117	$22,094	$40,000	$20,000	$42,094	($17,978)
2011	$2,455	$0	$30,218	$17,158	49,832	$22,094	40,000	$40,000	22,094	27,738
2012	$3,812	$0	$46,319	$27,116	77,247	$22,094	40,000	$60,000	2,094	75,153
2013	$3,945	$0	$47,335	$28,570	79,850	$0	0	$0	0	79,850
2014	$4,083	$0	$48,377	$30,104	82,565	$0	0	$0	0	82,565
2015	$4,226	$0	$49,445	$31,723	85,394	$0	0	$0	0	85,394
2016	$4,374	$0	$50,540	$33,431	88,345	$0	0	$0	0	88,345
2017	$4,527	$0	$51,662	$35,233	91,422	$0	0	$0	0	91,422
2018	$4,686	$0	$52,812	$37,135	94,633	$0	0	$0	0	94,633
2019	$4,850	$0	$53,990	$39,143	97,983	$0	0	$0	0	97,983
2020	$5,019	$0	$55,198	$41,261	101,479	$0	0	$0	0	101,479
2021	$5,195	$0	$56,437	$43,497	105,129	$0	0	$0	0	105,129
2022	$5,377	$0	$57,706	$45,857	108,940	$0	0	$0	0	108,940
2023	$5,565	$0	$59,007	$48,347	112,920	$0	0	$0	0	112,920
2024	$5,760	$0	$60,341	$50,976	117,077	$0	0	$0	0	117,077
2025	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$65,061	$0	$734,174	$517,695	$1,316,930	$66,282	$120,000	$120,000	$66,282	$1,250,648
NPV =	33,410	0	383,196	363,759	780,365	56,662	102,584	99,870	59,376	720,988

Total NPV = $720,988
Benefit/Cost Ratio = 13.14

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) 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 acc directly to the participant.

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

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 Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Costs: Direct Part. Costs (H)
2010	0.0023	$20,000	38,000	0	$0.057	$0.051	35	0	$46.02	$67.43	$23,759	$40,000
2011	0.0045	$40,000	76,000	0	$0.058	$0.052	69	0	$47.17	$69.12	$47,706	40,000
2012	0.0045	$60,000	114,000	0	$0.060	$0.054	104	0	$48.35	$70.85	$71,848	40,000
2013	0.0045	$0	114,000	0	$0.061	$0.055	104	0	$49.56	$72.62	$12,144	0
2014	0.0044	$0	114,000	0	$0.063	$0.056	104	0	$50.80	$74.44	$12,448	0
2015	0.0044	$0	114,000	0	$0.064	$0.058	104	0	$52.07	$76.30	$12,759	0
2016	0.0044	$0	114,000	0	$0.066	$0.059	104	0	$53.37	$78.20	$13,078	0
2017	0.0043	$0	114,000	0	$0.068	$0.061	104	0	$54.71	$80.16	$13,405	0
2018	0.0043	$0	114,000	0	$0.069	$0.062	104	0	$56.07	$82.16	$13,740	0
2019	0.0043	$0	114,000	0	$0.071	$0.064	104	0	$57.48	$84.22	$14,084	0
2020	0.0042	$0	114,000	0	$0.073	$0.065	104	0	$58.91	$86.32	$14,436	0
2021	0.0042	$0	114,000	0	$0.075	$0.067	104	0	$60.39	$88.48	$14,797	0
2022	0.0042	$0	114,000	0	$0.077	$0.069	104	0	$61.90	$90.69	$15,167	0
2023	0.0042	$0	114,000	0	$0.079	$0.071	104	0	$63.44	$92.96	$15,546	0
2024	0.0041	$0	114,000	0	$0.081	$0.072	104	0	$65.03	$95.28	$15,934	0
2025	0.0041	0	0	0	$0.083	$0.074	0	0	$66.65	$97.67	$0	0
			1,596,000	0							$310,852	$120,000
											$215,600	111,067

Total NPV = $104,532
Benefit/Cost Ratio = 1.94

(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 Participant
(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 F
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Commercial High Efficiency A/C

Customer Class:	Commercial

Cost MDU

			$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Costs	$	-	$ -	$ -	$ -	$ -	$ -
Incentive Costs	$	500	$ 500	$ 20,000	$ 20,000	$ 20,000	$ 60,000
Admin & Advertising	$	2,094	$ 52	$ 2,094	$ 2,094	$ 2,094	$ 6,282
Total Cost			**$ 552**	**$ 22,094**	**$ 22,094**	**$ 22,094**	**$ 66,282**

Notes

Admin & Advertising			Calculated
Operating Cost			Calculated
Incentive	$	100.00	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%	17,042	
Total Customers With Central AC		50.00%	8,521	Estimated no survey data
Total Customers with Evap or Swamp Coolers		0.00%	-	
Total Available for program	8,521			
Total Estimated Saturation Percentage	1.4%			
Total Participants	**120**		0.70%	Of total Customer Base
Participation Year 1	40			
Participation Year 2	40			
Participation Year 3	40			

Energy Savings Calculation

Equipment	kw Conn	Annual kWh	Utilization Factor	
10 SEER Unit	6.86	5,700	67%	Trane 5 ton Unit
12 Seer Unit	5.56	4,750		Trane 5 ton Unit
Energy Reduction	**1.3**	**950**		

	Per Part
Summer Demand Reduction	0.9
Winter Demand Reduction	0.0
Summer Energy Reduction	950
Winter Energy Reduction	0

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

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

Project: **Commercial Motors**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.04427
1a) Retail Rate Winter ($/kWh) =	$0.03858
Fuel Clause Adjustment (FCA)	$0.01132
Escalation Rate =	2.50%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.02795
Escalation Rate =	3.50%
3) Retail Summer Demand Rate ($/kW/season) =	$44.90
3a) Retail Winter Demand Rate ($/kW/season) =	$65.79
Escalation Rate =	2.50%
4) System Conservation Demand Cost ($/kW/yr)	$336.77
MAPP Reserve Margin=	15.0%
Escalation Rate =	4.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	49.5%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	1,488,732,948
Growth Rate =	2.02%
8) Total Customers by class =	17,479
Growth Rate =	0.70%
9) Utility Discount Rate =	8.27%
10) Social Discount Rate(Tbill) =	3.99%
11) General Input Data Year =	2009
12) Project Analysis Year 1 =	2010
12a) Project Analysis Year 2 =	2011
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.90%
14b) System Energy Line loss factor	7.90%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$5,576
Direct Operating Costs =	$0
Incentive Costs =	$28,167
Total Utility Project Costs Year 1 =	**$33,743**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$5,576
Direct Operating Costs =	$0
Incentive Costs =	$28,167
Total Utility Project Costs Year 2 =	**$33,743**
15b) Total Utilty Cost Year 3 =	**$28,167**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
15e) Total Utility Operating Cost (Program Life) =	**$0**
Escalation Rate =	0.00%
16) Direct Participant Costs ($/Part.) =	$1,467
Escalation Rate =	3.00%
17a) Other Participant Costs (Annual $/Part.) =	$ -
Escalation Rate =	3.00%
17b) Other Participant Savings (Annual $/Part.) =	$ -
Escalation Rate =	0%
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	0.1
20a) Avg Winter kW/part Saved =	0.3
21) Avg. Summer kWh/Part. Saved =	588
21a) Avg. Winter kWh/Part. Saved =	1,175
22) Number of Participants (First Year) =	107
22a) Number of Participants (Second Year) =	107
22a) Number of Participants (Third Year) =	107
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 264

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial Motors**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$95,654
Total Program Participants	320
Utility Cost per Participant (First Year) =	$316.80
Utility Cost per Participant (Program) =	$299.35
Total kW Reduction	138
Total Energy Reduction (kWh)	8,509,884
Societal Cost per kwh	$0.04

Test Results

	NPV	B/C
Utility Test	$504,059	4.81
Ratepayer Test	$554,371	7.75
Societal Cost Test	$851,503	3.49
Participant Test	$76,891	1.18

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 Motors**

		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)	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	2010	202,616	$0.0289	$0	46	$395.70	$24,052	$33,743	2,453	$36,196	($12,144)
2	2011	405,233	$0.0299	0	92	$404.33	49,308	$33,743	4,851	38,594	10,714
3	2012	607,849	$0.0310	0	138	$413.18	75,819	$28,167	7,188	35,355	40,464
4	2013	607,849	$0.0321	0	138	$422.25	77,729	$0	7,094	7,094	70,635
5	2014	607,849	$0.0332	0	138	$431.54	79,693	$0	6,993	6,993	72,700
6	2015	607,849	$0.0344	0	138	$441.07	81,713	$0	6,886	6,886	74,827
7	2016	607,849	$0.0356	0	138	$450.83	83,790	$0	6,771	6,771	77,019
8	2017	607,849	$0.0368	0	138	$460.84	85,927	$0	6,649	6,649	79,278
9	2018	607,849	$0.0381	0	138	$471.10	88,125	$0	6,520	6,520	81,605
10	2019	607,849	$0.0394	0	138	$481.61	90,385	$0	6,383	6,383	84,003
11	2020	607,849	$0.0408	0	138	$492.39	92,710	$0	6,237	6,237	86,474
12	2021	607,849	$0.0422	0	138	$503.43	95,102	$0	6,082	6,082	89,020
13	2022	607,849	$0.0437	0	138	$514.76	97,562	$0	5,918	5,918	91,644
14	2023	607,849	$0.0452	0	138	$526.36	100,093	$0	5,745	5,745	94,347
15	2024	607,849	$0.0468	0	138	$538.26	102,696	$0	5,562	5,562	97,134
16	2025	0	$0.0485	0	0	$550.45	0	0	0	0	0
Total =		8,509,884			1,931		$1,224,703	$95,654	$91,332	$186,985	$1,037,717
NPV =							636,515	82,144	50,312	132,456	504,059

Total NPV = $504,059
Benefit/Cost Ratio = 4.81

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(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 Motors**

	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)
2010	$5,861	$0	$18,191	$24,052	$33,743	$33,743	($9,691)
2011	12,133	0	37,175	49,308	$33,743	33,743	15,565
2012	18,836	0	56,983	75,819	$28,167	28,167	47,652
2013	19,496	0	58,233	77,729	$0	0	77,729
2014	20,178	0	59,515	79,693	$0	0	79,693
2015	20,884	0	60,828	81,713	$0	0	81,713
2016	21,615	0	62,175	83,790	$0	0	83,790
2017	22,372	0	63,555	85,927	$0	0	85,927
2018	23,155	0	64,970	88,125	$0	0	88,125
2019	23,965	0	66,420	90,385	$0	0	90,385
2020	24,804	0	67,906	92,710	$0	0	92,710
2021	25,672	0	69,430	95,102	$0	0	95,102
2022	26,571	0	70,991	97,562	$0	0	97,562
2023	27,501	0	72,592	100,093	$0	0	100,093
2024	28,463	0	74,233	102,696	$0	0	102,696
2025	0	0	0	0	0	0	0
Total =	$321,506	$0	$903,196	$1,224,703	$95,654	$95,654	$1,129,049
NPV =	165,100	0	471,415	636,515	82,144	82,144	554,371

Total NPV = $554,371
Benefit/Cost Ratio = 7.75

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (A) + (B) + (C)
(E) = Total Utility Project Costs (15)
(F) = (E)
(G) = (D) - (F)

Table 3

Societal Cost Test

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

Compar **Montana-Dakota Utilities Co.**
Project: **Commercial Motors**

	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)
2010	$5,861	$0	$18,191	$12,263	$36,315	$33,743	$156,254	$28,167	$161,830	($125,515)
2011	$12,133	$0	$37,175	$25,894	75,202	$33,743	156,254	$56,334	133,663	(58,461)
2012	$18,836	$0	$56,983	$41,011	116,830	$28,167	156,254	$84,502	99,919	16,910
2013	$19,496	$0	$58,233	$43,305	121,033	$0	0	$0	0	121,033
2014	$20,178	$0	$59,515	$45,731	125,424	$0	0	$0	0	125,424
2015	$20,884	$0	$60,828	$48,297	130,009	$0	0	$0	0	130,009
2016	$21,615	$0	$62,175	$51,010	134,801	$0	0	$0	0	134,801
2017	$22,372	$0	$63,555	$53,881	139,807	$0	0	$0	0	139,807
2018	$23,155	$0	$64,970	$56,916	145,041	$0	0	$0	0	145,041
2019	$23,965	$0	$66,420	$60,128	150,513	$0	0	$0	0	150,513
2020	$24,804	$0	$67,906	$63,525	156,235	$0	0	$0	0	156,235
2021	$25,672	$0	$69,430	$67,118	162,220	$0	0	$0	0	162,220
2022	$26,571	$0	$70,991	$70,920	168,482	$0	0	$0	0	168,482
2023	$27,501	$0	$72,592	$74,942	175,035	$0	0	$0	0	175,035
2024	$28,463	$0	$74,233	$79,198	181,894	$0	0	$0	0	181,894
2025	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$321,506	$0	$903,196	$794,139	$2,018,841	$95,654	$468,762	$169,003	$395,412	$1,623,429
NPV =	165,100	0	471,415	557,207	1,193,722	82,144	400,728	140,652	342,220	851,503

Total NPV = $851,503
Benefit/Cost Ratio = 3.49

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) 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 acc directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial Motors**

		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 Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)
2010	0.0061	$28,167	62,594	125,188	$0.057	$0.051	14	28	$46.02	$67.43	$40,706	$156,254
2011	0.0120	$56,334	125,188	250,375	$0.058	$0.052	28	57	$47.17	$69.12	$82,039	156,254
2012	0.0119	$84,502	187,782	375,563	$0.060	$0.054	43	85	$48.35	$70.85	$124,022	156,254
2013	0.0119	$0	187,782	375,563	$0.061	$0.055	43	85	$49.56	$72.62	$40,508	0
2014	0.0118	$0	187,782	375,563	$0.063	$0.056	43	85	$50.80	$74.44	$41,521	0
2015	0.0117	$0	187,782	375,563	$0.064	$0.058	43	85	$52.07	$76.30	$42,559	0
2016	0.0116	$0	187,782	375,563	$0.066	$0.059	43	85	$53.37	$78.20	$43,623	0
2017	0.0115	$0	187,782	375,563	$0.068	$0.061	43	85	$54.71	$80.16	$44,713	0
2018	0.0114	$0	187,782	375,563	$0.069	$0.062	43	85	$56.07	$82.16	$45,831	0
2019	0.0114	$0	187,782	375,563	$0.071	$0.064	43	85	$57.48	$84.22	$46,977	0
2020	0.0113	$0	187,782	375,563	$0.073	$0.065	43	85	$58.91	$86.32	$48,151	0
2021	0.0112	$0	187,782	375,563	$0.075	$0.067	43	85	$60.39	$88.48	$49,355	0
2022	0.0111	$0	187,782	375,563	$0.077	$0.069	43	85	$61.90	$90.69	$50,589	0
2023	0.0111	$0	187,782	375,563	$0.079	$0.071	43	85	$63.44	$92.96	$51,854	0
2024	0.0110	$0	187,782	375,563	$0.081	$0.072	43	85	$65.03	$95.28	$53,150	0
2025	0.0109	0	0	0	$0.083	$0.074	0	0	$66.65	$97.67	$0	0
			2,628,942	5,257,883							$805,597	$468,762
											$510,758	433,868

Total NPV = $76,891
Benefit/Cost Ratio = 1.18

(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 Participan
(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 F
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Commercial High Efficiency Motors

Customer Class:	Commercial & Industrial

Cost MDU

			$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Cost	$0		$ -	$ -	$ -	$ -	$ -
Incentive Costs	$264		$ 264	$ 28,167	$ 28,167	$ 28,167	$ 84,502
Admin & Advertising	$5,576		$ 52	$ 5,576	$ 5,576	$ 5,576	$ 16,728
Total Cost			**$ 317**	**$ 33,743**	**$ 33,743**	**$ 33,743**	**$ 101,230**

Notes

Admin & Advertising		Calculated
Operating Cost		Calculated
Incentive	$ 0.150	Per kWh Saved

Participant Costs (Incremental Cost Basis)

Avg Cost of Standard Motor	$ 3,320	50HP 3600 rpm - Motor Master
Avg Cost of High Efficiency Motor	$ 4,787	50 HP 3600 rpm - Motor Master
Increased cost of Higher Eff Model	**$ 1,467**	

Participation Rate Calc

		% of Cust	Cust	
Total Customers is Class		100.00%	17,042	
Customer with Standard Motors		75.00%	12,782	
Estimated Motors per Customer			5	
Total Motors Available for Program	63,908			
Total Estimated Saturation Percentage	0.5%			
Total Motors	**320**		1.88%	Of total Customer Base
Participation Year 1	107			
Participation Year 2	107			
Participation Year 3	107			

Energy Savings Calculation

Electric Motor Data	kw Conn	Annual kWh	Utilization Factor	
Standard Motor (50hp)	37.3	106,860	100%	4380 hrs per year operation @ 60 % Load Factor
High Efficiency Motor(50hp)	36.9	105,097	100%	4380 hrs per year operation @ 60% Load Factor
Energy Savings	**0.4**	**1,763**		Energy Calculation based on Motor Master - DOE
		Per Part		Example is based on 50 hp - 3600 rpm - 460 v TEFC
Summer Demand Reduction		0.133	Levelized for 4 months	
Winter Demand Reduction		0.267	Levelized for 8 Months	
Total Demand Reduction		**0.400**	**Total demand Reduction for Measure**	
Summer Energy Reduction		588		
Winter Energy Reduction		1175		

Notes:
TEFC = Total Enclosed Fan Cooled

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

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

Project: **Residential New Construciton Bundle**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.07212
1a) Retail Rate Winter ($/kWh) =	$0.06174
Fuel Clause Adjustment (FCA)	$0.01132
Escalation Rate =	2.50%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.02795
Escalation Rate =	3.50%
3) Retail Summer Demand Rate ($/kW/season) =	$0.00
3a) Retail Winter Demand Rate ($/kW/season) =	$0.00
Escalation Rate =	2.50%
4) System Conservation Demand Cost ($/kW/yr)	$336.77
MAPP Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	49.5%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	814,894,507
Growth Rate =	2.02%
8) Total Customers by class =	87,262
Growth Rate =	0.70%
9) Utility Discount Rate =	8.27%
10) Social Discount Rate(Tbill) =	3.99%
11) General Input Data Year =	2009
12) Project Analysis Year 1 =	2010
12a) Project Analysis Year 2 =	2011
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.90%
14b) System Energy Line loss factor	7.90%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$3,141
Direct Operating Costs =	$0
Incentive Costs =	$34,000
Total Utility Project Costs Year 1 =	**$37,141**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$3,141
Direct Operating Costs =	$0
Incentive Costs =	$51,000
Total Utility Project Costs Year 2 =	**$54,141**
15b) Total Utilty Cost Year 3 =	**$65,141**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
15e) Total Utility Operating Cost (Program Life) =	**$0**
Escalation Rate =	0.00%
16) Direct Participant Costs ($/Part.) =	$1,095
Escalation Rate =	3.00%
17a) Other Participant Costs (Annual $/Part.) =	$ -
Escalation Rate =	3.00%
17b) Other Participant Savings (Annual $/Part.) =	$ 40
Escalation Rate =	3%
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	0.47
20a) Avg Winter kW/part Saved =	0.93
21) Avg. Summer kWh/Part. Saved =	393
21a) Avg. Winter kWh/Part. Saved =	785
22) Number of Participants (First Year) =	60
22a) Number of Participants (Second Year) =	90
22a) Number of Participants (Third Year) =	110
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 565

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Residential New Construciton Bundle**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$156,423
Total Program Participants	260
Utility Cost per Participant (First Year) =	$619.02
Utility Cost per Participant (Program) =	$601.63
Total kW Reduction	391
Total Energy Reduction (kWh)	4,561,921
Societal Cost per kwh	$0.03

Test Results

	NPV	B/C
Utility Test	$1,202,657	7.11
Ratepayer Test	$1,267,571	10.62
Societal Cost Test	$2,478,139	17.30
Participant Test	$284,668	2.10

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 New Construciton Bundle**

		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)	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	2010	76,244	$0.0289	$0	90	$395.70	$37,952	$37,141	2,005	$39,146	($1,194)
2	2011	190,610	$0.0299	0	226	$404.33	97,023	$54,141	5,030	59,171	37,852
3	2012	330,390	$0.0310	0	391	$413.18	171,982	$65,141	8,747	73,888	98,094
4	2013	330,390	$0.0321	0	391	$422.25	175,890	$0	8,773	8,773	167,117
5	2014	330,390	$0.0332	0	391	$431.54	179,899	$0	8,798	8,798	171,101
6	2015	330,390	$0.0344	0	391	$441.07	184,011	$0	8,821	8,821	175,190
7	2016	330,390	$0.0356	0	391	$450.83	188,231	$0	8,842	8,842	179,388
8	2017	330,390	$0.0368	0	391	$460.84	192,560	$0	8,862	8,862	183,698
9	2018	330,390	$0.0381	0	391	$471.10	197,001	$0	8,879	8,879	188,122
10	2019	330,390	$0.0394	0	391	$481.61	201,557	$0	8,895	8,895	192,663
11	2020	330,390	$0.0408	0	391	$492.39	206,232	$0	8,908	8,908	197,325
12	2021	330,390	$0.0422	0	391	$503.43	211,029	$0	8,918	8,918	202,110
13	2022	330,390	$0.0437	0	391	$514.76	215,949	$0	8,926	8,926	207,023
14	2023	330,390	$0.0452	0	391	$526.36	220,998	$0	8,932	8,932	212,067
15	2024	330,390	$0.0468	0	391	$538.26	226,178	$0	8,934	8,934	217,245
16	2025	0	$0.0485	0	0	$550.45	0	0	0	0	0
Total =		4,561,921			5,405		$2,706,494	$156,423	$122,270	$278,694	$2,427,800
NPV =							1,399,386	131,815	64,914	196,729	1,202,657

Total NPV = $1,202,657
Benefit/Cost Ratio = 7.11

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(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 New Construciton Bundle**

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)
2010	$2,206	$0	$35,747	$37,952	$37,141	$37,141	$811
2011	5,707	0	91,316	97,023	$54,141	54,141	42,882
2012	10,238	0	161,744	171,982	$65,141	65,141	106,841
2013	10,597	0	165,293	175,890	$0	0	175,890
2014	10,968	0	168,931	179,899	$0	0	179,899
2015	11,351	0	172,660	184,011	$0	0	184,011
2016	11,749	0	176,482	188,231	$0	0	188,231
2017	12,160	0	180,400	192,560	$0	0	192,560
2018	12,586	0	184,415	197,001	$0	0	197,001
2019	13,026	0	188,531	201,557	$0	0	201,557
2020	13,482	0	192,750	206,232	$0	0	206,232
2021	13,954	0	197,075	211,029	$0	0	211,029
2022	14,442	0	201,507	215,949	$0	0	215,949
2023	14,948	0	206,051	220,998	$0	0	220,998
2024	15,471	0	210,707	226,178	$0	0	226,178
2025	0	0	0	0	0	0	0
Total =	$172,883	$0	$2,533,610	$2,706,494	$156,423	$156,423	$2,550,070
NPV =	88,076	0	1,311,310	1,399,386	131,815	131,815	1,267,571

Total NPV = $1,267,571

Benefit/Cost Ratio = 10.62

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

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

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

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

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Cost Test

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

Compar **Montana-Dakota Utilities Co.**
Project: **Residential New Construciton Bundle**

Year	Decreases: Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Increases: Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2010	$2,206	$0	$35,747	$19,350	$57,303	$37,141	$65,723	$33,923	$68,941	($11,639)
2011	$5,707	$0	$91,316	$50,951	147,974	$54,141	98,585	$84,808	67,918	80,056
2012	$10,238	$0	$161,744	$93,025	265,007	$65,141	120,492	$147,000	38,633	226,374
2013	$10,597	$0	$165,293	$97,993	273,883	$0	0	$0	0	273,883
2014	$10,968	$0	$168,931	$103,233	283,132	$0	0	$0	0	283,132
2015	$11,351	$0	$172,660	$108,761	292,772	$0	0	$0	0	292,772
2016	$11,749	$0	$176,482	$114,593	302,823	$0	0	$0	0	302,823
2017	$12,160	$0	$180,400	$120,745	313,305	$0	0	$0	0	313,305
2018	$12,586	$0	$184,415	$127,236	324,237	$0	0	$0	0	324,237
2019	$13,026	$0	$188,531	$134,084	335,641	$0	0	$0	0	335,641
2020	$13,482	$0	$192,750	$141,310	347,542	$0	0	$0	0	347,542
2021	$13,954	$0	$197,075	$148,934	359,962	$0	0	$0	0	359,962
2022	$14,442	$0	$201,507	$156,979	372,928	$0	0	$0	0	372,928
2023	$14,948	$0	$206,051	$165,468	386,467	$0	0	$0	0	386,467
2024	$15,471	$0	$210,707	$174,427	400,606	$0	0	$0	0	400,606
2025	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$172,883	$0	$2,533,610	$1,757,088	$4,463,582	$156,423	$284,800	$265,731	$175,493	$4,288,090
NPV =	88,076	0	1,311,310	1,230,806	2,630,193	131,815	239,739	219,501	152,053	2,478,139

Total NPV = $2,478,139
Benefit/Cost Ratio = 17.30

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) 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 acc directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential New Construciton Bundle**

		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 Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)		Direct Part. Costs (H)
2010	0.0007	$33,923	23,554	47,108	$0.086	$0.075	28	56	$0.00	$0.00	$41,850		$65,723
2011	0.0017	$84,808	58,885	117,769	$0.088	$0.077	70	140	$0.00	$0.00	$104,971		98,585
2012	0.0017	$147,000	102,067	204,133	$0.090	$0.079	121	242	$0.00	$0.00	$182,565		120,492
2013	0.0017	$0	102,067	204,133	$0.092	$0.081	121	242	$0.00	$0.00	$36,195		0
2014	0.0017	$0	102,067	204,133	$0.094	$0.083	121	242	$0.00	$0.00	$36,842		0
2015	0.0016	$0	102,067	204,133	$0.097	$0.085	121	242	$0.00	$0.00	$37,505		0
2016	0.0016	$0	102,067	204,133	$0.099	$0.087	121	242	$0.00	$0.00	$38,184		0
2017	0.0016	$0	102,067	204,133	$0.102	$0.089	121	242	$0.00	$0.00	$38,880		0
2018	0.0016	$0	102,067	204,133	$0.104	$0.091	121	242	$0.00	$0.00	$39,594		0
2019	0.0016	$0	102,067	204,133	$0.107	$0.094	121	242	$0.00	$0.00	$40,326		0
2020	0.0016	$0	102,067	204,133	$0.109	$0.096	121	242	$0.00	$0.00	$41,075		0
2021	0.0016	$0	102,067	204,133	$0.112	$0.098	121	242	$0.00	$0.00	$41,844		0
2022	0.0016	$0	102,067	204,133	$0.115	$0.101	121	242	$0.00	$0.00	$42,632		0
2023	0.0016	$0	102,067	204,133	$0.118	$0.103	121	242	$0.00	$0.00	$43,439		0
2024	0.0015	$0	102,067	204,133	$0.121	$0.106	121	242	$0.00	$0.00	$44,267		0
2025	0.0015	0	0	0	$0.124	$0.108	0	0	$0.00	$0.00	$0		0
			1,409,305	2,818,610							$810,168		$284,800
											$544,233		259,566

Total NPV = $284,668
Benefit/Cost Ratio = 2.10

(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 Participan
(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 F
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Residential New Construction Bundle
AC, Lighting, & Energy Star Appliances

Customer Class:	Residential

Program Cost

		$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Costs		$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 565	$ 565	$ 34,000	$ 51,000	$ 62,000	$ 147,000
Administrative Costs	$3,141	$ 36	$ 3,141	$ 3,141	$ 3,141	$ 9,423
Total Cost		**$ 602**	**$ 37,141**	**$ 54,141**	**$ 65,141**	**$ 156,423**

Incentive AC & Lighting	$ 500
Incentive full package (AC, Lighting, & 2 Appliances)	$ 600

Participant Costs (Incremental Cost Basis)

Incremental Cost

13 to 15 SEER Air Conditioner (Includes Heat Pump)	$ 900	3 Ton Unit
Compact Flourscent Lighting (15 Bulbs installed in home)	$ 45	$3 per Bulb Minimum of 15
Base Package Total	**$ 945**	
Energy Star Refrigerator	$ 30	Energy Star Calculator
Energy Dish Washer	$ -	Energy Star Calculator
Energy Star Clothes Washer	$ 200	Energy Star Calculator
Full Package Total	**$ 1,175**	
Participant Rate Ratio incremental cost	**$ 1,095**	

Participation Rate Calc

	% of Cust	Cust	
3 Year Average number of new homes	100.00%	895	2006-2008 Avg New Services

Total Available for program		895		
Total Estimated Saturation Percentage		10.0%		
		AC & Lighting	Full Package	Total
Participation Year 1	2010	20	40	60
Participation Year 2	2011	30	60	90
	2012	40	70	110
Total Participants		**90**	**170**	**260**
		34.6%	*65.4%*	

Energy Savings Calculation

Equipment	Eff	kW	kWh
13 to 15 SEER Air Conditioner	15 SEER	0.55	222
Compact Flourscent Lighting (15 Bulbs)	E-STAR	0.8	855
Bases Package Total		**1.33**	**1,077**
Energy Star Refrigerator	E-STAR	0.10	52
Energy Dish Washer	E-STAR	0.00	76
Energy Star Clothes Washer	E-STAR	0.00	26
Full Package Total		**1.43**	**1,231**

Other Particpant Savings

Gas dk	Gas $	Water Gallons	Water $
0	$0.00	0	$0.00
0	$0.00	0	$0.00
0	**$0.00**	**0**	**$0.00**
0	$0.00	0	$0.00
1.3	$16.00	481	$2.00
0.9	$ 11.18	$ 7,000	$31.60
2.2	**$27.18**	**7,481**	**$33.60**

Total Other Savings $ 60.78

Particiapation Rate Ratio Savings

kW Total	1.40	
	Summer	0.47
	Winter	0.93
KWH	1,178	
	Summer	393
	Winter	785
Other Savings $	$39.74	

AC Savings Detail

Equipment	kw Conn	Annual kWh	UF
13 SEER Unit	3.43	1,662	67%
15 SEER Unit	2.88	1,440	
Energy Reducti	**0.55**	**222**	

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

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

Project: **Irrigation Demand Response**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.04427
1a) Retail Rate Winter ($/kWh) =	$0.03858
Fuel Clause Adjustment (FCA)	$0.01132
Escalation Rate =	2.50%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.02795
Escalation Rate =	3.50%
3) Retail Summer Demand Rate ($/kW/season) =	$44.90
3a) Retail Winter Demand Rate ($/kW/season) =	$65.79
Escalation Rate =	2.50%
4) System Peak Shaving Demand Cost ($/kW/yr)	$109.36
MAPP Reserve Margin=	15.0%
Escalation Rate =	4.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	49.5%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	1,488,732,948
Growth Rate =	2.02%
8) Total Customers by class =	17,479
Growth Rate =	0.70%
9) Utility Discount Rate =	8.27%
10) Social Discount Rate(Tbill) =	3.99%
11) General Input Data Year =	2009
12) Project Analysis Year 1 =	2010
12a) Project Analysis Year 2 =	2011
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.90%
14b) System Energy Line loss factor	7.90%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$0
Direct Operating Costs =	$175,500
Incentive Costs =	$2,100
Total Utility Project Costs Year 1 =	**$177,600**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$0
Direct Operating Costs =	$175,500
Incentive Costs =	$2,100
Total Utility Project Costs Year 2 =	**$177,600**
15b) Total Utilty Cost Year 3 =	**$177,600**
15c) Total Utilty Cost Year 4 =	**$2,100**
15d) Total Utility Cost Year 5 =	**$2,100**
15e) Total Utility Operating Cost (Program Life) =	**$2,100**
Escalation Rate =	0.00%
16) Direct Participant Costs ($/Part.) =	$0
Escalation Rate =	3.00%
17a) Other Participant Costs (Annual $/Part.) =	$ -
Escalation Rate =	3.00%
17b) Other Participant Savings (Annual $/Part.) =	$ -
Escalation Rate =	0%
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	19.5
20a) Avg Winter kW/part Saved =	0.0
21) Avg. Summer kWh/Part. Saved =	0
21a) Avg. Winter kWh/Part. Saved =	0
22) Number of Participants (First Year) =	10
22a) Number of Participants (Second Year) =	10
22a) Number of Participants (Third Year) =	10
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 156

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Irrigation Demand Response**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$537,000
Total Program Participants	30
Utility Cost per Participant (First Year) =	$17,760.00
Utility Cost per Participant (Program) =	$17,900.00
Total kW Reduction	630
Total Energy Reduction (kWh)	0
Societal Cost per kwh	#DIV/0!

Test Results

	NPV	B/C
Utility Test	$231,537	1.49
Ratepayer Test	$231,537	1.49
Societal Cost Test	$849,204	2.85
Participant Test	$264,499	#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: **Irrigation Demand Response**

		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)	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	2010	0	$0.0289	$0	210	$128.50	$26,985	$177,600	0	$177,600	($150,615)
2	2011	0	$0.0299	0	420	$131.30	55,146	$177,600	0	177,600	(122,454)
3	2012	0	$0.0310	0	630	$134.17	84,529	$177,600	0	177,600	(93,071)
4	2013	0	$0.0321	0	630	$137.12	86,384	$2,100	0	2,100	84,284
5	2014	0	$0.0332	0	630	$140.13	88,285	$2,100	0	2,100	86,185
6	2015	0	$0.0344	0	630	$143.23	90,234	$2,100	0	2,100	88,134
7	2016	0	$0.0356	0	630	$146.40	92,231	$2,100	0	2,100	90,131
8	2017	0	$0.0368	0	630	$149.65	94,279	$2,100	0	2,100	92,179
9	2018	0	$0.0381	0	630	$152.98	96,377	$2,100	0	2,100	94,277
10	2019	0	$0.0394	0	630	$156.39	98,528	$2,100	0	2,100	96,428
11	2020	0	$0.0408	0	630	$159.89	100,733	$2,100	0	2,100	98,633
12	2021	0	$0.0422	0	630	$163.48	102,993	$2,100	0	2,100	100,893
13	2022	0	$0.0437	0	630	$167.16	105,310	$2,100	0	2,100	103,210
14	2023	0	$0.0452	0	630	$170.93	107,684	$2,100	0	2,100	105,584
15	2024	0	$0.0468	0	630	$174.79	110,118	$2,100	0	2,100	108,018
16	2025	0	$0.0485	0	0	$178.75	0	0	0	0	0
Total =		0			8,820		$1,339,817	$558,000	$0	$558,000	$781,817
NPV =							699,306	467,768	0	467,768	231,537

Total NPV = $231,537
Benefit/Cost Ratio = 1.49

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(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: **Irrigation Demand Response**

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)
	Decreases			Increases			
2010	$0	$0	$26,985	$26,985	$177,600	$177,600	($150,615)
2011	0	0	55,146	55,146	$177,600	177,600	(122,454)
2012	0	0	84,529	84,529	$177,600	177,600	(93,071)
2013	0	0	86,384	86,384	$2,100	2,100	84,284
2014	0	0	88,285	88,285	$2,100	2,100	86,185
2015	0	0	90,234	90,234	$2,100	2,100	88,134
2016	0	0	92,231	92,231	$2,100	2,100	90,131
2017	0	0	94,279	94,279	$2,100	2,100	92,179
2018	0	0	96,377	96,377	$2,100	2,100	94,277
2019	0	0	98,528	98,528	$2,100	2,100	96,428
2020	0	0	100,733	100,733	$2,100	2,100	98,633
2021	0	0	102,993	102,993	$2,100	2,100	100,893
2022	0	0	105,310	105,310	$2,100	2,100	103,210
2023	0	0	107,684	107,684	$2,100	2,100	105,584
2024	0	0	110,118	110,118	$2,100	2,100	108,018
2025	0	0	0	0	0	0	0
Total =	$0	$0	$1,339,817	$1,339,817	$558,000	$558,000	$781,817
NPV =	0	0	699,306	699,306	467,768	467,768	231,537

Total NPV = $231,537
Benefit/Cost Ratio = 1.49

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)
(F) = (E)
(G) = (D) - (F)

Table 3

Societal Cost Test

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

Compar **Montana-Dakota Utilities Co.**
Project: **Irrigation Demand Response**

Year	Decreases: Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Increases: Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2010	$0	$0	$26,985	$13,758	$40,743	$177,600	$0	$1,557	$176,043	($135,300)
2011	$0	$0	$55,146	$28,960	84,106	$177,600	0	$3,114	174,486	(90,380)
2012	$0	$0	$84,529	$45,722	130,251	$177,600	0	$4,671	172,929	(42,678)
2013	$0	$0	$86,384	$48,127	134,511	$2,100	0	$0	2,100	132,411
2014	$0	$0	$88,285	$50,662	138,947	$2,100	0	$0	2,100	136,847
2015	$0	$0	$90,234	$53,333	143,567	$2,100	0	$0	2,100	141,467
2016	$0	$0	$92,231	$56,149	148,381	$2,100	0	$0	2,100	146,281
2017	$0	$0	$94,279	$59,118	153,396	$2,100	0	$0	2,100	151,296
2018	$0	$0	$96,377	$62,247	158,624	$2,100	0	$0	2,100	156,524
2019	$0	$0	$98,528	$65,545	164,073	$2,100	0	$0	2,100	161,973
2020	$0	$0	$100,733	$69,022	169,755	$2,100	0	$0	2,100	167,655
2021	$0	$0	$102,993	$72,688	175,681	$2,100	0	$0	2,100	173,581
2022	$0	$0	$105,310	$76,552	181,862	$2,100	0	$0	2,100	179,762
2023	$0	$0	$107,684	$80,627	188,311	$2,100	0	$0	2,100	186,211
2024	$0	$0	$110,118	$84,922	195,040	$2,100	0	$0	2,100	192,940
2025	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$0	$0	$1,339,817	$867,430	$2,207,247	$558,000	$0	$9,342	$548,658	$1,658,589
NPV =	0	0	699,306	609,892	1,309,198	467,768	0	7,775	459,994	849,204

Total NPV = $849,204
Benefit/Cost Ratio = 2.85

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) 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 acc directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Irrigation Demand Response**

		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 Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)
2010	0.0006	$1,557	0	0	$0.057	$0.051	195	0	$46.02	$67.43	$10,514	$0
2011	0.0011	$3,114	0	0	$0.058	$0.052	389	0	$47.17	$69.12	$21,476	0
2012	0.0011	$4,671	0	0	$0.060	$0.054	584	0	$48.35	$70.85	$32,903	0
2013	0.0011	$0	0	0	$0.061	$0.055	584	0	$49.56	$72.62	$28,938	0
2014	0.0011	$0	0	0	$0.063	$0.056	584	0	$50.80	$74.44	$29,661	0
2015	0.0011	$0	0	0	$0.064	$0.058	584	0	$52.07	$76.30	$30,403	0
2016	0.0011	$0	0	0	$0.066	$0.059	584	0	$53.37	$78.20	$31,163	0
2017	0.0011	$0	0	0	$0.068	$0.061	584	0	$54.71	$80.16	$31,942	0
2018	0.0011	$0	0	0	$0.069	$0.062	584	0	$56.07	$82.16	$32,740	0
2019	0.0011	$0	0	0	$0.071	$0.064	584	0	$57.48	$84.22	$33,559	0
2020	0.0011	$0	0	0	$0.073	$0.065	584	0	$58.91	$86.32	$34,398	0
2021	0.0011	$0	0	0	$0.075	$0.067	584	0	$60.39	$88.48	$35,258	0
2022	0.0010	$0	0	0	$0.077	$0.069	584	0	$61.90	$90.69	$36,139	0
2023	0.0010	$0	0	0	$0.079	$0.071	584	0	$63.44	$92.96	$37,043	0
2024	0.0010	$0	0	0	$0.081	$0.072	584	0	$65.03	$95.28	$37,969	0
2025	0.0010	0	0	0	$0.083	$0.074	0	0	$66.65	$97.67	$0	0
			0	0							$464,102	$0
											$264,499	0

Total NPV = $264,499
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 Participant
(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 F:
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Irragation Demand Response - Direct Control

Customer Class:	Irrigation

Cost MDU

			$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Costs (Turnkey)	$ 500	kW	$ 17,500	$ 175,500	$ 175,500	$ 175,500	$ 526,500
Incentive Costs (per kW)	$6.00		$ 6	$ 2,100	$ 2,100	$ 2,100	$ 2,100
Admin & Advertising			$ -	$ -	$ -	$ -	$ -
Total Cost			**$ 17,506**	**$ 177,600**	**$ 177,600**	**$ 177,600**	**$ 528,600**

Notes

Incentive is $3 per Kw 155.70

Operating is turnkey program form M2M Communcations

Participant Costs

None $ -

Participation Rate Calc

	% of Cust	Cust
Total Customers is Class	100.00%	100
Total Customers in class available for program	100.00%	100

Total Available for program	100		
Total Estimated Saturation Percentage	30.0%		
Total Participants	**30**	30.00%	Of total Customer Base
Participation Year 1	10		
Participation Year 2	10		
Participation Year 3	10		

Energy Savings Calculation

Equipment	kw Conn	Annual kWh	Utilization Factor	
Avg Load per cust	34.6	0	75%	Per Rate code analysis
Cycling Hours per Year	0	100 hrs		100 hrs of curtailment per year or 10% cycling rate
Peak kW Reduced	**25.95**			Utilization Factor is estimated

	Per Part
Summer Demand Reduction	19.5
Winter Demand Reduction	0.000
Summer Energy Reduction	-
Winter Energy Reduction	0

Attachment C

SUPPLY-SIDE AND INTEGRATION ANALYSIS DOCUMENTATION

Supply Side Analysis

TABLE OF CONTENTS

Supply-Side and Integration Analysis

OVERVIEW

The supply-side analysis was conducted to identify the feasible supply-side resources to be added to Montana-Dakota's generating system to determine the most cost effective plan. These potential new resources must be proven technology and be able to provide the same system reliability that Montana-Dakota's customers have come to expect over the years. The integration process considers the supply-side resources and the feasible demand-side resources and integrates them into a single least-cost plan. The analysis also considered potential economical and political issues that could arise in the future.

Capacity Needs

The resource expansion analysis considered all resource options available to Montana-Dakota and produced a least-cost plan which satisfied the energy and capacity requirements to reliably serve Montana-Dakota's customers. The resulting resource plan had to meet the reserve capacity obligation (RCO) of fifteen percent required by the Mid-Continent Area Power Pool (MAPP) Generation Reserve Sharing Pool. To meet this RCO, sufficient accredited capacity would be needed to cover the projected annual peak demand plus fifteen percent, which is known as peak load obligation.

Montana-Dakota's plan in the 2007 IRP was to extend one of the current contracts with Northern States Power Company (NSP) that would expire in 2010 to cover Montana-Dakota's capacity until Big Stone Unit II came on-line in the 2011-2012 timeframe. However, with the delay of Big Stone Unit II until 2015, the need for capacity became a major concern for the 2011-2014 time period as well as for the years following the addition of Big Stone Unit II.

Load and Capability

To further understand Montana-Dakota's capacity needs, a comparison of its summer accredited capability in MAPP and the peak load obligation is shown in Figures 1-1, 1-2, and 1-3 for the base, low-growth, and high-growth forecast scenarios described in detail in the load forecast provided in Attachment A. The generating capability shown in the forecast scenarios included Montana-Dakota's existing units and power purchase agreements along with the committed resources at this time.

Figure 1-1 shows that starting in 2011 Montana-Dakota will be capacity deficit by 8.3 MW with a capacity deficiency of 26.5 MW by 2015. As shown in Figure 1-2, under the low-growth scenario forecast, the capacity deficit would occur in the 2012-2014 time period, and then not again until 2021. With the high-growth scenario forecast, as shown in Figure 1-3, a capacity deficit of 19.5 MW occurs in 2009.

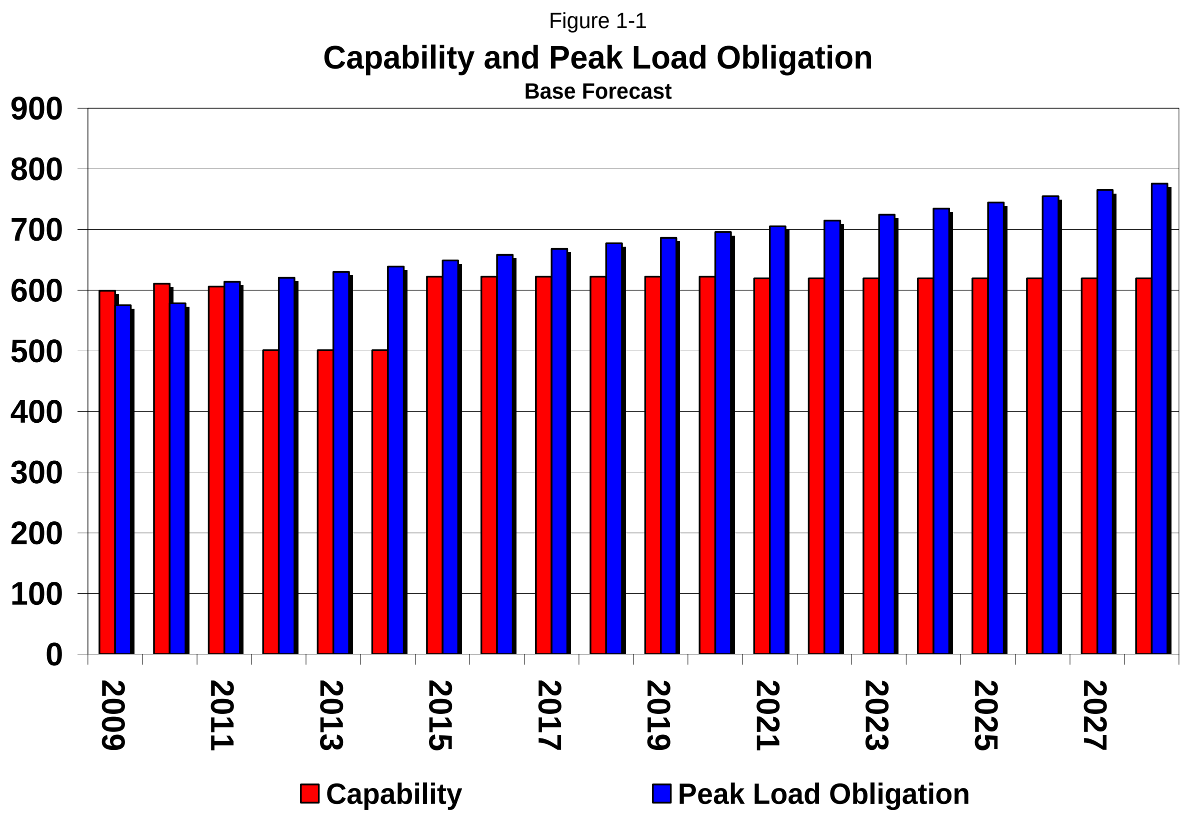


Figure 1-2

Capability and Peak Load Obligation

Low Growth Forecast

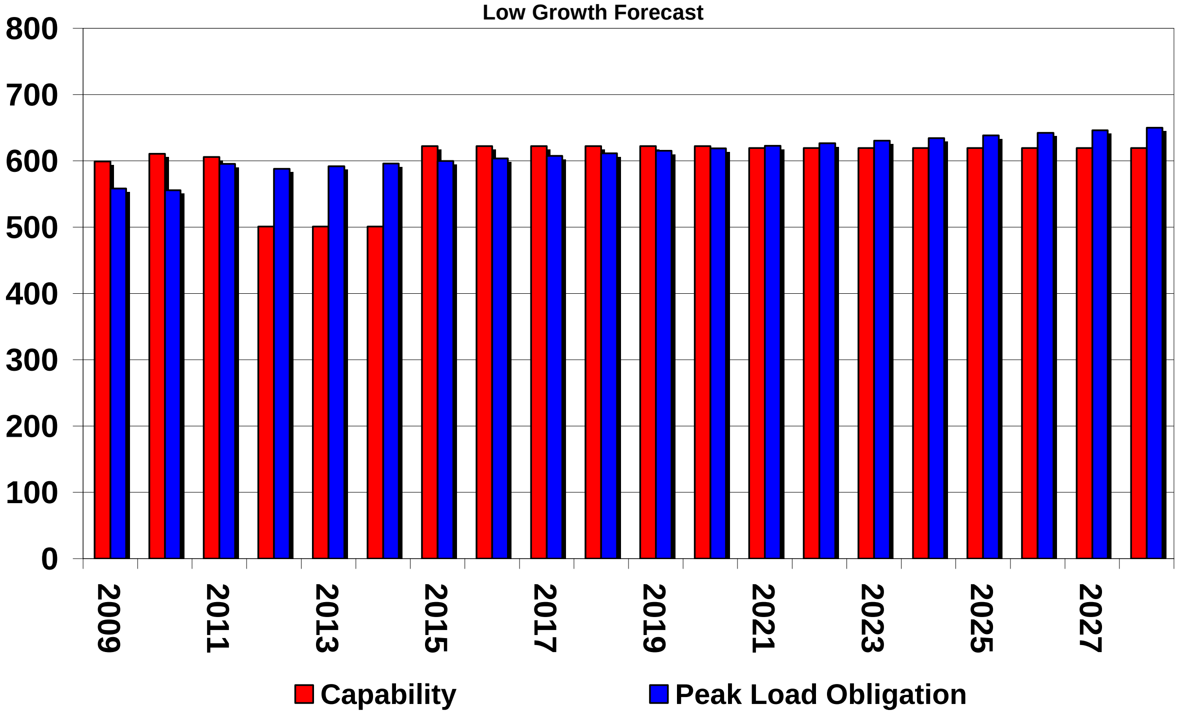
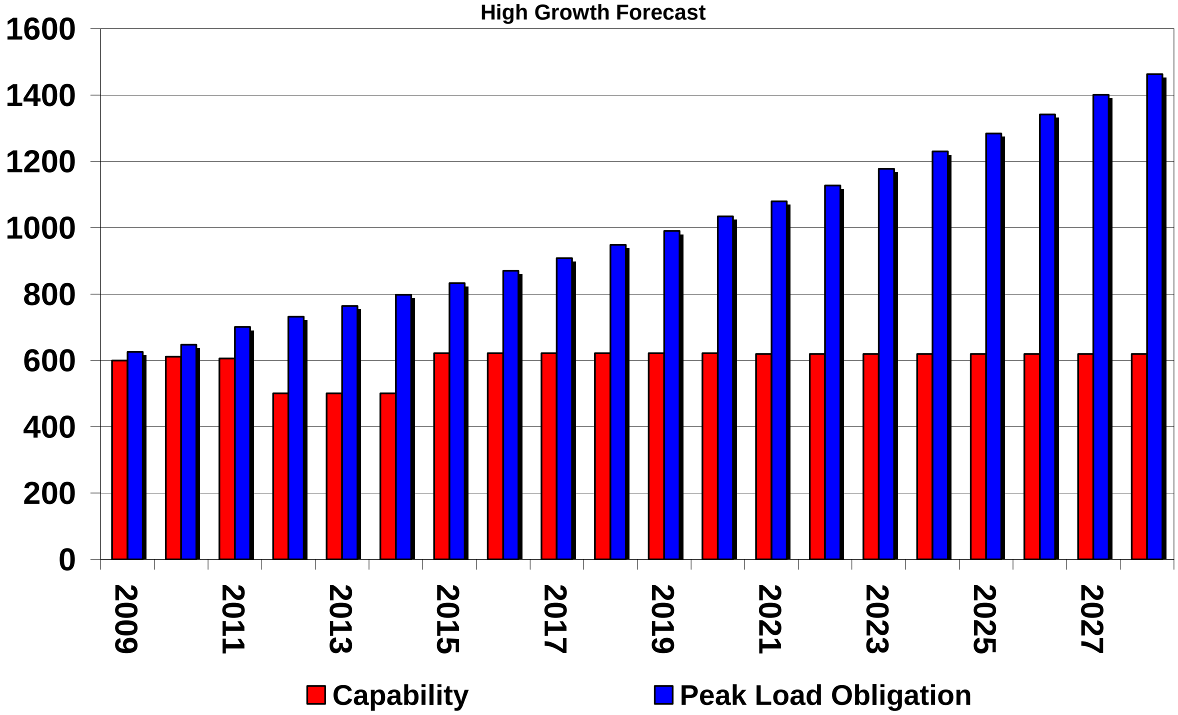


Figure 1-3

Capability and Peak Load Obligation

High Growth Forecast



1. Analysis Method

A computer model called Electric Generation Expansion Analysis System (EGEAS) version 9.02, developed by the Electric Power Research Institute (EPRI), is used to perform the resource expansion analysis and develop the least-cost integrated resource expansion plan. The analysis included various scenarios based on the load forecasts, availability of resources, and economic variables. Each of the scenarios constituted a resource expansion plan unique to the assumptions used in that scenario. The resource expansion analysis minimized the present worth of revenue requirements (PWRR), or net present value (NPV), over fifty years by using an algorithm called "dynamic programming." The dynamic program in EGEAS calculated each scenario one year at a time to satisfy the reliability constraints and to fulfill the forecasted energy and capacity requirements. For each year, this process identified all possible states that satisfied the reliability requirements. Finally, each year was combined to determine the least-cost plan.

The base year used in the resource expansion analysis was 2008 with the study period starting in 2009. This means that the costs indicated in this report are in 2008 dollars, unless specified. The study was run over a 20-year period (2009-2028) in which new resources are allowed to be added to meet the forecasted load growth and compensate for unit retirements. To model unused capital investment of the resources installed during the study period, an additional 30 years, called the extension period, was added. During this extension period, loads stayed the same as the final year of the study period, and any resource retirements during this extension period were replaced with an identical resource. However, all associated costs continue to be escalated through the extension period. The associated costs include fuel and fixed and variable operating and maintenance (O&M) costs.

2. Resources

Montana-Dakota's existing generation portfolio includes coal, natural gas, diesel, and wind, along with two capacity purchase contracts. Additional wind generation, a waste heat unit, and Big Stone Unit II are also part of Montana-Dakota's current generation portfolio for expansion planning purposes. The resource expansion analysis considered potential from available alternative resources to build out the generation portfolio to meet forecasted energy and capacity requirements. All resources were modeled with their capacity, fixed and variable O&M costs, and fuel costs that are shown in Tables 2-1 through 2-5 below.

The summer accredited capacity shown in Tables 2-1 through 2-5, also known as MAPP Uniform Rating Generating Equipment (URGE) capacity, is the resources' accredited capacity for July, which is Montana-Dakota's forecasted peak month. This URGE capacity represents the previously mentioned capability of Montana-Dakota to meet its peak load obligation. MAPP requires its members to run URGE tests on their thermal generation resources (steam units and combustion turbines) at least once a year and accredits the members' monthly generating capability based on the results of the tests.

The MAPP accreditation process considers the variable generation resources such as wind, solar, and run-of-river hydro differently. The accreditation for those variable generation resources is based on a four-hour window around the peak hour for every day of the month. The median value of all these values for the month is the monthly capacity to be accredited. Therefore, the existing Diamond Willow wind farm has a nameplate capacity of 19.5 MW, but its summer accredited capacity is estimated at 4.37 MW. Because of the potential variability of its fuel supply, the committed Glen Ullin Station 6 waste heat unit would also fall into the variable generation category. While its expected nameplate capacity is 7.5 MW, the corresponding accredited capacity is projected at 4.5 MW.

2.1. Existing Resources

The existing generation portfolio is broken down to three groups: coal, natural gas, and miscellaneous. The miscellaneous group consists of the capacity purchase contracts, wind, and diesel. Figure 2-1 shows Montana-Dakota's existing generation mix by summer accredited capacity.

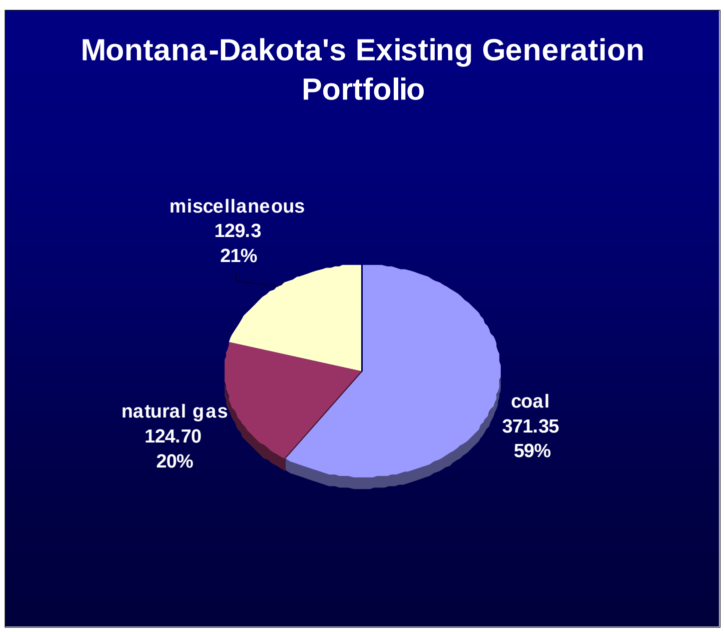


Figure 2-1: Montana-Dakota's Existing Generation Mix by Capacity (in MWs)

2.1.1. Coal

Montana-Dakota currently owns five coal-fired units two of which are jointly owned with other regional utilities. Coal currently counts for 59% of the summer accredited capacity on Montana-Dakota's system. Table 2-1 shows the summer accredited capacity (MW) and costs for each coal-fired plant serving Montana-Dakota's customers.

Table 2-1

Montana-Dakota's Existing Coal-Fired Units

Unit	Summer Accredited Capacity (MW)[1]	Fixed O&M ($/kW-year)	Variable O&M ($/MWh)	Fuel ($/MBTU)
Coyote[2]	106.75	20.20	2.25	1.14
Big Stone Unit I[3]	107.50	19.89	1.50	1.57
Heskett 1	27.96	50.57	5.98	1.59
Heskett 2	74.17	44.71	7.07	1.59
Lewis & Clark	52.30	43.55	2.47	1.13

1. Based on July URGE rating (1/1/08-10/31/09)
2. Montana-Dakota's 22.7% ownership share
3. Montana-Dakota's 25% ownership share

2.1.2. Natural Gas

The natural gas-fired combustion turbines, operated as peaking units, make up about 20 percent of Montana-Dakota's existing summer accredited capacity. Summer accredited capacity and costs for Montana-Dakota's existing combustion turbines are shown in Table 2-2.

Table 2-2

Montana-Dakota's Existing Natural Gas Combustion Turbines

Unit	Summer Accredited Capacity (MW)[1]	Fixed O&M ($/kW/year)	Variable O&M ($/MWh)	Fuel ($/MBTU)
Glendive 1	36.0	9.48	2.35	6.90
Glendive 2	41.6	5.58	2.35	6.90
Miles City	24.5	9.06	2.35	6.90
Williston	9.6	3.08	2.35	6.90

1 - Based on July URGE rating (11/1/08-10/31/09)

2.1.3. Miscellaneous

In addition to coal and natural gas, Montana-Dakota has other generation resources: capacity from purchased power, diesel, and renewable energy. These three different types of resources, shown in Table 2-3, make up about 21 percent of Montana-Dakota's generation mix.

Table 2-3
Montana-Dakota's Existing Contracts, Wind Farm, and Diesel Unit

Unit	Summer Accredited Capacity (MW)[1]	Fixed O&M ($/kW/year)	Variable O&M ($/MWh)	Fuel ($/MBTU)
Diamond Willow[1]	4.37	10.16	-27.23	-
Glendive Diesel	2.01	4.00	2.35	16.57
NSP contract[2]	95.00	17.70	84.30	-
NSP contract[3]	10.00	17.70	184.30	-
WAPA contract[4]	2.80	-	16.84	-

1. Summer Accredited Capacity is based on 22.43% capacity factor and the negative variable O&M represents the Production Tax Credit
2. Increase to 100 MW in 2010 with option years in 2010 with option years in 2011-12
3. Expires in 2010
4. Expires in 2020

2.2. Committed Resources

With the need for more capacity, Montana-Dakota has committed to add three renewable resource projects and extend an existing contract. The first renewable resource is a waste heat unit, called Glen Ullin Station 6, which is expected to be operated commercially in mid-July 2009. This unit will take the waste heat produced from a compressor station, located along the Northern Border natural gas pipeline near Glen Ullin, North Dakota, to produce energy. The unit will be rated at 7.5 MW, but anticipated to be accredited in MAPP at 4.5 MW for summer capacity. The next two renewable resources are wind projects. The first wind project is an addition to the existing Diamond Willow wind farm. Another seven wind turbines with a nameplate rating of 1.5 MW each will be added to this wind farm for a total nameplate capacity of 30 MW. The other wind project is a new wind farm, called Cedar Hills, located near the city of Rhame in Bowman County, North Dakota. With thirteen wind turbines at 1.5 MW each, Cedar Hills will have a nameplate capacity of 19.5 MW. Both committed wind projects are expected to be on-line by the end of the third quarter of 2010.

The next committed resource is Big-Stone Unit II, which will be a jointly owned coal-fired unit. This unit will be located near Big Stone City, South Dakota. The unit is planned for commercial operation in 2015, and Montana-Dakota's expected capacity share of the plant will be not more than 22.58 percent or 131 MW. The current co-owners are:

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

The final joint decision to construct Big Stone Unit II has not yet been made, but Montana-Dakota intentions are to participate, and as a majority of the permits have been approved, Big Stone Unit II was considered a committed unit in the EGEAS model.

The last committed resource is the option to extend the power purchase agreements with Northern States Power (NSP). Although Montana-Dakota has not formally announced its intention to exercise the contract option for 105 MW of capacity during the 2011 summer season, the option was modeled in the EGEAS analysis.

All the above committed resources can be seen in Table 2-4.

Table 2-4

Montana-Dakota's Committed Resources

Unit	In-Service Date	Summer Accredited Capacity (MW)	Capital Cost ($/kW)	Fixed O&M ($/kW/year)	Variable O&M ($/MWh)	Fuel ($/MBTU
Big Stone Unit II	2015	131.00	2938.59	29.84	1.80	1.66
NSP Contract Extension	2011	105.00	-	21.00	77.50	-
Diamond Willow Addition[1]	2010	2.24	2400.00	10.16	-27.23	-
Cedar Hills Wind[1]	2010	4.37	2400.00	10.16	-28.77	-
Glen Ullin	2009	4.50	2558.00	31.33	6.50	

1 - Summer Accredited Capacity is based on 22.43% capacity factor, and Variable O&M includes the Production Tax Credit, which is modeled as a negative variable O&M cost.

2.3 Resource Alternatives

Montana-Dakota analyzed the following supply-side alternatives as described in more detail below:

- Combustion Turbine
- Combined Cycle
- Coal
- Wind
- Purchased Capacity

2.2.1. Combustion Turbine

The simple cycle combustion turbine (CT) is primarily built for peaking situations and usually supplies a limited amount of energy because CT is fueled by natural gas or oil, which results in higher fuel costs. The CT units are, however, low in capital costs compared to other unit types and can be installed with a relatively short lead time (two to three years). Two options for the combustion turbines were analyzed for the resource expansion analysis: one at 43 MW and the other at 75 MW. Their associated costs are shown in Table 2-5.

2.2.2. Combined Cycle

The combined cycle (CC) generating unit is similar to the simple cycle combustion turbine, except the exhaust gas from the CT passes through a heat recovery steam generator (HRSG) that produces steam for conventional steam turbine/electric generator. Because combined cycle units use natural gas or fuel oil as fuel, the units are high-cost energy producers and their capital costs are between those of a combustion turbine and a base load unit. The advantage of a combined cycle unit is that it is more efficient to operate than a combustion turbine, but its hours of operation could be limited because of its high energy costs compared to other available resources. The costs associated with CC are shown in Table 2-5.

2.2.3. Coal

In addition to Big Stone Unit II, which was modeled as a committed resource, the resource expansion analysis was allowed to consider other base load coal-fired generation. This type of generation has a high capital cost, but for the same heat content coal is cheaper than natural gas, which allows for lower fuel costs. The coal generation alternative was modeled in blocks of 30 MW instead of a whole, larger unit. The costs associated with a future coal-fired unit are shown in Table 2-5.

2.2.4. Wind

In the resource expansion analysis, the Production Tax Credit (PTC) for renewable resources was modeled as a negative variable O&M cost of $20/MWh (after tax). The PTC was assumed to be in effect through the year 2014, and once the wind generation was selected (as part of the least-cost plan), the tax credit would continue for ten years from its year of installation. Table 3-5 shows two different wind options: The option with wind before 2015 includes the PTC, while the other wind resource does not include the tax credit. The costs associated with both wind options are shown in Table 2-5.

2.2.5. Purchased Capacity

The last resource alternative is purchased capacity. . Also, the purchased capacity was modeled for the entire year, as opposed to the summer seasons only. The proposals received as the results of Montana-Dakota's request for proposal issued on December 22, 2008 (2008 RFP) indicated seasonal (only) capacity would not be available for purchase. The purchased capacity alternative was assumed to be available only in the years of 2011-2014 based on the results of the 2008 RFP. In addition, during the 2011-2014 time period, Montana-Dakota will also need additional capacity for the winter months. The purchased capacity option was modeled in blocks of 10 MW to allow EGEAS to determine the needed capacity amounts. The costs associated with the purchased capacity, shown in Table 2-5, were taken from the results of the 2008 RFP.

Table 2-5

Resources Alternatives Available to Montana-Dakota

Unit	Size (MW)	Available Date	Capital Cost ($/kW)	Fixed O&M ($/kW-year)	Variable O&M ($/MWh)	Fuel Cost ($/MBTU)
Combustion Turbine	43	2010	850	$11.63	$2.00	$6.90
Combustion Turbine	75	2010	750	$8.67	$2.00	$6.90
Combined Cycle	140	2010	1150	$12.50	$6.00	$6.90
Coal	blocks of 30	2013	3900	$48.00	$2.50	$1.50
Wind	blocks of 30	2009	2400	$23.33	$2.00	-
Wind before 2014[1]	blocks of 30	2013	2400	$23.33	-$27.23	-
Purchased Capacity	blocks of 10	2012	-	$34.80	$111.50	-

1 - The PTC modeled as negative variable O&M cost.

2.4. Retirements

At this time, Montana-Dakota has only considered the possibility of retiring the Williston combustion turbines (9.6 MW). This was modeled to occur when the next non-purchase resource after 2010 will be added to Montana-Dakota's system.

2.5. Integration of Demand- and Supply-Side Resources

As indicated in Chapter 2 of the 2009 Integrated Resource Plan, the DSM programs identified in the 2007 IRP are reflected as reductions in energy and peak demand in Montana-Dakota's load forecast. Therefore, these programs have already been integrated with the supply-side options in all resource expansion analysis runs. These DSM programs are:

- Conservation Programs
    - EnergyStar® Refrigerator rebates
    - EnergyStar® Freezer rebates
    - Refrigerator Round-up program
    - LED Exit Sign rebates
    - Commercial High-Efficiency Air Conditioner rebates
    - High-Efficiency Motor rebates
    - Demand Response Programs
    - Interruptible Large Power Rates 38 & 39

- Residential Air Conditioner Cycling
- Commercial Air Conditioner Cycling

As the result of the demand-side analysis described in Attachment B, two new DSM programs, Residential Lighting and Residential New Construction Bundle, were found feasible. The demand-side analysis also showed higher expected customer participations, compared to those predicted in the 2007 IRP, for the Residential Air Conditioner Cycling and Commercial Lighting programs. The impact of the two new DSM programs and the incremental customer participation in the other two are bundled in a "New DSM Package," which was allowed to compete with the supply-side options in a separate resource expansion analysis run. The amounts of energy and demand reduction and costs associated with the "New DSM Package" are shown in Table 2-6.

Table 2-6
"New DSM Package"

Program	Incremental kW Reduction	Incremental kWh Reduction	Installed $ / kW	Installed $ / kWh
Residential AC Cycling (Increase)	2,766	5,177,952	$562.31	$0.300
Commercial Lighting (increase)	4,460	89,200,000	$202.03	$0.010
Residential Lighting Progam (New)	505	4,424,405	$129.71	$0.015
Residential New Construction Bundle (New)	391	4,561,921	$399.59	$0.034
Totals	**8,122**	**103,364,278**	**$323.41**	**$0.090**

3. Summaries of Results

Thirteen planning scenarios, which include the base case, the base case with "New DSM Package," and eleven sensitivity runs, were considered. The least-cost resource plan and associated NPV for these scenarios are shown in Table 3-1. A summary of the analysis results are provided below.

Table 3-1: Optimal resource Expansion Plans for the Studied Scenarios

	Base Case	New DSM Package	$30/ton Carbon Tax	$50/ton Carbon Tax	High Gas $12/MBtu in 2012	High Gas $20/MBtu in 2012	RPS	Low Growth	High Growth	High Peaking Capital Costs	No Big Stone Unit II	No Big Stone Unit II w/ $30/ton Carbon	No Big Stone Unit II w/ $50/ton Carbon Tax
2009	Glen Ullin	Glen Ullin	Glen Ullin	Glen Ullin	Glen Ullin	Glen Ullin	Glen Ullin	Glen Ullin	Glen Ullin & 30 MW Peaking	Glen Ullin	Glen Ullin	Glen Ullin	Glen Ullin
2010	30 MW wind	30 MW wind	30 MW wind	30 MW wind	30 MW wind	30 MW wind	30 MW wind	30 MW wind	30 MW wind & 40 MW Peaking	30 MW wind	30 MW wind	30 MW wind	30 MW wind
2011	NSP Extension & 10 MW Peaking	NSP Extension & 10 MW Peaking	NSP Extension & 10 MW Peaking	NSP Extension & 10 MW Peaking	NSP Extension & 10 MW Peaking	NSP Extension & 10 MW Peaking	NSP Extension & 10 MW Peaking	NSP Extension	NSP Extension & 100 MW Peaking	NSP Extension & 10 MW Peaking	NSP Extension & 10 MW Peaking	NSP Extension & 10 MW Peaking	NSP Extension & 10 MW Peaking
2012	120 MW Peaking	120 MW Peaking	120 MW Peaking	120 MW Peaking	120 MW Peaking	120 MW Peaking	120 MW Peaking	90 MW Peaking	130 MW Peaking, CT43 & CT75	120 MW Peaking	120 MW Peaking	120 MW Peaking	120 MW Peaking
2013	130 MW Peaking	120 MW Peaking	130 MW Peaking	130 MW Peaking	130 MW Peaking	130 MW Peaking	130 MW Peaking	100 MW Peaking	10 MW Peaking & 2-CT75	130 MW Peaking	130 MW Peaking	130 MW Peaking	130 MW Peaking
2014	140 MW Peaking	130 MW Peaking	140 MW Peaking	140 MW Peaking	140 MW Peaking	140 MW Peaking	140 MW peaking & 30 MW wind	100 MW Peaking	40 MW Peaking	140 MW Peaking	140 MW Peaking	140 MW Peaking	140 MW Peaking
2015	Big Stone II & CT75	Big Stone II & CT75	Big Stone II & CT75	Big Stone II & CT75	Big Stone II & CT75	Big Stone II & CT75	Big Stone II & 75 MW CT	Big Stone II	Big Stone II	Big Stone II & CT75	2-CT43 & CT75	2-CT43 & CT75	2-CT43 & CT75
2016											CT43	CT43	CT43
2017									CT43				
2018									CT43				
2019									CT43				
2020							40 MW Wind		CT43		CT43	CT43	CT43
2021	CT43	CT75	CT43	CT43	CT43	CT43		43 MW CT	CT43	CT43			
2022							CT75		CT43				
2023									CT43				
2024									CT43				
2025	CT43		CT43	CT43	CT43	CT43	40 MW Wind		CT75	CT43	CT43	CT43	CT43
2026									CT43				
2027									CT75				
2028									CT43				
NPV	$2,125.70	$2,072.39	$3,178.05	$3,821.58	$2,146.27	$2,181.74	$2,541.35	$1,811.43	$4,714.71	$2,164.43	$2,156.60	$3,281.42	$3,930.59

* CT43 - 43 MW Combustion Turbine

* CT75 - 75 MW Combustion Turbine

3.1. Base Case Results

The base case least-cost plan selects a purchased capacity option until 2015 when Big Stone Unit II comes on-line. Purchase capacity requirements between 2011 and 2014 include: 10 MW in 2011, 120 MW in 2012, 130 MW in 2013, and 140 MW in 2014. In addition to Big Stone Unit II, a 75 MW combustion turbine is needed in 2015 along with two 43 MW combustion turbines in 2021 and 2025.

When the "New DSM Package" was added as a resource option in the base case, it was selected to be implemented in 2010, taking until 2012 to reach its full customer participation. This DSM package lowered the NPV by about 2.5% from the base case. Compared to the base case, the expansion resource plan had the same amounts of purchase power requirements in 2011 (10 MW) and 2012 (120 MW), but 10 MW less in 2013 (120 MW) and 2014 (130 MW). The 75 MW combustion turbine was still needed in 2015 and, instead of the two 43 MW combustion turbines in 2021 and 2025, one 75 MW combustion turbine was selected in 2021.

3.2. Sensitivity Analysis

The eleven sensitivity scenarios consist of various assumptions regarding carbon taxes, higher natural gas prices, low and high load growth, mandatory renewable portfolio standards (RPS), higher capital costs for combustion turbines, and the potential Big Stone Unit II would not be available as a resource to Montana-Dakota.

3.2.1. Carbon Tax

With the potential of a future carbon penalty applied to fossil fuel units, an assumed carbon tax was applied to every ton of CO_2 emitted from system energy purchases, existing coal-fired units and natural gas-fired combustion turbines and well as new units added to the resource plan starting in 2015. While no carbon tax was modeled in the base case, Montana-Dakota considered a wide range of prices for carbon tax used in the industry and decided to use the carbon tax values of $30 and $50 per ton of CO_2 for sensitivity analysis on the resource expansion plan. For both $30 and $50 per ton scenarios, the resource plan remained the same as the base case. At $30 per ton the NPV increased by 49.5% above the base case, and at $50 per ton the NPV increased by 79.8% over the base case. Montana-Dakota recognizes the amount and applicability of any carbon penalty has not yet been established, but conducted these analysis to begin to understand possible impacts to our customers of the various options being discussed across the nation.

3.2.2. High Gas Price

Natural gas purchased from a third-party marketer and delivered under a transportation service arrangement was assumed for the existing turbines, generic combustion turbines, and generic combined cycle plants. The gas was priced for delivery at $7.30/MBTU starting in 2009, and escalated up by an average of three percent annually for the base case. However, with the volatility of natural gas prices, there is a need to consider what impact higher gas prices would have on the least-cost plan. Therefore, two high gas price scenarios were also developed, whereby the gas price used in the base case was increased by $4/MBTU and by $12/MBTU in the year 2012. In both scenarios, the gas prices were escalated by three percent annually after 2012. Changes in natural gas prices above the base case value of $8/MBTU in 2012 did not change the resource plan from the base case. The scenario with $12/MBTU in 2012 ($4/MBTU higher than the base case) resulted in less than a one percent increase in NPV over the base case. The scenario with $20/MBTU in 2012 ($12/MBTU higher than base case) resulted in an increase of 2.6% in NPV over the base case.

The gas price modeled in the base case was developed in the fall of 2008 based on Montana-Dakota's view of the long-term outlook of natural gas pricing. At the time this IRP report is prepared (June 2009), however, the short-term outlook remains bearish. The discovery of natural gas in the shale rock formations in the southern and eastern portions of the United States have been prolific over the past couple of years, and drilling was very active during 2008 as high natural gas prices drove natural gas and oil drilling rig counts to high levels. This along with the downturn in the U.S. and world economies has left the world in a current oversupply situation. This supply/demand imbalance is expected to remain until late 2009 or may run well into 2010 depending on when the economy recovers and how rapid the depletion rate of the producing wells tapers off. The supply/demand imbalance should continue to put downward pressure on the price of natural gas from a fundamental view of the market. Speculators will have a play in the pricing of natural gas and could put upward pressure on gas prices.

The long term outlook for natural gas pricing continues to be perceived that natural gas will be a fuel of choice and will result in higher natural gas prices than we are currently experiencing. The outcome of carbon legislation could have a big impact on demand and pricing for natural gas in the future as the carbon foot print is considered less for natural gas than other fossil fuels for electric generation. Montana-Dakota believes the gas pricing modeled in the base case are valid over the 50 years considered by the resource expansion analysis.

3.2.3. Mandatory Renewable Portfolio Standard (RPS)

With the potential for additional state and/or a federal RPS standard in the future, this scenario looked at the effects an additional RPS requirement would have on the resource plan. System-wide RPS levels of ten percent by 2015, fifteen percent by 2020, and twenty percent by 2025 were studied as a part of this sensitivity. The resource plan changed with additional wind resources, and a 75 MW combustion turbine added in 2022. 30 MW of additional wind was required in 2014, 40 MW of additional wind in 2020, and an additional 40 MW of wind in 2025. This addition of 110 MW of wind would amount to 160 MW of wind generation in Montana-Dakota's resource portfolio by 2025, which is about 25 percent of Montana-Dakota's forecasted peak demand in that year. This scenario increased the NPV by 19.6% over the base case. The RPS scenario is not only costly, but also exposes Montana-Dakota to the operational issues of having such a large amount of variable generation on its system.

3.2.4. Low Growth

This scenario looked at the growth potential being less than the base case at an average annual increase of 0.72% for peak demand and an annual increase of 0.5% for energy, except for 2011 with the addition of the Keystone XL Pipeline load. These assumptions came from Montana-Dakota's historical growth rate that occurred during 1985-1993, as described in the Load Forecast in Attachment A. With this scenario, there is less future capacity and energy needed. Less purchased capacity is required between 2011-2014, with zero in 2011, 90 MW in 2012, and 100 MW in both 2013 and 2014. After Big Stone Unit II comes online in 2015, one 43 MW combustion turbine is needed in 2021.

3.2.5. High Growth

A high-growth scenario caused an average annual increase in peak demand by 4.48% and an annual increase in energy demand by 4.4%, except for 2011 with the addition of the Keystone XL Pipeline load. The values used came from Montana-Dakota's historical growth rate that occurred during 1977-1985, as described in the Load Forecast in Attachment A. This scenario showed the need, over the base case, for a total of 16 combustion turbines (five 75 MW CTs and eleven 43 MW CTs) over the study period, along with capacity purchase in 2009 and 2010.

3.2.6. High Combustion Turbine Costs

This scenario included a 20% increase in capital and O&M costs for future combustion turbines. The resource plan stays the same with a 1.8% increase in the NPV over the base case.

3.2.7. "Big Stone Unit II Not Available"

In the event Big Stone Unit II is not a resource available to Montana-Dakota, the resource plan for purchase capacity remains the same for the period 2011 to 2014, but in 2015 three combustion turbines (two 43 MW CTs and one 75 MW CT) are needed. Three additional 43 MW combustion turbines are needed in 2016, 2020, and 2025. Under this scenario, the NPV increased by 1.5% over the base case.

3.2.8. "Big Stone Unit II Not Available" and Carbon Tax

The last scenarios examined the effect of a carbon tax if Big Stone Unit II is not available as a resource, and $30 and $50 per ton carbon tax levels are applied to all system purchases and coal- and natural gas-fired generation. The resource plan remains the same as the "Big Stone Unit II Not Available" scenario. At a $30 per ton carbon tax, the NPV is increased by 54.4% over the base case, and at a $50 per ton carbon tax, the NPV is increased by 84.9% over the base case.

3.3. Effects of Carbon Tax

As seen above, from the resource addition viewpoint, without Big Stone Unit II in 2015, Montana-Dakota would have to add combustion turbines in 2015, 2016, 2020, and 2025. In regards to all studied carbon tax levels ($0 in the base case and $30 and $50 per ton in the sensitivity cases), such a resource expansion plan (with all peaking capacity additions) would result in higher total cost.

Table 3-2 shows a comparison of Montana-Dakota's carbon intensity and total CO_2 emissions, between the base case and the "Big Stone Unit II Not Available" scenarios. This table shows that when Big Stone Unit II comes on-line in 2015 Montana-Dakota's carbon footprint would be reduced from 2014 and also would be lower than in the case without Big Stone Unit II in 2015. The results come from the fact that, from the CO_2 emission viewpoint, Big Stone Unit II is a very efficient unit. Its generated energy would displace the energy from the older, less efficient existing coal-fired units, causing them to run less and therefore lowering Montana-Dakota's total carbon footprint.

Table 3-2

Carbon Footprint
CO_2 Intensity & Total CO_2 Emissions Tons

	Carbon Intensity (lb/MWh)				Total CO_2 Emissions (1,000 Tons)			
	2014	2015	2020	2025	2014	2015	2020	2025
Base Case	2,383	2,184	2,207	2,227	3,464	3,249	3,518	3,794
No Big Stone Unit II	2,383	2,371	2,357	2,336	3,464	3,506	3,743	3,971

4. Conclusions

Based on the results of the supply-side and integration analysis, the resource plan resulting from the base case with the "New DSM Package" added as a resource option is the best choice for Montana-Dakota's customers. In this plan, Montana-Dakota would purchase capacity between 2011 and 2014 and build two 75 MW combustion turbines in 2015 and 2021, in addition to the continuation and implementation of the ten DSM programs described in the Demand-Side Analysis (Attachment C) between 2010 and 2012. These DSM programs would amount to 22.7 MW of peak demand reduction. Along with these resources are the committed resources: Glen Ullin Station 6 in 2009, the expansion of Diamond Willow in 2010, Cedar Hills in 2010, the extension of the NSP contract to 2011, and Big Stone Unit II in 2015. Table 4-1 shows the capacity mix (in megawatts and percent) by fuel and unit type for 2010, 2015, and 2020 for the least-cost resource expansion plan.

Table 4-1

Montana-Dakota's Capacity Mix (in MW and Percent)*
for the Least-Cost Resource Expansion Plan

Fuel/Unit Type	2010	2015	2020
Natural Gas/Peaking	113.7 (17%)	179.1 (24%)	179.1 (24%)
Purchased Power	112.8 (17%)	2.8 (0%)	2.8 (0%)
Renewable	57.5 (9%)	57.5 (8%)	57.5 (8%)
Demand-Side/Interruptible	7.6 (1%)	22.7 (3%)	22.7 (3%)
Fossil/Base Load	368.7 (56%)	499.7 (66%)	499.7 (66%)

* Resource capacity values in MW are based on summer accredited capacity, except for variable generation resources whose nameplate capacity is used.

The most impacted sensitivity scenarios are those with carbon tax and high load growth. With a $30 per ton carbon tax, the resource plan remains the same as the base case, but the NPV increased by 49.5%. With "Big Stone Unit II Not Available and $30/ton Carbon," the NPV increased by 54.4%. The same can be seen with $50 per ton carbon tax – the NPV increases, but the resource plan remains the same. Based on Montana-Dakota's current generation portfolio and looking at possible future carbon taxes and combustion turbine alternatives, the base case expansion plan (with the "New DSM Package" added as a resource option) is the least-cost option for Montana-Dakota's customers and would lower Montana-Dakota's CO_2 emissions.

5. References

MAPP Generation Reserve Sharing Pool Handbook. (December 2, 2009)

EGEAS User's Guide Version 9.02. New York, New York: Stone & Webster Management Consultants, Inc., June 1999.

MAPP Restated Agreement. (December 9, 2008)

Attachment D

PUBLIC ADVISORY GROUP DOCUMENTATION

ATTACHMENT D

PUBLIC ADVISORY GROUP DOCUMENTATION

This Attachment is comprised of the official Public Advisory Group roster as well as the description of the meetings and the topics discussed at each meeting. No minutes of the meetings are taken.

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In addition to the Montana-Dakota personnel included on the roster, the following Montana-Dakota personnel participated in one or more of the Public Advisory Group meetings as presenters:

Karl Tammar	System Operations & Planning Manager*
Lynn Paulsen	Special Projects Manager*
Duane Steen	Director - New Generation Development
Wayne Buelow	Electric System Engineering Supervisor*
Kevin Magstad	Community Energy Development Manager*
John Renner	Executive Vice President—Finance, Integration and Acquisitions
Jeremy Fischer	Electric Systems Engineer
Kevin Kingsley	Electric Market Administration Supervisor
Mark Johnson	Electric System Operations Compliance Coordinator
Abbie Krebsbach	Environmental Manager
Dave Goodin	President & CEO (MDU Utilities Group)
Allan Welte	Director of Generation

* No longer employed with Montana-Dakota Utilities Co.

MEETINGS OF THE IRP PUBLIC ADVISORY GROUP

September 17, 2008 Meeting Agenda

IRP Process	Karl Tammar Hoa Nguyen
Montana-Dakota’s New and future Generation	Duane Steen
MISO Transmission Expansion Plan (MTEP) Process	Wayne Buelow
Montana-Dakota’s New and Future Demand-side Management Programs	Larry Oswald
Montana-Dakota’s Renewable Biomass Energy	Kevin Magstad
Montana Energy Overview	Jeff Blend
North American Electric Reliability Corporation (NERC)	Hoa Nguyen

Working of the IRP Public Advisory Group Discussion
- Meeting Logistics
- Future meetings
- Meeting Schedule through 2008

November 17, 2008 Meeting Agenda

Intermountain Gas Acquisition and “One Utility” Integration Process	John Renner
Electric Load Forecast	Kayla Kaul
Summer Peak Demand vs. Ambient Temperature	Jeremy Fischer
Update on Current Generation Projects	Darcy Neigum
Search for the New Capacity Expansion Model	Lynn Paulsen
The Bridge to Big Stone II	Brian Giggee
Potential North Dakota Energy-Related Legislations	Ryan Rauschenberger

General Discussion
Schedule Date for Next Meeting

January 26, 2009 Meeting Agenda

Midwest ISO Ancillary Services Market	Kevin Kingsley Mark Johnson
MDU Updates	
Generation Projects	Darcy Neigum
Winter 2008 Peak Demand	Kayla Kaul
Montana Community Renewable Energy Projects	Hoa Nguyen
Regional Environmental Updates	Abbie Krebsbach
Regional Activities Addressing Integration of Wind Generation	Lynn Paulsen
Plan for Demand-Side Management Analysis and	Larry Oswald
Resource Planning Update	Brian Giggee
Recommendations General Discussion Next Meeting	Public Advisory Group

April 15, 2009 Meeting Agenda

Midwest ISO Ancillary Services Market	Kevin Kingsley Mark Johnson
“Four Brands, One Utility”	Dave Goodin
Midwest ISO Cost Allocation Activities	Lynn Paulsen
Montana 2009 Legislation Updates	Jeff Blend
North Dakota 2009 Legislation Updates	Ryan Rauschenberger
Wind turbine Experience and Challenges	Alan Welte
Update on Generation Projects	Darcy Neigum
Request for Proposal for Capacity and Energy Supply	Hoa Nguyen
2009 Integrated Resource Plan: Supply-Side Resources	Brian Giggee
2009 Integrated Resources Plan: Demand-Side Resources	Larry Oswald

2009 IRP Filings
Feedback from IRP Public Advisory Group Members
Future PAG Membership