Integrated Resource Plan 2017

Submitted to the
Montana Public Service Commission
September 15, 2017

Volume I: Main Report

Montana-Dakota Utilities Co.

2017 Integrated Resource Plan

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Volume I

Main Report

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

INTEGRATED RESOURCE PLAN

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EXECUTIVE SUMMARY

Montana-Dakota Utilities Co.'s (Montana-Dakota) 2017 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 30-year practice of documenting efforts used to determine 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 and cost-effective energy, and provide a road map for Montana-Dakota's future resources. Considered resources include a combination of traditional generating stations, distributed generation, renewable resources, and demand-side management programs.

Montana-Dakota's IRP process encompasses four main areas: load forecasting, demand-side analysis, supply-side analysis, and integration and risk analysis. A summary of the IRP study results for each of these areas is provided.

The **load forecasting** activities, as discussed in Chapter 2, employ an econometric forecasting method along with other forecasting methods and analyses resulting in a combined analysis approach 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 2017-2036 timeframe, the projected average annual growth rate for summer peak demand is 1.1 percent prior to any reductions due to demand response programs, while annual energy requirements are expected to increase at a rate of 1.3 percent.

The **demand-side analysis** is an evaluation process to identify the feasible demand-side management (DSM) programs for Montana-Dakota's system. As discussed in Chapter 3, Montana-Dakota evaluated a number of energy efficiency and demand response programs, hereinafter referred to collectively as DSM programs, for its customers in Montana, North Dakota, and South Dakota. Montana-Dakota's expected DSM program plans over the 2018-2020 period for each state are discussed at the end of Chapter 3.

The **supply-side analysis** is an evaluation process to determine the feasible generation options available to serve Montana-Dakota's system. The potential resource options studied included simple-cycle combustion turbines, combined cycle combustion turbines, simple-cycle reciprocating internal combustion engines, coal-fired generation, wind generation, solar, biomass, short term capacity purchases, and Thunder Spirit Wind Expansion. Along with the potential resource options, Midcontinent Independent System Operator (MISO) energy purchases are available to meet energy needs.

The **integration and risk** process considers the feasible supply-side and demand-side options to determine a least-cost resource expansion plan to economically and reliably meet customer requirements into the future. A number of scenarios were investigated to determine the sensitivity of the least-cost plan to several factors that may impact the expansion plan. These sensitivity scenarios included; high and low natural gas prices, high and low load growth, high and low energy market prices, high capital costs on natural gas units, diminishing energy markets, and applying a carbon tax to fossil fired units. The analytical tool used for the integration process was the Electric Generation Expansion Analysis System (EGEAS), a resource 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 integration analysis indicate that Montana-Dakota's current Base Case resource plan includes: purchase of the 48 MW Thunder Spirit Expansion Wind Project and the addition of a combined cycle unit in or after 2025. As previously noted, the results of the least-cost model and sensitivity analyses are used to inform the process of selecting the best plan to meet the future needs of Montana-Dakota's customers.

In addition, the integration analysis supports expanding the demand response program developed under a third party contract to reach a total of 25 MW by end of 2017, and promoting the existing interruptible rates to reach a total of 20 MW by 2019.

Figure E-1 provides an overview of the identified need for capacity for the period 2017-2036 assuming the additions of the above DSM and the Thunder Spirit Wind Expansion. In this figure, "PRMR UCAP" represents Montana-Dakota's customer load obligation or planning reserve margin requirements (PRMR) prescribed by MISO based upon Montana-Dakota's current 50/50 demand forecast with an 80.7 percent coincident factor. "Existing ZRC" represents the amount the amount of capacity supply resources or zonal resource credits (ZRC) that Montana-Dakota has secured to meet its capacity requirements or PRMR. For resource adequacy purposes, Montana-Dakota must have an amount of ZRC (capacity supply resources) equal to or greater than PRMR (customer load obligations); otherwise deficiency charges are assessable under the MISO tariff.

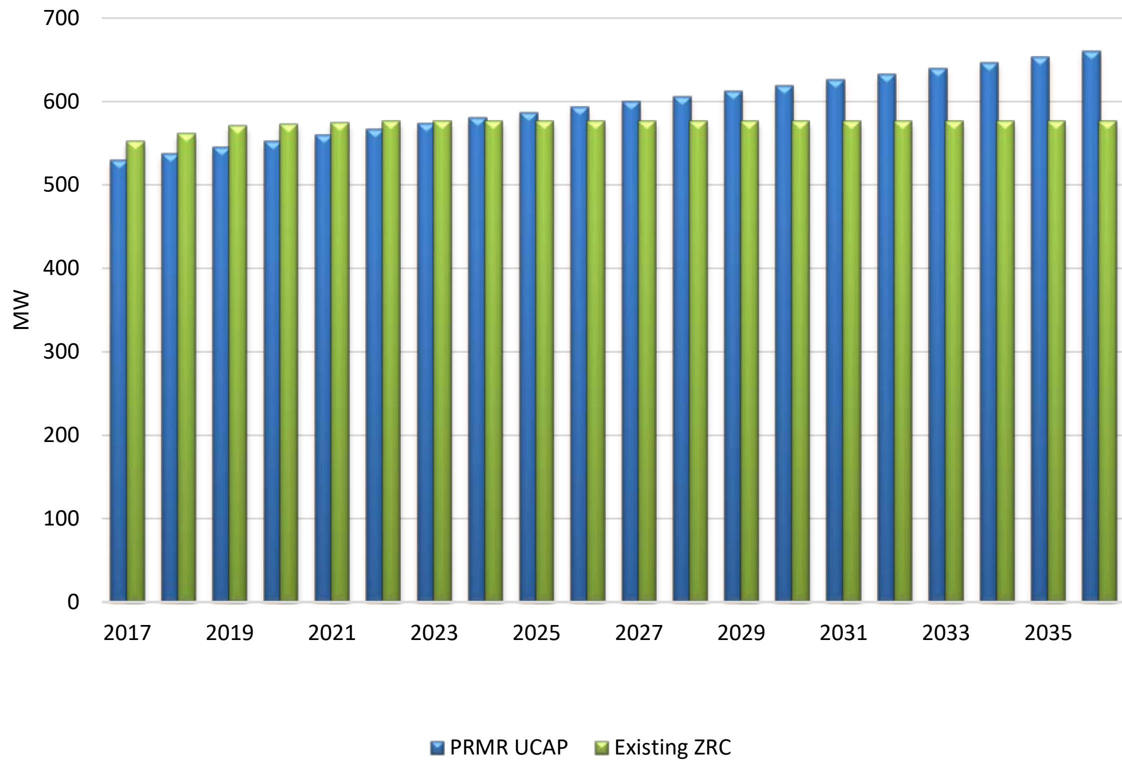

Figure E-1: 2017-2018 MISO Planning Year Zonal Resource Credit and Planning Reserve Margin Requirement

Based on the analysis of the resource expansion models and the consideration of customer impacts, market availability of capacity and energy, and other factors such as environmental regulations and the balance of its generation mix, Montana-Dakota's recommended resource plan is to pursue the following resources to meet the requirements identified for the 2017-2026 period:

- Purchase the Thunder Spirit Wind expansion project comprised of up to 48MW incremental capacity with new turbines to be online by the end of 2018,
- Continue the implementation of the commercial demand response program and the interruptible rate to obtain a total of 45 MW by 2019,
- Continue the design and engineering work on a natural gas-fired combined cycle combustion turbine resource to be online in or after 2025, and
- Meet any short-term capacity deficits via the MISO Capacity Auction or through bi-lateral capacity purchase agreements in the event of changes in forecast or generation.

The recommended resource plan is considered to be the best plan to economically and reliably meet customers' requirements over the ten-year planning horizon. Montana-Dakota issued a request for proposal for capacity and energy resources in 2016 to start the process for this planning cycle.

The 2017 IRP process and product (report and attachments) were enhanced by 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 2017 advisory group was established at the beginning of the 2017 planning cycle and provided Montana-Dakota with input throughout the 2017 IRP process.

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For ease of handling, this IRP report is printed and bound in four separate volumes:

Volume I – Main Report (the current document)

Volume II – Attachment A: Load Forecast Documentation

Volume III – Attachment B: Demand-Side Analysis Documentation

Volume IV – Attachment C: Supply-Side and Integration Analysis Documentation

Attachment D: Public Advisory Group Documentation

Attachment E: Supply Side Resources Study

Attachment F: 2016 Capacity and Energy RFP

Attachment G: Transmission Impacts

Attachment H: MISO RTO Overview

Attachment I: Montana Public Service Commission Comments on Montana-Dakota's 2015 IRP

Attachment J: Montana Department of Environmental Quality Comments on Montana-Dakota's 2015 IRP

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 actively provides comments to federal and state legislative and regulatory activities related to environmental issues, including air emissions, greenhouse gases (GHG), waste disposal and water discharges. The Company has also established memberships in relevant trade organizations to assist in monitoring the potential impact of proposed legislation and regulation to the Company's operations.

The U.S. Environmental Protection Agency (EPA) has finalized significant air emissions regulations for coal-fired electric generating facilities and has proposed significant new regulations that aim to reduce air emissions, including GHGs, at fossil-fired electric generating facilities and pollutants in wastewater discharges. The EPA also published a final rule in the Federal Register on April 17, 2015, for management of coal ash at coal-fired electric generating facilities. The culmination of all various pending environmental requirements, including any new EPA rulemaking to reduce carbon dioxide emissions from existing fossil fuel fired electric generating units, may result in the retirement of existing coal-fired baseload units earlier than otherwise would occur. Montana-Dakota will continue to monitor regulation changes, and will take both proposed and final regulations into consideration when planning for future resource needs.

<u>Renewable Energy</u>

Montana-Dakota has been involved with renewable energy analysis and development for many years, and has several renewable energy installations.

Montana-Dakota has 157.5 MW of installed wind generation capacity at three locations, providing over 20 percent of its customers' electric energy requirements, and plans to install up to 48 MW of additional of wind generation at the Thunder Spirit Wind project near Hettinger, North Dakota, by the end of 2018. The Company also owns a 7.5 MW heat recovery facility on the Northern Border Pipeline Compressor Station in south-central North Dakota, which uses high-temperature exhaust gas as the primary heat source. Given that waste heat is utilized as the "fuel" for this generating facility, no additional fossil fuel is required and therefore incremental emissions to generate electricity are negligible.

Commitment to Reducing Air Emissions

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 (CO_2) emission intensity by three to five percent by 2010. Montana-Dakota has shown its commitment by reducing the Company's CO_2 emissions intensity in 2008 by approximately seven percent as compared to 2003. In 2010, Montana-Dakota updated its CO_2 emissions intensity goal, committing to a 10 percent reduction of the Company's average CO_2 emissions intensity from its electric generating facilities by 2012 compared to 2003 levels. Montana-Dakota continues to see reductions in its CO_2 emission intensity with the additions of renewable and gas-fired generation since 2010. As of January 1, 2017, Montana-Dakota achieved greater than 26 percent reduction from the Company's 2003 electric generating facility CO_2 emissions intensity.

Montana-Dakota has been active in researching options for CO_2 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 (EERC) at the University of North Dakota and is one of seven regional partnerships across the United States. The Company has also been a member of the Partnership for CO_2 Capture (PCOC) project since 2014, which is also led by the EERC. PCOC provides support of pilot-scale demonstrations and researches and evaluates promising CO_2 capture technologies that can enhance the cost and performance of CO_2 capture systems.

Montana-Dakota has also actively participated in the environmental workgroups of the North Dakota Lignite Energy Council such as the Lignite Technology Development Workgroup and the Environmental Workgroup. In the last few years, these workgroups have focused on CO_2-related issues such as lignite gasification, oxyfuel combustion, pre- and post-combustion CO_2 capture technologies, exploration of Allam Cycle utilization of lignite fuel, and beneficial uses of CO_2.

Environmental Regulation Pollution Control Project Impacts

The Regional Haze (RH), Mercury and Air Toxics Standard (MATS) and Coal Combustion Residuals (CCR) rules have had the most immediate impact on operations at Montana-Dakota's electric generating facilities. Significant projects have been implemented to comply with these rules including a filterable particulate matter pollution control project for MATS rule compliance at the Lewis & Clark Station installed in 2015, the air quality control system (AQCS) project at the Big Stone Plant completed in 2015, limestone addition at R.M. Heskett Station Unit 2 fluidized bed for sulfur dioxide emissions reductions began in 2017, and advanced separated over-fire air installation at Coyote Station for nitrogen oxides control completed in 2016 for the RH rule compliance, and bottom ash pond replacement project at Lewis & Clark Station in 2015 related to CCR rule requirements. All of these projects are in operation. Additional air emissions regulations that will impact the utilization of fossil fuel-fired generation resources are GHG regulations. Discussion on the GHG rulemaking status for fossil-fired electric generation units is provided further below.

Mercury and Air Toxics Standard Rule

The MATS Rule, published as a final rule in the Federal Register on February 16, 2012, requires existing coal-fired electric generating units (EGUs) to meet hazardous air pollutant (HAP) emission standards reflecting the application of maximum achievable control technology (MACT). The deadline to demonstrate compliance with the MATS Rule emission limits and operating requirements was April 16, 2015, with a potential additional year extension for installation of pollution control projects approved through the state air permitting authority. With the exception of Lewis & Clark Station (Lewis & Clark), the majority of MATS air pollution control projects implemented at Montana-Dakota's electric generating facilities did not result in significant cost.

Lewis & Clark was required to install additional particulate matter pollution controls for compliance with the MATS non-mercury metals emission standard and received approval from the Montana Department of Environmental Quality on January 30, 2015, for an extension to install pollution controls by April 16, 2016. AECOM designed a scrubber retrofit to Lewis & Clark's particulate matter controls which included installing enhanced mist elimination, a sieve tray and spray header, and forced oxidation within the confines of the existing scrubber vessel and mist eliminator section of the stack. This retrofit was completed and in service by December 23, 2015, and Lewis & Clark demonstrated initial compliance with the MATS non-mercury metals emission standard on March 22, 2016. The total cost of installing MATS pollution controls at Lewis & Clark was $16.7 million.

Effluent Limitations Guidelines (ELG) Rule

On September 30, 2015, the EPA published a final Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (ELG Rule) in the Federal Register. This rule requires reductions in pollutants discharged to surface waters from wastewater associated with steam electric generating units by imposing stringent discharge limits and treatment technology requirements. Montana-Dakota determined there are no significant pollution control projects required to be implemented at the Company's electric generating facilities for compliance with the ELG rule. On April 13, 2017, EPA published a notice in the Federal Register that the agency will review and reconsider the final ELG rule. Montana-Dakota will review upcoming EPA ELG rulemaking when it is available and evaluate whether there would be any potential impacts to the Company's electric generation resources.

Coal Combustion Residual (CCR) Rule

On April 17, 2015, the EPA published a final Coal Combustion Residual (CCR) rule that requires management of coal ash through solid waste regulations. The rule requires ground water and location restriction evaluations to be conducted at ash impoundments and landfills not located at coal mines. The outcome of these evaluations may require closure of impoundments and landfills that do not meet specific criteria, resulting in the need to replace ash management systems.

In 2015, Lewis & Clark implemented an ash system project as a result of the CCR rule. The project consisted of three main parts: (1) retirement of the large ash pond; (2) construction of a new concrete bottom ash settling tank; and (3) modifications necessary to handle fly ash entirely as a dry material. The pond was retired in 2015, with final capping and shaping in 2017, and replaced with a new concrete bottom ash settling tank which was completed during the outage for the MATS project. Lewis & Clark converted to dry fly ash management to minimize the size and cost of the new concrete bottom ash settling tank. Converting to dry fly ash management involved adding equipment and making modifications to handle fly ash entirely as a dry material from the collection hopper through transportation in trucks to the ash disposal site. Lewis & Clark installed this portion of the project in phases, with the dry fly ash management system operational on April 14, 2016. The costs for the three portions of the project were approximately $1.8 million for retiring the ash pond, $5.3 million for construction of the new concrete bottom ash tank, and $8.8 million for the fly ash system, for a total project cost of about $15.9 million.

On December 16, 2016, the Water Infrastructure Improvements for the Nation (WIIN) Act was signed into law, providing the EPA and states the authority to administer and enforce CCR rule requirements through permitting programs. Administration of the CCR rule by the EPA and states may potentially result in availability of alternative compliance options. Additional CCR-related projects that could be required at Montana-Dakota's coal-fired generation stations in the future will be reviewed pending changes to federal and state requirements and timelines associated with the CCR rule. The magnitude of future impacts to Montana-Dakota associated with additional CCR rule implementation is expected to be less than the total cost of the Lewis & Clark Station ash system project in 2015.

316(b) Rule – Aquatic Species Protection

On August 15, 2014, the EPA published a rule under Section 316(b) of the Clean Water Act, establishing requirements for water intake structures at existing steam electric generating facilities. The purpose of the rule is to reduce impingement and entrainment of fish and other aquatic organisms at cooling water intake structures. The majority of the Company's electric generating facilities are either not subject to the rule or have completed studies that indicate compliance costs are not expected to be significant. Lewis & Clark Station will complete the required reports that will be submitted to the Montana DEQ by July 31, 2019, to be used in determining any required controls. The installation schedule for any required controls would be established with the permitting agency after the study is completed. Discussion of required controls and cost impacts from these controls will be included in future IRPs.

Greenhouse Gas (GHG) Rules for Fossil-fired Electric Generating Units

On March 28, 2017, President Trump issued an Executive Order (EO) titled "Promoting Energy Independence and Economic Growth" directing the administrator of the EPA to review the New Source Performance Standards (NSPS) GHG rule, referred to as the 111(b) rule, which established carbon dioxide limits for new, modified, and reconstructed fossil-fired electric generation units and the Clean Power Plan (CPP) rule, referred to as the 111(d) rule, which established carbon dioxide limits for existing fossil-fired electric generation units. These rules became final on October 23, 2015. The administrator of the EPA is directed to review the rules for consistency with the policy set forth in the EO and if appropriate to publish for notice and comment proposed rules suspending, revising or rescinding the rules.

In addition, the EPA also filed a motion with the D.C. Circuit Court on March 28, 2017, requesting the CPP rule case, as well as the current case involving the NSPS GHG rule, be held in abeyance while the agency conducts its review of the rules, and that the abeyance remain in place until 30 days after the conclusion of review and any resulting forthcoming rulemaking. The EPA also published a proposed rule on April 4, 2017, initiating review of the CPP rule and NSPS GHG rule. Compliance requirements and costs for existing and new fossil-fired electric generation resources, if any, will become clearer as the EPA completes its review. Montana-Dakota will evaluate any additional rulemaking and incorporate changes as needed into the evaluation of supply-side resources.

Regional Haze Rule (RH Rule)

The EPA promulgated the Regional Haze Rule (RH) in 1999 to address visibility impairment in Class I areas in the United States, constituting 156 national parks and wilderness areas. This rule was developed in accordance with the Clean Air Act's (CAA) national goal of remedying existing and preventing future visibility impairment of Class I areas due to man-made air pollution. In 2005, the EPA published a revised rule that included guidelines for control technology determinations under the RH rule for Best Available Retrofit Technology (BART) sources and for sources addressed for reasonable progress.

State environmental agencies are required to submit State Implementation Plans (SIPs) to the EPA which present the implementation strategy for reducing emissions from man-made sources that may contribute to regional haze, and to set reasonable progress goals toward meeting the goal of no man-made visibility impairment in Class I areas by 2064. The first round of RH SIPs were finalized in 2012 and considered emission reductions from BART sources, as well as other emissions sources in consideration of reasonable progress toward improving visibility. During this first period, three of Montana-Dakota's owned and co-owned coal-fired electric generation units were required to install pollution controls. The air quality control system (AQCS) project at the Big Stone Plant was completed in 2015, limestone addition at R.M. Heskett Station Unit 2 fluidized bed for sulfur dioxide emissions reductions was completed in 2016, and advanced separated over-fire air installation at Coyote Station for nitrogen oxides control was completed in 2016. Periodic reviews, every five to ten years, will continue to be completed by States and the EPA in order to continue progress toward the 2064 goal. The next round of regional haze emissions reductions is projected to be required by approximately 2023 to 2025.

Most recently, the EPA finalized amendments to the RH rule in the Federal Register on January 10, 2017, implementing additional requirements for States as they complete their periodic reviews while also extending the next periodic review by three years. The next periodic review is to be completed by July 31, 2021 instead of 2018. However, President Trump issued a Regulatory Freeze Pending Review Memo on January 20, 2017 that could result in the EPA modifying the RH rule amendments. As RH rulemaking changes and any additional future emissions reduction requirements are made available, Montana-Dakota will incorporate the requirements into future IRP supply-side resource evaluations.

CHAPTER 2

LOAD FORECASTING

Montana-Dakota uses econometric modeling as the starting point for its forecasts. The econometric models for the 2017-2036 Integrated System forecast were developed using the statistical software package called SAS® with adjustments to account for recent growth and slowdown periods associated with the Bakken oil field activity resulting in a combined analysis approach to the forecast.

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. The energy forecast is developed for each sales sector on a state by state basis – Montana, North Dakota, and South Dakota – and the forecasts by state are combined to arrive at the Integrated System forecast in total. The Integrated System peak demand forecast is developed on a total system basis. Detail regarding the specific econometric factors used in the energy sales forecast and peak demand forecast is given in the detailed description of the load forecast provided as Attachment A.

<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 end-use categories which were then forecasted separately. Four 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 tried initially in the development of the forecasted sales for the three primary customer categories by state – residential, SC&I, and General LC&I – while sales forecasts for the street lighting and miscellaneous sectors were developed primarily using linear regression. The final models used for each of the primary customer categories were a combination of econometrics and judgment. The sales forecasts for the LC&I end-use customers 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 sales forecast is included in the load forecast in Attachment A.

Peak Demand Forecast

The peak demand forecast is developed for the summer peaking season on a total integrated system basis; it is not disaggregated by state or by sector. 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 Demand Response Rate 38 and/or customer outages) that occurred at the time of the summer peak were added to the historical actual summer peak used in the peak demand econometric model. 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 is described 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 for each state and an initial peak demand forecast. Reductions to the energy sales forecasts by sector and by state 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

The load forecast presented in this IRP was prepared in 2016 (*Electric Load Forecast 2017-2036*, published December 31, 2016). The DSM programs that were selected for the 2015 IRPs were incorporated in the forecast so that it reflects reductions resulting from the DSM programs planned at that time.

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 10 years is 8.198 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 planned in the 2015 IRP and then adjusted for losses to calculate the total energy requirements and demand forecast. This is the amount of energy and capacity that must be acquired to meet Montana-Dakota's customers' energy needs.

The final forecast results are presented in 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 Management Programs from 2015 IRP
Calendar Month Basis

	Total Energy Requirements (net of DSM and EE)		Summer Peak - MW				Winter Peak 2/				Demand Response		
Year	MWh	% Change	Total Demand Before any DSM or EE	Energy Efficiency (EE)	Demand Net of EE 1/	% Change	Total Demand Before any DSM or EE	Energy Efficiency (EE)	Demand Net of EE 1/	% Change	Rate 38/39 Interrupt Loads	Commercial Demand Response	Residential Demand Response
2006	2,397,793				485.5				397.2				
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	2,593,368	-0.14%			473.8	-0.59%			459.6	1.01%			
2010	2,718,192	4.81%			502.5	6.06%			457.8	-0.39%			
2011	2,776,082	2.13%			535.8	6.63%			510.8	11.58%			
2012	2,919,752	5.18%			573.6	7.05%			516.2	1.06%			
2013	3,115,064	6.69%			546.9	-4.65%			582.1	12.77%			
2014	3,250,683	4.35%			533.0	-2.54%			557.2	-4.28%			
2015	3,263,271	0.39%			611.5	14.73%			514.9	-7.59%			
2016	3,206,737	-1.73%			596.8	-2.40%			not yet available				
2017	3,344,581	4.30%	598.5	0.6	597.9	0.18%	549.5	0.6	548.9		16.0	15.0	2.0
2018	3,401,299	1.70%	607.1	0.7	606.4	1.42%	559.5	0.6	558.9	1.82%	16.0	15.0	4.0
2019	3,458,081	1.67%	615.6	0.7	614.9	1.40%	569.6	0.7	568.9	1.79%	16.0	15.0	6.0
2020	3,515,837	1.67%	624.3	0.7	623.6	1.41%	579.8	0.7	579.1	1.79%	16.0	15.0	8.0
2021	3,567,809	1.48%	632.3	0.7	631.6	1.28%	589.0	0.7	588.3	1.59%	16.0	15.0	10.0
2022	3,619,625	1.45%	640.4	0.7	639.7	1.28%	598.1	0.7	597.4	1.55%	16.0	15.0	10.0
2023	3,665,050	1.25%	647.9	0.7	647.2	1.17%	606.2	0.7	605.5	1.36%	16.0	15.0	10.0
2024	3,713,246	1.32%	655.6	0.7	654.9	1.19%	614.7	0.7	614.0	1.40%	16.0	15.0	10.0
2025	3,755,533	1.14%	662.7	0.7	662.0	1.08%	622.2	0.7	621.5	1.22%	16.0	15.0	10.0
2026	3,800,005	1.18%	670.1	0.7	669.4	1.12%	630.0	0.7	629.3	1.26%	16.0	15.0	10.0
2027	3,843,862	1.15%	677.4	0.7	676.7	1.09%	637.8	0.8	637.0	1.22%	16.0	15.0	10.0
2028	3,888,305	1.16%	684.7	0.8	683.9	1.06%	645.6	0.8	644.8	1.22%	16.0	15.0	10.0
2029	3,933,368	1.16%	692.1	0.8	691.3	1.08%	653.6	0.8	652.8	1.24%	16.0	15.0	10.0
2030	3,978,987	1.16%	699.6	0.8	698.8	1.08%	661.7	0.8	660.9	1.24%	16.0	15.0	10.0
2031	4,025,257	1.16%	707.1	0.8	706.3	1.07%	669.8	0.8	669.0	1.23%	16.0	15.0	10.0
2032	4,072,137	1.16%	714.7	0.8	713.9	1.08%	678.1	0.8	677.3	1.24%	16.0	15.0	10.0
2033	4,119,650	1.17%	722.4	0.8	721.6	1.08%	686.5	0.8	685.7	1.24%	16.0	15.0	10.0
2034	4,167,820	1.17%	730.1	0.8	729.3	1.07%	695.0	0.8	694.2	1.24%	16.0	15.0	10.0
2035	4,216,657	1.17%	737.9	0.8	737.1	1.07%	703.7	0.8	702.9	1.25%	16.0	15.0	10.0
2036	4,266,394	1.18%	745.8	0.8	745.0	1.07%	712.5	0.8	711.7	1.25%	16.0	15.0	10.0

1/ Historical demand reported is system actual demand.
2/ 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 combined analysis forecasting 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, with an average temperature forecast, by definition actual peak demand would have a 50 percent probability of being lower than the forecast values and a 50 percent probability of exceeding forecast values (50/50 forecast). It can appear that peak demand is under-forecasted when the actual temperature at the time of system peak exceeds average temperatures.

Montana-Dakota conducts a study periodically 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 2016 study results indicated each one degree increase in temperature at the time of summer peak would result in an increase of approximately 6.7 MW in summer peak demand.

Further statistical analysis of temperatures at the time of system peak for the years 1984 through 2015 (prior to 1984 Montana-Dakota was a winter peaking utility) provided the results shown in 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%	96.8	0.0
75.0%	99.8	20.1
80.0%	100.6	25.5
85.0%	101.5	31.5
90.0%	102.6	38.9
95.0%	104.2	49.6
97.0%	105.2	56.3

As Table 2-2 shows, with a weighted average temperature of 96.8°F at the time of peak, there is a 50 percent probability the temperature at peak would be lower than 96.8°F and a 50 percent probability the temperature at peak would be higher than 96.8°F. This forecast is referred to as the 50/50 demand forecast.

Also from Table 2-2, there is a 90 percent probability actual temperature at the time of the system peak will not exceed 102.6°F. However, at this temperature (102.6°F), the system peak demand would be 38.9 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.

Montana-Dakota is a member of MISO and for resource adequacy requirements is only required to maintain sufficient capacity resources to meet its 50/50 forecast demand with adjustments per MISO's rules for resource adequacy.

Table 2-3

Alternate Summer Peak Demand Forecast Comparison

Year	Base Forecast (96.8 degrees F) 50/50 Forecast (MW)	Growth Rate	Alternate Forecast (102.6 degrees F) 90/10 Forecast (MW) */
2017	597.9		636.8
2018	606.4	1.42%	645.9
2019	614.9	1.40%	655.0
2020	623.6	1.41%	664.3
2021	631.6	1.28%	672.8
2022	639.7	1.28%	681.4
2023	647.2	1.17%	689.4
2024	654.9	1.19%	697.6
2025	662.0	1.08%	705.2
2026	669.4	1.12%	713.1
2027	676.7	1.09%	720.9
2028	683.9	1.06%	728.6
2029	691.3	1.08%	736.5
2030	698.8	1.08%	744.5
2031	706.3	1.07%	752.5
2032	713.9	1.08%	760.6
2033	721.6	1.08%	768.8
2034	729.3	1.07%	777.0
2035	737.1	1.07%	785.3
2036	745.0	1.07%	793.7

*/ 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 taken 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 of these periods consist of eight years of history.

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.

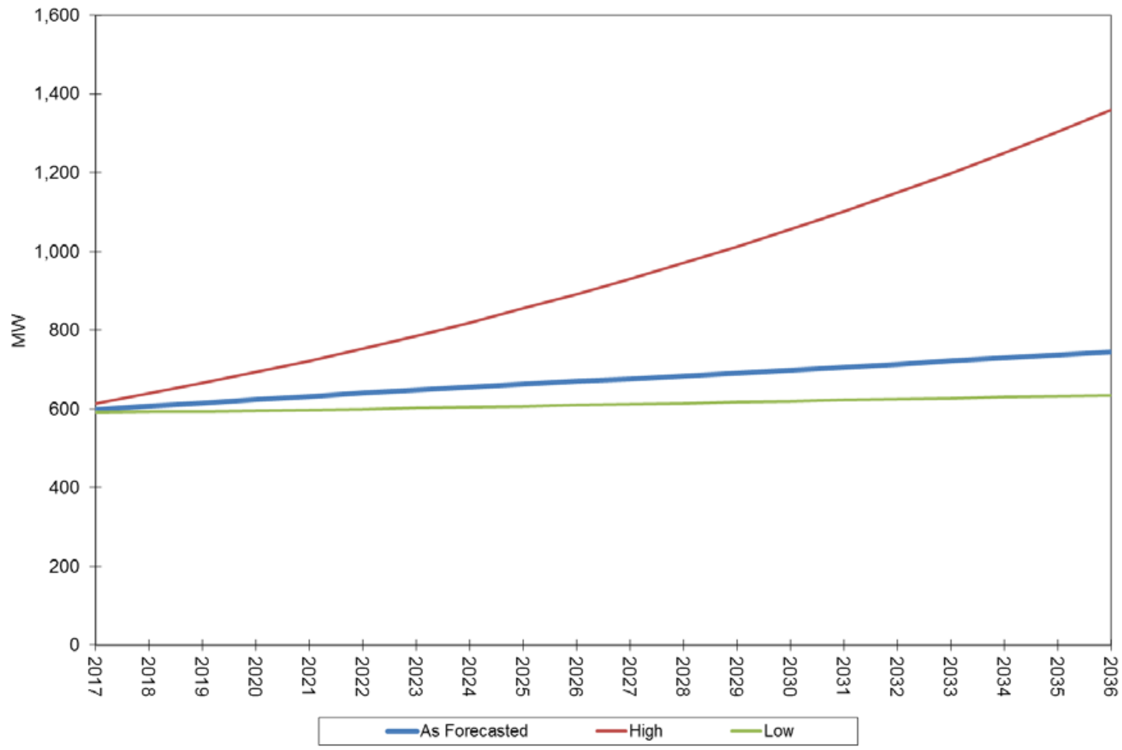
Table 2-4

High-Growth and Low-Growth Scenarios
Total Annual Energy (GWh) and
Summer Peak Demand (MW)

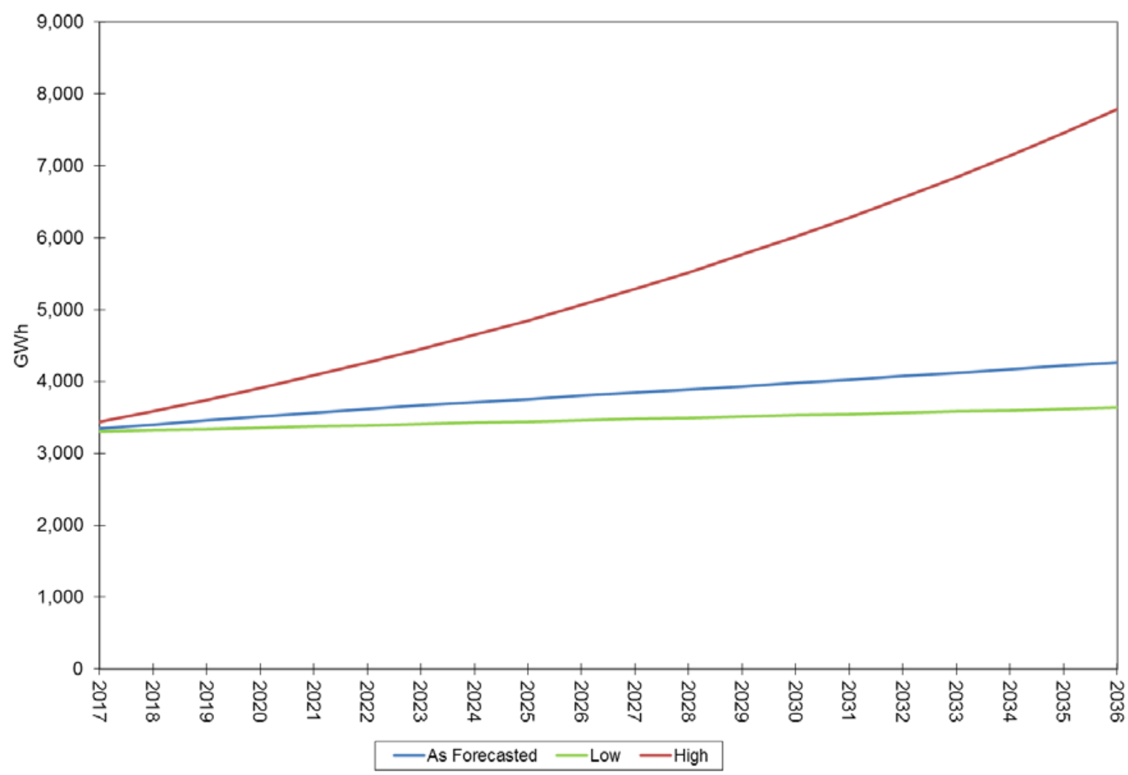
	ENERGY			DEMAND		
	Forecast	HIGH 1/	LOW 2/	Forecast	HIGH	LOW
2017	3,344.6	3,434.6	3,306.2	597.9	614.0	591.0
2018	3,401.3	3,585.7	3,322.7	606.4	639.3	592.4
2019	3,458.1	3,743.5	3,339.3	614.9	665.6	593.8
2020	3,515.8	3,908.2	3,356.0	623.6	693.2	595.3
2021	3,567.8	4,080.2	3,372.8	631.6	722.3	597.1
2022	3,619.6	4,259.7	3,389.7	639.7	752.8	599.1
2023	3,665.1	4,447.1	3,406.6	647.2	785.3	601.6
2024	3,713.2	4,642.8	3,423.6	654.9	818.9	603.8
2025	3,755.5	4,847.1	3,440.7	662.0	854.4	606.5
2026	3,800.0	5,060.4	3,457.9	669.4	891.4	609.1
2027	3,843.9	5,283.1	3,475.2	676.7	930.1	611.8
2028	3,888.3	5,515.6	3,492.6	683.9	970.1	614.3
2029	3,933.4	5,758.3	3,510.1	691.3	1012.0	616.9
2030	3,979.0	6,011.7	3,527.7	698.8	1055.8	619.5
2031	4,025.3	6,276.2	3,545.3	706.3	1101.3	622.1
2032	4,072.1	6,552.4	3,563.0	713.9	1148.7	624.6
2033	4,119.7	6,840.7	3,580.8	721.6	1198.2	627.2
2034	4,167.8	7,141.7	3,598.7	729.3	1249.7	629.7
2035	4,216.7	7,455.9	3,616.7	737.1	1303.3	632.2
2036	4,266.4	7,784.0	3,634.8	745.0	1359.2	634.7

1/ High forecast assumes 4.4% growth per year (actual 77-85 growth).
2/ Low forecast assumes 0.5% growth per year (actual 85-93 growth).

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



Montana-Dakota Integrated System
High-Growth and Low-Growth Scenarios - Energy in GWh



CHAPTER 3

DEMAND-SIDE ANALYSIS

Overview

Demand-Side Management (DSM) 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.

With the demand for electricity and the need for additional resources growing, Montana-Dakota recognizes the value that DSM can play in meeting our customer's future energy requirements. However, the implementation of DSM programs cannot be done without cost consideration to the utility's customers and shareholders. Interests need to be balanced to achieve results at an affordable cost to both the utility and its customers.

Montana-Dakota's DSM analysis is completed on a state by state approach (Montana, North Dakota, and South Dakota) versus an Integrated System approach, due to the complexities of offering DSM programs across multiple jurisdictions and then in total for the Integrated System. The DSM benefit/cost analysis is contained in Attachment B of this IRP.

Provided in this Chapter is a summary of current DSM Programs and activities, a discussion of the DSM program planning activities, a summary of the DSM program benefit/cost analysis, and Montana-Dakota's future DSM implementation plan for 2018-2020.

Current Program Portfolio Summary

Montana-Dakota currently offers Energy Efficiency DSM Programs only in Montana which are funded through the Universal Systems Benefit Charge. Demand Response DSM Programs are available to commercial customers in Montana, North Dakota, and South Dakota. The following is an overview of program details associated with each residential and commercial DSM measure that is currently being offered. The overview provides a description of the program, jurisdictions where the program is or will be offered, DSM measures included in the program, incentive levels, and the marketing and promotion plan. A summary of all the programs is presented in Table 3-4.

Summary of Portfolio of Programs Table 3-1			
	Montana	**North Dakota**	**South Dakota**
Residential Programs			
Central Air Conditioner Tier 1 (14.5 SEER) - Replacement	$100/ton		
Central Air Conditioner Tier 2 (16 SEER) - Replacement	$200/ton		
Central Air Conditioner Tier 2 - New	$200/ton		
Window Air Conditioner Units	$50		
Thermal Storage with Air-Source Heat Pump	$60/kW		
Residential Lighting	$2/bulb		
Commercial Programs			
Commercial Lighting	$0.40/watt		
Commercial Motors - Replacement	$15/HP		
Commercial Motors - New/On Failure of Exist. Equip.	$4/HP		
Variable Speed Drives - VFD	$30/HP		
Commercial Central Air Conditioner Tier 1 (14.5 SEER)	$100/ton		
Commercial Central Air Conditioner Tier 1 (16 SEER)	$200/ton		
Commercial Air Conditioner - Split Systems	$100/ton		
Commercial Air Conditioner - Packaged Systems	$100/ton		
Commercial Partnership Program (Custom)	Project-Specific		
Commercial Demand Response Resources (DRR) Program	Customer-Specific	Customer-Specific	Customer-Specific
Interruptible Rate Demand Response Program	$5.00/kW	$3.00/kW	

DSM Activity Summary

Montana-Dakota currently offers Energy Efficiency DSM Programs in Montana and Demand Response DSM Programs in Montana, North Dakota, and South Dakota. The following is a discussion of the activity in the currently offered programs.

Montana Energy Efficiency (EE) DSM Programs

The Montana EE Programs are funded through the Universal Systems Benefit Charge and have been offered for the last several years.

Participation in the Montana EE portfolio of programs continues to be limited. In 2016 there were a total of three participants in the residential programs and a total of nine participants in the commercial programs. However, participation in the commercial lighting program is increasing with thirteen approved projects year-to-date in 2017.

Commercial Demand Response Programs

Montana-Dakota currently offers two demand response programs for commercial and industrial customers. The Commercial Demand Response Program and Interruptible Demand Response Rate which together provide demand response options to customers starting at 50 kW of demand billing. Combined these programs are currently providing 24.9 MW of demand response at year end 2016, with an overall goal of providing 35 MW of demand response by 2019.

Commercial Demand Response Resources (DRR) Program

The DRR Program was launched in June of 2012 and is available to commercial and industrial electric customers in all states, with a priority focused on customers with loads of 150 kW or higher. In 2016 the program had 9.5 MW enrolled and participating in the program by year end. The total program goal remains 25 MW, in our initial integration analysis a conservative approach was taken assuming 15 MW for the summer of 2019. Since then a large industrial customer has come forward requesting to add an additional 15 MW into the program in 2017 taking our total project enrollment to almost 25 MW by the end of 2017.

Interruptible Demand Response Rate

The Interruptible Demand Response Rate has been available for several years and is available to commercial and industrial electric customers with loads of 500 kW or higher. This program currently has 15.4 MW enrolled and Montana-Dakota's goal is to increase participation by 2.1 MW or to a total enrollment of 20 MW by the summer of 2019.

Montana-Dakota continues to work with customers and engineering companies to promote the use of the Interruptible Demand Response Rate and expects that the goal of 20 MW will be achieved by the summer of 2019.

DSM Program Planning

In the 2013 IRP Montana-Dakota provided the results of the Nexant Energy Efficiency Potential Study that was completed for the Montana service territory, which also included an energy efficiency attitudes survey of customers. In addition, Montana-Dakota provided the results of the Nexant Program Planning Study for the Montana service territory in the 2015 IRP. Montana-Dakota continues to use the key findings of both studies in our DSM planning process for the 2017 IRP.

Montana-Dakota used the study ramp rates and achievable potential to estimate the achievable potential for the integrated system. The Montana service territory ramp rates and achievable potential are projected for South Dakota due to similar market characteristics. The North Dakota service territory ramp rates and achievable potential have been increased over what is projected for the Montana service territory due to larger communities served and a stronger contractor network.

Based on the results of the Montana study and Montana-Dakota's market knowledge of the service territory, Montana-Dakota estimates the achievable annual energy reduction of 0.35 percent of annual energy sales (MWh) and 1.73% of demand (MW) over the IRP planning period. A summary of the MWh and MW results are shown below in Tables 3-2 and 3-3, respectively. The complete state by state analysis and discussion are contained in Attachment B.

Table 3-2: Montana-Dakota's System-Wide Potential MWh Savings Summary

YEAR	Total Sales Sales (MWh)	Achievable EE %	Achievable MWh
2017	3,293,602	0.13%	4,316
2018	3,384,513	0.13%	4,445
2019	3,477,760	0.18%	6,244
2020	3,546,859	0.19%	6,907
2021	3,618,907	0.26%	9,545
2022	3,685,174	0.27%	10,022
2023	3,745,006	0.36%	13,542
2024	3,802,740	0.36%	13,757
2025	3,860,511	0.43%	16,650
2026	3,918,107	0.43%	16,909
2027	3,976,553	0.43%	17,172
2028	4,033,737	0.43%	17,433
2029	4,091,759	0.43%	17,698
2030	4,150,628	0.43%	17,967
2031	4,210,361	0.43%	18,239
2032	4,270,944	0.43%	18,516
2033	4,331,336	0.43%	18,794
2034	4,392,609	0.43%	19,075
2035	4,455,122	0.43%	19,363
Cumulative	**77,441,188**	**0.35%**	**269,218**

Table 3-3: Montana-Dakota's System-Wide Potential MW Savings Summary

Year	Summer Peak (MW)	Achievable EE %	Achievable MW	Winter Peak (MW)	Achievable EE %	Achievable MW
2017	647.5	0.10%	0.65	624.2	0.10%	0.62
2018	660.2	0.10%	0.66	641.8	0.10%	0.64
2019	672.7	0.10%	0.67	659.6	0.10%	0.66
2020	682.9	0.10%	0.68	673.1	0.10%	0.67
2021	693.3	0.10%	0.69	686.9	0.10%	0.69
2022	703.2	0.10%	0.70	699.7	0.10%	0.70
2023	712.5	0.10%	0.71	711.3	0.10%	0.71
2024	721.3	0.10%	0.72	722.4	0.10%	0.72
2025	730.3	0.10%	0.73	733.6	0.10%	0.73
2026	739.3	0.10%	0.74	744.8	0.10%	0.74
2027	748.3	0.10%	0.75	756	0.10%	0.76
2028	757.2	0.10%	0.76	767.1	0.10%	0.77
2029	766	0.10%	0.77	778.2	0.10%	0.78
2030	775.2	0.10%	0.78	789.7	0.10%	0.79
2031	784.4	0.10%	0.78	801.3	0.10%	0.80
2032	793.6	0.10%	0.79	813.1	0.10%	0.81
2033	803.1	0.10%	0.80	824.8	0.10%	0.82
2034	812.3	0.10%	0.81	836.5	0.10%	0.84
2035	821.9	0.10%	0.82	848.9	0.10%	0.85
Cummulative					**1.73%**	**14.7182**

Montana-Dakota also used the key findings of the Nexant Program Planning study for Montana discussed above to review the existing DSM program offerings and delivery mechanisms. As discussed in the 2015 IRP, the portfolio of DSM programs included in the study are not significantly different from the currently offered programs, however different program delivery and outreach efforts should be considered to increase participation A summary of the program delivery and increased outreach efforts that were considered are:

- Point of sale options for residential LED Lighting
- Additional prescriptive measure(s) added to commercial lighting program
- Commercial Lighting Preferred Trade Ally Direct install program
- Contractor network development and training
- Development of additional energy education and outreach material

The portfolio of energy efficiency programs included in the benefit cost analysis for this IRP include the cost associated with program delivery and outreach efforts discussed above.

Benefit/Cost Analysis

To determine which programs are cost effective, and therefore should be included as resource options in the integration analysis, a benefit/cost analysis by state was performed for each of the potential 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 five different cost-effectiveness tests: the Participant Test, the Utility Test, the Ratepayer Test, Societal Cost Test and the Total Resource Cost (TRC) 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* includes environmental externalities and considers the impact on the "society" (both the participants and non-participants).

The *Total Resource Cost Test* reflects the total benefits and costs to all customers (both the participants and non-participants). In determining whether a program is cost effective, Montana-Dakota relied on the resulting benefit/cost ratio of the TRC Test as well as the practicality of implementation and the ongoing administration of that program.

A summary of the benefit/cost ratios by state are contained below in Table 3-4. A discussion of the results and the complete DSM program analysis by state and in total for Montana-Dakota's Integrated System is contained in Attachment B and Appendix A of Attachment B of this report.

Table 3-4: DSM Benefit/Cost Summary

Montana-Dakota Utilities Co.
Montana Electric DSM Program Summary

Benefit/Cost Ratios						
DSM Program	Customer Class	RIM	Utility	Societal	Participant	Total Resource Cost
Total Portfolio		2.14	2.56	3.76	6.45	2.59
Residential Programs						
Residential Lighting	Residential	1.05	3.13	2.63	2.57	1.61
Demand Response						
Residential AC Cycling	Residential	1.38	1.41	3.03	3.47	1.99
Commercial Programs						
Commerical Lighting	Commerical	1.50	6.33	7.12	4.13	3.76
Commercial Partnership Program (Custom)	Commerical	1.40	6.14	5.28	3.48	3.15
Demand Response						
Commercial Demand Response Program	Commercial	2.58	2.58	3.53	40.52	2.54
Interruptible Rate DR Program	Commercial	3.44	3.53	4.47	10.81	3.22

Montana-Dakota Utilities Co.
North Dakota Electric DSM Program Summary

Benefit/Cost Ratios						
DSM Program	Customer Class	RIM	Utility	Societal	Participant	Total Resource Cost
Total Portfolio		1.81	2.02	3.03	6.12	2.12
Residential Programs						
Residential Lighting	Residential	0.98	2.97	2.47	2.67	1.52
Demand Response						
Residential AC Cycling	Residential	1.20	1.23	2.64	3.46	1.73
Commercial Programs						
Commerical Lighting	Commerical	1.29	5.87	6.57	5.69	3.47
Commercial Partnership Program (Custom)	Commercial	1.21	5.78	4.94	4.64	2.95
Demand Response						
Commercial Demand Response Program	Commercial	1.79	1.79	2.36	12.50	1.69
Interruptible Rate DR Program	Commercial	3.44	3.53	4.47	10.81	3.22

Montana-Dakota Utilities Co.
South Dakota Electric DSM Program Summary

Benefit/Cost Ratios						
DSM Program	Customer Class	RIM	Utility	Societal	Participant	Total Resource Cost
Total Portfolio		1.18	1.89	3.27	4.07	2.06
Residential Programs						
Residential Lighting	Residential	0.80	2.48	2.26	2.89	1.39
Demand Response						
Residential AC Cycling	Residential	1.20	1.23	2.64	3.49	1.73
Commercial Programs						
Commerical Lighting	Commerical	1.10	5.25	6.18	5.36	3.26
Commercial Partnership Program (Custom)	Commercial	1.02	4.71	4.41	4.27	2.64
Demand Response						
Commercial Demand Response Program	Commercial	2.85	2.85	3.08	2.48	2.13

DSM Implementation Plan

The following is a discussion by state of the expected DSM activity for program years 2018-2020. Also included is a discussion on Montana-Dakota's continued research into distributed generation as a possible fit for future system supply.

Montana

Montana-Dakota is planning to continue with the existing energy efficiency programs offered in Montana until the fall of 2017 at which time all existing programs will be closed to new participants. Beginning in January 2018, Montana-Dakota plans to implement the portfolio of cost-effective programs included in the 2017 IRP. The portfolio will include increased education and outreach efforts, a residential LED lighting program, a commercial lighting program, and a commercial partnership program.

In addition, Montana-Dakota will continue to implement the Commercial Demand Response Program and promote the Interruptible Demand Response Rate.

North Dakota

Montana-Dakota will continue to implement the Commercial Demand Response Program and promote the Interruptible Demand Response Rate.

South Dakota

Montana-Dakota will continue to implement the Commercial Demand Response Program.

Distributed Generation

Distributed Generation (DG) refers to decentralized energy production that takes place on, or near the site being served. DG operates independently of traditional, centralized utility-scale electric generation facilities and can be paired with energy storage devices to run independently of the grid, or can *supplement* grid tied resources to provide peaking and resiliency benefits.

Examples of DG resources include cogeneration (fired by fossil or bio fuels), small wind, rooftop or community solar photovoltaic (PVE), and solar thermal. Decentralized projects can be as simple as placing a single solar panel on a residential rooftop, or can entail combining multiple resources together with storage for micro grids which provide power at a "campus" or small community level.

While traditional fuel sources such as coal, gas, and large wind remain best cost resources for electric generation, on-site energy production is becoming increasingly cost competitive. And with the price of many distributed technologies declining, and the continued advancement of storage, distributed generation has tremendous potential to impact the grid and shape the way customers use energy—although the extent of these impacts will vary greatly region by region.

Regardless of the form Distributed Generation takes, it will be essential to continue monitoring technologies as they emerge and to determine what resources and adaptations (storage, smart grid upgrades, policy changes, new programs, etc.) may be needed to effectively adjust to an evolving energy economy.

The core technologies that are likely to have the greatest impacts in Montana-Dakota's electric service area are described below:

Distributed Solar

Solar photovoltaic energy (PVE) is an intermittent resource which is collected through panels and converted into electricity that can be used on site or fed back to the electric grid. Although this technology has been around for decades, in recent years its presence has grown significantly on a national scale. This is because of marked increased in enabling regulations and tax credits across the country, as well as the maturation of solar technology itself, increasing electric rates, and the emergence of viable battery technologies.

In Montana-Dakota's electric service area, low electric rates have kept the presence of solar to a minimum. However, as the costs of solar technologies continue to decline and average electric rates gradually increase over time, our region will begin to see an increased solar presence.

Montana-Dakota will monitor opportunities for the prudent integration of distributed solar energy, as well as consider optimal metering and interconnection policies. These are necessary first steps to effectively manage an emerging solar presence. A proactive, coordinated approach to the eventuality of solar will ensure greater benefit and stability for the nascent solar market in our region and help avoid the "duck curve", and associated reliability concerns experienced in areas where solar planning was not approached holistically.

Distributed Natural Gas-Fired Combined Heat and Power (CHP)

Cogeneration, otherwise known as Combined Heat and Power (CHP), captures and utilizes excess heat generated during the production of electric power. Natural gas fired CHP is often valued from a source efficiency standpoint since line losses from traditional electric generation are mitigated by the use of natural gas. Likewise, CHP powered by waste heat or biogas has additional environmental benefits and can be relatively low cost if the fuel derives from an existing waste process.

CHP technologies include fuel cells, combustion/micro turbines and combined cycle plants. Waste heat can be used for hot water and steam for electrical generation. These technologies lead to savings for electric customers, reduced load benefits from a demand side management standpoint (DSM), and greater resiliency.

Montana-Dakota will continue to examine the viability of cogeneration where existing gas capacity and/or availability of appropriate fuel sources allow for cost-effective application of this technology for DSM. From a holistic distributed generation standpoint, this technology would be of particular value within the context of a micro-grid in which intermittent resources are operating that could benefit from the smoothing effect of a more stable fuel source.

Storage

Storage technologies such as lithium-ion batteries have continued to become increasingly prolific due in part to the electric vehicle industry. Further development of storage has taken place due to the proliferation of the rooftop solar industry, and major investments in the technology by the states of New Jersey, California, Washington and New York.

Although not yet at a viable price point within Montana-Dakota's electric service area, the significant ramp-up of large scale investments in lithium-ion and flow battery technologies across the country will continue to drive down costs. At the same time, storage will become increasingly essential to manage the emerging presence of solar, to manage peak, and otherwise optimize customer usage.

Montana-Dakota will continue to monitor energy storage technologies such as lithium-ion, and vanadium flow batteries as technology costs continue to decline and will consider if limited testing of this technology, paired with an intermittent resource such as wind or solar might be prudent.

Future Policy Considerations

As suggested above, there is a great deal of developing activity on the horizon when it comes to DG technologies. Much of what takes place in Montana-Dakota's service area will depend on the price of electricity, the rate at which the costs of distributed technologies decline, the market appetite for these technologies, and the value they serve from a system reliability standpoint.

In addition to these factors, it is likely that national policy outcomes will also have a strong influence on the role of distributed generation— in particular the role of renewable DG. The outcomes of this and other policy will also have significant impacts on the future of DG, as will any state or regulation driven mandates that emerge in the future.

CHAPTER 4

SUPPLY SIDE RESOURCE ANALYSIS

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

The supply-side analysis considers generation resource 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

Current Resources

Montana-Dakota's existing generation serving the Integrated System is comprised of baseload coal-fired generation at the Heskett Station (Units 1 and 2), the Lewis & Clark Station 1, Montana-Dakota's shares of the Coyote and Big Stone Stations, and natural gas-fired peaking generation at Glendive (Units I and II), Miles City, Heskett 3, and Lewis & Clark Station 2. Montana-Dakota also owns and operates the Diamond Willow, Cedar Hills, and Thunder Spirit wind farms, three 2 MW portable diesel units, and the Glen Ullin Station 6 waste heat generating unit serving the Integrated System. Total zonal resource credits (ZRC) available from the existing units in 2017 are 528.2 ZRC.

Future Capacity and Energy Resources

As part of the development of the 2017 IRP, Montana-Dakota issued a request for proposals of capacity and energy resources in August of 2016 (2016 RFP). Screening of the responses to the 2016 RFP identified the expansion of the Thunder Spirit Wind farm as a possible future energy resource with the addition of wind turbines capable of producing up to 48 MW of energy. The original Thunder Spirit Wind farm went online in December 2015 with 107.5 MW of wind turbines and included development rights for a total project sized at 150 MW. This project was selected from other submitted proposals because of its low-cost energy price, and because the project has all necessary permits, a completed MISO interconnection, and is connected to Montana-Dakota's transmission system. The 48 MW Thunder Spirit Wind Expansion Project is scheduled to be completed and online by the end of 2018. Additional information on the 48 MW Thunder Spirit Wind Expansion Project is contained in Section 2.2 of Attachment C to the 2017 IRP Report.

Considered Supply-Side Resource Alternatives (Described in greater detail in Attachment C)

Coal

Coal-fired baseload generation is a stable capacity and energy source characterized as having a high capital cost with low operating and fuel costs. With low operating and fuel costs, baseload units produce large amounts of energy at a relatively low cost. The high capital costs are spread over the life of the project. However, as significant new federal air quality, water discharge, and waste management regulations have been implemented, new coal-fired baseload generation is unlikely to be feasible in the foreseeable future.

Simple Cycle Combustion Turbines

Simple-cycle combustion turbines (SCCT) are primarily used to supply low-cost capacity, but a limited amount of energy, since they are fueled by either natural gas or fuel oil, which have been historically more expensive than coal. Combustion turbines have a relatively low capital cost, but the energy produced is more expensive than that produced from coal because of the historically higher fuel costs. As natural gas prices have dropped with the development of shale gas formations in the U.S., new natural gas-fired resources have become cost competitive other traditional forms of generation like coal-fired plants. Combustion turbines can be installed with a relatively short lead time (two to three years) and serve peaking capacity needs for the Company.

Simple Cycle Reciprocating Internal Combustion Engine

Simple-cycle reciprocating internal combustion engines (RICE) are primarily built to serve peaking capacity needs. Because they are fueled by natural gas or fuel oil, which have been historically more expensive than coal, they are usually limited in the amount of energy they supply. The RICE units, however, can be installed within a relatively short lead time (two to three years) and are normally more thermally efficient and require lower fuel pressure compared to SCCT's of similar power output.

Combined Cycle Combustion Turbines

A conventional combined cycle combustion turbine (CCCT) burns natural gas or fuel oil in a SCCT. The hot exhaust gases from the SCCT pass through a heat recovery steam generator that produces steam for a steam turbine. CCCT's can have one of the highest efficiencies of any new power plant, at more than 60 percent. These units are usually used as an intermediate unit today, but in the future could be used as more of a baseload unit to replace retired coal units. However, because CCCTs use natural gas or fuel oil, CCCTs have historically had higher fuel costs than coal-fired baseload units. The advantage of a CCCT is that it is more efficient to operate than a SCCT, but its hours of operation could be limited because of what have been historically high fuel costs.

Wind (Self-Built)

A wind energy resource is characterized as a renewable resource with low energy costs associated with its operation and maintenance. The main disadvantage of wind generation is that, because of the variability of wind, it cannot be relied on as a firm capacity resource. Unlike the thermal resources such as coal-fired units and combustion turbines, wind energy resources are allowed limited zonal resource credits (ZRC) by MISO. Therefore, the installation of additional wind generation on Montana-Dakota's system requires adding other capacity resources to meet the MISO planning reserve margin requirements. This option represents Montana-Dakota self-building a wind generation project.

Solar

Another renewable resource alternative is solar, which has a higher capital cost than wind generation. Like wind, solar is a variable output energy resource and must rely on other capacity resources to meet Montana-Dakota's MISO zonal reserve margin requirements. Two different types of solar options were included in the model: concentrated and photovoltaic solar.

Biomass

There are several types of fuels that can be used for biomass generation including but not limited to: agriculture wastes, forestry by-products, and municipal waste. The biomass option is considered a renewable resource with high capital and fuel costs as compared to coal and natural gas fired options.

Existing Resources

The need for any type of new planning 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 existing facilities due to aging, high maintenance, high environmental compliance costs, and economic competitiveness will also trigger the need for new resources. For modeling purposes in the 2017 IRP, Montana-Dakota assumes the retirement of the Heskett I, Heskett II, and Lewis & Clark coal-fired generating plants in 2024.

For an understanding of Montana-Dakota's capability to serve projected loads, a comparison of ZRCs and planning reserve margin requirement (PRMR) is shown in Tables 4-1 through 4-3. ZRCs are defined as the total resources within MISO available to meet Montana-Dakota's own PRMR. MISO requires each generator to determine its summer capability through a Generator Verification Test Capability (GVTC) process that establishes the generator's Installed Capacity (ICAP) value. The ICAP value and each individual generator's equivalent forced outage rate ($XEFOR_d$) are then used to establish an unforced capacity (UCAP) value for the generator:

$$UCAP = ICAP – (1\text{-}XEFOR_d).$$

UCAP values are then directly converted to ZRCs, which are used to verify the ability to meet Montana-Dakota's peak load obligation, as required by MISO.

As a member of MISO, Montana-Dakota is required to maintain a total number of ZRCs equal to or greater than the Company's projected yearly MISO non-coincident summer peak demand with a 1.9 percent adder for MISO losses, plus a 7.8 percent planning reserve margin (PRM).

Montana-Dakota is required to meet an 80.7 percent coincident factor for the 2017-18 planning year in MISO based on the fact Montana-Dakota does not peak at the time of the MISO system-wide peaks.

Table 4-1 shows that, under the current system load forecast, Montana-Dakota has adequate capacity to meet its PRMR through 2020. The capacity deficit in 2021 will be 6.8 ZRC and grow to 66.4 ZRC in 2030. With the high-growth scenario forecast, as shown in Table 4-2, a capacity deficit will occur in 2018 (13.6 ZRC) and grow to 114.2 ZRC in 2022. Under the low-growth scenario forecast, as shown in Table 4-3, a capacity deficit never occurs in the 14 years shown in the table.

To address future long-term capacity deficits, Montana-Dakota will need additional demand-side and/or supply-side resources. The analyses in this IRP will help provide direction for the best selection of new resources to economically and reliably meet customers' requirements.

Table 4-1

Montana-Dakota Utilities Co. Integrated System
Load and Capability Comparison

BASE FORECAST

Year	Zonal Resource Credits[1]	50/50 Coincident Summer Peak Demand w/MISO Losses	Planning Reserve Margin Requirement	Surplus/ Deficit (+)/(-)
2017	553.1	491.7	530.2	22.9
2018	553.1	498.7	537.6	15.5
2019	553.1	505.7	545.1	8.0
2020	553.1	512.8	552.8	0.3
2021	553.1	519.4	559.9	-6.8
2022	553.1	526.0	567.1	-14.0
2023	553.1	532.2	573.7	-20.6
2024	553.1	538.5	580.6	-27.5
2025	553.1	544.4	586.6	-33.5
2026	553.1	550.5	593.4	-40.3
2027	553.1	556.5	599.9	-46.8
2028	553.1	562.4	606.3	-53.2
2029	553.1	568.5	612.8	-59.7
2030	553.1	574.6	619.5	-66.4

1 – Total based on 2017-18 MISO Planning Year Zonal Resource Credits

Table 4-2

Montana-Dakota Utilities Co. Integrated System
Load and Capability Comparison

HIGH-GROWTH FORECAST

Year	Zonal Resource Credits[1]	50/50 Coincident Summer Peak Demand w/MISO Losses	Planning Reserve Margin Requirement	Surplus/ Deficit (+)/(-)
2017	553.1	504.9	544.3	8.8
2018	553.1	525.7	566.7	-13.6
2019	553.1	547.3	590.0	-36.9
2020	553.1	570.0	614.5	-61.4
2021	553.1	594.0	640.3	-87.2
2022	553.1	619.1	667.3	-114.2
2023	553.1	645.8	696.1	-143.0
2024	553.1	673.8	725.9	-172.8
2025	553.1	702.6	757.4	-204.3
2026	553.1	733.0	790.2	-237.1
2027	553.1	764.9	824.5	-271.4
2028	553.1	797.7	860.0	-306.9
2029	553.1	832.2	897.1	-344.0
2030	553.1	868.2	935.9	-382.8

1 – Total based on 2017-18 MISO Planning Year Zonal Resource Credits

Table 4-3

Montana-Dakota Utilities Co. Integrated System
Load and Capability Comparison

LOW-GROWTH FORECAST

Year	Zonal Resource Credits[1]	50/50 Coincident Summer Peak Demand w/MISO Losses	Planning Reserve Margin Requirement	Surplus/ Deficit (+)/(-)
2017	553.1	486.0	523.9	29.2
2018	553.1	487.2	525.1	28.0
2019	553.1	488.3	526.4	26.7
2020	553.1	489.5	527.7	25.4
2021	553.1	491.0	529.3	23.8
2022	553.1	492.7	531.1	22.0
2023	553.1	494.7	533.3	19.8
2024	553.1	496.5	535.3	17.8
2025	553.1	498.7	537.6	15.5
2026	553.1	500.9	540.0	13.1
2027	553.1	503.1	542.3	10.8
2028	553.1	505.2	544.6	8.5
2029	553.1	507.3	546.9	6.2
2030	553.1	509.4	549.2	3.9

1 – Total based on 2017-18 MISO Planning Year Zonal Resource Credits

CHAPTER 5

INTEGRATION AND RISK ANALYSIS

The integration process considers all the demand-side programs discussed in Chapter 3 as well as the supply-side options discussed in Chapter 4 and integrates both resource types into a single least-cost plan. The Electric Generation Expansion Analysis System version 9.02 (EGEAS), a computer program developed by the Electric Power Research Institute (EPRI), is used to perform the resource expansion analysis and develop the least-cost integrated resource plan. From this analysis, Montana-Dakota will determine the least-cost integrated resource plan to guide its future resource selections.

Integration of Demand-Side and Supply-Side Resources[1]

The reduction in energy and peak demand for previously implemented DSM programs has been included in Montana-Dakota's load forecast or as supply side DSM resources in the EGEAS model. Energy efficiency programs reduce Montana-Dakota's load forecast while supply side DSM resources are not reduced from the load forecast amounts.

As a result of the demand-side analysis described in Chapter 3, the A/C cycling program was included as a resource option in the Base Case starting in 2018 at 2 MW and growing the program to 10 MW by 2022. All models did include a committed amount of 14.6 MW from the interruptible rate and 10.3 MW of the commercial demand response program in 2017 and increasing to 20 MW and 15 MW respectively by 2019.

Sensitivity Analysis

A sensitivity analysis was performed to see how the resource expansion plans would be affected by variations of certain key parameters that may change in the future from modeled assumptions.

Carbon Tax

Montana-Dakota analyzes new environmental requirements as information becomes available. Potential future rules impacting carbon-dioxide emissions, solid waste, other air emissions and water quality management at the existing plants have been evaluated, although no engineering analysis has been conducted on compliance with these proposed regulations. With the potential of a future carbon penalty applied to all fossil fuel units and MISO energy purchases, a carbon tax

1)Refer to Chapter 11 2017 IRP Update pages 62-66 for updated analysis on Demand-Side.

was modeled to assess the impact on the resource expansion plan. The assumed carbon tax wasapplied to all carbon emissions from Montana-Dakota's existing coal-fired units and natural gas-fired SCCTs, energy purchases from the MISO market, and new generating units added to the resource plan starting in 2024. While no carbon tax was modeled in the base case, Montana-Dakota modeled a carbon tax of $30 per ton for a sensitivity analysis.

<u>Natural Gas Price Sensitivity</u>

Prices for natural gas supplies as delivered to Montana-Dakota's existing turbines, future combustion turbines, and future combined cycle plants were developed in-house for use in the resource expansion analysis based on Montana-Dakota's view of the long-term outlook of natural gas pricing. For the base case, natural gas was priced for delivery at $3.06/MBTU for 2017, and increasing to $3.18/MBTU in 2021. After 2021, natural gas prices were escalated by three percent annually. Considering the historical fluctuations of natural gas prices, there is a need to consider what impact both higher and lower gas prices would have on the least-cost plan. Therefore, high and low gas price scenarios were also developed, whereby the gas price used in the base case was increased by $3/MBTU and decreased by $1/MBTU from the Base Case, respectively.

<u>High- and Low-Growth Scenario Forecasts</u>

The base forecast in Chapter 2 projected that summer peak demand would increase at an average rate of 1.35 percent per year for the next five years and at an average rate of 1.09 percent per year through 2036. Energy requirements would increase at an average rate of 1.59 percent per year for the next five years, and at an average rate of 1.14 percent per year through 2036. 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 over the twenty year period. EGEAS runs were made using both the high- and low-growth load forecasts to determine the least-cost resource plan under those scenarios.

<u>High Combustion Turbine and Reciprocating Internal Combustion Engines Costs</u>

Historically the costs of materials associated with the construction of generation have generally increased at a rate higher than general inflation 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 and O&M costs of new generation (i.e., combustion turbines) on the resource plan. Therefore, to determine the sensitivity of the base case to increases in combustion turbine costs, a sensitivity scenario was developed that increased the installed cost and O&M costs of combustion turbines by 20 percent over the Base

Case. The higher combustion turbine and reciprocating internal combustion engine cost scenario also accounts for differences in site constructability through Montana-Dakota's service territory, as some areas like the Bakken Region have seen higher construction costs due to higher labor, housing, and material costs. These higher cost areas may have additional benefits, like system reliability or access to trapped natural gas, associated with their developments which are considered when selecting a new generation site.

MISO Energy Purchases

Historically, Montana-Dakota has been able to purchase energy from the MISO market to meet our needs at lower costs than running our own gas fired SCCT units on non-peak hours and majority of the peak hours. With these scenarios, Montana-Dakota modeled sensitivities of a $10/MWh adder to the base case on energy prices for on and off peak for a high energy price scenario and used the one year historical energy prices for both on and off peak for a low energy price scenario. For the availability of the market, Montana-Dakota reduced the modeled amount of energy purchases available from 200 MW on and off peak to zero by 2022 and 2027.

Ninety percent coincident factor for MISO Resource Adequacy (RA)

The ninety percent coincident factor sensitivity scenario reflects a higher capacity need for MISO RA, however the energy needs do not change. This scenario was done in part to show the change in capacity need if there was a change to Montana-Dakota's current 80.7 percent coincident factor within MISO.

Thunder Spirit Wind Expansion Ownership

The Thunder Spirit Wind Expansion Ownership scenario reflects the ownership of the wind farm as compared to the power purchase agreement arrangement. The base case and all other sensitivities were modeled using the power purchase agreement costs.

CHAPTER 6

RESULTS

This section presents the results of the 2017 Integrated Resource Plan, taking into consideration the results of the resource expansion analysis as well as other factors Montana-Dakota deemed critical in evaluating future resources. The additional factors not modeled in EGEAS but considered when determining the final resource plan are as follows.

Economic, Societal, and Customer 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 the MISO market,
- The possibility of unexpected new large load developing in Montana-Dakota's service territory,
- The integration of renewable generation resources and the economic and social benefits that they provide, and
- Public interest programs.

Midcontinent Independent System Operator, Inc. Market

Since the beginning of the MISO energy market in 2005, and with the Ancillary Service Market (ASM) and Capacity Market startup in 2009, the ability of Montana-Dakota to use its existing resources within these markets has expanded. Therefore, when considering which resources to consider as benefiting retail customers, the presence of the markets available in MISO is a factor.

Montana-Dakota continues to perform integrated resource planning based on the obligation to serve its customers with a safe, stable and reliable power supply and the expectations that it be least cost, sustainable and environmentally friendly. The MISO energy market provides opportunities and benefits to Montana-Dakota, but Montana-Dakota does not 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. Figure 6-1 shows the forecasted MISO market energy prices used within the model. The model included a 200 MW block of energy for off-peak and on-peak periods.

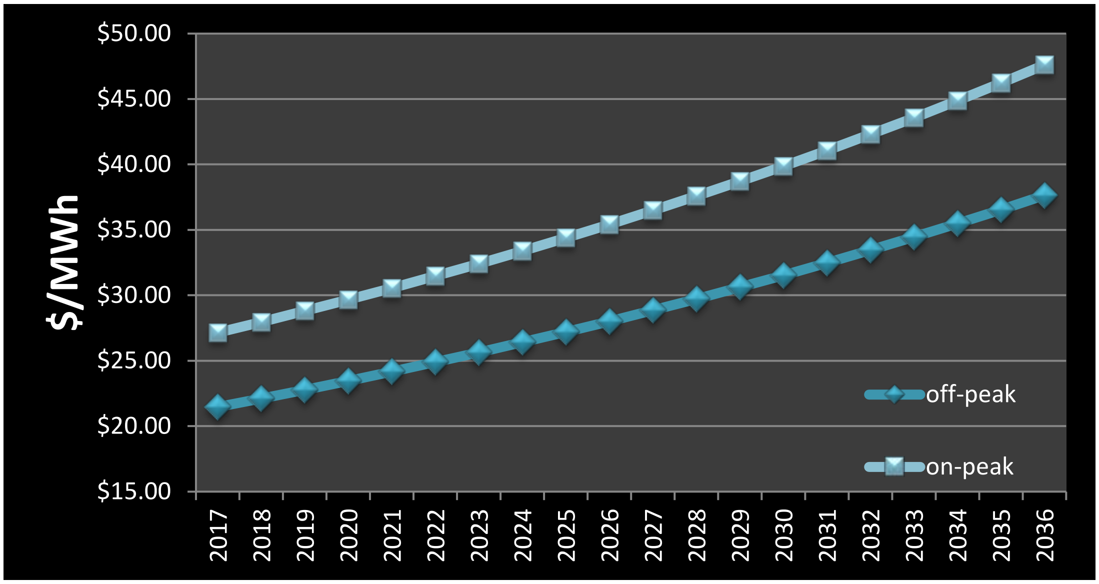


Figure 6-1: Forecasted On-Peak and Off-Peak MISO Market Prices developed by Montana-Dakota

MISO implemented an annual capacity auction starting with the 2013-14 planning year. Montana-Dakota has purchased capacity from the MISO Capacity Auction in past years. Montana-Dakota will continue to monitor and utilize the MISO Capacity Auction as a short-term economical option for needed capacity or look to enter into economic long-term capacity purchases through bi-lateral agreements if available.

Reliance on Natural Gas

About 31 percent of Montana-Dakota's owned generating nameplate capacity is natural gas-fired as of 2017. As shown on Figure 6-2, natural gas prices, though historically volatile, have stabilized with the development of shale gas formations in the U.S. Unlike coal, longer-term supply contracts for natural gas are generally not available and tend to be more seasonal in duration.

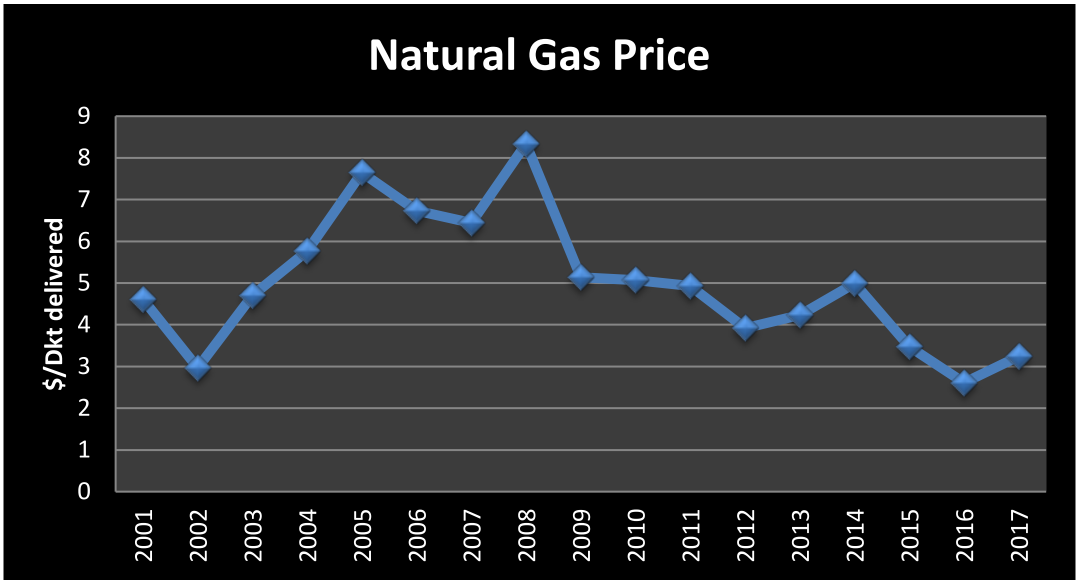


Figure 6-2: Historical Natural Gas Prices of Montana-Dakota's existing combustion turbines (Based on 12-Month Average)

Resource Expansion Analysis Results[2]

The most probable load forecast, fuel prices, and resource installed costs were modeled in the EGEAS Base Case. The Base Case least-cost plan consists of the following resource additions for the 2017-2026 period:

- Continue the commercial demand response program to achieve 15 MW by 2019 and achieve 20 MW from Montana-Dakota's interruptible rate;
- Implement the residential A/C Cycling program by 2018 to reach a total of 10 MW in the program by 2022; and
- Purchase the additional 48 MW at the existing Thunder Spirit Wind; and
- Install a natural gas-fired Combined Cycle Combustion Turbine unit in 2025.

In the later years an additional 41 MW combustion turbine was selected in 2035. The net present value of the Base Case least-cost plan over the 50-year study period equates to $3.02129 billion in 2016 dollars, as shown in Attachment C Table 3-1.

2)Refer to Chapter 11 2017 IRP Update pages 62-66 for updated Base Case analysis.

Sensitivity scenarios indicate that the Base Case plan is fairly robust under all assumptions in showing the need for a large combined cycle to meet for future capacity and energy needs. However, load growth has a significant impact on the resource selection. As expected, the low-growth scenario indicates the need for less peaking capacity and energy, while the high-growth scenario shows much more peaking capacity and energy is needed than is shown in the Base Case. The high and low gas price scenarios also support the Base Case selections for capacity, except that the high gas price case also selected an additional 20 MW of self-built wind throughout the 20 years.

The cost of materials and labor as well as potential environmental costs put upward pressure on the cost estimates for both baseload coal-fired units and combustion turbines. The scenario in which the installed cost of combustion turbines increased by 20 percent also selected a combined cycle, however a smaller sized combined cycle than in the Base Case.

Montana-Dakota has successfully utilized the MISO market for energy purchases, when available, to serve its customer load instead of using higher priced existing energy resources. In the low energy market price scenario, the resource plan never changed and had a slight decrease in NPV. Under the high energy market price scenario, the model selected a larger and more efficient combined cycle to offset the higher energy market purchases and slightly increasing the NPV. The scenario of Montana-Dakota being self-sufficient and not relying on the market in the future added in an additional combined cycle and increase in the NPV.

The carbon tax sensitivity scenarios show the economic impact of a tax on CO_2 on Montana-Dakota's generating system and customers. The total production costs increase significantly, and with low natural gas prices, causes existing coal units to run less at $30/ton of CO_2.

As shown in Figures 6-3 and 6-4, in 2017 approximately 31 percent of Montana-Dakota's Zonal Resource Credits come from natural gas- and oil-fired combustion turbines while in 2025, based on the Base Case plan, approximately 56 percent of the Company's Zonal Resource Credits would be made up of natural gas- and oil-fired combustion turbines or engines.

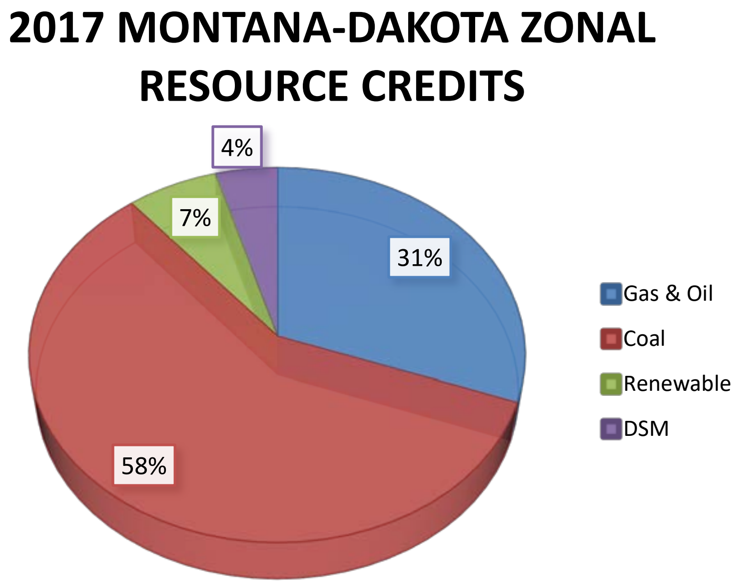


Figure 6-3: 2017 Montana-Dakota Zonal Resource Credits

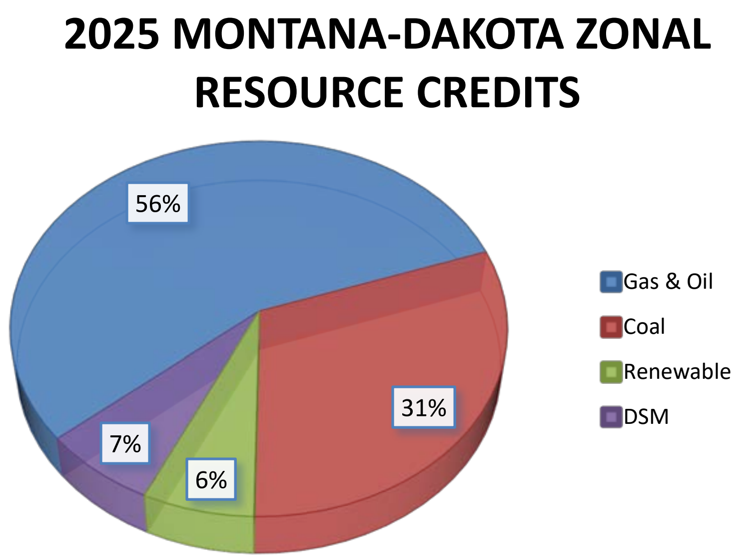


Figure 6-4: 2025 Montana-Dakota Zonal Resource Credits

<u>Future Resource Plan</u>

Based on the analysis of the resource expansion models and the consideration of customer impacts, market availability of capacity and energy, and other factors such as environmental regulations and the balance of its generation mix, Montana-Dakota's recommended resource plan is to pursue the following resources to meet the requirements identified for the 2017-2026 period:

- Continue the commercial demand response program to achieve 25 MW by the end of 2017 and achieve 20 MW from Montana-Dakota’s interruptible rates;

- Purchase the additional 48 MW at the existing Thunder Spirit Wind; and

- Continue the design and engineering work on a natural gas-fired combined cycle combustion turbine resource to be online in or after 2025.

The recommended resource plan is considered to be the best plan to economically and reliably meet customers’ requirements over the ten-year planning horizon, as explained below.

Montana-Dakota’s recommended resource plan satisfies future customer requirements through a balance of additional wind, increases to the existing and new demand response programs and the addition of a large natural gas-fired combined cycle resource timed with potential coal-fired plant retirements. Additional factors that are considered in confirming the best cost new supply-side resource option include, but are not limited to: site location issues, susceptibility to inclement weather and sustained cold temperature operation, fuel delivery requirements and limitations, transmission interconnection options, transmission upgrade requirements, long-term maintenance strategies, synergies with other Company resources, and overall operation and maintenance costs.

CHAPTER 7

TWO-YEAR ACTION PLAN

This section of the report provides the two-year action plan resulting from this IRP analysis. 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 evaluate the accuracy of its demand and energy forecasts and make improvements where needed.

Demand-Side Resources

- Montana-Dakota will continue to expand its customer interruptible rate programs to achieve a total of 20 MW by 2019.
- Montana-Dakota will continue to expand its commercial demand response program to achieve 25 MW of customer participation by the end of 2017.

Supply-Side Activities

- Montana-Dakota will continue with its purchase of the Thunder Spirit Wind expansion project to be online by the end of 2018.
- Montana-Dakota will continue with engineering to support siting, permitting, and approval of a combined cycle combustion turbine facility, including potential partnerships, with an in-service date in or after 2025.
- Montana-Dakota will (1) review the options for accelerating the depreciation of its older coal-fired generation facilities to reduce the remaining net book when these generation resources are ultimately retired, and (2) review the fuel management and delivery arrangements of its older coal-fired generation facilities to support an end-of-life transition plan.
- Montana-Dakota will continue to study the need to install local generation projects, including community solar, throughout its service area to support load growth, mitigate transmission constraints, and provide customer requested programs.

- Montana-Dakota will continue to monitor the availability and price of energy and short-term capacity in the MISO market or through bi-lateral arrangements and will purchase additional capacity as needed to meet customer demand when economic to do so.

- Montana-Dakota will continue to monitor the development or changes of environmental rules for generation sources, and influence the outcomes where possible.

RTO Transmission Arrangements

- Montana-Dakota will continue to monitor the impacts and benefits of its RTO transmission arrangements with MISO and SPP to ensure a safe, reliable, and economic transmission system for its customers.

Other Activities

- Montana-Dakota will maintain the IRP Public Advisory Group to provide input to and review the Company's future resource plans.

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 2017 IRP advisory group was established at the beginning of the 2017 planning cycle and held its first meeting in December 2016.

Objective

The objective of the PAG is to provide Montana-Dakota with input to its integrated resource planning process from a non-utility perspective. This advisory group reviews, evaluates, and recommends 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 is 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 are also selected to balance representation from consumer advocacy groups, government agencies (including regulatory bodies), business concerns, and academia.

As a result, the PAG consists of two members from Montana, six 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 2017 PAG participants are shown in Table 8-1.

Table 8-1
The 2017 IRP Public Advisory Group

Montana

Barbara Roberts
Action for Eastern Montana
Glendive, Montana

Garrett Martin
Department of Environmental Quality
Helena, Montana

North Dakota

Mike Fladeland
North Dakota Department of Commerce
Bismarck, North Dakota

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

John Klein PE LEED®AP
Apex Engineering Group
Bismarck, North Dakota

Bruce Conway
OptCTS, Inc
Williston, North Dakota

Rich Wardner
North Dakota State Senate
Dickinson, North Dakota

Mike Wamboldt
Kadrmas Lee & Jackson
Bismarck, North Dakota

Victor Schock
North Dakota Public Service Commission
Bismarck, North Dakota
(Invited as an observer)

South Dakota

Patrick Steffensen
South Dakota Public Utilities Commission
Pierre, 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 2017 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. The group's discussions, therefore, tended to concentrate on issues, policies, and overall results. The public advisory process enhances Montana-Dakota's IRP analysis and reports through the information and suggestions provided by the group.

There were two 2017 IRP PAG meetings 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.

Since the PAG functions 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 to document their opinions or concerns.

Conclusions

Montana-Dakota is pleased with its public advisory process. The public involvement resulted in better study assumptions and provided useful information to both the Company and the PAG participants and their constituents.

CHAPTER 9

RESPONSES TO MONTANA PUBLIC SERVICE COMMISSION COMMENTS REGARDING MONTANA-DAKOTA'S 2015 IRP

This chapter provides responses to the Montana Public Service Commission's (PSC) comments issued on August 2, 2016, in Docket No. N2015.7.54 regarding Montana-Dakota's 2015 IRP. The PSC comments are included in their entirety in Attachment I to this IRP. The PSC comments (printed in *italics*) and Montana-Dakota's corresponding responses are presented below:

1. *The MISO energy market plays a significant role in MDU's day-to-day operations, yet MDU's 2015 IRP provides no information as to how MDU interacts with MISO, and what role, if any, the MISO energy or capacity market plays in MDU's planning exercises. MDU's 2017 IRP should explain what benefits being a member of MISO provides to MDU's customers, as well as how MDU interacts with MISO on a day-to-day basis. MDU should explain what advantages participating in the MISO capacity market provides, and whether or not capacity obtained from the MISO capacity market can provide a reasonable alternative to acquiring MDU-owned capacity resources, such as peaker units which are only dispatched occasionally.*

   See Attachment H MISO and RTO.

   MISO capacity market purchases are only for a single year in term and do not provide any local reliability benefits nor are there any dispatchable rights to a specific generator associated with the capacity market purchase. Thus, we feel the MISO capacity market does not provide a reasonable alternative to acquiring MDU-owned capacity resources.

2. *The 2015 IRP provided little, if any, information with respect to how MDU forecasts market electricity and natural gas prices. The market for both electricity and natural gas plays a critical role in how MDU makes resource acquisition decisions. In the 2017 IRP, MDU should explain how it forecasts MISO energy prices and natural gas fuel prices. MDU should compare its MISO market forecasting methods to forecasting methods used by other members of MISO or MISO itself. MDU should explain why its long-term forecasting method is preferable to others methods.*

   Montana-Dakota does prepare forecasts for both electric market and natural gas prices. The electric market prices have historically been based on a five-year historical average of actual electric market prices with sensitivities done for a high and low market prices. The 2017 IRP looked at a mid-price between the one and five-year historical average

market prices for use in the Base Case. The natural gas prices are developed by Montana-Dakota's Gas Supply Department utilizing an average of three sources (NYMEX, Wood Mackenzie, and Energy Information Administration (EIA)) to establish a five-year forecast.

Montana-Dakota has not directly compared its methodology to MISO or others, however Montana-Dakota does sensitivities around both electric market and natural gas prices to assess impacts of possible future price changes on the Base Case.

See Chapter 6 Results for more information on electric market and natural gas prices.

3. *MDU should provide a clear source for the cost information of the resources that are available to the EGEAS model in its generation expansion analysis. In particular, MDU should provide the source of MDU's assumed cost responsibility in the potential sharing agreement for a large combined cycle combustion turbine (CCCT) which was identified as a preferred resource that is expected to come online in or after 2020. To the extent possible, MDU should also provide details with respect to the potential sharing agreement for a large CCCT, including potential ownership partners, siting information, and any potential transmission concerns.*

   See Attachment E Supply-Side Resources Study.

   The 2015 pricing assumptions for the large CCCT partnership project was based upon confidential discussions that Montana-Dakota had with a group of area utilities. This partnership group ultimately decided to go forward with a smaller project outside of Montana-Dakota's service territory.

4. *MDU stated at the May 9 public meeting that EGEAS is not configured to sell power into the MISO energy market when it makes economic sense to do so; however, MDU itself does sell power into the MISO energy market on occasion in its actual day-to-day operations. MDU should configure EGEAS so that it is capable of selling power into the MISO energy market when it makes economic sense and run the model on several portfolios to compare the results against MDU's traditional configuration of EGEAS. If MDU is going to use EGEAS to determine its optimal generation expansion plan, EGEAS should be configured in a manner that most closely resembles MDU's actual operations. To the extent EGEAS is used to select an optimal capacity expansion plan while not being configured in a way which resembles how MDU actually operates, MDU should provide an explanation as to why the configuration was chosen.*

The EGEAS model does not have the capability to identify economic energy sales into a market, but the model can force in a set amount of energy sales for each year at an average annual price. However, Montana-Dakota at this time sells very little energy into the market as compared to total energy needs as seen in Figure 9-1. So, with the limited capability of the model and the resources necessary to predict MISO's economic dispatch coupled with the small percentage of sales each year there would not be a big effect in the modeling results with the addition of energy sales into the model. Note, the MISO market began in May of 2005 and Montana-Dakota's power purchase agreement with Basin Electric for purchase of 66 MW from Antelope Valley Station II end in October of 2006.

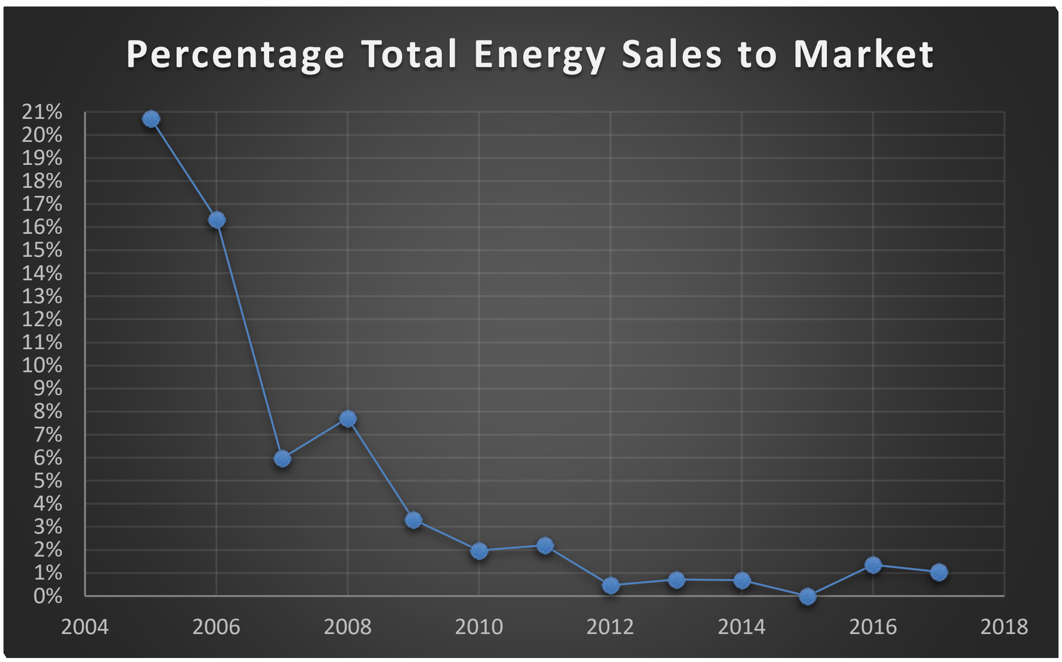


Figure 9-1: Historical percentages of energy sales to market compared to total energy sales

5. *MDU's 2017 IRP should contain updates on proposed strategies to comply with Rule 111(d), as well as updates on any signification modifications to generating plants that may be necessary to comply with other EPA rules.*

   See Chapter 1 Environmental Considerations.

6. *MDU should evaluate its Energy Efficiency programs to see if participation rates in its current programs can be increased and if new programs are cost effective and could boost MDU's achievable potential. Technologies and program costs have likely changed since the 2012*

Nexant study contracted by MDU. The 2012 Nexant study found that MDU's achievable potential rate its Montana service territory is only 0.3% of annual energy sales, which is lower than estimated regional and national averages.

Montana-Dakota is currently reviewing its portfolio of energy efficiency programs and program delivery methods. Montana-Dakota expects to close the existing energy efficiency programs in Montana on September 30, 2017 and launch the new programs on January 1, 2018.

See Chapter 3 Demand-Side Management Analysis and Attachment B Demand-Side Analysis Documentation.

7. *MDU's 2017 IRP should contain updates on the purchase of transmission service under the Southwest Power Pool's Network Integrated Transmission Service, and should contain updates on any transmission projects MDU is involved in with MISO.*

   See Attachment G Transmission Service Charge Impacts.

8. *MDU should provide an update in the 2017 IRP with respect to its load obligation in the Bakken region. The update should include load forecasts specific MDU's load in the Bakken, a description of transmission projects that have been developed in the Bakken since the 2015 IRP, potential transmission constraints to the area, and a discussion of how the RICE units are being used to effectively and economically serve MDU's load in the Bakken compared to available alternatives.*

   Since the 2015 IRP there has been a drop in oil prices which has slowed the growth of the Bakken region, and allowed for the transmission projects that were put in place or planned during the growth period to adequately meet the current load serving obligations in the Bakken region.

   The RICE units have been dispatched economically in MISO energy market, and continue to be available to serve Montana-Dakota's load in the Bakken region for transmission constraints, local reliability issues, and resource adequacy requirements. In 2016, the L&C Rice units ran a total of 1077 hours with a total generation of 11,917 MWh.

CHAPTER 10

RESPONSES TO MONTANA DEPARTMENT OF ENVIRONMENTAL QUALITY COMMENTS REGARDING MONTANA-DAKOTA'S 2015 IRP

This chapter provides responses to the Montana Department of Environmental Quality (DEQ) comments issued on October 23, 2015 in Docket No. N2015.7.54 regarding Montana-Dakota's 2015 IRP. The DEQ comments are included in their entirety in Attachment J to this IRP. The DEQ comments (printed in *italics*) and Montana-Dakota's corresponding responses are presented below:

1. *The Department of Environmental Quality (DEQ) is required to comment on integrated least-cost plans submitted to the Public Service Commission. According to 69-3-1205 (2) (a)) MCA, DEQ "shall review a plan and comment on the need for new resources, the alternatives evaluated to meet the need, the environmental implications of the resource choices, and other related issues that it considers important."*

2. *In Table 2-1, energy efficiency's peak demand impact is estimated at 1.5 MW for all years between 2015 and 2034 for both winter and summer periods. This is greater than the achievable peak demand savings reported in Table 3-2. Should the numbers in table 2-1 be revised or are they reporting something different than the numbers shown in Table 3-2?*

   The 1.5 MW of energy efficiency shown in Table 2-1is the amount of energy efficiency projected in the 2013 IRP. The difference between what is reported in Table 2-1 and Table 3-2 occurs due to timing; the load forecast reflected in this IRP was completed prior to the 2015 IRP DSM analysis. The Electric Load Forecast 2016-2035 published December 31, 2015 reflects the updated DSM projections shown in Table 3-2.

3. *Twelve customers participating in Montana-Dakota Utilities' (MDU) energy efficiency programs in Montana is not indicative of an effectively operated energy efficiency program and represents a poor return on investment for MDU and its customers. DEQ supports MDU's proposal in this Integrated Resource Plan (IRP) to increase its efforts in obtaining customer participation in its energy efficiency programs. However, there is no guarantee that MDU's increased efforts are going to translate into any greater customer participation. The Public Service Commission (PSC) and MDU should consider whether metrics (e.g., customers participating, kilowatt-hours saved) should be implemented to evaluate over periods shorter than the two year IRP process to determine whether the energy efficiency programs are operating effectively. The energy efficiency programs could be designed such that a failure to*

achieve at least some percentage of the projected energy savings or customer participation over a particular period would trigger increased rebates, more aggressive and direct marketing efforts, or cancellation of the particular programs. More aggressive or generous energy efficiency programs may appear to be less cost-effective than more passive, economical programs, however, if the latter options don't actually translate into customer participation and energy savings, then the money spent in developing and administering those programs is essentially wasted.

Montana-Dakota understands that participation in the current programs is very low, however Montana-Dakota does not have a significant amount of fixed operating costs for the programs which helps them remain cost-effective even with lower than projected participation. As discussed in the 2015 IRP Montana-Dakota does plan to re-evaluate our current portfolio of programs, including the existing delivery mechanisms used to implement the programs. Montana-Dakota currently is in the final stages of the evaluation and expects the new programs and delivery mechanisms to be launched on January 1, 2018. All current Montana energy efficiency programs will be closed to new applicants on September 30, 2017.

4. *DEQ is in agreement with MDU that energy storage technologies should continue to be evaluated in future IRPs for their potential to address transmission and distribution constraints and their ability to be paired with intermittent generating resources, such as wind and solar energy, to provide a more useful electricity asset for the MDU grid and MISO region.*

   MDU did receive a couple energy storage proposals from the 2016 Request for Proposal (2016 RFP), but through the screening process of the proposals the costs were still higher than other alternatives that were received in the 2016 RFP. However, MDU will continue to look at energy storage options as new technologies become available and the costs of energy storage options are an economical option to serve energy to our customers.

5. *As a result of federal climate change regulations for the electricity sector, DEQ recommends that MDU consider not just standard renewable energy technologies in their future supply-side resource analyses but also hybrid arrangements between renewable and fossil fuel resources, such as using geothermal or solar energy to preheat water for use in a steam or combined cycle power plant or pairing a natural gas power plant with a wind farm. Such hybrid arrangements may be able to better take advantage of the carbon- free attributes of the region's renewable energy resources while also using the inexpensive, dispatchable generation attributes of the fossil fuel resources.*

MDU will continue to look at all resource options and combinations of resource options in the future that would be best to serve MDU customers.

6. *In Volume I: Main Report on page 47, the sensitivity analysis for natural gas should raise the price of natural gas far more than $3.00/dkt from the Base Case. Natural gas was over $10.00/dkt as recently as 2008. DEQ suggests conducting a records review to see what the highest annual average natural gas price was for MDU's system over the past 20 years and using that as the high price.*

   Natural gas prices have been staying steady since the increase of extraction of shale gas from the several fields throughout the United States. With the abundance of shale gas there doesn't seem to be a reason to model $10/dkt in a high natural gas scenario in the near future. However, if something unexpected would occur with the extraction of shale gas, or if there is a major increase in the need for natural gas this could be looked at as a possible scenario in future IRPs.

7. *In Volume II: Attachment A, pp. A-8 and A-9. Can additional information be provided explaining what these allocations and ratios represent?*

   The allocations given on A-8 are explained in detail on pages 37-39 of Volume II, Attachment A of the IRP. They are used to allocate the annual sales, customers, and demand volumes forecasted to the months of the year. However, the sales allocation factors on A-8 are billing cycle allocation factors and put annual sales into monthly billing cycle volumes. The factors given on A-9 are used to convert sales from billing-month to calendar-month quantities and are based on actual billing cycle information from Montana-Dakota's Customer Care and Billing system.

8. *In Volume II, Attachment A, p. C-2. Why is North Dakota's small business electricity demand expected to rise so rapidly? Has MDU modeled alternatives where low oil prices or other factors results in less economic growth for the state and consequently less growth for the state's small businesses?*

   The primary driver in the North Dakota Small C&I sales model is employment. Employment is tied to growth in residential customers which is projected to be fairly strong, especially for the next several years due to Bakken development. As shown on page 24 of Volume II, Attachment A, the North Dakota Small C&I sales sector has grown at 10.59% for 2004-2014 and at 12.67% for 2009-2014. Forecasted growth for the North Dakota Small C&I sector is projected to be fairly strong at 7.18% for 2015-2020 and

gradually tapers off. It is interesting to note that in the 20 years from 1994 to 2014, North Dakota Small C&I sales grew from 203,784 MWh to 609,044 MWh, a growth of nearly 300%. Growth for the next 20 years (2014-2034) is projected to be lower at approximately 255%. All forecast uncertainty is addressed as described on pages 30-36 of Volume II, Attachment A. As outlined there, high-growth and low-growth scenario forecasts are developed in total for the Integrated System. The new preliminary load forecast in Chapter 11 shows a slight decline from the 2017 IRP load forecast, but the low-growth scenario in the 2017 IRP analysis more than covers the change in the load forecast.

9. *In Volume II, Attachment A, pp. C-8 to C-11. What does the column 'load factor' represent?*

   Load Factor is a percentage that represents the portion of time that power is used; i.e., a measure of the efficiency of electrical energy usage. It is calculated to be the average load divided by the peak load for a specific period of time, in this case annually. For example, in 2016, Montana's summer peak is projected to be 160.1 MW while the annual energy requirements are projected to be 913.5 GWh, therefore, load factor is 913,500/(160.1 x 24 x 365) or 65.13%.

10. *Are zonal resource credits defined anywhere in the report? If not, please define in Attachment C.*

    Zonal Resource Credits (ZRC) are defined in Attachment C on pages 1 and 2.

CHAPTER 11

2017 IRP UPDATE

This chapter provides an update to the integrated resource plan since the filing of the North Dakota Integrated Resource Plan filing on July 1, 2017. Several things have changed with the slight reduction in the new load forecast for 2018 and growing the commercial demand response program to 25 MW by the end of 2017 as described below.

Load Forecast

The load forecast used in the North Dakota 2017 IRP and referenced in Chapter 2 of the Montana IRP was developed and finalized in late 2016, and since then a new load forecast has been developed. The new load forecast has total sales increasing by 1.23% over the first five-years compared to the load forecast in the North Dakota 2017 IRP of 1.65% for the same period. The primary drivers for lower total sales is the decline in the five-year growth rate of the residential sales sector from 1.2% to 0.62%, and the Small C&I sales sector going from 3.1% to 2.22%. The total energy requirements for 2018 in the new load forecast is 3,342.6 GWh compared to the North Dakota 2017 IRP total energy requirements for 2018 of 3,401.3 GWh, a decrease of 58.7 GWh or 1.73%.

The summer peak demand also had a decrease in the five-year average from 1.36% in the North Dakota 2017 IRP to 1.17% in the new load forecast. The peak demand for 2018 in the new load forecast is 604.0 compared to 606.4 in the North Dakota 2017 IRP load forecast, which results in a decrease of approximately 0.4%. The comparison of the two forecasts can be seen in Table 11-1.

The change in the load forecast was one of the drivers for the A/C cycling program to not be selected in the updated Base Case modeling results.

Table 11-1

Comparison of the 2017 IRP load forecast and the new load forecast

	North Dakota 2017 IRP Load Forecast		New Load Forecast	
	Demand (MW)	Total Energy Requirements (GWh)	Demand (MW)	Total Energy Requirements (GWh)
2016	588.0	3206.7		
2017	597.9	3344.6	597.1	3302.0
2018	606.4	3401.3	604.0	3342.6
2019	614.9	3458.1	611.2	3383.6
2020	623.6	3515.8	618.4	3425.6
2021	631.6	3567.8	625.5	3467.1
2022	639.7	3619.6	632.9	3511.0
2023	647.2	3665.1	639.8	3549.8
2024	654.9	3713.2	647.0	3591.7
2025	662.0	3755.5	654.1	3632.4
2026	669.4	3800.0	661.4	3675.4
2027	676.7	3843.9	668.8	3719.1
2028	683.9	3888.3	676.1	3763.4
2029	691.3	3933.4	683.6	3808.4
2030	698.8	3979.0	691.2	3854.0
2031	706.3	4025.3	698.9	3900.2
2032	713.9	4072.1	706.6	3947.1
2033	721.6	4119.7	714.3	3994.7
2034	729.3	4167.8	722.2	4043.0
2035	737.1	4216.7	730.1	4092.0
2036	745.0	4266.4	738.1	4142.0
2037			746.2	4192.7

<u>Commercial Demand Response Program</u>

The original plan for the Commercial Demand Response program was to potentially grow the program from a current total of 10 MW to 15 MW by 2019. Since the original modeling was completed, a current customer in the Commercial Demand Response program has decided to add an additional 15 MW of demand response. With this addition of demand response, the Commercial Demand Response program would grow to a total of 25 MW by the end of 2017. The additional 10 MW to the Commercial Demand Response program was the other main factor in driving the A/C cycling program to not be selected as part of the updated Base Case modeling results.

Updated Base Case Results

The North Dakota 2017 IRP Base Case was run under two scenarios along with the new load forecast. The first scenario which is labeled “Original” in Table 11-2 assumes the Commercial Demand Response program was growing to a total of 15 MW by 2019 as was the case in the North Dakota 2017 IRP Base Case. The other scenario, labeled “25 MW Commercial,” takes into account the addition of the extra 15 MW of Commercial Demand Response that will be available by the end of 2017. In both scenarios, the A/C cycling program was not selected in the Base Case scenario. The model was run again forcing in the A/C cycling program to see what the increase in the Net Present Value (NPV) would be in each scenario with the results shown in Table 11-2. The need for the Thunder Spirit Wind expansion and combined cycle combustion turbine continued to be selected as part of both the Base Cases.

With these updated results, the action plan going forward has changed since the original modeling of the North Dakota 2017 IRP. Based on these results, Montana-Dakota’s recommended resource plan is to pursue the following resources to meet the requirements identified for the 2017-2026 period:

- Continue the commercial demand response program to achieve 25 MW by the end of 2017 and achieve 20 MW from Montana-Dakota’s interruptible rates by 2019;
- Purchase the additional 48 MW at the existing Thunder Spirit Wind; and
- Continue the design and engineering work on a natural gas-fired combined cycle combustion turbine resource to be online in or after 2025.

The load and capability can be seen in Figure 11-3 that shows these additions along with the potential retirement of the coal units and the wind farms at their twenty year life.

Table 11-2

Updated Base Case Results

	2018 Load Forecast			
	Original		25 MW Commercial Demand Response	
	Base Case	Base Case AC Cycling	Base Case	Base Case AC Cycling
2017				
2018		AC Cycling		AC Cycling
2019	TSW	TSW	TSW	TSW
2020				
2021				
2022				
2023				
2024				
2025	Heskett CC	CC-SGT-800(140)	CC-SGT-800(140)	CC-SGT-800(140)
2026				
2027				
2028				
2029				
2030		PP(10)	PP(10)	
2031		PP(20)	PP(20)	PP(10)
2032				PP(20)
2033		RICE(36)	RICE(36)	PP(20)
2034	PP(10)	PP(10)	PP(10)	RICE(36)
2035	CT(41)	CT(41)	CT(41)	CT(41)
2036				
NPV ($M)	$2,937.44	$2,946.23	$2,945.98	$2,955.66

Resources:

PP(x) - Purchased Capacity with number representing MW value
AC Cycling - 10 MW phased in over 5 years
TSW - 48 MW Phase II of Thunder Spirit Wind
Heskett CC - Another GE 7EA added with a steam turbine and heat recovery steam generator - 180 MW additional
CC-7FA(323) - 323 MW GE 7FA (1x1) combined cycle combustion turbine
CC-SGT-800(140) - 139.8 MW Siemens SGT-800 (2x1) combined cycle combustion turbine
CT(41) - 41.3 MW GE LM6000PH simple cycle combustion turbine
CT(78) - 78.4 MW GE 7EA simple cycle combustion turbine
WIND(x) - Self-built wind option
BIOMASS - 9.3 MW Biomass
RICE(36) - 36.5 MW Wartsila Reciprocating Internal Combustion Engine (4 units)

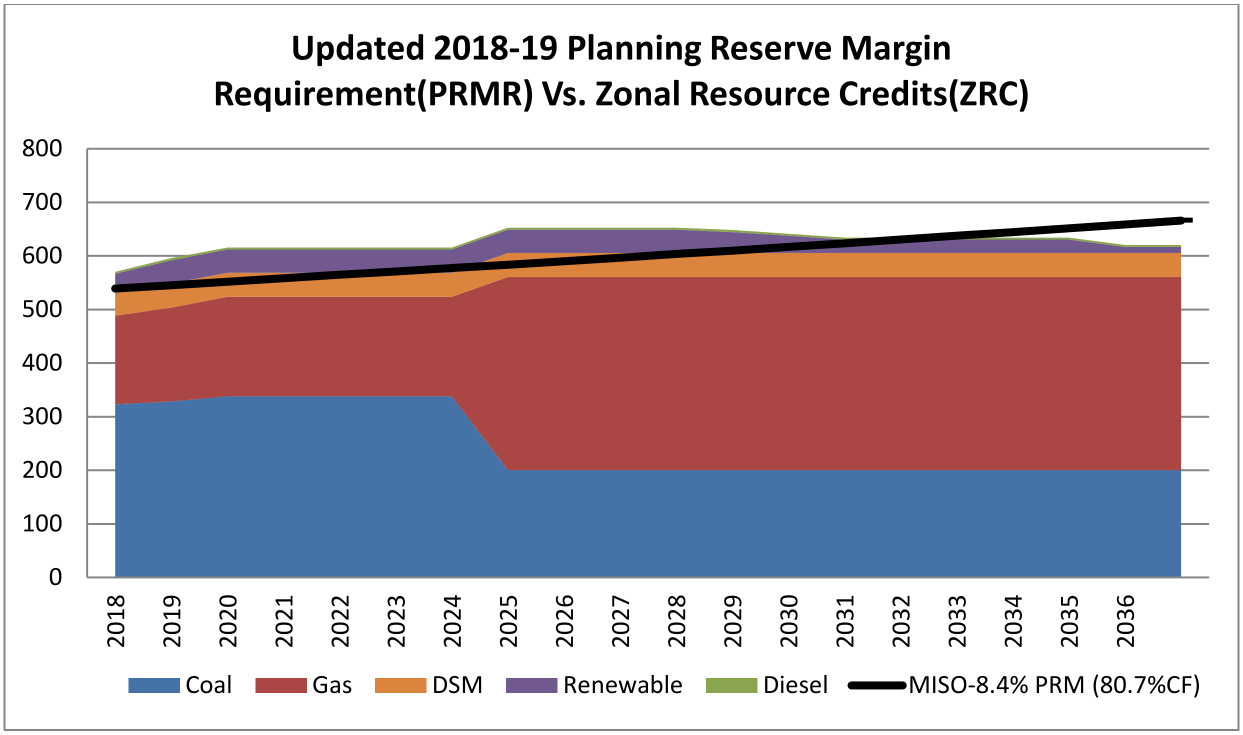


Figure 11-3: The load and capability with new load forecast