Integrated Resource Plan 2024

Submitted to the
Montana Public Service Commission
September 30, 2024

Volume I: Main Report

Montana-Dakota Utilities Co.

2024 Integrated Resource Plan

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Main Report

MONTANA-DAKOTA UTILITIES CO.

A Subsidiary of MDU Resources Group, Inc.

In the Community to Serve®

INTEGRATED RESOURCE PLAN

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EXECUTIVE SUMMARY

Montana-Dakota Utilities Co.'s (Montana-Dakota) 2024 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 35-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. Resources considered 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 20 years into the future. The results for the base forecast show that, during the 2024-2043 timeframe, the projected average annual growth rate for summer peak demand is 0.69 percent prior to any reductions due to demand response programs, while annual energy requirements are expected to increase at a rate of 0.55 percent.

The **demand-side analysis** is an evaluation process to identify the feasible demand-side management (DSM) programs, including energy efficiency programs for Montana-Dakota's system. As discussed in Chapter 3, Montana-Dakota updated the evaluation of several 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 2024-2027 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 including unit retirements. The potential resource options studied included simple cycle combustion turbines, combined cycle combustion turbines, simple cycle reciprocating internal combustion engines, wind generation, solar photovoltaic (PV), battery storage, and short-term capacity purchases. 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 meet customer requirements economically and reliably into the future. There were four base cases established with the current MISO Resource Adequacy summer and winter seasons along with MISO's future Direct Loss of Load (DLOL) for both summer and winter seasons. Several sensitivity scenarios were investigated to determine the sensitivity of the least-cost plan in each of the base cases to several factors that may impact the resource plan. These sensitivity scenarios included high and low natural gas prices, high and low load growth, high and low energy market prices, higher environmental costs for new combustion turbine alternatives, a combination of high and low natural gas and energy market prices, limiting energy market, Coyote Station retirement scenarios, increases in renewable and demand response resources, lower accreditation capacity for units, EPA's new Greenhouse Gas Rule, 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 having a capacity and energy contract through May 31, 2026, along with the increased reliance on MISO market purchases. The Summer IRP model also selected a future simple cycle combustion turbine and the Winter IRP model selected additional wind and simple cycle combustion turbine. The Summer DLOL model selected future storage and the Winter DLOL model selected a future simple cycle combustion turbine, wind, and storage. 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.

Figures E-1 and E-2 provide an overview of the identified need for capacity for the period 2024-2043 assuming the existing capacity contract and adding Heskett 4 for both the summer and winter season. 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 the coincident factor 82.6 percent summer and 92 percent winter. "Existing ZRC" represents 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.

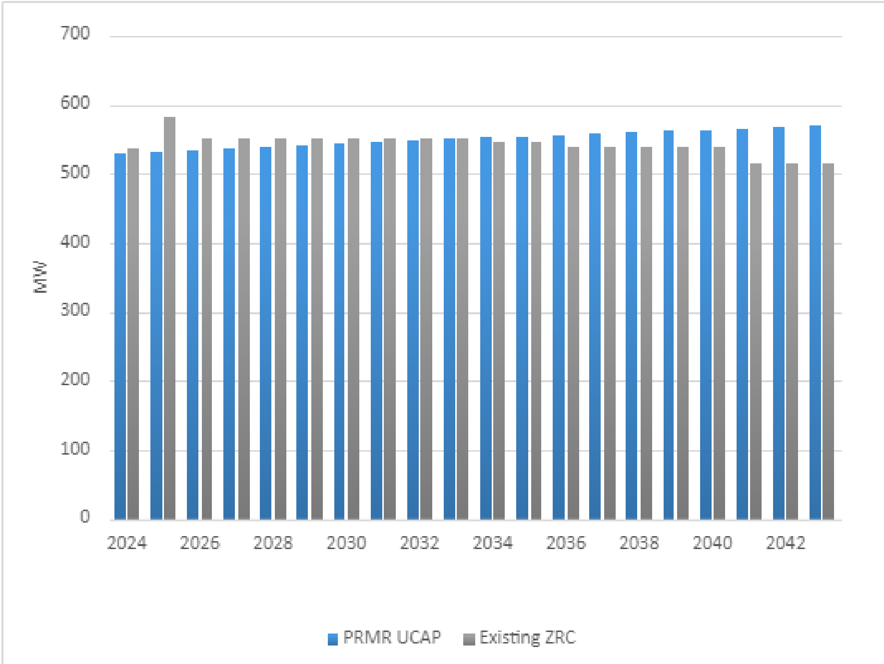

Figure E-1: 2024-2043 Summer MISO Planning Year Zonal Resource Credit and Planning Reserve Margin Requirement

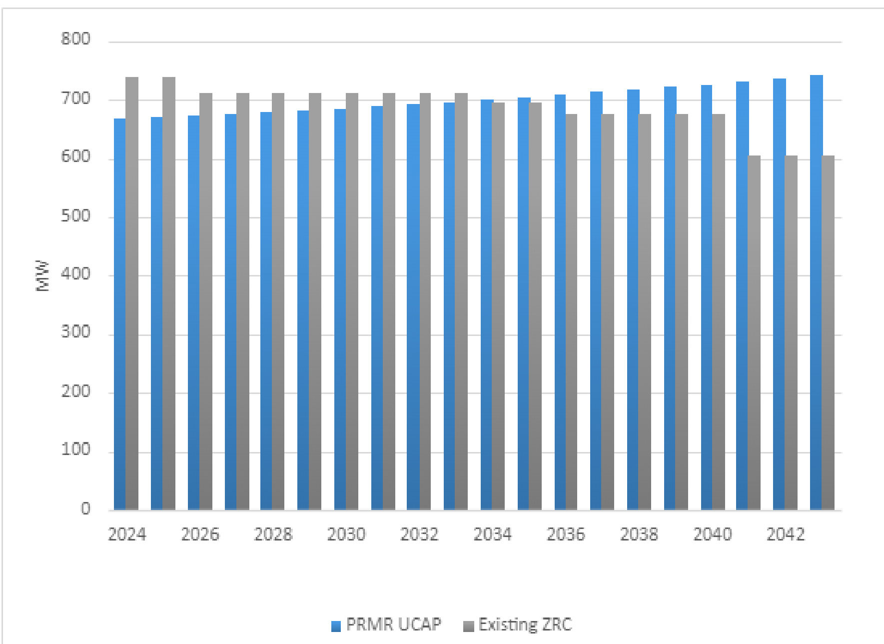

Figure E-2: 2024-2043 Winter MISO Planning Year Zonal Resource Credit and Planning Reserve Margin Requirement

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 plan to meet the requirements identified for the 2024-2029 period is as follows:

- Complete the startup of the new 88 MW Heskett 4 simple cycle combustion turbine at Heskett Station in 2024.
- Issue a new request for proposal for supply side and demand side resources prior to the next IRP.
- Monitor the development of and impacts to Coyote Station associated with the second round of regional haze determination.
- Monitor the impact of the U.S. Environmental Protection Agency (EPA) Greenhouse Gas (GHG), Mercury and Air Toxic Standards (MATS), and Effluent Guidelines (EFG) final rules on Bigstone and Coyote Station.
- Meet short-term capacity deficits via the MISO Capacity Auction or through bi-lateral capacity purchase agreements.
- Increase energy purchases from MISO, as necessary.
- Consider new legislation in North Dakota regarding reliability.
- Monitor the impacts associated with the planned generation shifts within MISO including the Long-Range Transmission Plan, multi-season resource adequacy requirements, Direct Loss of Load (DLOL) future resource adequacy requirements, additional electrification of load associated with carbon reduction future scenarios, and expansion of electric vehicle technologies. Included in the multi-season resource adequacy requirements may be the need to evaluate the conversion of Heskett 3 and 4 to dual fuel combustion.
- Continue the evaluation of the new 150 MW wind opportunity.

The recommended resource plan is considered the best to meet customers' requirements economically and reliably over the planning horizon.

The 2024 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 2024 advisory group was established at the beginning of the 2024 planning cycle and provided Montana-Dakota with input throughout the 2024 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: Transmission Impacts

Attachment G: MISO RTO Overview

CHAPTER 1

ENVIRONMENTAL CONSIDERATIONS

The Company's Environmental Policy states:

> *"The 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 be a good steward of the environment while providing high quality and reasonably priced products and services; and*
> - *To comply with or surpass 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 proposed regulation, 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.

Over the past several years, the U.S. Environmental Protection Agency (EPA) has finalized, proposed new and/or reproposed significant regulations for fossil-fired electric generating facilities that aim to reduce air emissions, including GHGs, and pollutants in wastewater discharges. Most recently, EPA published three final rules on May 7-9, 2024, related to curbing greenhouse gas emissions from fossil fuel-fired generation sources, a new mercury air toxics standard impacting coal-fired power plants, and the effluent limitations guidelines rule. The culmination of these environmental requirements may result in the retirement of existing coal-fired baseload units earlier than otherwise would occur. EPA also published the final legacy coal ash rule on May 8, 2024. Potential expenses incurred by the legacy coal ash rule to evaluate and conduct potential remediations of former coal ash management units will not drive early retirement of existing coal-fired baseload units. These expenses would occur whether a coal-fired generating facility continues to operate or has already retired.

Additional emission controls such as carbon capture and sequestration (CCS) could be implemented to avoid retirement of fossil-fired units to comply with EPA's rule requiring GHG reductions at fossil-fired facilities, but it has not been demonstrated that the technology can be accomplished under the timeline or at the capture rate EPA has finalized. These controls would significantly increase capital and operational costs and reduce the net output of the units due to the significant energy consumption for operating the emissions controls. We anticipate new zero-carbon resources such as wind or solar electric generation facilities would likely be required to comply with President Biden's decarbonization targets for the electric sector. Further, while not an environmental issue, additional electric generation facility-related buildouts such as costly CCS, over build of renewables, energy storage systems, or other emerging net-zero emissions technologies, would be required to meet reliability requirements along with the needed additional electric transmission line buildouts.

Montana-Dakota will continue to monitor regulation changes and will take both proposed and final regulations into consideration when planning for future resource needs.

Renewable Energy

Montana-Dakota has 205 MW of installed wind generation capacity at three locations, providing over 25 percent of its customers' electric energy requirements. Montana-Dakota 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 Greenhouse Gas 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. In 2017, a new target was developed to reduce the Company's electric generation resource fleet CO_2 emission intensity by 45 percent from 2005 in

2030. Since 2005, Montana-Dakota's electric generation resource fleet CO_2 emission intensity has been reduced by approximately 38 percent. We anticipate demonstrating progress toward achieving this target with additional future renewable generation and the past retirements of Lewis & Clark Station Unit 1 and R. M. Heskett Stations Units 1 and 2.

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 performance and reduce costs 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. These workgroups have focused on environmental and CO_2 related issues such as lignite gasification, oxyfuel combustion, pre- and post-combustion CO_2 capture technologies, exploration of advanced baseload options for utilization of lignite fuel, and beneficial uses of CO_2.

GHG emissions have also been reduced from Montana-Dakota's energy efficiency and conservation programs for electric residential and commercial customers. For example, the total kilowatt-hour savings from electric energy efficiency and conservation programs completed in 2023 was about 468,123 kilowatt-hours, equating to a reduction of approximately 366 metric tons of CO_2e.

<u>Environmental Regulation Pollution Control Project Impacts</u>

Recently finalized GHG emissions regulations by EPA will impact the utilization and cost of operating fossil fuel-fired generation resources. An EPA decision expected in later 2024 on Regional Haze could result in significant pollution control requirements at Coyote Station. The new MATS standards will require an increase in capital and operation and maintenance (O&M) expenses at coal-fired generation facilities, most significantly at lignite-fired facilities. The retirements of coal-fired facilities at Lewis and Clark Station in 2021, and Heskett Station in 2022, included closure of CCR facilities associated with each location. The recently finalized CCR Legacy Rule will result in additional costs to manage CCR at each site and could require additional remediation of facilities. These impacts are discussed below. The Effluent Limitations Guidelines Rule is not expected to have an impact on Montana-Dakota owned or co-owned facilities.

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

On May 9, 2024, EPA published GHG emission standards under Clean Air Act Sections 111(b) and (d) for fossil-fired electric generating units in the Federal Register. The rules include EPA's *New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units,* and *Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil-Fuel Fired Electric Generating Units*. EPA also repealed the previous administration's *Affordable Clean Energy Rule*.

For existing fossil fuel-fired units, EPA chose to finalize new regulations for steam electric generation units (i.e., coal, natural gas, and oil-fired boilers), while electing not to address new emissions guidelines for existing stationary combustion turbines or reciprocating internal combustion engines (RICE) at this time. Montana-Dakota does not own any natural gas or oil-fired boilers, so this portion of the rule addressing existing fossil fuel-fired units is only impactful to our coal units located at Coyote and Big Stone. EPA had promulgated GHG emission standards for new coal-fired units in 2015, requiring carbon capture and sequestration, and did not change those standards in this rulemaking.

Existing coal-fired facilities are addressed under three subcategories : 1) continue with normal O&M at the facility and retire prior to Jan. 1, 2032; 2) co-fire with 40% natural gas beginning in 2030 (or an equivalent 16% GHG emission rate reduction by other means), and retire prior to Jan. 1, 2039; or 3) install CCS prior to Jan. 1, 2032, capable of capturing 90% of GHG emissions, and the unit is allowed to continue operating beyond Jan. 1, 2039. The States have primacy over the existing units under this rule and have until May 11, 2026, to submit a state implementation plan to EPA. Montana-Dakota, in coordination with facility co-owners, will be engaging with the various state primacy agencies during drafting of the state plans, to determine what compliance mechanisms may be available for each respective coal-fired generating unit. EPA provides some limited flexibilities for states to consider remaining useful life of units and grid reliability while drafting their respective plans. Once the states finalize and submit their plans to EPA, EPA will need to approve, partially approve, or disapprove each state plan.

For new and reconstructed fossil-fired units, EPA established three new categories for natural-gas fired units: 1) baseload units which operate with a capacity factor >40%; 2) intermediate load units operating at capacity factors of 20-40%; and 3) low load (peaking) units operating at less than 20%

capacity factors. For low load subcategories, the only requirement beyond the capacity factor restriction is to utilize a low carbon fuel such as natural gas. Intermediate units have similar requirements as well as utilizing highly efficient simple cycle turbine technology. Baseload units must incorporate CCS at a 90% capture rate by Jan. 1, 2032.

After EPAs' final GHG rule was published in the Federal Register, multiple entities filed petitions in the District of Columbia (DC) Circuit Court challenging the rule. North Dakota, South Dakota, Montana, and Wyoming are all parties in the petition filed by *West Virginia et. al.* Also, on July 1, 2024, Montana-Dakota filed a petition for review of the GHG rule in the DC Circuit Court. Montana-Dakota will continue to monitor the state implementation efforts and legal challenges to the rule and incorporate changes as needed into the evaluation of supply-side resources.

Regional Haze Rule (RH Rule)

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, EPA published a revised rule that included guidelines for control technology determinations under the RH rule for sources subject to Best Available Retrofit Technology (BART) requirements and for sources addressed for reasonable progress.

State environmental agencies are required to submit State Implementation Plans (SIPs) to 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. Round one of regional haze was finalized in about 2012 and considered emission reductions from BART sources, as well as other emissions sources in consideration of reasonable progress toward improving visibility. During round one, 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 the Heskett 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 ten years, will continue to be completed by States and EPA to continue progress toward the 2064 goal.

On January 10, 2017, EPA finalized amendments to the RH rule that included additional requirements for states as they complete their periodic reviews and extended the next periodic review (round two) by three years. States were then required to submit regional haze round two SIPs to EPA by July 31, 2021. Any required controls for round two would have to be installed and operating by July 31, 2028.

On April 19, 2019, Montana Department of Environmental Quality (MT DEQ) requested Montana-Dakota submit information to support the agency's reasonable progress analysis for Lewis & Clark 1 by September 30, 2019. On February 19, 2019, Montana-Dakota released a planned retirement date for Lewis & Clark 1 of approximately the end of 2020. Since Lewis & Clark 1 ceased operation on March 31, 2021, the Company did not install pollution controls.

The North Dakota Department of Environmental Quality (ND DEQ), sent requests to sources, including Heskett Station and Coyote Station, to submit a four-factor analysis for consideration of round two emissions controls to ND DEQ by January 31, 2019. The analyses were prepared and submitted to ND DEQ. The four-factor analysis is a review of technically feasible SO_2 and NO_x pollution controls that could be applied to a source to reduce emissions that can contribute to regional haze. The analysis includes evaluation of cost of compliance, time necessary for compliance, energy, and non-air quality environmental impacts of compliance, and remaining useful life of the unit.

Although pollution controls for Heskett 1 and Heskett 2 were submitted to ND DEQ for evaluation in the four-factor analysis, a planned retirement date of about the end of 2021 was released by Montana-Dakota on February 19, 2019, for Heskett 1 and Heskett 2. Since Heskett 1 and Heskett 2 ceased operation prior to the end date of round two, the Company did not install pollution controls.

Coyote Station's four-factor analysis identified feasible NO_x and SO_2 pollution controls for ND DEQ to evaluate. ND DEQ evaluated the four-factor analysis and Coyote Station co-owners submitted supplemental information on pollution controls for ND DEQ review. After review, ND DEQ provided recommendations to the regional modeling contractor for modeling emissions reductions and progress with meeting the glidepath.

The capital cost estimates included in Coyote Station's four-factor analysis are wide ranging, largely depending on whether Coyote Station would be able to continue using its existing flue gas desulfurization (FGD) equipment. For example, and as a point of reference, the capital cost of installation of a dry sorbent injection (DSI) combined with other operational improvements to the existing FGD is projected to be in the $24 million range with annual operating costs projected at $12.5 million. However, replacing existing controls by installing a new FGD, like controls at several other North Dakota plants, would have a capital cost of approximately $243 million with annual operating costs projected at $20.6 million. One of the factors used in selecting the pollution control option is cost-effectiveness, and lower cost control options that achieve substantial emissions reductions may have an advantage depending on what ND DEQ considers as a final cost-effectiveness threshold.

ND DEQ made the draft SIP available for public comment in June of 2022. The draft recognized that the State was well on its glide path to help reach the national visibility goal in 2064 and recommended no additional pollution controls for Coyote. Following the public comment period, ND DEQ finalized their SIP and submitted it to EPA on August 11, 2022. EPA determined that the application was complete on August 23, 2022. The CAA deadline for EPA action on a SIP is 12 months from the EPA's determination that the SIP is complete. The EPA failed to act within the allotted time for the ND SIP, as well as other SIPs across the country. Sierra Club, et al. sued the EPA for failure to act and the parties eventually entered a consent decree. As part of that agreement, EPA has stated a commitment to take final action on the ND SIP by November 22, 2024. This would be the date when Montana-Dakota anticipates EPA will make known whether the SIP is approved, disapproved, or partially disapproved. If disapproved or partially disapproved, EPA would propose a federal implementation plan that could result in a different pollution controls decision for Coyote Station. Montana-Dakota will continue monitoring the SIP process and incorporate the outcome into IRP supply-side resource evaluations.

The Coyote Station is co-owned by four utilities. The economics of the plant are different for each owner and are currently under review by the owners, independently. Any actions taken because of the economic analyses by any owner, may have an impact on the economics of the other owners.

Mercury and Air Toxics Standards (MATS)

EPA recently finalized MATS rule revisions which update previously established emission standards for hazardous air pollutants such as mercury and other metals. In the revisions, EPA lowered the filterable particulate matter (fPM) emissions standards to 0.010 lb./MMBtu for all coal-fired units which is a surrogate limit for emissions of non-mercury metals, and eliminated the subcategory for lignite for mercury (Hg) emissions, lowering the standard from 4.0 lbs. of Hg per trillion Btu (TBtu) to 1.2 lbs. of Hg per TBtu. EPA is also requiring facilities to install particulate matter continuous emissions monitoring systems (CEMS) to monitor compliance with the revised fPM emissions standard.

All Montana-Dakota's co-owned coal-fired facilities will incur additional capital costs to install a particulate matter CEMS to monitor emissions, as none of the units currently have this technology. Coyote Station will incur additional O&M costs to control emissions due to the revised mercury standard. Coyote Station is a lignite coal-fired plant which is subject to the revised mercury emission standard of 1.2 lb. of Hg per TBtu and must increase addition of halogenated activated carbon to enhance mercury capture to meet the new standard. The mercury content in lignite is higher and more variable than in sub-bituminous, hence the support for lignite-fired units initially having their own subcategory for mercury emissions standards. Big Stone Plant is a sub-bituminous coal-fired unit and has been complying with the more stringent mercury emissions standard at the outset of the MATS rule in 2018. Compliance with the new requirements for Coyote Station and Big Stone Plant must be achieved by May 7, 2027.

Coal Combustion Residuals (CCR) Rule and Legacy Rule

On April 17, 2015, 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.

On December 16, 2016, the Water Infrastructure Improvements for the Nation (WIIN) Act was signed into law, providing EPA and states the authority to administer and enforce CCR rule requirements through permitting programs. Administration of the CCR rule by EPA and states may potentially result in availability of alternative compliance options.

In 2018 and 2019, the following projects were completed at Montana-Dakota's owned and co-owned coal-fired electric generation resources for compliance with CCR rule requirements: a scrubber pond retrofit at Lewis & Clark Station completed in 2018, a bottom ash handling system retrofit along with a pond and temporary ash storage area closure at Big Stone Plant was completed in 2018, and a similar retrofit and pond closure project at Coyote Station was completed in 2019.

With the retirements and decommissioning of the Lewis & Clark Station Unit 1 in 2021, and Heskett Station Units 1 and 2 in 2022, Montana-Dakota has closed ash handling activities at those sites. Details on closure plans for ash-related facilities are available on the Company's website.

On May 8, 2024, EPA published the final rule, addressing legacy CCR surface impoundments and CCR Management Units. The final rule will go into effect 180 days after being published. Utilities are expected to conduct Facility Evaluation Reports to determine if legacy ash is present, assess the extent of ash on the site, monitor for potential impacts, and close and remediate if necessary. Montana-Dakota is determining the potential CCR units that may fall under these requirements. We will likely incur costs for installation and monitoring of additional ground water monitoring wells and may incur costs to complete additional closure requirements at CCR management units that would be identified through the rule’s required facility evaluations. Facility evaluations are to be completed by February 8, 2027; at which time we will have a more complete understanding of potential costs we may incur.

CHAPTER 2

LOAD FORECASTING

Montana-Dakota typically conducts a 20-year load forecast study annually with the last such study conducted in 2023. Montana-Dakota uses econometric modeling as the starting point for its forecasts. The econometric models for the 2024-2043 Integrated System forecast conducted in 2023 were developed using the statistical software package called SAS® with adjustments to account for recent growth and slowdown periods associated with recent 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:

- Econometrics explicitly measures the effects of underlying causes of trends and patterns.
- Econometrics provide statistical evaluation of forecast uncertainty.
- Econometrics 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. Details regarding the specific econometric factors used in the energy sales forecast and peak demand forecast are 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 customers whose peak demand averages less than 50 kilowatts per month over a year's time.
- Large Commercial & Industrial (LC&I) sector. This sector consists of those customers whose peak demand averages 50 or more kilowatts per 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 started with their actual 2022 levels and then are held constant for the remainder of the forecast. The final models used for each primary customer category 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 using 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 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 2023 (*Electric Load Forecast 2024-2043,* published December 31, 2023). The DSM programs that were selected for the 2021 IRP 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 calculated in the 2023 study was 8.147 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 2021 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 from the 2023 study are presented in Table 2-1 summarizing the total energy requirements and seasonal peak demand.

Montana-Dakota Utilities Co.
Historical and Forecasted Energy and Demand
Integrated System
Reflecting Demand-Side Management Programs from 2021 IRP
Calendar Month Basis

	Total Energy Requirements (net of DSM and EE)		Summer Peak - MW				Winter Peak 2/			
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
2013	3,115,064				546.9				582.1	
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%			564.9	9.71%
2017	3,251,539	1.40%			579.1	-2.97%			565.1	0.03%
2018	3,313,387	1.90%			572.4	-1.16%			563.8	-0.22%
2019	3,301,537	-0.36%			536.9	-6.20%			571.1	1.29%
2020	3,169,086	-4.01%			585.6	9.07%			572.7	0.28%
2021	3,240,600	2.26%			603.7	3.09%			558.0	-2.57%
2022	3,305,682	2.01%			590.2	-2.24%			585.7	4.96%
2023	3,263,461	-1.28%			588.8	-0.24%	Not yet available			
2024	3,251,040	-0.38%	573.4	0.6	572.8	-2.72%	569.8	0.6	569.2	
2025	3,262,875	0.36%	576.9	0.6	576.3	0.61%	572.0	0.6	571.4	0.39%
2026	3,276,381	0.41%	580.6	0.6	580.0	0.64%	574.4	0.6	573.8	0.42%
2027	3,291,338	0.46%	584.5	0.6	583.9	0.67%	577.1	0.6	576.5	0.47%
2028	3,304,290	0.39%	588.1	0.6	587.5	0.62%	579.4	0.6	578.8	0.40%
2029	3,319,364	0.46%	591.9	0.6	591.3	0.65%	582.1	0.6	581.5	0.47%
2030	3,333,013	0.41%	595.6	0.6	595.0	0.62%	584.5	0.6	583.9	0.41%
2031	3,351,640	0.56%	599.9	0.6	599.3	0.72%	587.9	0.6	587.3	0.58%
2032	3,370,689	0.57%	604.1	0.6	603.5	0.70%	591.3	0.6	590.7	0.58%
2033	3,389,765	0.57%	608.4	0.6	607.8	0.71%	594.7	0.6	594.1	0.57%
2034	3,408,922	0.57%	612.7	0.6	612.1	0.71%	598.2	0.6	597.6	0.59%
2035	3,428,151	0.56%	616.9	0.7	616.2	0.68%	601.6	0.6	601.0	0.57%
2036	3,448,941	0.61%	621.4	0.7	620.7	0.73%	605.4	0.6	604.8	0.63%
2037	3,469,787	0.60%	625.8	0.7	625.1	0.71%	609.1	0.6	608.5	0.61%
2038	3,490,230	0.59%	630.3	0.7	629.6	0.72%	612.8	0.6	612.2	0.61%
2039	3,511,186	0.60%	634.7	0.7	634.0	0.70%	616.5	0.6	615.9	0.60%
2040	3,532,235	0.60%	639.2	0.7	638.5	0.71%	620.3	0.6	619.7	0.62%
2041	3,556,134	0.68%	644.0	0.7	643.3	0.75%	624.6	0.6	624.0	0.69%
2042	3,580,110	0.67%	648.7	0.7	648.0	0.73%	628.9	0.6	628.3	0.69%
2043	3,604,271	0.67%	653.5	0.7	652.8	0.74%	633.3	0.6	632.7	0.70%

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 integrated resource planning purposes, a single forecast does not allow 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- 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, 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 2023 study results indicated each one degree increase in temperature at the time of summer peak would result in an increase of approximately 6.9 MW in summer peak demand.

Further statistical analysis of temperatures at the time of system peak for the years 1984 through 2022 (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 Summer Peak Demand (MW)
50%	96.4	0.0
75%	100.5	28.3
80%	101.5	35.2
85%	102.7	43.5
90%	104.2	53.9
95%	106.4	69.1
97%	107.8	78.8

*/ Using 6.9 MW/Degree F

As Table 2-2 shows, with a weighted average temperature of 96.4°F at the time of peak, there is a 50 percent probability the temperature at peak would be lower than 96.4°F and a 50 percent probability the temperature at peak would be higher than 96.4°F. This forecast is referred to as the 50/50 demand forecast.

Also, from Table 2-2, there is a 90 percent probability that actual temperatures at the time of the system peak will not exceed 104.2°F. However, at this temperature (104.2°F), the system peak demand would be 53.9 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 2023 study's 50/50 probability and 90/10 probability impact on the summer demand forecast to yield an Alternate Summer Peak Demand Forecast Comparison.

Montana-Dakota is a member of MISO and for resource adequacy requirements is only required to maintain enough 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 (96.4 degrees F) 50/50 Forecast (MW)	Growth Rate	Alternate Forecast (104.2 degrees F) 90/10 Forecast (MW) */
2024	572.8		626.7
2025	576.3	0.61%	630.5
2026	580.0	0.64%	634.5
2027	583.9	0.67%	638.8
2028	587.5	0.62%	642.7
2029	591.3	0.65%	646.9
2030	595.0	0.62%	650.9
2031	599.3	0.72%	655.6
2032	603.5	0.70%	660.2
2033	607.8	0.71%	664.9
2034	612.1	0.71%	669.6
2035	616.3	0.69%	674.2
2036	620.7	0.73%	679.1
2037	625.1	0.71%	683.9
2038	629.6	0.72%	688.8
2039	634.0	0.70%	693.6
2040	638.5	0.71%	698.5
2041	643.3	0.75%	703.7
2042	648.0	0.73%	708.8
2043	652.8	0.74%	714.1

*/ 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.

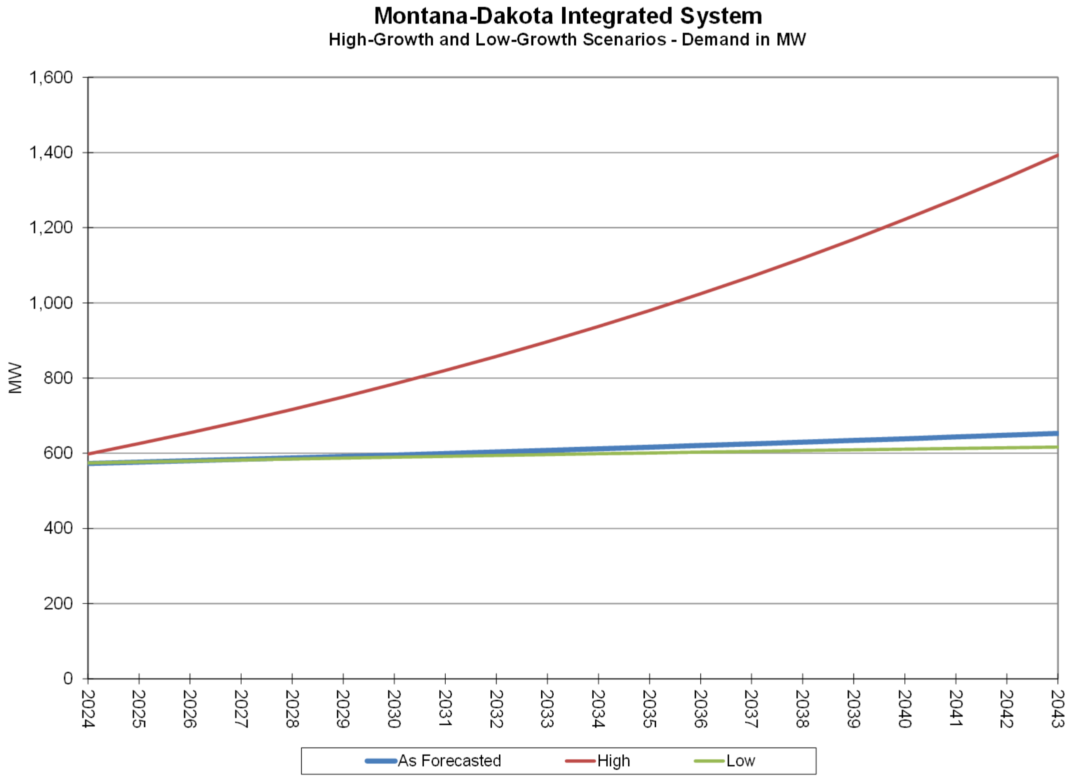
Historical total energy was analyzed in order to find a period during which unusually high growth was experienced and a period during which unusually low growth was experienced. Based on the historical sales data, the average growth rate that occurred from 1977 to 1985 was used as the high-growth rate, and the average growth rate that occurred from 2013 to 2021 was used as the low-growth rate. Both periods consist of eight years of history.

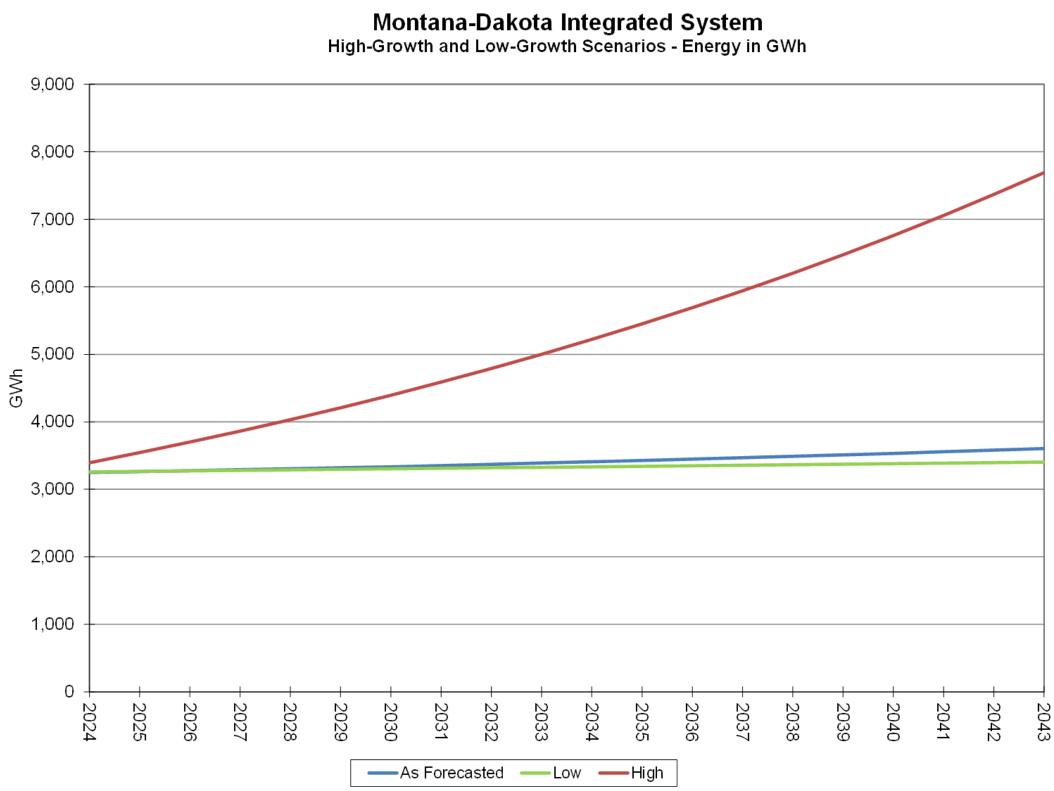
Demand for each scenario was derived by applying the load factors calculated from the base forecast to the high-growth and low-growth scenario forecasted energy. The high- and low-growth scenarios for energy and demand from the 2023 study are shown on Table 2-4. The following page presents the graphs 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
2024	3,251.0	3,394.0	3,258.5	572.8	598.0	574.1
2025	3,262.9	3,543.3	3,266.0	576.3	625.8	576.9
2026	3,276.4	3,699.2	3,273.5	580.0	654.8	579.5
2027	3,291.3	3,862.0	3,281.0	583.9	685.1	582.1
2028	3,304.3	4,031.9	3,288.5	587.5	716.9	584.7
2029	3,319.4	4,209.3	3,296.1	591.3	749.8	587.1
2030	3,333.0	4,394.5	3,303.7	595.0	784.5	589.7
2031	3,351.6	4,587.9	3,311.3	599.3	820.3	592.1
2032	3,370.7	4,789.8	3,318.9	603.5	857.5	594.2
2033	3,389.8	5,000.6	3,326.5	607.8	896.6	596.4
2034	3,408.9	5,220.6	3,334.2	612.1	937.3	598.6
2035	3,428.2	5,450.3	3,341.9	616.3	979.8	600.8
2036	3,448.9	5,690.1	3,349.6	620.7	1024.1	602.9
2037	3,469.8	5,940.5	3,357.3	625.1	1070.3	604.9
2038	3,490.2	6,201.9	3,365.0	629.6	1118.8	607.0
2039	3,511.2	6,474.8	3,372.7	634.0	1169.2	609.0
2040	3,532.2	6,759.7	3,380.5	638.5	1222.0	611.1
2041	3,556.1	7,057.1	3,388.3	643.3	1276.7	613.0
2042	3,580.1	7,367.6	3,396.1	648.0	1333.6	614.7
2043	3,604.3	7,691.8	3,403.9	652.8	1393.2	616.5

1/ High forecast assumes 4.4% growth per year (actual 1977-85 growth).
2/ Low forecast assumes 0.23% growth per year (actual 2013-21 growth).


Montana-Dakota Integrated System
High-Growth and Low-Growth Scenarios - Demand in MW
MW
1,600
1,400
1,200
1,000
800
600
400
200
0
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
2041
2042
2043
As Forecasted
High
Low


Montana-Dakota Integrated System
High-Growth and Low-Growth Scenarios - Energy in GWh
GWh
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
2041
2042
2043
As Forecasted
Low
High

Data Center Load Additions

Montana-Dakota created a new Rate 45 - High Density Contracted Demand Response tariff in North Dakota and South Dakota to help attract large data center loads to its electric service territory. These large data center load under Rate 45 need to be a new customer with greater than 10 MWs of load and are subject to a 5-year electric service agreement negotiated with the company and approved by the Public Service Commission of North Dakota or Public Utility Commission of South Dakota.

Load forecasts for Rate 45 customers are not included in the IRP analysis because these special loads are not serviced by Montana-Dakota's rate-based generation fleet and rely on MISO market purchases and/or specific supply arrangements to meet the data center customer load requirements.

2021 IRP Forecast Review

Comparing the 2021 IRP load forecast to the 2024 IRP load forecast, shows a decrease in forecasted to actual peak demand and energy over the last three years. In 2021, there was still a lot of speculation with potential load growth in the oil fields either with upgrades or additions to existing loads that have not moved forward since the 2021 IRP. In addition, in the 2021 load forecast the effects of COVID were still not known on how load was going to come back once the COVID restrictions were lifted, with some businesses closing and more people working from home. The load growth has slowed noticeably since the COVID pandemic, and we know that there continues to be natural customer energy efficiency gains through more efficient appliances and lighting. The projection going forward is the load forecast growth will stay fairly flat outside of the addition of larger industrial loads and data centers.

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 electric 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 selected GDS Associates, Inc. to conduct an Electric Energy Efficiency Potential Study and DSM Program analysis, which is included in Attachment B of this IRP. 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 2024-2027.

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 currently being offered. The overview provides a program, description, the jurisdictions where the program is 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 3-1.

Summary of Portfolio of Programs Table 3-1			
	Montana	**North Dakota**	**South Dakota**
Residential Programs			
Residential LED Lighting (A-line, 40W, 60W, 75W & 100W equivalent)	50% of the package price of the bulb – maximum $5/bulb		
Residential LED Lighting (Globe, Indoor Flood & Outdoor Flood)	50% of the package price of the bulb – maximum $7/bulb		
Commercial Programs			
Commercial Lighting	Prescriptive program, based on measure		
Commercial Partnership Program (Custom)	Project-Specific		
Commercial Demand Response Resources (DRR) Program	Customer-Specific	Customer-Specific	Customer-Specific
Interruptible Rate Demand Response Program	$3.50/kW	$3.50/kW	

DSM Activity Summary

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

Montana Energy Efficiency (EE) DSM Programs

The current 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 on the residential side. In 2023 there were seven participants (179 bulbs) in the residential LED lighting program, 17 participants in the commercial lighting program, and one participant in the commercial electric partnership program. The Commercial Lighting program continues to see steady participation, which mainly due to an active contractor network in the Montana electric service territory.

Commercial Demand Response Programs

Montana-Dakota currently offers two demand response programs for commercial and industrial customers. The Commercial Demand Response Resources (DRR) Program and Interruptible Demand Response Rate which together provide demand response options to customers starting at 25 kW of demand billing. Combined, these programs are currently providing 36.2 MW of demand response at year end 2023, with an overall goal of providing up to 60 MW of demand response by 2027.

Commercial Demand Response Resources (DRR) Program

The DRR Program was initially 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. As of year-end 2023, Montana-Dakota had 33 customers enrolled in this program providing 23.4 kW of demand response. Target enrollment for the DRR program is 40 MW by 2027.

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 12.8 MW enrolled and Montana-Dakota's goal is to increase participation by 7.2 MW or to a total enrollment of 20 MW by the summer of 2027.

DSM Program Planning

In late 2022, Montana-Dakota began the process of undergoing an Electric Energy Efficiency Potential Study (Potential Study) which was completed in October 2023. Montana-Dakota selected GDS Associates, Inc. (GDS) to conduct the study. The first part of the study was to conduct primary research to collect updated equipment saturation and efficiency characteristics, as well as measure customer willingness to participate in energy efficiency programs/measures. The study examines the potential to reduce electric consumption and peak demand through the implementation of DSM technologies and practices in residential, commercial, and industrial facilities. This study provided results on a state-by-state basis and distinguishes three types of energy efficiency potential.

1) Technical Potential – the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all factors.

2) Economic Potential – refers to the subset of the technical potential that is economically cost-effective. Economic potential only considers the costs of efficiency measures themselves.
3) Achievable Potential – the among of energy use that efficiency can realistically displaced. This is broken into Maximum Achievable Potential (MAP) and Realistic Achievable Potential (RAP). This considers real-world barriers in adopting efficiency measures, the non-measure costs of delivering programs and the capability of programs and administrators to boost program activity over time. The study assessed two types of achievable potential: maximum (MAP) and realistic (RAP). The difference between MAP and RAP is the incentive level. MAP assumes the incentive is 100% of the incremental cost of the measure, while RAP assumes the incentive to be approximately 40% of the incremental cost of the measure.

Based on the results of the Potential Study, Montana-Dakota estimates a realistic achievable annual energy reduction of 0.84 percent of annual energy sales (MWh) and 4.37% 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
2024	3,006,130	0.63%	18,884
2025	3,017,074	0.71%	21,280
2026	3,029,563	0.72%	21,809
2027	3,043,393	0.70%	21,394
2028	3,055,369	0.71%	21,712
2029	3,069,307	0.77%	23,693
2030	3,081,928	0.84%	25,982
2031	3,099,152	0.88%	27,290
2032	3,116,766	0.89%	27,672
2033	3,134,405	0.93%	29,111
2034	3,152,119	0.99%	31,140
2035	3,169,900	0.93%	29,395
2036	3,189,123	0.99%	31,716
2037	3,208,399	0.93%	29,970
2038	3,227,302	0.89%	28,783
2039	3,246,679	0.90%	29,185
2040	3,266,142	0.89%	29,230
2041	3,288,241	0.84%	27,564
2042	3,310,411	0.83%	27,627
2043	3,332,751	0.83%	27,795
Cumulative	**63,044,153**	**0.84%**	**531,233**

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
2024	572.8	0.26%	1.48	569.3	0.22%	1.27
2025	576.3	0.28%	1.59	571.4	0.23%	1.33
2026	580.0	0.27%	1.59	573.8	0.23%	1.32
2027	583.8	0.27%	1.56	576.5	0.22%	1.29
2028	587.5	0.27%	1.56	578.9	0.22%	1.27
2029	591.2	0.28%	1.65	581.5	0.23%	1.33
2030	595.0	0.29%	1.74	583.9	0.24%	1.42
2031	599.3	0.30%	1.82	587.3	0.25%	1.47
2032	603.5	0.31%	1.85	590.7	0.25%	1.50
2033	607.8	0.31%	1.89	594.1	0.26%	1.54
2034	612.0	0.31%	1.92	597.6	0.26%	1.56
2035	616.3	0.30%	1.86	600.9	0.25%	1.52
2036	620.7	0.33%	2.07	604.9	0.27%	1.65
2037	625.2	0.31%	1.95	608.5	0.26%	1.57
2038	629.7	0.29%	1.81	612.2	0.24%	1.45
2039	634.1	0.30%	1.89	615.8	0.25%	1.53
2040	638.5	0.28%	1.82	619.7	0.24%	1.47
2041	643.3	0.27%	1.73	624.0	0.22%	1.40
2042	648.0	0.26%	1.68	628.4	0.21%	1.34
2043	652.8	0.25%	1.64	632.6	0.21%	1.31
Cummulative					**4.37%**	**28.55**

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 four different cost-effectiveness tests: The Participant Test (PCT), the Utility Test (UCT), the Ratepayer Test (RIM), 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 *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 the program.

The GDS Team conducted research and analysis to provide a recommendation for Montana-Dakota Utilities to consider as potential improvements to their electric energy efficiency program portfolio. The primary objective is to expand energy efficiency for all customers and to offer sector specific programs for residential, and commercial & industrial customers. The GDS Team combined market research of regional peer electric energy efficiency programs with the realistic potential outcomes from the marker potential assessment, in addition to current industry trends and best practices. This activity was not a comprehensive portfolio optimization analysis, instead priorities focused on energy efficiency offerings for all customers. The proposed programs are presented in 4 categories: 1) Residential Home Energy Improvement (Residential HEI); 2) Residential Low-Income; 3) Commercial & Industrial Prescriptive; and 4) Commercial and Industrial Custom. Each category consists of several individual program measures. The following outlines the programs included in each category.

Residential Home Energy Efficiency (HEI)		
Air Sealing	Ductless AC	Pipe Wrap
Air Source Heat Pump	Exterior Lighting Controls	Heat Pump Water Heater
Attic Fan	Ductless Heat Pump	Room AC
Basement Insulation	Duct Sealing	Shower Valve
Bathroom Aerator	Kitchen Aerator	Showerhead
Central AC	Light Sensor	Smart Thermostat

Residential Low-Income*		
Air Sealing	Energy Star Door	Heat Pump Water Heater
Air Source Heat Pump	Exterior LED Lighting	Room AC
Attic Fan	Ductless Heat Pump	Shower Valve
Basement Insulation	Duct Sealing	Showerhead
Bathroom Aerator	Kitchen Aerator	Smart Thermostat
Central AC	LED Lighting	Wall Insulation
Ductless AC	Pipe Wrap	

** Dedicated to customers who are elibible for the Low-Income Energy Assistance Program*

Commercial & Industrial Prescriptive		
Daylighting Controls	LED High Bays	LED Troffers
Dishwashers	LED Interior Directional Fixtures	LED Wallpacks
Exterior Area Light Fixtures	LED Low Bays	Occupancy Sensors
LED Downlight Fixtures	LED T8 Tube Replacements	

Commercial & Industrial Prescriptive - End Uses		
HVAC	Ventilation	Whole Building New Construction
Refrigeration	Compressed Air	

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
Table B-5

Benefit/Cost Ratios					
DSM Program	**Customer Class**	**Ratepayer RIM**	**Utility UCT**	**Participant PCT**	**Total Resource TRC**
Total Portfolio		0.23	2.09	12.09	1.39
Residential Programs					
Home Energy Improvement (HEI) Program	Residential	0.19	0.90	7.70	0.71
Residential Low-Income Program	Residential	0.17	0.57	6.92	0.68
Commercial Programs					
Commercial & Industrial Prescriptive Program	Commerical	0.24	2.68	12.50	1.69
Commercial & Industrial Custom Program	Commerical	0.24	2.43	17.76	1.64

Montana-Dakota Utilities Co.
North Dakota Electric DSM Program Summary
Table B-6

Benefit/Cost Ratios					
DSM Program	**Customer Class**	**Ratepayer RIM**	**Utility UCT**	**Participant PCT**	**Total Resource TRC**
Total Portfolio		0.24	2.29	15.78	1.51
Residential Programs					
Home Energy Improvement (HEI) Program	Residential	0.21	1.47	12.88	1.09
Residential Low-Income Program	Residential	0.17	0.60	7.88	0.64
Commercial Programs					
Commercial & Industrial Prescriptive Program	Commerical	0.25	3.07	16.94	1.90
Commercial & Industrial Custom Program	Commerical	0.25	2.49	19.70	1.65

Montana-Dakota Utilities Co.
South Dakota Electric DSM Program Summary
Table B-7

Benefit/Cost Ratios					
DSM Program	**Customer Class**	**Ratepayer RIM**	**Utility UCT**	**Participant PCT**	**Total Resource TRC**
Total Portfolio		0.23	2.30	16.24	1.56
Residential Programs					
Home Energy Improvement (HEI) Program	Residential	0.19	1.07	8.25	0.83
Residential Low-Income Program	Residential	0.15	0.42	4.99	0.44
Commercial Programs					
Commercial & Industrial Prescriptive Program	Commerical	0.24	3.25	18.65	1.94
Commercial & Industrial Custom Program	Commerical	0.23	2.08	24.08	1.53

DSM Implementation Plan

The following is a discussion by state of the expected DSM activity for program years 2024-2027. Also included is a discussion on Montana-Dakota's continued research into distributed energy resources as a possible fit for future system supply.

Montana

Although the Potential Study provided a portfolio of program recommendations for Residential Customers, Low-Income Residential Customers, Commercial Prescriptive Programs and Commercial Custom Programs, Montana-Dakota is monitoring activity for the types of programs that will be offered by the state of Montana through the Inflation Reduction Act (IRA) funding they receive. Currently, there have not been any plans implemented in Montana, but Montana-Dakota anticipates programs will be ramped up in the next 1-2 years.

Montana-Dakota proposes to continue to offer the existing portfolio of programs (Residential LED Lighting, Commercial Lighting, and Commercial Electric Partnership) until more is known about the proposed State of Montana EE programs funded through the IRA. Montana-Dakota will evaluate and seek to implement programs that will complement the state programs funded through the IRA, to maximize energy savings. In addition, Montana-Dakota will continue to implement the Commercial Demand Response Program and promote the Interruptible Demand Response Rate.

North Dakota

Although the Potential Study provided a portfolio of program recommendations for Residential, Residential Low-Income, Commercial Prescriptive, and Commercial Custom Programs, Montana-Dakota is monitoring activity for the types of programs that will be offered by the state of North Dakota through the IRA funding they receive. Currently there have not been any plans implemented in North Dakota, but Montana-Dakota anticipates programs will be ramped up in the next 1-2 years.

Montana-Dakota will review the state of North Dakota's plan and evaluate the implementation of programs that will complement the state programs funded through the IRA, to maximize energy savings.

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

South Dakota

Although the Potential Study provided a portfolio of program recommendations for Residential, Residential Low-Income, Commercial Prescriptive, and Commercial Custom Programs, Montana-Dakota is monitoring activity for the types of programs that will be offered by the state of South

Dakota through the IRA funding they receive. Currently there have not been any plans implemented in South Dakota, but Montana-Dakota anticipates programs will be ramped up in the next 1-2 years.

Montana-Dakota will review the state of South Dakota's plan and evaluate the implementation of programs that will complement the state programs funded through the IRA, to maximize energy savings.

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

Distributed Energy Resources

Distributed Energy Resources (DER) refers to decentralized energy production that takes place on, or near, the site being served. DER 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 DER resources include cogeneration (fired by fossil or biofuels), small wind, rooftop or community solar photovoltaic (PV), 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. These may or may not feed energy back into the grid.

While traditional fuel sources such as coal, gas, and large wind remain the 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 energy resources have 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 DERs take, 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 (PV) 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 price decreases due to 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 likely 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.

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 using 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 energy resource standpoint, this technology would be of 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.

Fuel Cells

Fuel cells work like batteries, but they do not run down or need recharging. They produce electricity and heat as long as fuel is supplied. A fuel cell consists of two electrodes—a negative electrode (or anode) and a positive electrode (or cathode)—sandwiched around an electrolyte. A fuel, such as hydrogen, is fed to the anode, and air is fed to the cathode. In a polymer electrolyte membrane fuel cell, a catalyst separates hydrogen atoms into protons and electrons, which take different paths to the cathode. The electrons go through an external circuit, creating a flow of electricity.

In addition to electricity, fuel cells produce heat. This heat can be used to fulfill heating needs, including hot water and space heating. Combined heat and power fuel cells are of interest for powering houses and buildings, where total efficiency as high as 90% is achievable. Montana-Dakota recently had an industrial customer install combined heat and power fuel cells into their operation using natural gas as an input fuel and the exhaust heat to replace a heating system in their facility.

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 various states in the U.S.

Approaching 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 DER 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, potentials for reduction in regional transmission organization (RTO) transmission costs, and the value they serve from a system reliability standpoint.

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 which could be added to Montana-Dakota's generating portfolio. This analysis also discusses the timing of existing unit retirements. 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, which is 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, purchase, or retire. 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 Montana-Dakota's shares of the baseload coal-fired Coyote and Big Stone Stations, and natural gas-fired peaking generation at Glendive (Units 1 and 2), Miles City, Heskett (Units 3 and 4), and Lewis & Clark Station 2. Montana-Dakota also owns and operates the Diamond Willow, Cedar Hills, and Thunder Spirit wind farms, two 2 MW portable diesel units, Glen Ullin Station 6 waste heat generating unit, and the Commercial Demand Response Program and Interruptible Demand Response Rate serving the Integrated System. Montana-Dakota has signed a capacity and energy contract that runs through May 31, 2026, which supplies 30 MW of capacity and 75 MW of energy. Total zonal resource credits (ZRC) available from the existing units in the summer of 2024 are 536.8 and 740.3 ZRC in the winter.

Future Capacity and Energy Resources

As part of the 2019 IRP, Heskett 4 was selected as part of the least cost plan to replace the Heskett 1 and 2 coal-fired units that were retired in early 2022. Heskett 4 is an 88 MW simple cycle combustion turbine and is projected to be online in 2024.

On July 22, 2020, Montana-Dakota entered into a power purchase agreement (PPA) to purchase 30 MW of capacity and 75 MW of energy through May 31, 2026.

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

Simple Cycle Combustion Turbines

Simple cycle combustion turbines (SCCT) are primarily used to supply low-cost capacity, but a limited amount of energy, and are fueled by either natural gas or fuel oil. Combustion turbines have a relatively low capital cost, but the energy produced has historically been more expensive than that produced from coal because of 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 with other traditional forms of generation like coal-fired plants, however these units are rarely dispatched in the Montana-Dakota system of the MISO energy market. Combustion turbines can be installed with a shorter lead time than baseload and intermediate resources and serve as peaking and emergency backup generation needs for the Company.

Simple Cycle Reciprocating Internal Combustion Engines

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 with a shorter lead time than baseload and intermediate resources 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. With some of the latest advanced CCCT technology configurations, CCCT's have one of the highest efficiencies of any new fossil fuel power plant that was modeled. These units are usually used as an intermediate unit today but are increasingly being used as more of a baseload unit to replace retired coal 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 depending on fuel costs compared to other alternatives.

Wind Generation

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.

Solar PV

Another renewable resource alternative is solar PV, which has traditionally had a higher capital cost than other types of renewable generation. The installed cost of solar PV has come down in recent years with technology improvements and higher levels of manufacturing. Like wind generation, solar PV is a variable output energy resource and must rely on other capacity resources to meet Montana-Dakota's MISO zonal reserve margin requirements. In MISO's four-season planning model for resource adequacy, solar PV capacity credit ranges from 5 percent in the winter season to 50 percent in the summer to meet peak seasonal demand forecast requirements.

Battery Storage

A battery storage resource is used to store energy mainly on off-peak times to later be used when needed for peak conditions. These units are often paired with renewable resources or can be used to increase reliability and reduce loading on a transmission or distribution system. Like solar PV, the installed cost of battery storage has come down in recent years with technology improvements and higher levels of manufacturing.

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 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 seasonal capability through a Generator Verification Test Capability (GVTC) process that establishes the generator's Installed Capacity (ICAP) value. MISO then converts the ICAP value to a Seasonal Accredited Capacity (SAC) based on each unit's availability during the periods of highest risk and greatest need during each of the four seasons. The SAC values are then directly converted to a ZRC to be used to meet PRMR.

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 peak demand for the four seasons with an adder for MISO losses, plus a planning reserve margin (PRM). The PRM for the summer season is 9 percent and the winter season is 27.4 percent for the 2024-25 MISO Planning Year.

Montana-Dakota calculates a coincident factor for each that varies from 82.6 percent in the summer season to 92 percent in the winter season for the 2024-25 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 summer system load forecast, Montana-Dakota has adequate capacity to meet its PRMR through 2030 for the summer season. The capacity deficit in 2031 will be 2.2 ZRC and is expected to grow to 37.3ZRC in 2037. Under the winter season, as shown in Table 4-2, a capacity deficit will occur in 2034 (18.6 ZRC) and grow to 52.2 ZRC in 2037.

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 meet customers' requirements economically and reliably.

MISO's four-season resource adequacy requirement began in the 2023-24 MISO Planning Year. The impacts of the four-season resource adequacy requirement have not had a large impact on the generation requirements for Montana-Dakota's fleet. Montana-Dakota manages resource expansion needs by evaluating the amount of summer and winter seasonal capacity that it requires to meet the MISO Resource Adequacy (RA) requirements.

Table 4-1

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

SUMMER FORECAST

Year	Summer Zonal Resource Credits[1]	Summer Planning Reserve Margin Requirement	Surplus/ Deficit (+)/(-)
2024	536.8	528.6	8.2
2025	580.9	531.8	49.1
2026	550.9	535.3	15.6
2027	550.9	538.8	12.1
2028	550.9	542.2	8.7
2029	550.9	545.6	5.3
2030	550.9	549.1	1.8
2031	550.9	553.1	-2.2
2032	550.9	556.9	-6.0
2033	550.9	560.9	-10.0
2034	546.9	564.9	-18.0
2035	546.9	568.8	-21.9
2036	539.7	572.8	-33.1
2037	539.7	577.0	-37.3

1 – Total based on 2024-25 Summer MISO Planning Year Zonal Resource Credits

Table 4-2

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

WINTER FORECAST

Year	Winter Zonal Resource Credits[1]	Winter Planning Reserve Margin Requirement	Surplus/ Deficit (+)/(-)
2024	740.3	680.6	59.7
2025	740.3	683.1	57.2
2026	710.3	686.0	24.3
2027	710.3	689.2	21.1
2028	710.3	692.1	18.2
2029	710.3	695.2	15.1
2030	710.3	698.1	12.2
2031	710.3	702.1	8.2
2032	710.3	706.2	4.1
2033	710.3	710.3	0.0
2034	695.8	714.4	-18.6
2035	695.8	718.4	-22.6
2036	675.3	723.2	-47.9
2037	675.3	727.5	-52.2

1 – Total based on 2024-25 Winter 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 13 (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 least-cost analysis, Montana-Dakota will determine the best integrated resource plan to meet customer needs.

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

The reduction in energy and peak demand for previously implemented DSM programs has been reflected as a reduction 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 reflected as a resource and are not used to reduce the load forecast amounts.

As a result of the demand-side analysis described in Chapter 3, all models did include a committed amount of 15.2 MW from the interruptible rate and 25 MW of the commercial demand response program in 2024 and increasing to a total of 45.2 MW by 2027.

<u>Sensitivity Analysis</u>

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. The sensitivities were applied to both the summer and winter seasons along with applying it MISO's future Direct Loss of Load (DLOL) method for both summer and winter seasons.

<u>*Carbon Tax*</u>

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 was modeled to assess the impact on the resource expansion plan. The assumed carbon tax was applied to all carbon emissions from Montana-Dakota's 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 2028. While no carbon tax was modeled in the base case, Montana-Dakota modeled a carbon tax of $50 per ton for a sensitivity analysis.

Natural Gas Price Sensitivity

Prices for natural gas supplies as delivered to Montana-Dakota's existing turbines, potential future combustion turbines, and potential future combined cycle plants were developed in-house using historic pricing and forward gas indexes for use in the resource expansion analysis based on Montana-Dakota's view of the long-term outlook of natural gas pricing. For new resources in the base case, natural gas was priced for delivery at $2.68/MMBtu for 2024 and increasing to $4.12/MMBtu in 2028. After 2028, 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 developed, whereby the gas price used in the base case was increased by $2/MMBtu $5/MMBtu, and $7/MMBtu and decreased by $1/MMBtu from the Base Case ($2.68/MMBTU in 2024), respectively.

Montana-Dakota creates a forward price strip reflecting its expectations for future index settlements. This activity is done each month for a minimum of 60 future months for all applicable trading indexes. Montana-Dakota achieves this by aggregating price outlooks and other economic data from several industry and governmental publications including real-time market valuations. Index expectations are applied to our existing portfolio plan. Montana-Dakota must also consider this outlook, storage injections and withdrawals, and fixed price positions create a forward looking monthly weighted average cost of gas.

High- and Low-Growth Scenario Forecasts

The base forecast in Chapter 2 projected that summer peak demand would increase at an average rate of 0.64 percent per year for the next five years and at an average rate of 0.69 percent per year through 2043. The winter peak demand would increase at an average rate of 0.43 percent over the next five years and 0.56 percent per year through 2043. Annual energy requirements would increase at an average rate of 0.42 percent per year for the next five years, and at an average rate of 0.55 percent per year through 2043. The forecast also established high-growth and low-growth scenarios in which energy requirements were assumed to grow at 4.4 percent and 0.23 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.

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 most of the peak hours. With these scenarios, Montana-Dakota modeled sensitivities of a +25% and +50% adder for the high energy price scenarios and used a -25% reduction for a low energy price scenario to the base case on energy prices for both on and off peak. Montana-Dakota utilizes a third-party MISO forecast energy market price developed by Wood Mackenzie.

Montana-Dakota also looked at decreasing the amount of energy that can be purchased from 250 MW on and off peak to 0 MW over five- and ten-year periods.

Natural Gas and MISO Energy Purchases Combination

This sensitivity assumes both natural gas and the energy market prices are increased or decreased over the Base Case.

Coyote Retirement

As the technology requirements for Coyote Stations Regional Haze project are still unknown at this time, several sensitivity runs were done to show the impacts on the Company's Resource Plan if Coyote Station was retired by the end of 2027 and 2031. The model in the 2028 retirement allows Coyote to be picked again to run until the end of 2031. In the 2032 retirement case the model can pick Coyote to run through 2038 with a $25 million capital investment (MDU's portion 25%) to add natural gas to the unit to run with 60 percent coal/40 percent natural gas.

Higher Environmental Costs for Natural Gas Fired Alternatives

This sensitivity looked at the results of increasing the capital and O&M costs on natural gas fired alternative options that were included as part of the study in Attachment E.

Increase Renewables and Demand Response

As part of the Montana IRP Rules additional modeling is required to look at the effects of adding additional renewables and demand response to the portfolio. There were two different scenarios, the first being a 25 percent increase in renewables and a 5 percent increase in demand response over what Montana-Dakota currently owns and the second was increasing to 50 percent renewables and 10% demand response.

Lower Resource Adequacy Accreditation

As part of the new North Dakota IRP Rules a scenario was done to lower the amount of accreditation Montana-Dakota would get for each of its resources as part of MISO Resource Adequacy process. The scenario ran looked at decreasing every unit's accredited capacity by 10 percent.

Greenhouse Gas Rule

This sensitivity looked at the new EPA proposed rule for greenhouse gas emissions on existing coal-fired power plants and new natural gas fired power plants. The scenario looked at retiring both Coyote and Big Stone at the end of 2031 and limiting the run times on any new natural gas fired power plants that the model selected.

New Wind Opportunity

Montana-Dakota has come across a potential new wind opportunity in the later stage of the IRP cycle, so a sensitivity was done to include this new wind opportunity in the Base Case to if the new wind opportunity would be selected.

CHAPTER 6

RESULTS

This section presents the results of the 2024 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, and exceptionally reliable electric service. 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:

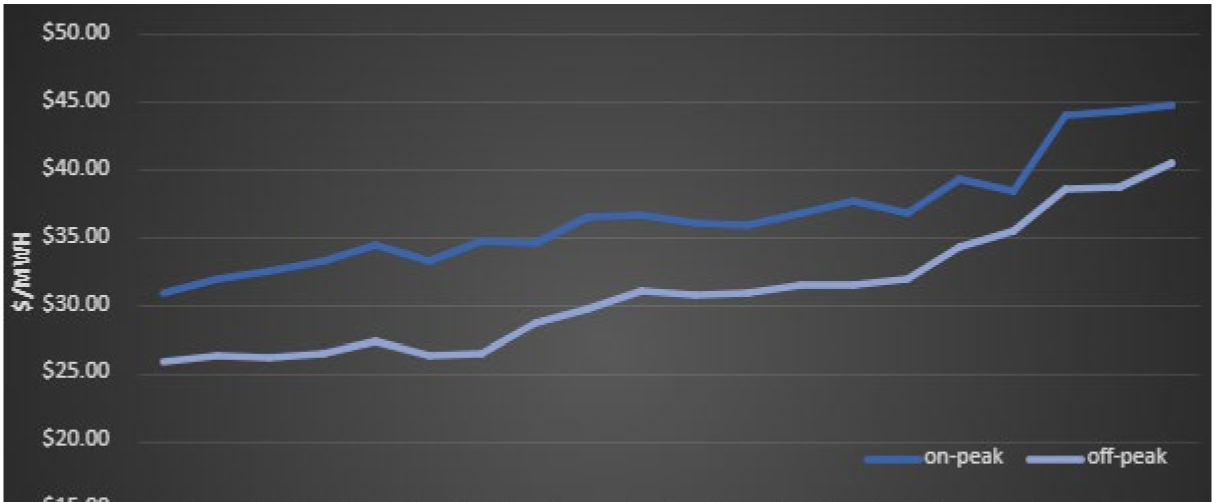
- System reliability and resiliency,
- Fuel price stability,
- Benefits resulting from participation in the MISO market,
- The possibility of unexpected new large load developing in Montana-Dakota's service territory,
- The integration of renewable generation resources and the economic and social benefits 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.

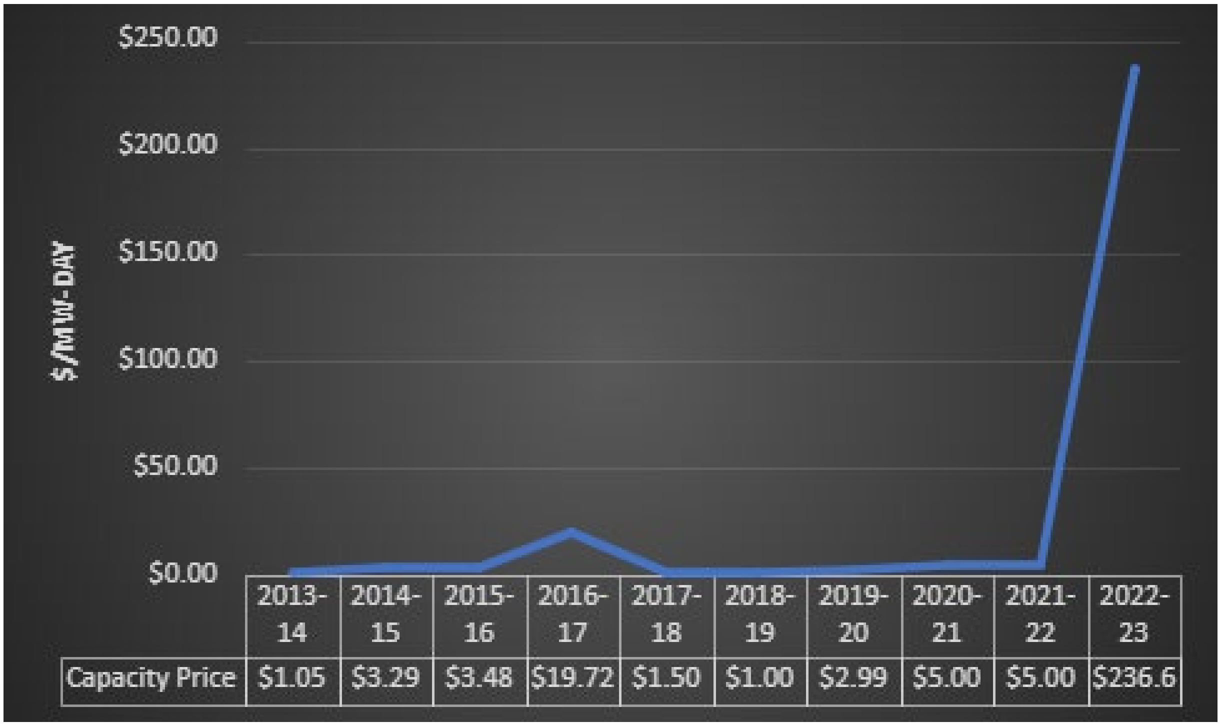
The MISO market provides a source for energy when prices are lower than Montana-Dakota's generating costs, or when, due to planned maintenance or forced outages, Montana-Dakota needs to purchase energy to maintain reliability. The market also provides a means whereby Montana-Dakota can sell energy into the market from its generating facilities that are 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 developed by Wood Mackenzie. The model included a 250 MW block of energy for off-peak and on-peak periods.



	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
on-peak	$30	$31	$32	$33	$34	$33	$34	$34	$36	$36	$36	$35	$36	$37	$36	$39	$38	$43	$44	$44
off-peak	$25	$26	$26	$26	$27	$26	$26	$28	$29	$31	$30	$30	$31	$31	$31	$34	$35	$38	$38	$40

Figure 6-1: Forecasted On-Peak and Off-Peak MISO Market Prices developed by Wood Mackenzie

MISO implemented an annual capacity auction starting with the 2013-14 planning year. Montana-Dakota has purchased small amounts of short-term capacity from the MISO Capacity Auction in the 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. Figure 6-2 shows the historical MISO Planning Resource Auction for zone 1, in which Montana-Dakota is located. The spike in 2022-2023 pricing on Figure 6-2 indicated a capacity shortfall in the MISO North/Central Regions. As shown in Figure 6-3 the seasonal capacity auction price returned to similar pricing as we had seen in the past. The auction clearing price does not necessarily represent a long-term trend but is a function of annual offer prices submitted but generators and the amount of capacity that market participants buy in the market which changes from year to year.



	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
Capacity Price	$1.05	$3.29	$3.48	$19.72	$1.50	$1.00	$2.99	$5.00	$5.00	$236.6

Figure 6-2: Historical Annual MISO Capacity Resource Auction Prices for Zone 1

	2023-24	2024-25
Summer	$10.00	$30.00
Fall	$15.00	$15.00
Winter	$2.00	$0.75
Spring	$10.00	$34.10

Figure 6-3: Historical Seasonal MISO Capacity Resource Auction Prices for Zone 1

Reliance on Natural Gas

About 42 percent of Montana-Dakota's owned generating nameplate capacity will come from natural gas-fired resources with the addition of Heskett 4 in 2024. As shown on Figure 6-4, 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. Short term price spikes still occur from time to time but on average natural gas forecast prices have remained low and stable. Figure 6-5 shows the future natural gas price that was used for future resources developed by Montana-Dakota's Gas Supply Department.

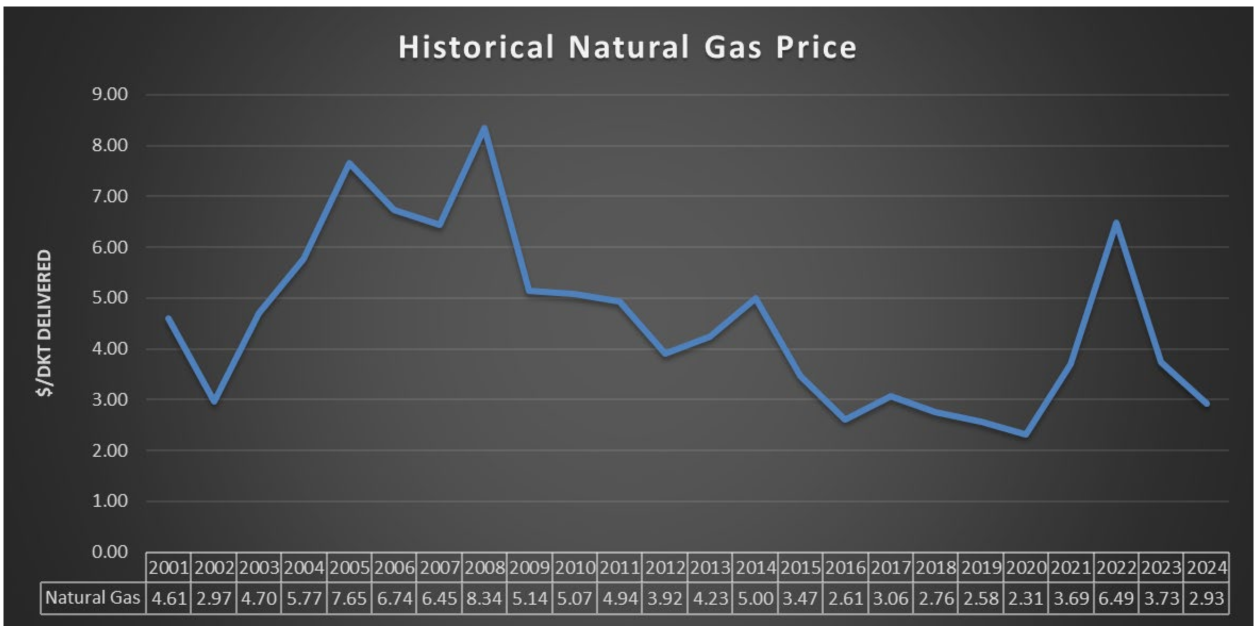


Figure 6-4: Historical Natural Gas Prices of Montana-Dakota's existing combustion turbines (Based on 12-Month Average)

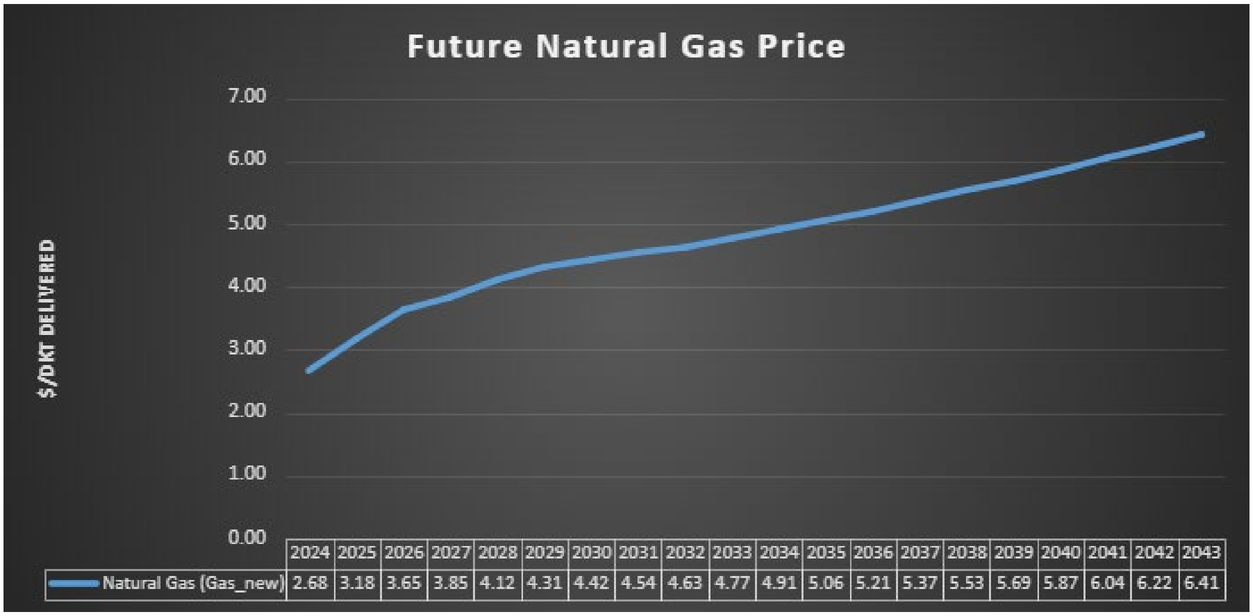


Figure 6-5: Future Natural Gas Prices of Future natural gas alternatives

<u>Resource Expansion Analysis Results</u>

The most probable load forecast, fuel prices, and resource installed costs were modeled in the EGEAS Base Case. The Summer and Winter Base Case least-cost plans consist of the following resource changes for the 2024-2029 period:

- Complete the commission of the Heskett 4 88 MW natural gas-fired Simple Cycle Combustion Turbine unit to be online in 2024.
- Continue to grow the Commercial Demand Response program to a total of 45 MW with a goal of reaching 60 MW.

The Summer Base Case selected a simple cycle combustion turbine in 2036 along with capacity purchases to bridge to the CT and in the later years. The Winter Base Case selected 2-100 MW blocks of wind (2036 and 2042) along with a simple cycle combustion turbine in 2041. The 50-year NPV of the summer is $2,644.41 and the winter is $2,767.82.

The Summer and Winter DLOL Base Cases have a need for capacity much earlier than the current MISO Resource Adequacy. The Summer DLOL Base Case selects 2-50 MW blocks of battery storage (2033 and 2041), and the Winter DLOL Base Case selects a simple cycle combustion turbine in 2027, 100 MW wind in 2039, and 50 MW of battery storage in 2041. The 50-year NPV increases in each of the DLOL Base Cases compared to the current resource adequacy at $2,684.72 in the Summer DLOL and $2,934.87 in the Winter DLOL.

Sensitivity scenarios indicate that the Base Case plans are robust under all assumptions in showing the need for similar type of resources across all the sensitivities for each of the Base Cases. However, load growth has a significant impact on the resource selection. As expected, the low-growth scenario indicates the need for less capacity and energy, while the high-growth scenario shows much more peaking capacity and energy is needed than is shown in the Base Cases. The high and low gas price scenarios also support the Base Cases selections for capacity throughout the 5-year action plan.

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 scenarios, the resource plans stay similar and have a slight decrease in NPV. Under the high energy market price scenarios, the model selected variations from the Base Case except for in the Summer Base Case. These scenarios resulted in a higher NPV than the Base Cases.

When increasing both the natural gas and MISO energy market prices the resource plans selected more wind compared to the Base Cases and does cause an increase in the NPV. In decreasing both the natural gas and MISO energy market prices the plan stays the same as the Base Case in both the Summer and Summer DLOL cases and both the winter Base Cases lean more towards natural gas options. All these cases had a lower 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 additional wind resources are added, existing coal units run less assuming a $50/ton of CO_2.

The complete results of all the sensitivities can be seen in Attachment C Tables 3-1 to 3-8.

Future Resource Plan

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 2024-2029 period:

- Continue to grow the Demand Response programs to a goal of reaching 60 MW.

- Complete the commission of the Heskett 4 88 MW natural gas-fired simple cycle combustion turbine resource, to be online in 2024.

- Issue a new request for proposal prior to the next IRP.
- Continue the evaluation of the new 150 MW wind opportunity.

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

Montana-Dakota's recommended resource plan satisfies future customer requirements through the addition of a natural gas-fired simple cycle resource, and contract for capacity and energy purchases through May 2026 and additional MISO energy and capacity market purchases.

CHAPTER 7

FIVE-YEAR ACTION PLAN

This section of the report provides the five-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.

<u>Load Forecasting</u>

- Montana-Dakota will continue to evaluate the accuracy of its demand and energy forecasts and make improvements where needed.

<u>Demand-Side Resources</u>

- Montana-Dakota will continue to implement existing, and evaluate new, cost-effective energy efficiency and demand response programs to meet the company's future requirements.

<u>Supply-Side Activities</u>

- Montana-Dakota will complete the commissioning of the Heskett 4 88 MW simple cycle combustion turbine to be online in 2024.

- Montana-Dakota will issue a new request for proposal of supply side resources prior to the next IRP.

- 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 or necessary to fill short term needs.

- Montana-Dakota will continue to monitor the development of and impacts to Coyote Station associated with changing economics in the MISO market and the next round of regional haze reductions and other changes of environmental rules for all generation sources and influence the outcomes where possible.

- Montana-Dakota will continue to monitor and evaluate the impacts of the EPA final Greenhouse Gas, Mercury and Air Toxic and Effluent Discharge rules issued in April of 2024.

- Montana-Dakota will continue to monitor new RTO resource adequacy requirements associated with changing fleet fuel mix including seasonal variation and reserve margins. Included in the multi-season resource adequacy requirements may be the need to evaluate the conversion of Heskett 3 and 4 to dual fuel combustion.

- Montana-Dakota will continue to evaluate solar and battery storage technologies and their potential for implementation within Montana-Dakota's system as generation and transmission devices.

- Montana-Dakota will continue to monitor the development and impacts of MISO's long transmission plan along with potential future addition of additional electrification from carbon reduction initiatives and the development of electric vehicles.

- Continue the evaluation of the new 150 MW wind opportunity.

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 2024 IRP advisory group was established at the beginning of the 2024 planning cycle and held its first meeting in November 2023.

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 three members from Montana, five members from North Dakota, and one member from South Dakota. In addition, the North Dakota Public Service Commission appointed a representative to participate as an observer. The names and affiliations of the 2024 PAG participants are shown in Table 8-1.

Table 8-1
The 2024 IRP Public Advisory Group

<u>Montana</u>

Kevin Thompson
Action for Eastern Montana
Glendive, Montana

Kyla Maki and Jeff Blend
Department of Environmental Quality
Helena, Montana

Stephen Schreibeis
Glendive Public Schools
Glendive, Montana

<u>North Dakota</u>

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

Darin Scherr
Bismarck Public Schools
Bismarck, North Dakota

Rich Garman
ND Department of Commerce
Bismarck, North Dakota

Rich Wardner
Former North Dakota State Senate
Dickinson, North Dakota

Martin Fritz
Kadrmas Lee & Jackson
Bismarck, North Dakota

Adam Renfandt
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 allowed 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 2024 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 three 2024 IRP PAG meetings held over conference calls. 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 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 2021 IRP

1. *The IRP represents a serious effort by MDU to put forth a comprehensive plan setting forth a path for providing service to customers across three states and regulatory jurisdictions. The Commission appreciates MDU's work in constructing the 2021 IRP. The also recognizes MDU's effort to engage with the public, the Commission, and other interested parties throughout the process by participating in public listening sessions and informational meetings.*

   Montana-Dakota continued the IRP Public Advisory Group, and three meetings were held throughout the process. Additionally, two public meetings, one in Glendive and the other in Miles City, were held as part of the development of the 2024 IRP.

2. *The 2021 IRP generally complies with the Commission's planning guidelines in Admin. R. Mont. 38.5.2001, et seq.*

3. *The use of competitive solicitations to acquire new resources is encouraged by Commission planning guidelines. Mont. Admin R. 38.5.2010. The Commission's planning guidelines encourage utilities to thoroughly document resource decisions so they can be reasonably understood by the Commission. Mont. Admin. R. 38.5.2001. The 2021 IRP does not indicate MDU selected the Minnkota PPA through a competitive process. MDU should therefore explain in the IRP the process it used to evaluate the cost-effectiveness of the resource or PPA that was acquired and explain why it chose not to use a competitive solicitation.*

   Montana-Dakota did not use a competitive process to acquire the Minnkota PPA. The contract was signed prior to the filing of the 2021 IRP, and it was a low-cost opportunity resource to help with bridging the capacity and energy need from the Heskett 1, Heskett 2 and Lewis & Clark retirements to the building of Heskett 4. The energy cost of the PPA was lower than the MISO purchase cost in the model on average and is used to hedge against the potential for higher MISO energy cost. The capacity cost would be lower than anything that could be built and slightly higher than the purchase power cost used in the model.

4. *Natural gas market prices have increased sharply since MDU filed the 2021 IRP. In fact, over the past 6 months, market prices have at times exceeded the high natural gas market price*

sensitivity scenario that MDU modeled in the 2021 IRP. In its next IRP, MDU should consider any changing natural gas market fundamental that may warrant changes in the way MDU develops its base case and sensitivity scenarios.

In 2022, there was a spike in natural gas prices on average for the year seen in Chapter 6 Figure 6-4, but the prices have returned to similar prices as seen prior to 2022. Montana-Dakota high gas price sensitivities would have exceeded this price seen in 2022 on a yearly average. The 2024 IRP still uses a forecasted natural gas price that is developed based on forward index pricing at Henry Hub and three high natural gas price sensitivities. There is also a sensitivity that looks at the high natural gas and high MISO market prices.

5. *The 2021 IRP lacks any significant discussion as to how MDU will meet customer loads if an extreme weather event causes a large outage on the system that also removes MDU's ability to import energy from the MISO market. The consequences of such an event could result in loss of life, and the IRP should discuss how MDU would be able to react in the most critical situations.*

   There were two sensitivities modeled in the 2021 IRP that reduced the amount of MISO energy purchases from the blocks of 300 MW to 100 MW to show the effects of limiting the MISO energy market. Similar sensitivities were done in the 2024 IRP along with some additional modeling that can be seen in Attachment C for extreme weather and natural gas supply outages.

6. *In response to MDU's 2019 IRP, the Commission stated MDU should conduct a new energy efficiency assessment and incorporate the results into future resource plan as soon as possible. The Commission is pleased that MDU's two-year action plan in the 2021 IRP states it will evaluate and implement new cost-effective energy efficiency and demand response programs; however, the Commission again reminds that MDU should conduct a new DSM assessment and incorporate the results into its nest resource plan. The 2012 and 2015 energy efficiency potential studies MDU has used to inform the DSM portfolio in the last several planning cycles are significantly outdated.*

   Montana-Dakota conducted a new energy efficiency assessment as part of the 2024 IRP, and the results of the study are in Chapter 3 of the Main Report and Attachment B.

7. *The Commission agrees with DEQ that MDU should explore potential costs and benefits related to residential demand response programs. Residential demand response programs may*

provide cost-effective flexible capacity that can offset extreme energy ramps. But the impacts of, and public sentiment toward, such a program should be studied and resolved before implementation decisions are made. MDU should evaluate the pros and cons of residential demand response programs on its system, such as electric space and water heating programs.

Demand Response programs were not part of the scope of the energy efficiency potential study that was included as part of the 2024 IRP. However, Montana-Dakota continues to implement our current commercial demand response programs as discussed in Chapter 3. Montana-Dakota will continue to review residential demand response programs as part of our action plans, however due to the low saturation of the electric heating and water heating our focus will be on residential air conditioning demand response programs.

8. *A stand-alone battery energy storage system ("BESS") appears to be absent from the supply-side resources MDU considered in the 2021 IRP. BESSs are becoming increasingly prevalent in utility supply portfolios and may play a significant role in the regional energy landscape in the future. In its next IRP MDU should consider the costs and benefits of adding a stand-alone BESS to its supply portfolio.*

   Montana-Dakota added a standalone 50 MW BESS option in the 2024 IRP for an alternative resource to be selected as part of the least cost plan.

9. *On August 31, 2022, the Federal Energy Regulatory Commission ("FERC") announced it had accepted revisions to MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff to establish a seasonal resource adequacy construct. The FERC decision will eliminate the summer-only resource adequacy requirement that has existed under MISO, which has historically provided a significant benefit to MDU and its customers. In its next plan, MDU should analyze the costs and benefits of remaining in MISO under the seasonal resource adequacy construct, compared to exiting MISO and joining the SPP. The analysis should include a discussion of the likely customer impacts, as well as the logistical and practical challenges that may need to be addressed if MDU were to join SPP.*

   The benefits for remaining in MISO can be seen in Attachment F. The analysis only looked at the summer and winter seasons as that is all SPP has as part of their resource adequacy.

10. *MDU is one of four joint owners of the Coyote Station plant. Otter Tail Power Company (OTPC"), one of the four joint owners has announced it intends to sell its share of Coyote Station by 2028. MDU's next IRP should discuss if OTPC's decision to sell or environmental upgrades related to compliance with the RH rule will have an impact on the continued operation of Coyote Station.*

    There is still some unknown on Coyote as no ruling on Coyote as it pertains to the RH rule has been decided at the time of filing of the IRP. OTP has now been given direction from the Minnesota Commission that they can continue to participate in the plant through 2031, after which Coyote could not be used to serve Minnesota customer loads.

    A couple of sensitivities were done in the 2024 IRP around Coyote closure and replacement scenarios. An addendum may be needed to the 2024 IRP if anything changes with Coyote prior to the 2027 IRP.

CHAPTER 10

RESPONSES TO MONTANA DEPARTMENT OF ENVIRONMENTAL QUALITY COMMENTS REGARDING MONTANA-DAKOTA'S 2021 IRP

1. *DEQ supports MDU's plan to expand their commercial demand response program and encourages MDU to evaluate residential demand response offerings.*

Demand response (DR) programs are an effective tool for utilities to secure flexible capacity resources. By providing an incentive to participating customers who agree to curtail their electrical load when called upon by the utility, these voluntary programs are a mechanism for utilities to manage load in peak demand hours. MDU's commercial and industrial DR programs reduce the utility's peak demand, thereby providing fuel cost savings, enhancing grid stability, reducing emissions from generating assets, and deferring the need for new transmission and generation capacity. DEQ commends MDU's goal to expand its current commercial demand response program to 60 megawatts ("MW") by 2023. Enrolling customers with a load of 25 kilowatts ("kW") or higher will capture unrealized demand savings across MDU's service territory.

Voluntary residential DR programs, including air conditioning cycling and hot water heater load control programs could also help provide additional capacity savings during peak demand periods. Notably, a residential air conditioning cycling program was submitted in response to MDU's 2020 request for proposals. While the residential DR program was not selected by MDU, the increasing importance of deploying a diverse array of flexible capacity resources underscores the need for continued review of these options. DEQ encourages MDU to thoroughly analyze the direct costs and benefits of residential DR programs to customers and the broader costs and benefits as a flexible resource to address system-level needs.

Montana-Dakota has not seen much growth in its commercial demand response programs but continues to target growth in the programs. Montana-Dakota will continue to review residential demand response programs as part of our action plans, however due to the low saturation of electric heating and water heating, our focus will be on residential air conditioning demand response programs.

2. *MDU should conduct a new electric energy efficiency potential study prior to its 2023 IRP planning process.*

MDU conducted its last Energy Efficiency Potential Study in 2012 followed by a program planning study in 2013. To ensure that MDU accurately accounts for cost-effective energy efficiency *resources available within its service territory, it is important that MDU conduct another Energy Efficiency Potential Study prior to developing its 2023 IRP. The new study should reflect updated market conditions, avoided costs, and customer demographics, all of which factor into the determination of the available cost-effective efficiency savings potential. DEQ recommends that the next study evaluate energy efficiency savings potential separately for each customer class in Montana, North Dakota, and South Dakota. Factors that affect energy efficiency savings potential, such as end-use characteristics, incentives, and regulatory mechanisms, can vary significantly from one state to another. DEQ also recommends that MDU provide an opportunity for its Public Advisory Group members to review and provide feedback on the inputs and assumptions of the study during the 2023 IRP planning process.*

Montana-Dakota conducted a new energy efficiency assessment as part of the 2024 IRP, and the results of the study are in Chapter 3 of Main Report and Attachment B.

3. *MDU should model diverse scenarios and alternatives that reflect greater uncertainty and risks associated with energy and capacity planning.*

Securing a reliable and affordable electricity supply portfolio is increasingly challenged by the risk and uncertainty presented by extreme weather events amplified by changes to climate, rapid technology developments, a shifting regulatory landscape, and evolving market dynamics. These uncertainties demand a fresh evaluation of energy planning assumptions. While DEQ understands that it is impossible to model every scenario MDU might face in an uncertain future, we recommend that MDU analyze additional diverse scenarios that reflect climate, technological, and market uncertainty and that evaluate potential impacts to fuel prices, energy supply, peak demand, and energy load growth.

One additional scenario that MDU should include in its load forecast is a high electrification scenario. Customer adoption of electric vehicles, and efficient electric space and water heating is increasing as the purchase price and operational costs of these electric end uses declines. This trend is leading to increasing electricity demand and shifting load shapes for utilities across the country. The load forecasts included in MDU's 2021 IRP considers two historical periods to develop a high and low-load growth forecast. MDU should model a scenario or scenarios that include projected growth of electric vehicle adoption and other electric end uses in the residential, commercial, and industrial sectors over the IRP action period.

Another source of uncertainty that MDU should reflect in its scenario and resource option analysis is the impact of extreme weather on availability of short-term market purchases and resource *adequacy requirements. For example, Winter Storm Uri in February 2021 impacted electricity generation and delivery for customers across 14 states, including Montana. While the storm had a negligible impact on electricity supply for MDU's customers, it impacted several states in the Midcontinent Independent System Operator ("MISO") market footprint, of which MDU is a member. MDU currently relies on bilateral arrangements in the MISO market to meet short-term capacity needs and plans to purchase additional capacity as needed to meet customer demands. In the 2021 IRP, MDU models low and high market price scenarios but does not evaluate scenarios in which market purchases would be significantly limited or unavailable due to extreme weather events. MDU should evaluate supply and demand-side resource options that could meet customer needs under extreme winter and summer scenarios when purchasing short-term capacity from MISO is not an option.*

MDU should also analyze emerging energy supply options for meeting MISO multi-season resource adequacy requirements. MDU's 2-Year Action Plan in the 2021 IRP includes an option to evaluate the conversion of Heskett Station Units 3 and 4 to dual fuel (natural gas generation with diesel fuel back-up). MDU should consider modeling additional resource options to meet multi-seasonal resource adequacy and capacity requirements including thermal and renewable resources paired with longer duration battery storage, and emerging energy supply options such as hydrogen fueled generation, small modular nuclear reactors, and advanced geothermal resources.

The changing economics and ownership dynamics of the Coyote Generating Station are an increasing source of risk and uncertainty for MDU and its customers. The Coyote Station is a 425 MW lignite coal-fired power plant located in Beulah, North Dakota. MDU owns a 25 percent share (107 MW) in the plant, which represents 20 percent of MDU's supply portfolio. In September 2021, Otter Tail Power, which has the largest (35 percent) ownership interest of the four facility owners, announced plans to sell its ownership share by 2028. MDU appropriately modeled a scenario in the 2021 IRP in which the Coyote station retires in 2028 and the utility plans to conduct detailed analysis of regional haze control costs for Coyote in the 2023 IRP. As part of that planned analysis, DEQ encourages MDU to also evaluate the full range of alternatives to implementing regional haze controls, which could include an earlier retirement with replacement generation, market purchases, and additional investment in demand-side resources such as energy efficiency and demand response. This broad analysis is necessary to identify the least-cost resource options for MDU customers, and to fully evaluate and prepare for the impacts on MDU customers of Coyote's potential retirement.

Additional modeling results in Attachment C to the 2024 IRP were done to model an extreme weather type event and a separate scenario with disruption to the natural gas supply.

The high growth scenario would cover any potential growth that a high electrification would cause on Montana-Dakota's system. The high electrification is being monitored by Montana-Dakota, but there still has not been a substantial increase in electrical usage per customer or penetration of electric vehicles in Montana-Dakota's system.

Montana-Dakota ran two sensitivities in the 2024 IRP that looked at reducing the MISO market energy available to see the impacts of not relying on the MISO market would have on the resource plan.

The 2024 IRP results were run looking at both the summer and winter seasons to see the impacts of the seasonal resource adequacy requirements and the differences in resources selected to meet the requirements.

There is still some unknown on Coyote as no ruling on Coyote as it pertains to the RH rule has been decided at the time of filing of the IRP. OTP has now been given direction from the Minnesota Commission that they can continue to participate in the plant through 2031, with after that date Coyote could not be used to serve Minnesota customers. A couple of sensitivities were done around Coyote were included in the 2024 IRP, and addendum may be needed to the 2024 IRP if anything changes with Coyote prior to the 2027 IRP.