Minnkota Power Cooperative, Inc.

– and –

Northern Municipal Power Agency

2025 Integrated Resource Plan

2026-2040

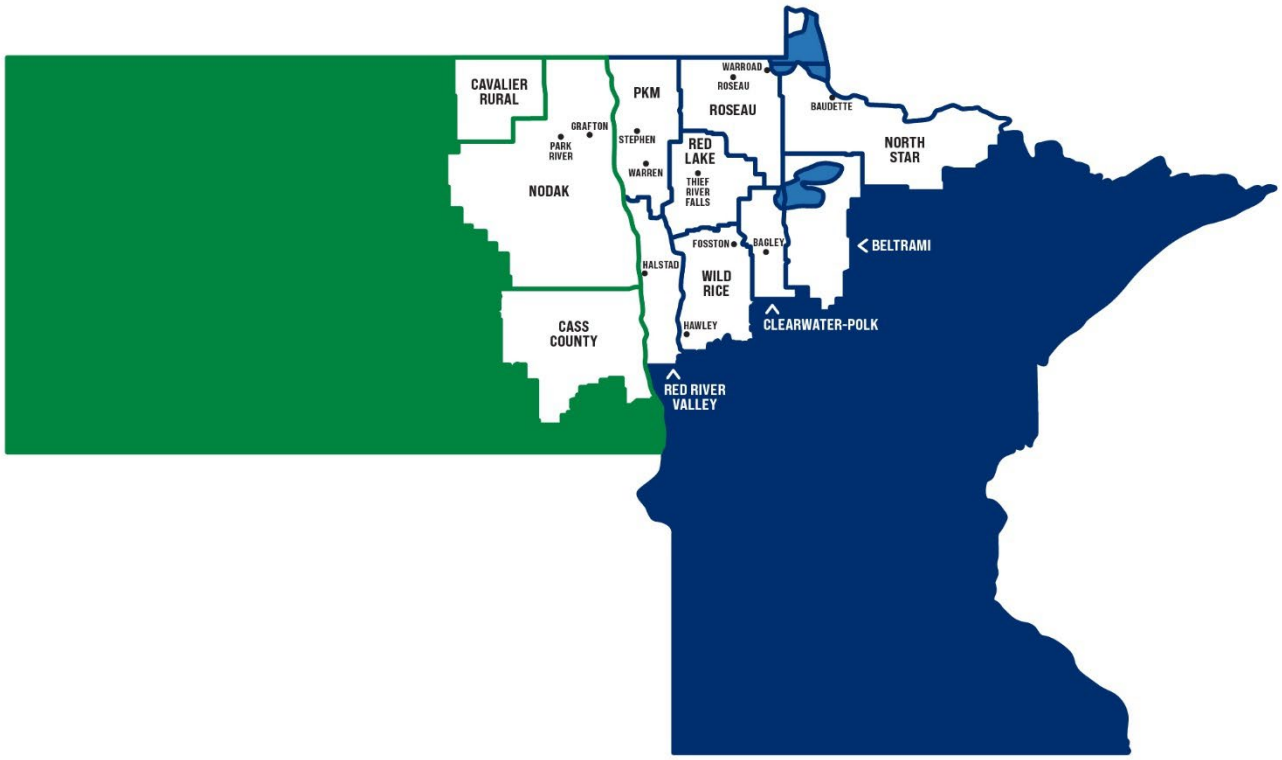
Submitted to the

Western Area Power Administration

– and the –

Minnesota Public Utilities Commission

SERVICE AREA



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SECTION 1
Introduction

Integrated Resource Plan

Minnkota Power Cooperative and the Northern Municipal Power Agency (NMPA) together submit this 2025 Integrated Resource Plan (IRP). This document has been prepared to fulfill the IRP requirements of WAPA and the Minnesota Public Utilities Commission.

The primary function of an IRP is to demonstrate how a utility plans to meet the electrical needs of its end-use consumers over the next 15 years. The resource plan includes the resource and demand side options that best fit the utility's forecasted energy requirements. Resource plans must consider how to maintain or improve electric service to consumers, maintain competitive electric rates, minimize environmental impacts and minimize the risk of adverse effects from financial and technological impacts.

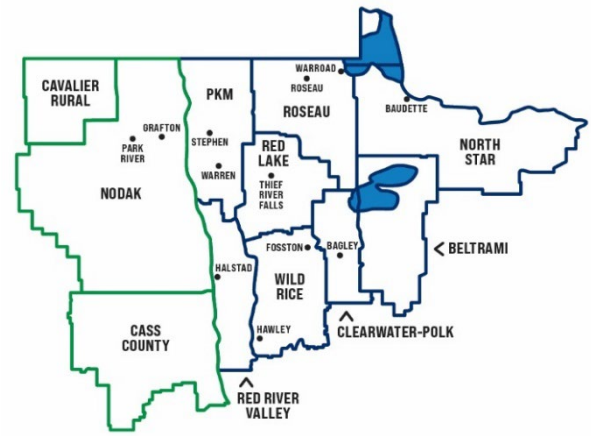
This is the eighth IRP that Minnkota and NMPA have filed jointly with the Minnesota Public Utilities Commission under MN Statute 216B.2422 and MN Rules Part 7843.

IRP Objectives

The objectives of this IRP are based on the resource planning requirements of Minnkota and NMPA and fulfill the evaluation criteria requirements of MN Rules Part 7843.

- Study Objective #1: Maintain or improve the adequacy and reliability of utility service.
- Study Objective #2: Keep customers' bills and the utility's rates as low as practicable, given regulatory and other constraints.
- Study Objective #3: Minimize adverse socioeconomic effects and adverse effects upon the environment.
- Study Objective #4: Enhance the utility's ability to respond to changes in the financial, social and technological factors affecting its operations.
- Study Objective #5: Limit the risk of adverse effects on the utility and its customers from financial, social and technological factors that the utility cannot control.

Minnkota Power Cooperative, Inc.



Minnkota Power Cooperative, Inc. (Minnkota) is a wholesale electric generation and transmission cooperative formed on March 28, 1940, and headquartered in Grand Forks, N.D. Minnkota provides, on a not-for-profit basis, wholesale electric service to 11 retail distribution cooperatives, which are the members and owners of Minnkota. Minnkota is also associated with the Northern Municipal Power Agency, which is a municipal power agency serving 12 municipals within its service territory.

The member-owner distribution cooperative systems (member systems) are cooperative associations that provide retail electric service to their own member-consumers. In general, the membership of the member systems consists of residential, commercial and industrial consumers within a contiguous geographic area.

The member systems' service areas, which encompass 34,500 square miles, are located in northwestern Minnesota and the eastern third of North Dakota and contain an aggregate population of approximately 400,000 people. The member systems serve approximately 153,000 consumers. The primary function of the member systems is to provide the total electrical requirements of their own member-consumers through wholesale purchases of capacity and energy from Minnkota and to deliver this capacity and energy through their electrical distribution facilities.

Member Systems' Wholesale Power Contracts

Minnkota has entered into an "Evergreen" Wholesale Power Contract with each of the 11 Class A member systems until Dec. 31, 2060. Starting on Jan. 1, 2026, the contracts will be automatically extended by two years each even-numbered year. That schedule will continue unless either Minnkota or the member cooperative formally requests a change. Additionally, Minnkota has a board of directors policy in place to review the contracts every five years. The evergreen structure helps provide stability and certainty for Minnkota and the members without the need for a multi-decade extension. Maintaining a contract length of more than 35 years ensures that optimal financing can be secured for current and future projects. In addition, the contracts help demonstrate financial health to potential lenders and rating agencies.

These Wholesale Power Contracts provide that Minnkota shall sell and deliver to each of the member systems, and that the member systems shall purchase and receive from Minnkota, at least 95% of the members' electrical capacity and energy requirements. The members may elect to purchase up to 5% of their requirements from sources other than Minnkota, providing certain conditions are met.

Each member system is required to compensate Minnkota for capacity and energy furnished under the Wholesale Power Contract in accordance with the rates set forth in the Wholesale

Power Rate Schedule. Minnkota reviews its Wholesale Power Rate Schedule at such intervals as it deems appropriate and is required to do so at least once every year.

The rates will be revised as necessary so that the revenues derived will be sufficient, together with its revenue from all other sources, to pay all operating and maintenance costs, taxes, the cost of purchased power, the cost of transmission services, and principal and interest on all indebtedness, and to provide for the establishment and maintenance of reasonable reserves. Any excess revenue is returned to the members as capital credits or reinvested into Minnkota's system, as determined by the board of directors.

The Wholesale Power Rate Schedule is structured to enable Minnkota to comply with all requirements under an Indenture of Mortgage, dated as of June 14, 2012, as supplemented, between Minnkota and the United States acting through the Administrator of the Rural Utilities Service (RUS), formerly the Rural Electrification Administration (REA). The Wholesale Power Rate Schedule is subject to the approval of the RUS.

Organizational Structure

Each member system is governed by a board of directors who are elected from the membership of that system. Minnkota is governed by a board of directors consisting of one director from each of the 11 Class A member systems. Directors are elected annually at Minnkota's annual meeting. Meetings of the Minnkota Board are held monthly. The officers are elected from the members of the board of directors by the board members. The officers are the Chair, Vice Chair and Secretary-Treasurer. The Minnkota Board also appoints an Assistant Secretary. The officers constitute the executive committee, which makes recommendations to the board.

Northern Municipal Power Agency

The Northern Municipal Power Agency (NMPA) consists of 12 municipal utilities, 10 in northwestern Minnesota and two in eastern North Dakota. The 12 municipal utilities serve the electrical requirements of approximately 16,350 customers.

NMPA was founded in 1976 and is headquartered in Thief River Falls, Minn. The board of directors of NMPA consists of one representative from each of the 12 participants. NMPA is a Class B member of Minnkota and selects a nonvoting member to attend meetings of Minnkota's Board of Directors as a liaison.

NMPA owns a 30% share of the Coyote generating plant, a 427 MW facility located near Beulah, N.D. NMPA also owns an undivided interest in Minnkota's transmission system based on the ratio of NMPA's load to the Joint System load. Minnkota is the operating agent for NMPA.

The 11 member systems are Class A members of Minnkota. NMPA is a Class B member of Minnkota. In addition, there are several other Class B members and Class C members, all of which may contract for short-term power purchases from Minnkota and are entitled to have delegates attend Minnkota annual meetings.

Joint System Concept and Relationship

Minnkota and NMPA effectively form a Joint System. This is by virtue of operating agreements and joint ownership of transmission facilities. Additionally, Minnkota's generation, NMPA's generation, Minnkota's Western Area Power Administration (WAPA) allocation, and the NMPA WAPA allocations are collectively utilized to serve the Joint System capacity and energy requirements consistent with applicable tax law relative to NMPA's tax-exempt financing. Also, both the member systems of Minnkota and the member municipals of NMPA purchase their total electric capacity and energy requirements under similar Wholesale Power Rate Schedules.

Management and Administration

Minnkota is operated by approximately 420 full-time employees under the direction of the President & Chief Executive Officer, who is appointed by and is responsible to the board and who is not eligible to serve as a director of Minnkota. Approximately 245 employees operate out of the general headquarters in Grand Forks, N.D. Approximately 175 are employed at the Milton R. Young Station located near Center, N.D.

Market Participant - Midcontinent Independent System Operator's Energy Market (MISO)

MISO is a not-for-profit, member-based organization that manages the reliable operation of the regional transmission system and energy markets. Minnkota is a market participant in MISO. Through this arrangement, Minnkota can both purchase power to meet the Joint System's needs and sell surplus generation into the market. All of Minnkota's generation and load are modeled, scheduled, dispatched, and financially settled within the MISO market framework.

SECTION 2
Load Forecast Study

Overview

A Load Forecast Study is a detailed analysis required by the U.S. Department of Agriculture's Rural Utilities Service (RUS) to project future electric system demand and energy requirements for a utility. The study evaluates historical data, consumer growth trends, economic conditions and other factors that influence electricity usage to forecast demand over a 30-year period. Its purpose is to ensure that the utility's infrastructure and financial planning are aligned with anticipated load growth, enabling sound decisions on system improvements, financing and long-term reliability.

Load Forecast Study Methodology

The Rural Utilities Service (RUS) defines a Load Forecast Study (LFS) as a comprehensive analysis of a borrower's electric loads and the factors influencing those loads to determine, as accurately as practical, the borrower's future energy and capacity requirements. For power supply borrowers, the LFS must integrate the studies of their member systems. RUS approval of an LFS requires compliance with the guidelines in Title 7, Part 1710, Subpart E of the Code of Federal Regulations, which outlines the purposes, policies and criteria for such studies.

The Joint System LFS consists of the Minnkota LFS and an LFS of the 12 NMPA municipal systems. Minnkota and its 11 member-owner distribution cooperatives are required to complete an RUS-approved LFS every two years. The most recent studies were completed in 2025.

Minnkota's LFS was developed using a bottom-up approach, aggregating the energy and capacity forecasts of each member system to form the overall Minnkota base forecast. A separate forecast was also developed for Minnkota's transmission losses.

Although NMPA's municipal members are not required to complete an LFS, a load forecast was prepared for each, using linear regression analysis of data from 2009 through 2024.

The Joint System's total energy forecast combines Minnkota's energy requirements, NMPA's energy requirements and transmission losses. Forecasts of winter and summer peak demands are based on historical trends.

Econometric modeling served as the primary forecasting technique for member system LFSs. This method identifies relationships between energy use and economic, demographic and system factors using 30 years of historical data. Variables include population, employment, income, weather, electricity and alternative fuel prices, and agricultural economic conditions, among others. The models quantify the factors that have historically influenced electric usage.

Econometric models were used to forecast residential and small commercial consumer counts and usage. Forecasts for large commercial customers were developed through input from member and municipal systems.

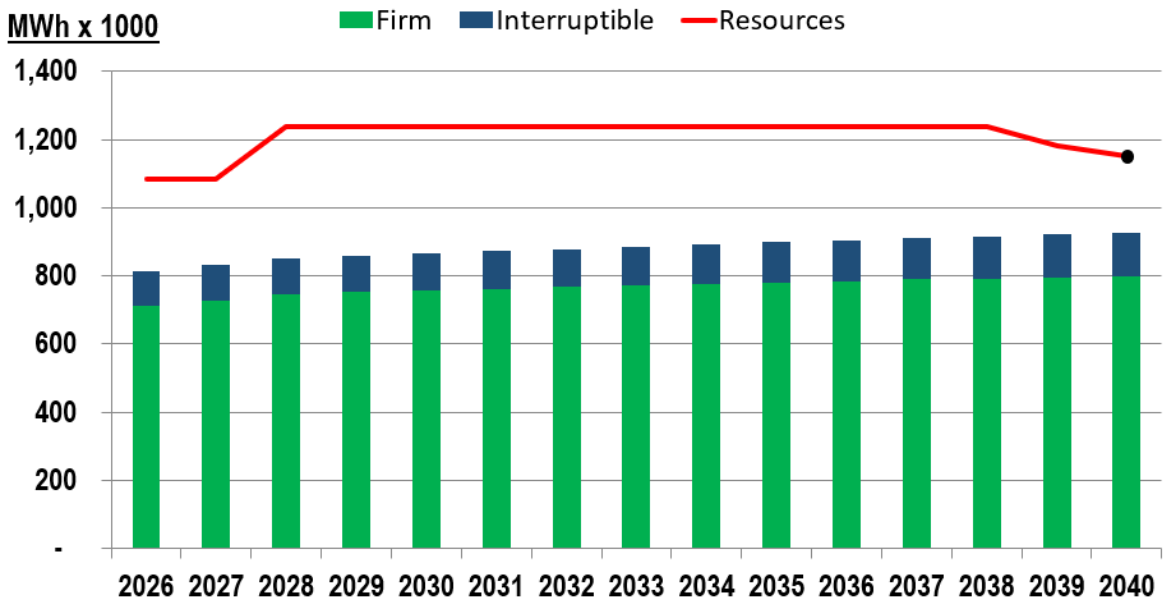
All models were developed using ordinary least squares regression and were selected based on theoretical soundness, statistical validity and the reasonableness of results.

Load Forecast Study Results

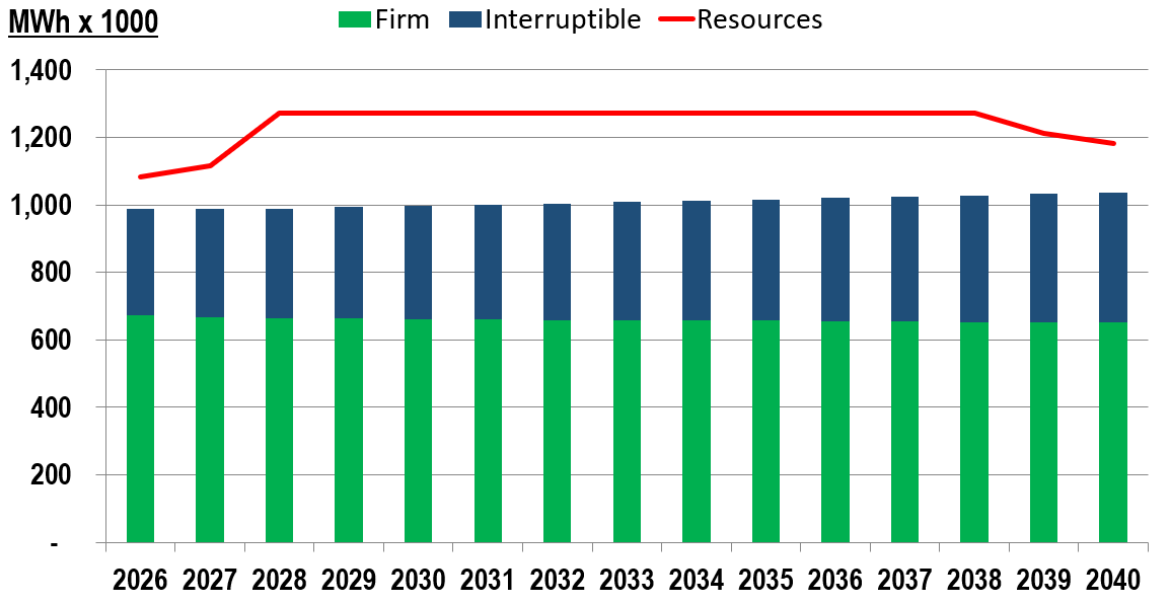
The Joint System legacy energy requirements are forecasted to increase at a rate of 0.8% per year. The summer and winter peak demands are also forecasted to increase at a rate of 0.7% and 0.6% respectively per year.

The following charts display the winter and summer peak demands, separated into the firm and interruptible components. Also shown in these charts are the winter and summer capacity resources. For purposes of illustration, capacity resources are the Joint System generation plants plus the WAPA firm power allocations plus power purchases minus power sales. The following Summer Resources vs. Load and Winter Resources vs. Load charts illustrate that the Joint System has more than sufficient resource capacity to serve its firm load during the next 15 years.

SUMMER RESOURCES VS. LOAD



WINTER RESOURCES VS. LOAD



Joint System Median Annual Energy Requirements, Winter Peak, and Summer Peak Forecasts

The Joint System median forecast of its annual energy requirements, winter peak demands and summer peak demands are shown in the following table:

Median Load Growth Forecasts

Year	Energy Requirements MWh	Winter Peak MW	Summer Peak MW
2026	4,971,296	1,097	815
2027	5,096,031	1,118	833
2028	5,247,449	1,143	854
2029	5,291,504	1,151	861
2030	5,338,280	1,160	868
2031	5,379,674	1,168	875
2032	5,418,095	1,175	881
2033	5,462,487	1,183	888
2034	5,504,349	1,191	895
2035	5,542,859	1,199	901
2036	5,580,144	1,206	907
2037	5,620,522	1,213	914
2038	5,651,906	1,219	919
2039	5,688,651	1,225	925
2040	5,727,287	1,232	931

The Joint System's median forecast of annual energy requirements is projected to increase at a rate of 0.8% per year. The winter peak demand is projected to increase at a rate of 0.7% per year and the summer peak demand is projected to increase at a rate of 0.8% per year. These numbers are based on the 30-year projections from the 2025 Load Forecast Study.

Joint System Annual Energy Requirements, Winter Peak Demand, and Summer Peak Demand Forecast Bandwidths

Analysis was completed to determine the sensitivity of projected load growth to weather, the economy and alternate fuel prices. This work was included in the LFS and has been incorporated into this IRP.

The low load growth scenario was based on the impacts that pessimistic economic conditions would have on the forecast. The high load growth scenario was based on the impacts that optimistic economic conditions would have on the forecast. Economic conditions were found to impact the forecast more than any other factor.

These two scenarios are the basis for the bandwidth forecasts for the member systems. Although the sensitivity analyses were only studied for the member systems, the same percentage variation was applied to the Joint System annual energy requirements, since the characteristics of the municipals' electric load are similar to those of the member systems' load characteristics.

The forecasts of the Joint System's annual energy requirements, winter peak demands, and summer peak demands for the low load scenario are shown in the following table:

Low Load Growth Forecasts

Year	Energy Requirements MWh	Winter Peak MW	Summer Peak MW
2026	4,669,320	1,007	748
2027	4,787,516	1,027	765
2028	4,930,014	1,050	784
2029	4,970,538	1,057	790
2030	5,013,794	1,065	797
2031	5,051,639	1,072	803
2032	5,086,595	1,079	809
2033	5,127,752	1,086	815
2034	5,166,189	1,093	821
2035	5,201,616	1,100	827
2036	5,236,146	1,106	833
2037	5,272,889	1,113	838
2038	5,301,684	1,118	843
2039	5,335,717	1,124	849
2040	5,371,038	1,131	854

The Joint System's low load growth scenario forecasts an increase of 0.72% per year for annual energy requirements. The winter peak demand is forecasted to increase at a rate of 0.45% per year and the summer peak demand is forecasted to increase at a rate of 0.45% per year.

The forecasts of the Joint System's annual energy requirements, winter peak demands and summer peak demands for the high load growth scenario are shown in the following table:

High Load Growth Forecasts

Year	Energy Requirements MWH	Winter Peak MW	Summer Peak MW
2026	5,261,387	1,197	890
2027	5,392,786	1,220	909
2028	5,552,895	1,247	932
2029	5,600,370	1,256	939
2030	5,650,497	1,266	947
2031	5,695,509	1,274	955
2032	5,737,145	1,283	962
2033	5,784,946	1,292	970
2034	5,830,187	1,300	977
2035	5,871,470	1,309	984
2036	5,911,445	1,316	990
2037	5,955,449	1,324	998
2038	5,989,330	1,331	1,003
2039	6,028,593	1,338	1,010
2040	6,070,558	1,346	1,017

The Joint System's high load growth scenario forecasts an increase of 1.8% per year for annual energy requirements. The winter peak demand is forecasted to increase at a rate of 1.3% per year and the summer peak demand is forecasted to increase at a rate of 1.2% per year.

SECTION 3
Demand Response Program

Overview

Beginning in 1973, Minnkota and the member systems instituted a comprehensive and effective Demand Response (DR) program. This program is voluntary for consumers who allow Minnkota to turn off, by remote control, electric heaters and other interruptible loads in exchange for a discounted retail electric rate. This capability enables Minnkota to more effectively manage its existing power resources and market purchases.

The program is popular with about 55,000 end-consumers participating. Loads most commonly involved in the program are dual fuel heating systems, water heaters, storage heaters, commercial loads with backup generators and other miscellaneous loads.

Due to the large amount of electric heating loads, Minnkota's DR program started with dual heating systems as the main focus of its effort. Most of these dual heat systems use electricity as the main source of heat with backup heat provided by fuel oil or propane when load control is in effect. A properly installed dual heat system automatically switches to the alternate fuel source, requiring no additional work from the consumer.

Minnkota's ongoing goal is to work closely with its member systems and associated municipals to provide consumers with safe, reliable and affordably priced electric power.

Interruptible Loads

The Joint System's philosophy is to develop interruptible loads in such a manner that the DR program causes as little inconvenience as possible to the end-use consumer, while also being cost-effective for both the end-user and the Joint System.

The Joint System has developed a high degree of expertise in determining what end-use loads are adaptable to the DR program and which ones are not. Today, for the winter season, the DR program utilizes, in addition to dual heating systems, water heaters, slab storage heating, thermal storage heating, electric transportation and other miscellaneous loads.

In the mid-1990s, the Joint System extended its DR program to include the summer season. This was done to offset increasing costs caused by growing summer load growth and increasing generation expansion costs.

Currently, for the summer season, the DR program utilizes large capacity water heaters, irrigation systems, low temperature grain drying, loads with generator backup, electric transportation and other miscellaneous loads.

Winter and Summer Interruptible Load Forecasts

Winter Season	Interruptible Load - MW
2026	350
2027	355
2028	360
2029	365
2030	370
2031	375
2032	380
2033	385
2034	390
2035	395
2036	400
2037	405
2038	410
2039	415
2040	420

Summer Season	Interruptible Load - MW
2026	100
2027	102
2028	104
2029	106
2030	108
2031	110
2032	112
2033	114
2034	116
2035	118
2036	120
2037	122
2038	124
2039	126
2040	128

Based on operational experience with winter and summer interruptible loads, the above is a forecast of the amount of demand relief that will be realized in future peak load periods.

SECTION 4
Existing Resources, Purchases, and Sales

Overview

The Joint System has a diverse electric generation portfolio that includes a mix of coal, wind, hydro, diesel and biomass resources. These existing resources economically and reliably fulfill the energy requirements of the end-use consumers of its member systems and the NMPA municipals.

Existing Power Supply

Milton R. Young Unit 1
Milton R. Young Unit 1 (Young 1) is owned, operated and maintained by Minnkota. Young 1 is a 250-MW lignite-based mine-mouth generator located approximately seven miles southeast of Center, N.D.

Milton R. Young Unit 2
Milton R. Young Unit 2 (Young 2) is a 455-MW lignite-based mine-mouth generator also located approximately seven miles southeast of Center, N.D. Square Butte Electric Cooperative owns Young 2 at the Milton R. Young Station. Minnkota, acting as agent for Square Butte, operates and maintains the plant and associated equipment. Square Butte is owned by the same 11 cooperatives that own Minnkota.

Coyote Plant
The Coyote Plant is a 427 MW lignite-based generating plant located southwest of Beulah, N.D., and is operated by Otter Tail Power Company (OTP). NMPA owns a 30 percent share (equivalent to 128.1 MW) of this unit and has appointed Minnkota as its agent for scheduling capacity and energy from Coyote and for operational management responsibilities.

Langdon Wind Energy Center
The Langdon Wind Energy Center is located near Langdon, N.D. The wind farm is owned and operated by NextEra. Minnkota has a long-term power purchase agreement with NextEra for 139.5 MW of capacity and energy.

Ashtabula Wind Energy Center
The Ashtabula Wind Energy Center is located near Pillsbury, N.D. The wind farm is owned and operated by NextEra Energy Resources. Minnkota has a long-term power purchase agreement with NextEra for 217.5 MW of capacity and energy.

Thief River Falls Hydro Plant
Thief River Falls, an NMPA member municipal, owns and operates a 0.500 MW hydro plant that has been in operation since 1927. This unit produces an average of 2,000 MWh annually.

Cass County Electric Cooperative Diesel Generation
Minnkota leases 10 diesel generating units for Cass County Electric Cooperative. These generators are located at several substations and are the financial responsibility of Cass County Electric. Minnkota purchases the capacity and energy from these units. The 10 diesel generators have a total capacity rating of 18.28 MW. Minnkota also purchases the capacity and energy from three of Cass County's customer-owned generators that have capacity ratings of 2.0 MW, 0.9 MW and 0.8 MW.

NMPA Diesel Generation
Three of the NMPA municipal members – Thief River Falls, Grafton and Halstad – have diesel generators leased to Minnkota. The total capacity of these NMPA diesel generators is 13.536 MW.

Planned New Generation

Flickertail Wind Farm
Minnkota has entered into a Purchase Power Agreement with Minnesota-based PRC Wind, the project owner and developer of the 370-megawatt Flickertail Wind Farm, to be built near New Rockford, N.D.

The project will include up to 112 wind turbines, a dedicated substation, 15 miles of transmission infrastructure, access roads, and an operations and maintenance facility. It has been carefully designed to complement local agricultural activities while safeguarding the surrounding natural environment.

Electricity generated by the project will be delivered to Minnkota's existing 345-kilovolt transmission line, which connects to a substation in Grand Forks. From there, the energy will be distributed to communities across eastern North Dakota and northwestern Minnesota.

The project began the state and local permitting process in 2025. Following approvals, detailed engineering, procurement and construction activities will commence. The facility is scheduled to be online in 2028.

Potential Natural Gas Development
To meet long-term growth needs and ensure a reliable, cost-effective power supply, Minnkota is evaluating the addition of natural gas generation in North Dakota. This effort is part of a broader strategy to align resources with the region's evolving energy needs while maintaining stability for decades to come.

The potential opportunity is tied to WBI Energy's plans to construct new pipeline infrastructure that would transport natural gas from the Bakken formation in western North Dakota to the eastern edge of the state. To help ensure the project's completion, the state of North Dakota has committed up to $500 million in support, distributed as $50 million annually over 10 years. Minnkota is actively engaged in these discussions. Current plans call for the western segment of the pipeline to be in service by the end of 2029, with the eastern segment following by the end of 2030.

As part of its evaluation, Minnkota is assessing potential facility locations and generation technologies, while also exploring additional opportunities to support future development needs.

Natural gas generation provides highly dispatchable capacity, with the ability to ramp output up or down rapidly in response to system needs. This operational flexibility has become an increasingly critical attribute as Minnkota's resource mix evolves and demand patterns grow more dynamic. By pursuing a measured expansion of natural gas resources, Minnkota can enhance its ability to respond to peak demand periods, mitigate exposure to market volatility and maintain reliability during sudden changes in renewable generation.

Long-Term Purchases

WAPA Firm Power Allocation to Minnkota
Minnkota has a Firm Power Allocation from WAPA. This allocation provides firm capacity and energy to the Joint System of 75.632 MW and 371,778 MWh per year.

WAPA Firm Power Allocation to the NMPA Municipals
Eight of the 12 NMPA municipals have a WAPA Firm Power Allocation. These allocations provide firm capacity and energy to the Joint System of 40.6 winter / 36.2 summer and 174,311 MWh per year.

Fargo Landfill Gas Facility
Minnkota purchases the electrical output from the Fargo, N.D., landfill gas facility, which has a capacity of 0.925 MW.

Bilateral Purchases and Sales

Montana-Dakota Utilities Sale
Minnkota has a sales agreement with Montana-Dakota Utilities through May 31, 2026, for 30 MW of energy and capacity.

200-MW Bilateral Purchase Transaction
Minnkota has entered into an agreement to purchase 200 MW of energy and capacity from mid-2027 through mid-2032. This agreement is designed to support the cooperative's growing member demand while also creating flexibility to accommodate future needs. In addition, the agreement provides a strategic hedge against increasing MISO market volatility, ensuring greater stability and reliability for the years ahead.

Retirements and Reassignments

Oliver III Wind Farm Purchase Power Agreement Transfer
With the planned addition of 370-MW of wind energy from the Flickertail Wind Farm, Minnkota is continuing to shape its resource portfolio. In June 2026, the cooperative will transfer its 100-MW Oliver III Wind Farm purchase power agreement to a neighboring utility. The Oliver III project, located in Morton and Oliver counties in North Dakota, is owned and operated by NextEra Energy Resources.

Infinity Wind
Minnkota's Infinity Wind Program features two 0.9-MW turbines that have served the cooperative and its members since 2002. The facilities have now reached the end of their service life. Both the Petersburg turbine and the Valley City turbine in North Dakota are scheduled for decommissioning in 2027. Together, these units have represented an early investment in renewable energy and a foundation for Minnkota's continued commitment to wind generation.

Local Job Impacts
Minnkota's current and planned generating resources associated with this IRP are located in North Dakota; therefore, the projects do not create direct, permanent local jobs within Minnesota.

The 370-megawatt Flickertail Wind project is expected to provide economic benefits in North Dakota, including an estimated 300 construction jobs during the build-out phase. In addition, the project developer, PRC Wind, is a Minnesota-based company, which provides indirect economic benefits to the state through corporate operations.

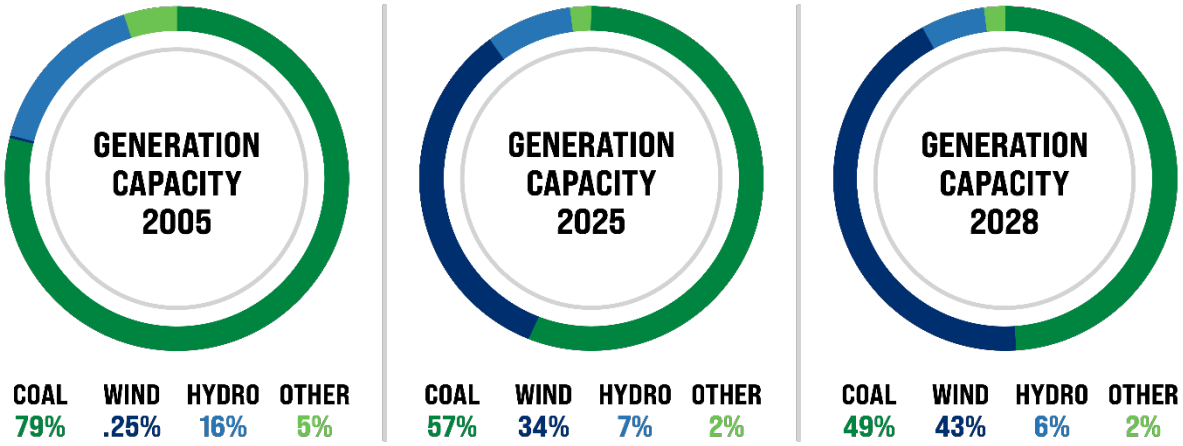
If Minnkota proceeds with the development of a new natural gas-fired generation facility, the project is expected to create additional construction employment during the development phase, along with a number of full-time operations and maintenance positions once the facility is placed into service. Minnkota will provide more detailed job impact information as project specifics, including size, location and technology, are finalized.

Minnkota remains committed to providing reliable, cost-effective power to its members while supporting regional economic activity associated with its resource development.

Summary

The Joint System's power supply portfolio provides a reliable, sustainable and cost-effective source of electricity for its member and municipal systems. The portfolio includes a mix of baseload generation and renewable resources that support both system reliability and continued progress toward decarbonization. Minnkota is taking a responsible approach to the energy transition by maintaining dependable generation while pursuing opportunities to reduce carbon emissions through new technologies and resource diversification. The chart below shows Joint System generation capacity in 2005, 2025 and projections for 2028.

Joint System Generation Capacity



SECTION 5
Resource Adequacy

Overview

The Joint System is a load serving entity within the MISO area of operations. As such, the Joint System is obligated to conform to MISO's Resource Adequacy requirements. A reliable bulk electric system requires, among other things, that generation capacity exceeds consumer demand by an adequate margin. The margins necessary to ensure adequate reliability are assessed on a near-term (operational) basis and on a longer-term (planning) basis.

The focus of Resource Adequacy is on the longer-term planning margins that are required to provide sufficient generating resources to reliably serve consumer demand in the planning horizon. Planning reserve margins must be sufficient to cover the following situations:

1. Planned generator maintenance;
2. Unplanned forced outages of generating equipment;
3. Reductions in generation capacity due to operational problems;
4. Uncertainty in demand forecasts;
5. Outages of transmission lines and other electrical equipment; and
6. Anticipated variations in weather patterns

MISO determines the amount of Minnkota's planning reserve margin on an annual basis. This determination takes into account Minnkota's demand forecasts, its generation resources and any transactions. Minnkota is required to meet MISO's planning reserve obligations, and failure to meet such obligations will result in charges assessed to Minnkota.

MISO Four-Season Construct

MISO's transition to a four-season construct has had an impact on Minnkota's overall capacity position. MISO is historically summer peaking, while Minnkota is a winter peaking utility, which was advantageous for Minnkota as its coincidental peak does not correlate with MISO's. Additionally, in alignment with utility best practices, Minnkota takes its three-year major maintenance outages in the fall season for its Milton R. Young units and in the spring for NMPA's Coyote generator when energy demands are typically lower. Under an annual construct these outages had no impact on Minnkota's capacity position. While Minnkota's surplus capacity position has increased most seasons under the four-season construct, this has resulted in Minnkota needing to procure capacity in the fall season every three years when its largest generating unit undergoes its extended major maintenance outage. Bilateral agreements with neighboring utilities has allowed Minnkota to cost-effectively meet its capacity obligations.

Minnkota continually evaluates its surplus capacity position in the market and strategically identifies opportunities to maximize its value for the Joint System. As electricity demand across the MISO footprint continues to rise, and with the implementation of the Reliability-Based Demand Curve, the market value of capacity is expected to strengthen over time. While current

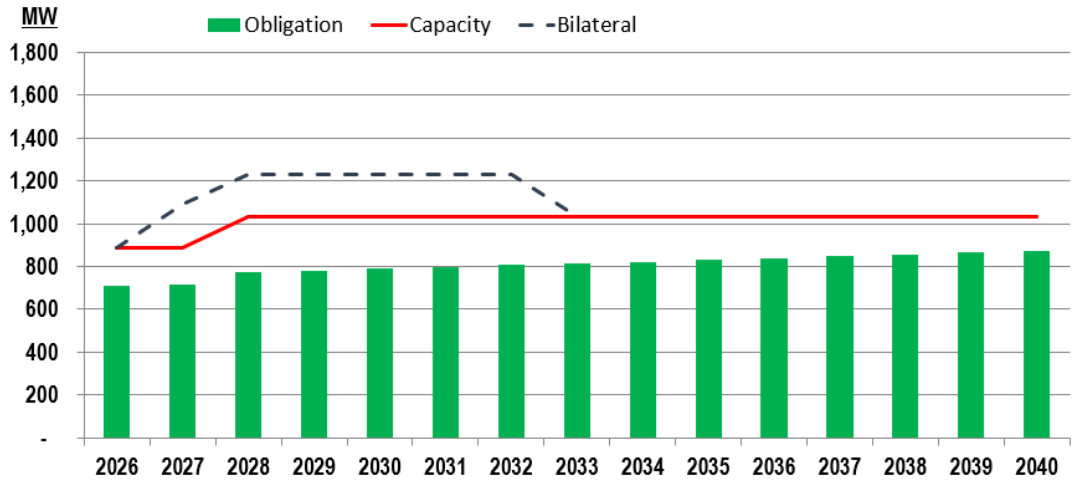
pricing remains relatively modest, Minnkota's proactive approach ensures that surplus capacity contributes meaningful benefits as market conditions evolve.

The following table and charts highlight Minnkota's long-term position in the MISO capacity market. The charts also highlight the 200-MW capacity transaction discussed in Section 4.

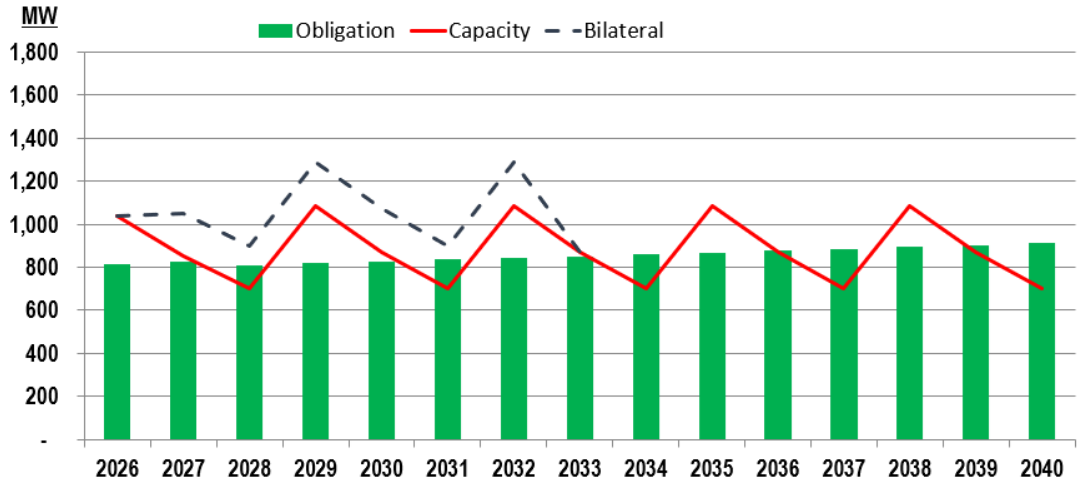
Joint System MISO Capacity Surplus/Shortfall (MW)

Planning Year	Summer	Fall	Winter	Spring
2020-2021	191			
2021-2022	149			
2022-2023	198			
2023-2024	261	376	446	305
2024-2025	262	16	466	176
2025-2026	285	(35)	354	301
2026-2027	180	256	282	224
2027-2028	163	0	258	125
2028-2029	206	(126)	220	169
2029-2030	190	177	200	151
2030-2031	174	191	180	60
2031-2032	176	(162)	173	128

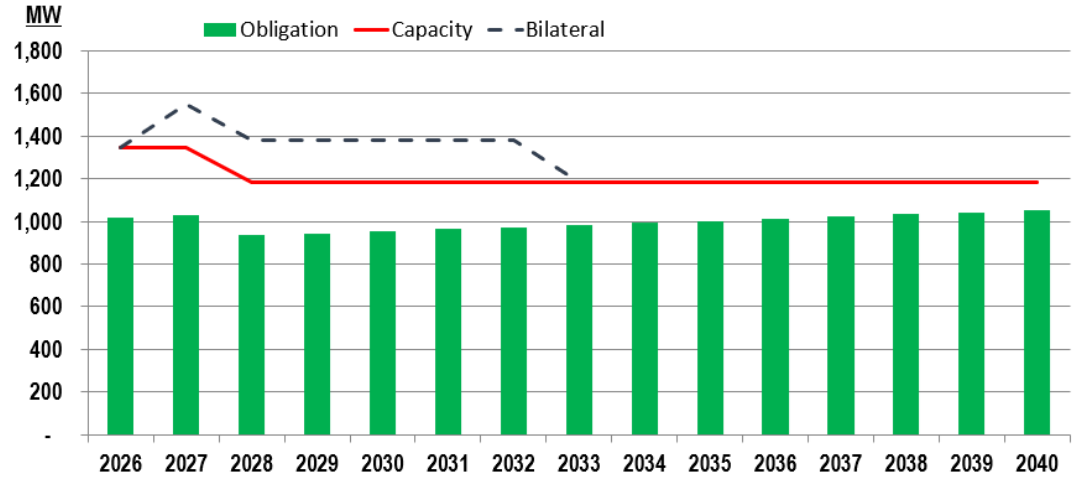
Summer Capacity vs. Obligation



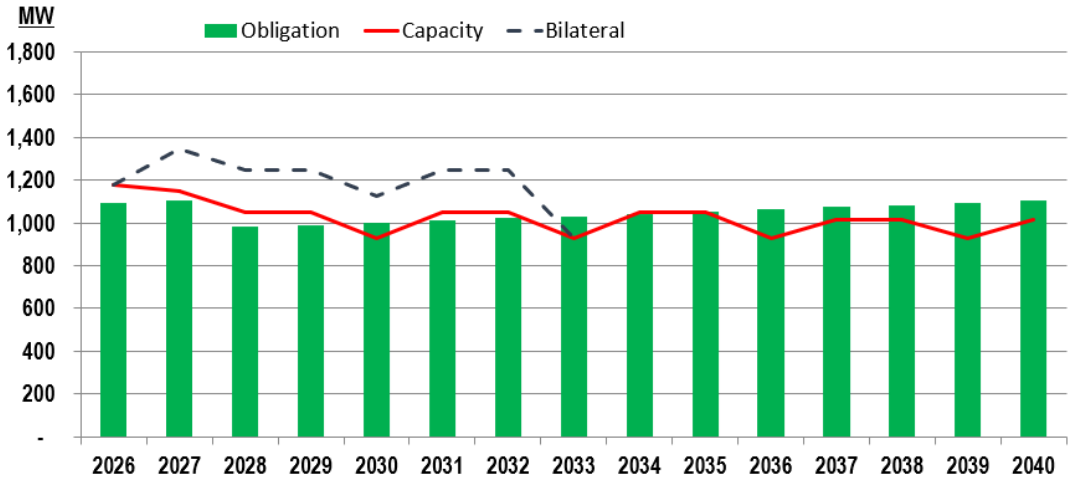
Fall Capacity vs. Obligation



Winter Capacity vs. Obligation



Spring Capacity



Analytical Techniques

Minnkota is a member of ACES, and utilizes its consulting services to provide analytical portfolio analysis used in the development of the IRP. ACES utilized EnCompass, a long-term capacity expansion and production cost modeling tool, to develop Minnkota's IRP. EnCompass provides best-in-class modeling technology and allows for simultaneous optimization of multiple criteria as part of a complex portfolio evaluation. Capacity expansion runs optimize long-term resource additions and retirements for the lowest cost portfolios – subject to reserve margin targets, energy market limits, and other constraints. For each portfolio and scenario, ACES ran an hourly dispatch and production cost simulation to provide a more detailed view of every hour using hourly price shapes, renewable energy shapes, and market conditions in a full 8760-hour model run. Figure 1 below shows the high-level architecture of the EnCompass modeling platform.

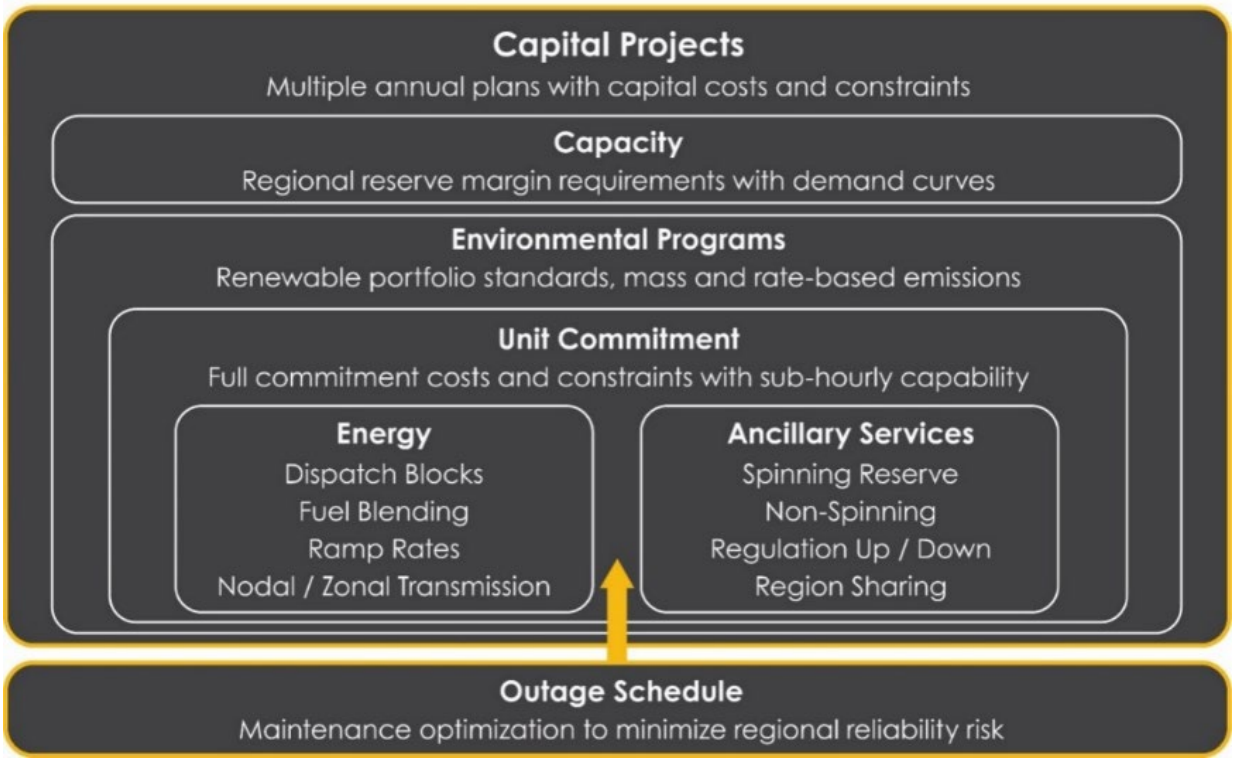


Figure 1

Forward curves for coal, wind power, natural gas, and capacity were developed using ACES' long-term fundamental forecasts. To create a long-term forecast for the model, ACES begins with the Horizons Energy national database then layers in ACES' long-term views on environmental regulations, cost projections for new resource technologies, and regional reserve planning targets. Figure 2 shows the market zones included in the Horizons Energy national database topology. Minnkota is in Zone 1 in the MISO-ND-MN region. Minnesota Hub and NNG-Ventura were used as reference points to estimate future power and natural gas prices.

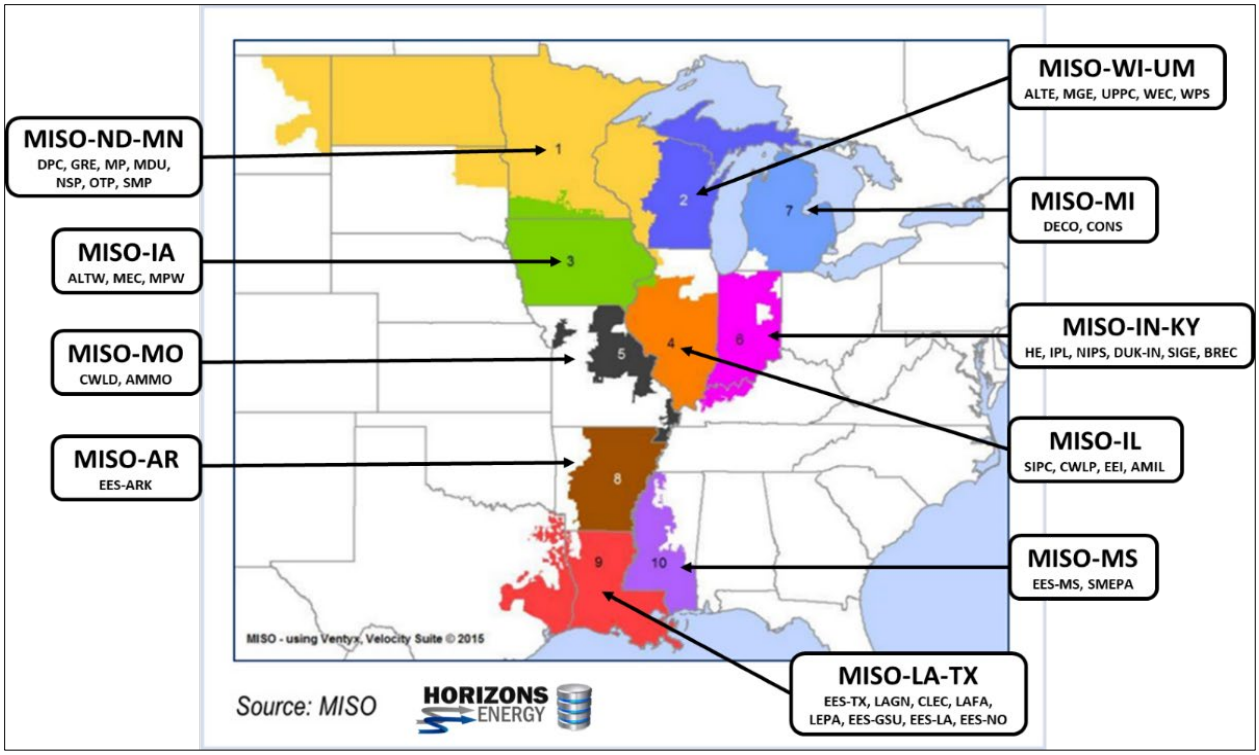


Figure 2

Minnkota's load forecast was used to determine the seasonal peak requirements for the IRP. Minnkota is winter peaking and has a forecasted peak of 875 MW in 2027, and the annual peak is forecast to escalate at approximately 0.7% annually. ACES modeled MISO's seasonal capacity market with a Planning Reserve Margin Requirement (PRMR) for each season. Figure 3 below shows the estimated PRMR for Minnkota each season after MISO implements the Direct Loss of Load (DLOL) framework in June 2028. The PRMR for each season was applied to the seasonal peak load to determine the total accredited capacity Minnkota must procure for each season.

Planning Reserve Margin Requirement (PRMR) after June 2028

	Summer	Fall	Winter	Spring
DLOL Reserve Margin	1.7%	5.3%	5.6%	1.1%

Figure 3

ACES modeled a firm or accredited capacity shape for each of Minnkota's existing resources and for each of the new resource options. The firm capacity percentage determined how much of each resource's installed capacity counted towards the seasonal capacity requirement. The firm capacity percentages for the existing resources were shared with Minnkota from MISO, and the annual shape was repeated from DLOL implementation through the end of the study. Firm capacity shapes for the generic new resources were based on MISO forecasts for future year accreditation.

The IRP included new resource options for Encompass to build to meet Minnkota's future load requirements. New resources modeled in the IRP include wind, solar, nuclear, and multiple natural gas and storage technologies. New resource costs and operating parameters were provided by ACES' Fundamentals team, with guidance from the National Renewable Energy Laboratory's (NREL) 2024 Annual Technology Baseline and the U.S. Energy Information Administration (EIA).

Minnesota's Renewable Energy Standard was also incorporated in the IRP modeling. Approximately 45% of Minnkota's load is in Minnesota, with the remainder in North Dakota. ACES included a requirement in Encompass for at least 45% of Minnkota's load to be served with carbon-free energy to account for the 100% carbon-free by 2040 requirement for the Minnesota portion of its load. In the capacity expansion optimization, EnCompass would add renewable resources to Minnkota's portfolio to ensure the total renewable energy was at least 45% of its total demand in each year. However, Minnkota's currently contracted renewable purchases and planned contract extensions were sufficient to serve all its carbon-free energy needs from 2028 through the end of the study, with baseload assumptions, so no new renewable resources needed to be added.

Summary

Minnkota continues to navigate market changes effectively, maintaining a strong and flexible position within MISO's evolving four-season construct. Its surplus capacity in most seasons presents valuable opportunities to enhance member benefits as market dynamics shift and capacity values rise. At the same time, Minnkota's use of bilateral sales and strategic agreements ensures compliance with capacity obligations, provides an economic outlet for surplus resources, and serves as a reliable buffer against market volatility and risk. This balanced approach enables Minnkota to manage uncertainty while positioning the Joint System to capture long-term value in an increasingly dynamic energy market.

SECTION 6
Energy Requirement Considerations

Overview

Another important consideration in generation planning is the degree to which the Joint System will be dependent on market-based resources to meet its energy requirements. The Joint System has the Young 1, Young 2 and Coyote coal-based generators, NMPA WAPA allocations, Minnkota's WAPA allocation, and purchase power agreements for wind energy from the Langdon and Ashtabula wind projects to fulfill its energy requirements. The cooperative also has signed a purchase power agreement for the Flickertail Wind Farm, which is scheduled to be online in 2028.

However, since the coal-based generating units require periodic maintenance during which time they are not generating energy, and since wind is intermittent by nature, the Joint System has several options to serve its load requirements. To meet short-term needs, Minnkota can continue to manage system balance through its well-established demand response program, which provides a reliable means of controlling load during peak conditions. Over the medium term, additional energy and capacity needs can be met through bilateral agreements with neighboring utilities, allowing Minnkota to secure firm resources in a cost-effective and flexible manner. When appropriate, the cooperative can also utilize direct MISO market purchases to supplement its supply, ensuring that member needs are met while longer-term resource solutions are developed.

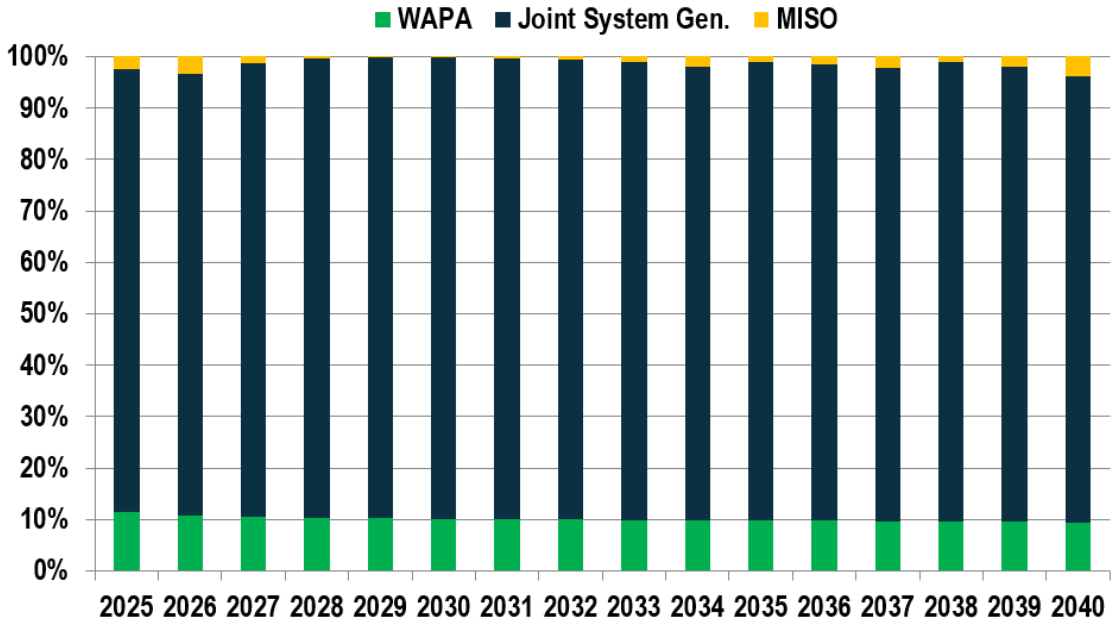
A financial risk exists in depending too greatly on the MISO capacity and energy markets, since the MISO market can be extremely volatile and expensive at times. Also, delivery of market power can be an issue. In order to minimize the financial risk of having to purchase high-cost energy, the Joint System prefers to fulfill as much of its energy requirements as practical from generating resources it owns or has agreements to purchase the output at fixed prices. This is among the drivers for the potential development of new natural gas generation within the next decade.

Percentage of Joint System Energy Requirements Purchased from MISO Energy Market

The following tables contain the forecasts of the annual Joint System energy requirements and the amounts of energy purchased from the MISO energy market for the low, median and high load scenarios.

The following table and graph contains the forecasts of the Joint System's annual energy requirements for the low growth, median growth, and the high growth scenarios.

How Joint System Energy Requirements Are Met



Year	Joint System Low Growth Scenario Energy Requirements MWh	Joint System Median Growth Scenario Energy Requirements MWh	Joint System High Growth Scenario Energy Requirements MWh
2026	4,669,320	4,971,296	5,261,387
2027	4,787,516	5,096,031	5,392,786
2028	4,930,014	5,247,449	5,552,895
2029	4,970,538	5,291,504	5,600,370
2030	5,013,794	5,338,280	5,650,497
2031	5,051,639	5,379,679	5,695,509
2032	5,086,595	5,418,095	5,737,145
2033	5,127,752	5,462,487	5,784,946
2034	5,166,189	5,504,349	5,830,187
2035	5,201,616	5,542,859	5,871,470
2036	5,236,146	5,580,144	5,911,445
2037	5,272,889	5,620,522	5,955,449
2038	5,301,684	5,651,906	5,989,330
2039	5,335,717	5,688,651	6,028,593
2040	5,371,038	5,727,287	6,070,558

The following table contains the forecasts of the Joint System's annual energy purchases from the MISO energy market for the low, medium and high growth scenarios:

Year	Energy Purchased from MISO Energy Market Low Growth Scenario MWh	Energy Purchased from MISO Energy Market Median Growth Scenario MWh	Energy Purchased from MISO Energy Market High Growth Scenario MWh
2026	125,596	174,188	234,472
2027	44,476	66,338	95,595
2028	9,420	16,778	26,797
2029	5,896	9,470	13,684
2030	7,111	11,052	16,413
2031	8,565	15,147	24,360
2032	25,964	37,851	52,461
2033	46,182	66,440	94,014
2034	83,403	115,454	157,082
2035	37,213	54,183	78,255
2036	60,693	87,434	120,557
2037	92,532	128,756	176,498
2038	41,626	61,161	89,149
2039	77,665	111,037	155,178
2040	161,237	223,544	300,288

The above tables show that the forecasted amounts of annual Joint System energy requirements purchased from the MISO energy market are quite small compared to the requirements fulfilled by its own generation and agreements. Given the small amounts of energy that will need to be purchased, the Joint System will be well-shielded from a high-cost and volatile MISO energy market. Therefore, there will be very little risk of financial damage since the Joint System will have minimal dependence on the MISO energy market.

Long-Term Resource Needs

The Joint System's existing generation resources, purchase power agreements and extensive demand response program will meet the near-term forecasts for peak demand and energy requirements. However, looking further into the planning horizon, Minnkota recognizes that additional resources will likely be needed to maintain long-term reliability and system flexibility. In particular, the cooperative is evaluating the development of new natural gas generation to provide firm, dispatchable capacity capable of supporting both member growth and the integration of renewable energy. At the same time, the addition of the Flickertail Wind Farm will strengthen Minnkota's renewable portfolio, providing cost-effective, renewable energy that complements the system's existing assets. Together, these planned additions reflect a balanced strategy positioning the Joint System to meet future energy needs.

SECTION 7
Minnesota Carbon-Free Energy Standard and Greenhouse Gas Emissions

Carbon-Free Energy Standard Objectives Overview

In February 2023, the state of Minnesota enacted legislation requiring all electric utilities serving load within the state to transition to 100% carbon-free electricity by 2040. This mandate introduces significant planning considerations related to both system reliability and long-term affordability.

The law establishes the following compliance milestones for electric cooperative and municipal utilities:

- By 2030, cooperative and municipal utilities must supply at least 60% of their retail electricity from carbon-free resources.
- By 2035, 90% of retail electricity sales must come from carbon-free resources; 55% of their retail electricity from renewable resources.
- By 2040, 100% of retail electricity sales must come from carbon-free resources.

These requirements apply to Minnkota's Minnesota member cooperatives and to NMPA Minnesota member municipals. The compliance targets will serve as key planning criteria in the development of Minnkota's long-term resource portfolio and integrated resource planning process.

Minnkota has power purchase agreements with NextEra, a wind developer, for portions of its Langdon and Ashtabula Wind Energy Centers located in North Dakota. From the Langdon Wind Energy Center, Minnkota has rights to the output of 93 wind turbines with a nameplate capacity of 139.5 MW. From the Ashtabula Wind Energy Center, Minnkota has rights to the output of 145 wind turbines with a nameplate capacity of 217.5 MW. Minnkota has also signed a Purchase Power Agreement with Minnesota-based PRC Wind for the Flickertail Wind Farm near New Rockford, N.D. The facility is scheduled to come online in 2028, at which point Minnkota will have the rights to the output of approximately 115 wind turbines with a nameplate capacity of 370 MW.

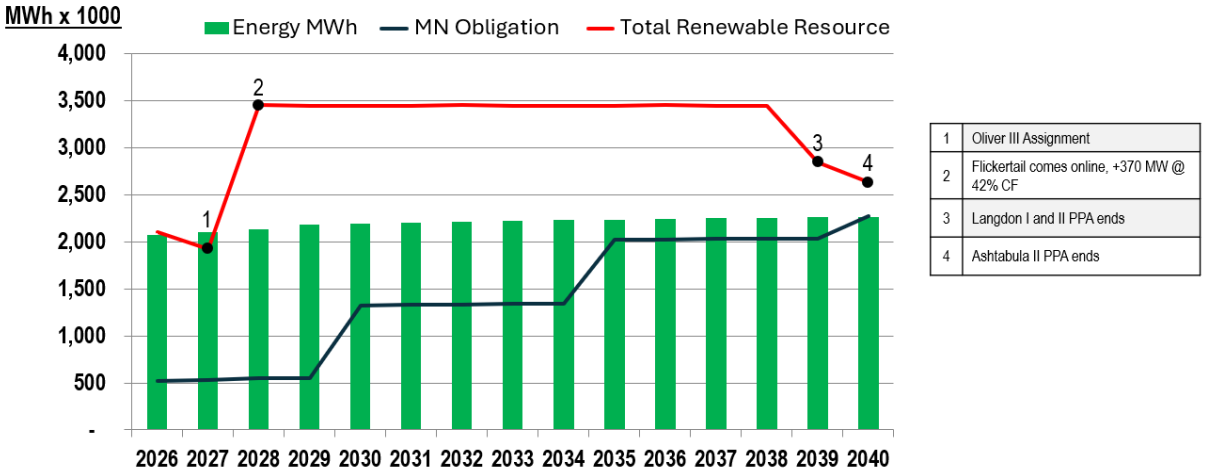
Between the Langdon, Ashtabula and Flickertail wind projects, Minnkota has secured the rights to 727 MW of nameplate wind capacity. For study purposes, it was assumed that the annual capacity factor would be 42% at the Langdon and Ashtabula facilities and 55% at the Flickertail facility, which translates to approximately 1,751,500 MWh of wind energy for the Joint System. Additionally, Minnkota has access to WAPA hydro allocations that serve as another significant renewable energy resource, providing up to 103 MW of capacity.

The following table documents the Joint System's Minnesota Carbon-Free Standard (CFS) given its long-term energy forecast and the percentage required to be generated by carbon-free resources. Also displayed in the table are the amounts of renewable and carbon-free energy

forecasted to be generated by the portions of the Langdon, Ashtabula and Flickertail wind farms for which Minnkota has purchase power agreements, and its WAPA hydro allocations.

Year	Joint System Minnesota Retail Sales MWh	% Required For MN CFS	Energy Requirement For MN CFS MWh	Langdon, Ashtabula, and Flickertail Wind Energy and WAPA Hydro Production MWh
2026	2,097,722	25	524,431	2,100,577
2027	2,135,680	25	533,920	1,917,727
2028	2,183,620	25	545,905	3,452,246
2029	2,193,018	25	548,254	3,441,091
2030	2,203,372	60	1,322,023	3,441,091
2031	2,211,708	60	1,327,025	3,441,091
2032	2,218,936	60	1,331,362	3,452,246
2033	2,227,795	60	1,336,677	3,441,091
2034	2,235,617	60	1,341,370	3,441,091
2035	2,241,973	90	2,017,776	3,441,091
2036	2,247,866	90	2,023,080	3,452,246
2037	2,254,528	90	2,029,075	3,441,091
2038	2,257,766	90	2,031,989	3,441,091
2039	2,262,822	90	2,036,540	2,843,084
2040	2,268,736	100	2,268,736	2,629,506

Minnesota Carbon-Free Requirement



1	Oliver III Assignment
2	Flickertail comes online, +370 MW @ 42% CF
3	Langdon I and II PPA ends
4	Ashtabula II PPA ends

*MN Obligation includes the higher percentage between MN Renewable Energy Standard and Carbon Free Standard

Greenhouse Gas Emissions

Minnesota Statute 216H.02 addresses the state's greenhouse gas emissions reduction goal, which to reduce statewide greenhouse gas emissions across all sectors producing greenhouse gas emissions by at least the following amounts, compared with the level of emissions in 2005: 15% by 2015; 30% by 2025; 50% by 2030; and to net zero by 2050.

All of the Joint System's generation resources are located in North Dakota. As noted in the chart below, Joint System CO_2 emissions in 2005 are 2,143,689 tons. The CO_2 emissions are calculated based on the MWh required to serve Minnesota load and the associated average carbon emission rate of the generating portfolio used to meet that load. The projected generation mix assumes the use of renewable energy resources to reduce the amount of carbon-emitting generation required to serve Minnesota load. These assumptions are reflected in the emission rate applied to the portion of load not served by renewable energy credits. Based on these projections, Minnkota demonstrates its ability to meet the Greenhouse Gas Reduction Goals.

Year	Total MN Load (MWh)	Load Served by Renewable Energy Credits (MWh)	Load Served by Balance of Portfolio (MWh)	Weighted Average Carbon Emission Rate (lb/MWh)	2005 CO_2 Baseline (tons)	Annual MN CO_2 Emissions (tons)	CO_2 Reduction from 2005 Baseline (%)
2005	1,790,744						
2021	1,841,266	368,253	1,473,013	1,934	2,143,689.25	1,424,545	-33.55%
2022	1,952,177	390,435	1,561,741	1,782		1,391,433	-35.09%
2023	1,904,333	380,867	1,523,466	1,948		1,484,119	-30.77%
2024	1,864,321	372,864	1,491,457	1,861		1,388,151	-35.24%
2025	1,926,615	481,654	1,444,962	1,815		1,311,432	-38.82%
2026	2,097,722	524,431	1,573,292	2,073		1,630,756	-23.93%
2027	2,135,680	533,920	1,601,760	2,117		1,695,248	-20.92%
2028	2,183,620	545,905	1,637,715	1,701		1,392,636	-35.04%
2029	2,193,018	548,255	1,644,764	1,757		1,444,930	-32.60%
2030	2,203,372	1,322,023	881,349	1,917		844,799	-60.59%
2031	2,211,708	1,327,025	884,683	1,866		825,398	-61.50%
2032	2,218,936	1,331,362	887,574	1,931		857,153	-60.02%
2033	2,227,795	1,336,677	891,118	1,921		855,811	-60.08%
2034	2,235,617	1,341,370	894,247	1,870		835,974	-61.00%
2035	2,241,973	2,017,776	224,197	2,118		237,424	-88.92%
2036	2,247,866	2,023,079	224,787	2,110		237,100	-88.94%
2037	2,254,528	2,029,075	225,453	2,066		232,881	-89.14%
2038	2,257,766	2,031,989	225,777	2,122		239,572	-88.82%
2039	2,262,822	2,036,540	226,282	2,316		262,091	-87.77%
2040	2,268,736	2,268,736	0	2,382		0	-100.00%

From the tables in Section 7, it can be seen that the Joint System purchases from renewable and carbon-free energy resources are significantly greater than its requirements. These tables demonstrate the Joint System's strong dedication to fulfilling its Minnesota RES and CFS requirements.

SECTION 8
Energy Efficiency and Conservation Program

Overview

Minnesota's Energy Conservation and Optimization Act (ECO Act), enacted in 2021, modernized the longstanding Conservation Improvement Program (CIP) to support a broader approach to utility energy efficiency. Under state law, Minnesota electric utilities must achieve annual energy savings through approved programs.

Minnkota and its participating member cooperatives and municipal utilities administer these efforts under the PowerSavers brand, which provides incentives for residential and business consumers to adopt cost-effective energy-efficient technologies and practices.

Minnkota has consistently met Minnesota's conservation and energy efficiency requirements since the inception of PowerSavers and is committed to continued compliance.

The current PowerSavers participants include:

- *City of Alvarado
- *Baudette Municipal Utilities
- Beltrami Electric Cooperative
- *Fosston Municipal Utilities
- Hawley Public Utilities
- North Star Electric Cooperative
- Roseau Electric Cooperative
- Roseau Municipal Utilities
- Thief River Falls Municipal Utilities
- *Warren Municipal Utilities
- Wild Rice Electric Cooperative

Starred utilities are exempt from CIP but are still participating voluntarily.

Applicable ECO Act provisions for Minnkota's Minnesota members include:

- 1.5% annual savings goal
    - At least 0.90% from traditional energy conservation
    - Up to 0.60% may come from expanded opportunities such as fuel-switching and load optimization
    - Utilities may request temporary goal reductions (not below 0.95%) under qualifying circumstances
- Spending requirements
    - The general 1.5% spending requirement was eliminated – unless a utility does not meet minimum savings for three consecutive years

- Low-income spending requirement remains at 0.2%
  - Up to 15% eligible for pre-weatherization support

The table below shows the annual kWh savings totals reached through the PowerSavers program from 2014 to 2024.

Year	kWh Savings
2014	27,209,892
2015	27,678,829
2016	33,330,584
2017	27,628, 406
2018	21,538,490
2019	18,343,689
2020	18,529,409
2021	19,418,632
2022	19,587,440
2023	19,362,151
2024	23,352,303

Note: The decrease in kWh savings from 2018-2021 is due to legislation that was passed in 2017. This legislation allowed municipals with fewer than 1,000 customers and cooperatives with fewer than 5,000 members an exemption from CIP requirements. Due to the passing of the legislation, we had cooperatives and municipals decide to no longer participate in the PowerSavers program.

Program Structure

PowerSavers includes tailored offerings for both residential and business consumers.

Residential Programs

- **The Residential Prescriptive Incentive Program** is designed to support end-use consumers choosing high-efficiency equipment at the time normal equipment is replaced or during major renovations.
- **The Residential Income-Eligible Program** provides direct installation services to improve energy efficiency in qualifying homes. These services focus on domestic hot water, lighting, energy consumption and weatherization. The program is available to households earning 80% or less of the area's median income, or those who meet the income requirements for financial assistance through state, municipal or utility programs approved by the Minnesota Department of Commerce.
- **The Residential Direct Installation Program** is designed to make an immediate impact on home electric energy usage through the installation of high-efficiency measures.
- **The Residential Existing Homes Program** provides homeowners with information, access to qualified contractors and financial incentives to improve energy efficiency for their homes.
- **The Residential Energy Behavior Use Change Program** is designed to help consumers decide how to best address their own energy use behavior. This is done through an online program that allows customers to actuate their own energy usage and monitor how their energy usage increases and/or decreases based on behavior changes they make in their homes.

Business Programs

- **The Business Prescriptive Incentive Program** provides financial incentives and information to increase the use of high-efficiency HVAC technologies, lighting, motors and drives, variable speed drives and food service equipment commonly utilized by businesses.

- **The Business Custom Program** aids retail, agricultural, school, commercial and industrial customers in installing a variety of energy-saving technologies not included in the Business Prescriptive Incentive Program.

- **The Business Direct Installation Program** is designed to make an immediate impact on commercial electric energy usage through the installation of high-efficiency measures. These measures include LEDs, low-flow faucet aerators, showerheads, pre-rinse sprayer valves, water heater temperature turndown and LED exit light retrofits.

SECTION 9
Region Transmission Operator (RTO) Participation

Overview

Minnkota periodically evaluates the potential benefits and risks of joining a Regional Transmission Organization (RTO). With strong transmission ties to both the Southwest Power Pool (SPP) and the Midcontinent Independent System Operator (MISO), those organizations would be the most logical options. Minnkota currently participates in the MISO market, allowing it to buy and sell energy and capacity as needed.

To date, these evaluations have consistently shown that RTO membership would not provide net benefits for the Joint System. As a result, there are no current plans to pursue RTO membership.

SECTION 10
Transmission Planning

Joint System Transmission Facilities

The Joint System is committed to transmitting safe, reliable and sustainable electricity through its power delivery resources. The cooperative operates and maintains a robust set of electric transmission infrastructure, including more than 3,388 miles of transmission line and 265 substations. The entire process is monitored and controlled from Minnkota's Energy Control Center where power system operators oversee the delivery of electricity on the grid 24 hours a day.

The Joint System's transmission facilities consist of 464 miles of 345 kV, 447 miles of 230 kV, 307 miles of 115 kV and 2,168 miles of line up to and including 69 kV.

The transmission system is directly interconnected with seven area utilities: Manitoba Hydro, Montana-Dakota Utilities Company, Minnesota Power, Otter Tail Power Company, Xcel Energy, Great River Energy and WAPA.

The Joint System's extensive transmission system and large number of interconnections with other utilities serves to enhance service reliability to the end-use consumer and permits the sale or purchase of energy with neighboring companies.

Transmission Planning

Transmission lines are built for four main reasons, which are outlined below:

1. To serve local load
2. To provide an outlet for generation resources
3. To maintain or improve transmission system reliability
4. To enable wholesale economic energy transactions between utilities

Because the construction of transmission lines is driven by different needs as outlined above, transmission planning occurs in various venues. Minnkota is responsible for the transmission planning of its 345 kV, 230 kV, 115 kV, and 69 kV transmission facilities required to maintain reliable and economical service to its member systems' consumers. In some instances, this planning effort is done entirely by Minnkota. At other times, potential transmission additions will have impacts on other area utilities. When this is the case, Minnkota works with those utilities in a joint transmission planning process to ensure that its transmission projects do not cause problems for others. Joint planning with other area utilities also helps minimize future facility additions. By incorporating the various needs of the utilities into joint planning studies, the resultant project may be an integrated solution that is less costly and more reliable than the individual additions that would have been built absent joint planning.

Regional Planning

For transmission projects above 115 kV, Minnkota interacts with a number of entities such as MISO and Minnesota Transmission Owners (MTO).

MISO Transmission Planning
Through a Planning Coordinator (PC) services agreement, MISO has the responsibility to conduct regional transmission planning for Minnkota and others in its PC footprint to ensure the continued reliability and efficient expansion of its transmission system. MISO is required to develop a long-range transmission expansion plan that addresses both short-term and long-term load serving needs, generation interconnections, and economic analysis, all with transparency through stakeholder input. In addition, MISO coordinates with neighboring PCs, such as Southwest Power Pool (SPP).

Transmission owners that are members of MISO are responsible for developing their own system-specific transmission plans with help from MISO, which are then consolidated by MISO into an integrated overall MISO Transmission Expansion Plan. MISO planning staff incorporates the plans submitted by the individual MISO transmission owners and sub-regional planning groups with stakeholder input and includes generation interconnection requests to develop a regional integrated plan for the orderly and cost-effective expansion of the MISO transmission system.

Minnesota Transmission Owners
The Minnesota Transmission Owners (MTO) is an organization of 16 utilities that own or operate high-voltage transmission lines within the state of Minnesota. Minnkota is a member of the MTO.

The MTO has responsibility for the Minnesota Biennial Transmission Projects Report. The major purpose of the Report is to inform the public of transmission issues and to facilitate the tracking of proposed solutions to transmission issues.

The report addresses such issues as transmission system interruptions or curtailments, identifies present and reasonable foreseeable future transmission inadequacies, and determines the transmission system enhancements needed to meet the state's Carbon-Free Standard.

Wildfire Mitigation Plan

Minnkota has implemented a comprehensive Wildfire Mitigation Plan designed to proactively reduce wildfire risk and strengthen system resilience. The plan incorporates detailed risk analysis to identify the locations and conditions most susceptible to issues, along with a thorough evaluation of underlying risk drivers such as vegetation proximity, weather exposure and equipment age. It also outlines enhanced operational practices and heightened risk protocols that are activated during elevated fire conditions to minimize potential ignition sources. In addition, Minnkota has assessed construction programs to deploy more fire-resistant infrastructure and has reinforced inspection and maintenance protocols to ensure timely identification and correction of hazards. Together, these efforts demonstrate Minnkota's commitment to safeguarding the communities it serves while maintaining reliable electric service.

SECTION 11
Environmental Compliance

Overview

Minnkota has installed and maintains the necessary emissions control technologies to meet all applicable air quality compliance requirements. These systems are continuously monitored and operated in accordance with federal and state regulations, ensuring that facilities perform responsibly and within permitted environmental limits. The Joint System is committed to ongoing compliance with all applicable standards.

1. **Milton R. Young Station**
   Minnkota operates the Milton R. Young Station (MRYS) near Center, N.D. Unit 1 of the station is owned and operated by Minnkota and has a rating of 250 MW. Unit 2 is owned by Square Butte Electric Cooperative (affiliated with Minnkota by common ownership), has a rating of 455 MW, and is operated by Minnkota. Unit 1 began commercial operation in 1970, while Unit 2 began commercial operation in 1977. Both units are fueled by lignite coal obtained from the adjacent Center Mine, which is operated by BNI Coal, Ltd. Both units have the same suite of environmental controls, including wet lime flue gas desulfurization for SO_2 control, advanced separated over-fire air and selective non-catalytic reduction for NO_X control, an electrostatic precipitator for particulate matter control, and a halide and post-combustion activated carbon injection system for mercury control.

2. **Coyote Station**
   The Coyote Station (Coyote) is co-owned by Otter Tail Power Company (35%), Northern Municipal Power Agency (Minnkota serves as operating agent) (30%), Montana-Dakota Utilities (25%), and Northwestern Energy (10%). Otter Tail operates the plant, rated at 427 MW, on behalf of the owners. Coyote began commercial operation in 1981 and is fueled by lignite coal obtained from the adjacent Coyote Creek Mine, operated by Coyote Creek Mining Company, LLC, a subsidiary of North American Coal Corporation. Coyote employs dry flue gas desulfurization and a fabric filter baghouse for SO_2 and particulate matter control, separated over-fire air for NO_X control, and activated carbon injection for mercury control.

Environmental Compliance Outlook

The Joint System's environmental compliance outlook remains stable, with continued adherence to all applicable federal, state and local standards. Current operations are supported by established compliance programs emphasizing monitoring, training and coordination with regulatory agencies. In the near term, no significant compliance challenges are anticipated. The regulatory environment continues to evolve, with the Environmental Protection Agency rescinding or substantially revising certain rule changes that previously had the potential to introduce additional cost or operational impacts. Overall, the outlook reflects a steady compliance position and a low risk of material changes affecting environmental obligations or operational planning in the near term.

Coal Combustion Residuals (CCR) Rule

The final federal rule regulating the disposal of coal combustion residuals in landfills and surface impoundments was published in the Federal Register on April 17, 2015, and became effective on October 19, 2015. The CCR rule set requirements for both existing and newly-constructed impoundments/landfills, including location restrictions, structural integrity, operating criteria, groundwater protections, monitoring/reporting, closure/post-closure care, and the requirement of operators to publish facility data on a public-facing website.

In May 2024, EPA adopted the Legacy CCR Surface Impoundments rule, which added a new category of CCR units requiring a facility evaluation report to be completed to assess whether operators had units falling within the "legacy category" and monitoring obligations. In July 2025, the EPA issued a rule (direct to final) that extends certain compliance deadlines rule updated requirements, including new deadlines and some technical corrections. The extensions provide more flexibility and opportunity for operators to come within the compliance requirements. In November 2025, EPA granted the North Dakota Department of Environmental Quality (NDDEQ) primary authority to regulate the disposal of CCR in surface impoundments and landfills, which are permitted and inspected by the NDDEQ.

Minnkota does not anticipate challenges in maintaining compliance with the CCR Rule at the MRYS or Coyote Station.

Waters of the United States (WOTUS)

The long-standing definition of federally jurisdictional WOTUS, under the Clean Water Act (CWA), was updated in a final rule issued in May 2015. The rule significantly expanded the jurisdiction of the federal government to include four new categories – tributaries, adjacent waters and wetlands, certain regional features, and waters within the 100-year floodplain – and retained the four previously defined categories – traditional navigable waters, interstate waters, territorial seas, and impoundment of any of these.

As written, the 2015 definition of WOTUS would have had a tremendous impact by increasing costs associated with construction and maintenance of transmission and distribution infrastructure, plant construction, operation, maintenance and decommissioning.

North Dakota was among a group of 28 states in which the 2015 WOTUS rule was eventually stayed. As a result of Executive Order 13778 under President Trump, EPA and the Army Corps reviewed the 2015 WOTUS rule, rescinded it, and replaced it with a new WOTUS definition that was published in February 2019. The 2019 proposal was generally consistent with the pre-2015 definition of WOTUS, and was finalized in 2020.

On December 7, 2021, the EPA and Department of the Army (the agencies) published and on March 20, 2023, finalized the revised WOTUS (2023 WOTUS rule). The 2023 WOTUS rule put back into place the pre-2015 definition, updated to reflect consideration of recent Supreme Court decisions. On September 8, 2023, EPA and the Army Corps issued a "conforming" rule to revise

parts of the 2023 WOTUS rule to align with the *Sackett v. EPA* Supreme Court decision (issued May 2023), which required the removal of certain provisions and modified definitions contained within the 2023 WOTUS rule.

Minnkota intends to continue to follow closely the development of these rulemakings.

Steam Electric Effluent Limitation Guidelines (ELG)

The most recent updates to Effluent Limitations Guidelines (ELG) for steam electric generating units (EGUs) was finalized and became effective July 8, 2024 (40 CFR 423) and strengthens certain discharge limitations. The 2024 ELG rule includes limits on flue-gas desulfurization (FGD) wastewater, bottom ash transport water, combustion residual leachate and certain legacy wastewater. The additional regulatory standards for wastewater discharged to surface waters are incorporated into facility North Dakota Pollutant Discharge Elimination System (NDPDES) permits. In March 2025, EPA announced it would reconsider the 2024 ELG rule, specifically examining whether certain wastewaters from coal-fired power plants causes an "undue burden."

The ELG rule has minimal effect on the MRYS. The station utilizes closed-loop FGD systems that do not produce effluent that discharges to surface waters. Fly ash is managed in a dry form and produces no effluent. Bottom ash is managed in a dry form, and the water used to transfer the ash internally to day bins is not discharged.

Coyote Station operates a dry scrubber and has dry fly ash and bottom ash handling and does not produce associated effluent that discharges to surface waters.

Unless there are significant unexpected changes to the rule, compliance challenges are not anticipated.

National Ambient Air Quality Standards (NAAQS)

The NAAQS are established to protect human health (primary standard) or public welfare (secondary standard) for criteria pollutants, including particulate matter (PM), sulfur dioxide (SO_2), nitrogen oxides (NO_X), and ground-level ozone. The NAAQS impact both new and existing electric-generating facilities. For source facilities, if air dispersion modeling from a state approved protocol demonstrates that the NAAQS are being exceeded at a facility's property boundary, then corrective actions may be required to reduce emissions. Additionally, if a county that contains a source facility goes into non-attainment with the NAAQS, then existing facilities may need to undertake additional control measures to reduce emissions of that criteria pollutant. The EPA is required to review each NAAQS every five years to assess whether imposing more restrictive standards is warranted to protect human health and the environment. If the EPA determines that a state's air quality is not in compliance with the NAAQS, the state is required to adopt plans describing how it will reduce emissions to attain the NAAQS. The EPA recently reassessed NAAQS for NO_X, SO_2, and PM. Implementation of the EPA's February 2024 final rule lowering the annual primary standard for fine particulate matter began on May 6, 2024. On December 27, 2024, the EPA published a final rule in the Federal Register revising the

secondary SO_2 NAAQS while retaining the NO_X and PM secondary standards, with a final rule effective date of January 27, 2025.

Both Coyote Station and the MRYS's existing emission controls will remain compliant with existing or known proposed NAAQS revisions. Therefore, Minnkota does not anticipate any additional technology requirements for compliance with NAAQS during the period covered by the 2025 IRP.

Regional Haze

The Regional Haze program was established by the 1977 Clean Air Act Amendments. The second Regional Haze planning period is presently underway. The North Dakota Department of Environmental Quality (NDDEQ) requested that Minnkota complete a Four-Factor Analysis of technically feasible control measures applicable to the MRYS, and required the same of Otter Tail Power Company for the Coyote Station.

In August 2022, the NDDEQ State Implementation Plan (SIP) adopted its Round 2 Regional Haze SIP revision, which demonstrates that North Dakota is projected to meet 2028 visibility goals and remains on track for 2064 goals. On December 2, 2024, EPA issued a partially approving and partially disapproving decision of North Dakota's Regional Haze Plan for the second planning period. EPA determined that North Dakota's determination to reject controls at Coyote Station was improper. However, EPA did not include a Federal Implementation Plan (FIP) addressing the EPA's disapproval nor required any implementation action of North Dakota. No discussion of the MRYS is included in the EPA final determination.

With no FIP issued, if the partial disapproval is upheld, additional controls at Coyote Station by December 31, 2028, may be required. The timing of a final decision on any additional controls is undetermined, since litigation will affect the process.

On October 2, 2025, the EPA published an advanced notice of proposed rulemaking requesting comments on streamlining regulatory requirements impacting states' visibility improvement obligations under the CAA and clarifying certain requirements governing the Regional Haze program going forward. The EPA intends to use the information it receives to inform a forthcoming proposed rulemaking on the Regional Haze program.

Mercury & Air Toxics Standards (MATS)

EPA promulgated the final Utility MATS rule in February 2012. The MATS rule targets emissions reductions of heavy metals, including mercury, arsenic, chromium and nickel; and acid gases such as hydrochloric and hydrofluoric acids. These are also known as hazardous air pollutants (HAPs) or air toxics. For lignite-fired electric generating units (EGUs), such as the MRYS and Coyote Station, the primary standard of importance is for mercury, which was set at 4.0 lbs./TBtu (trillion Btu).

To achieve compliance with the MATS rule, the MRYS and Coyote Station have installed mercury control equipment. The rule became effective in 2015, and the MRYS and Coyote Station have maintained compliance since that date.

Various EPA actions on MATS have occurred since implementation. On June 11, 2025, the EPA proposed to repeal certain amendments issued on May 7, 2024. MRYS and Coyote will maintain and continue to operate mercury control systems to ensure compliance with the present 4 lbs./TBtu limit.

Greenhouse Gas Regulation

The Environmental Protection Agency's (EPA) Clean Power Plan (CPP) final rule was published under section 111(d) of the Clean Air Act in October 2015. The CPP was a phased program of "building blocks" that targeted a nationwide CO_2 reduction of 30% by 2030. Several states, including North Dakota and Minnesota, were more severely regulated than others; North Dakota was mandated a 45% emissions reduction and Minnesota a 40% reduction (both on a lbs./MWh rate basis). Extensive litigation ensued, and ultimately the CPP was stayed by the U.S. Supreme Court in February 2016.

Subsequently, the EPA finalized a new rule under President Trump – the Affordable Clean Energy (ACE) rule – that replaced the CPP under 111(d). The ACE rule was formally proposed on August 31, 2018, and finalized on June 19, 2019. In January 2021, the ACE rule was vacated by the United States Court of Appeals for the District of Columbia. Vacating the ACE rule also vacated the repeal of the CPP contained in the rulemaking that established ACE.

On April 2024, the EPA finalized GHG regulations establishing a new set of standards for both existing and new fossil fuel-fired electric generating units under Clean Air Act (CAA) Section 111. The proposed rule included reassessment of the "best system of emissions reduction" (BSER) determination under Section 111(d) and new source performance standards (NSPS) under Section 111(b). The EPA also included formal repeal of the ACE Rule.

On June 11, 2025, EPA Administrator Lee Zeldin proposed to repeal all "greenhouse gas" emissions standards for the power sector under Section 111 of the CAA. Minnkota intends to continue closely following the development of these rulemakings.

State Climate Initiatives: Carbon-Free Standard

Following legislation passed into law in 2023, the state of Minnesota is currently developing standards and frameworks to support the mandate for public utilities to generate or procure 80% carbon-free electricity by 2030, 90% by 2035, and 100% by 2040. The Commission has initiated proceedings in Docket Nos. E999/CI-23-151 and E999/CI-24-352 to address the implementation of the Carbon-Free Standard (CFS). Although not a regulated entity, eight of Minnkota's member-owner distribution cooperatives and 10 of the 12 NMPA municipals are impacted by CFS. As such, Minnkota is actively involved in CFS implementation efforts, along with other utilities, customers and interested stakeholders. The recommended 2025 Plan meets the CFS requirements.

Project Tundra

The Joint System recognizes that evolving regulatory and policy dynamics point to a future in which carbon management may be required. The cooperative is committed to making long-term progress toward decarbonization while upholding its responsibility to deliver reliable and affordable electricity to its members.

Project Description
Project Tundra is a carbon capture and storage (CCS) initiative designed to retrofit the Milton R. Young Station near Center, N.D., with post-combustion CO_2 capture technology. The project's objective is to capture and safely store up to 4 million metric tons of carbon dioxide (CO_2) annually. The CO_2 will be permanently stored approximately one mile underground in geologic formations. The project benefits from access to 222 million tons of permitted CO2 storage capacity situated directly beneath the power plant site. If completed, it would be one of the largest CCS projects of its kind, aligning with both state and federal goals for reducing greenhouse gas emissions while maintaining the reliability of the existing generation fleet.

Status Update
In 2025, much of the project's development efforts have been focused on navigating significant federal changes. Shifts in funding programs, evolving EPA rules for power plants and other related policy updates are critical to Project Tundra, and Minnkota continues to carefully assess their impact. At the same time, the project faces ongoing supply chain challenges and inflationary pressures that affect labor, equipment and materials required to build a carbon capture project in rural North Dakota.

Financial Update
Over the course of development, Project Tundra has earned strong local, state and federal support. The project has access to up to $350 million in Department of Energy funding through its Carbon Capture Demonstration Projects Program. The first installment of the funding ($4.2 million) was awarded in September 2024, with additional funding available as the project progresses through the award phases. The project also has access to $250 million in loans through the state of North Dakota and received an opportunity to negotiate an award of $48.6 million in 2024 for carbon transport and storage facility development through DOE's CarbonSAFE program. Also in 2024, Minnkota was selected to move forward in the federal Empowering Rural America (New ERA program), which intends to provide access to $9.7 billion to advance projects that reduce carbon emissions, like Project Tundra. The project would also have access to federal 45Q tax credits, which currently provide $85 per ton of CO_2 that is permanently stored underground or used for enhanced oil recovery.

Minnkota continues to evaluate funding options to the extent it benefits the Joint System.

Stakeholder Engagement

Over the course of this initiative, Minnkota has worked closely with member cooperatives, local landowners, community members and other key stakeholders. Consistent landowner meetings

are being held, project leaders present to county and state officials, and educational sessions are held with member system board directors and staff. A project website (ProjectTundraND.com) provides updates, information and other materials. Minnkota is committed to open communication as the evaluation process continues.

Execution and Cost Focus

There is strong confidence in the technical ability to build and operate a large-scale CCS project at the Milton R. Young Station. The current focus is on reducing overall project costs to ensure long-term economic viability. This includes evaluating technologies and approaches that can achieve the emissions reduction objectives at lower cost. A final investment decision will be made when financial, regulatory and market conditions align to support implementation in a manner that provides clear and sustained benefits to the membership.

SECTION 12
Two-Year Action Plan

The Joint System will take the following actions during the 2026-2027 timeframe as part of its ongoing efforts in Integrated Resource Planning.

A Load Forecast Study (LFS) will be completed for the Joint System in the fall of 2027. The LFS will track the growth in the demand and energy requirements of the Joint System.

Discussions and meetings will continue to take place between the member systems, the NMPA municipals and Minnkota. These meetings will focus on strategies to maintain reliable, affordable and sustainable electricity for end-use consumers.

Several resource adjustments are planned during this timeframe. The Infinity wind turbines located near Valley City and Petersburg, N.D., will be decommissioned as they reach the end of their service life. The Oliver III wind resource will be reassigned to a neighboring utility effective June 1, 2026. Progress is also anticipated on the development of the Flickertail Wind Farm. Further, Minnkota expects to gain greater clarity on Project Tundra's future and the evaluation of prospective natural gas development.

SECTION 13
Five-Year Action Plan

In addition to the activities outlined in the Two-Year Action Plan, the Joint System will take the following actions during the 2028-2030 timeframe as part of its ongoing efforts in Integrated Resource Planning.

A Load Forecast Study will be completed for the Joint System in 2029. These studies will track the growth in the demand and energy requirements of the member systems. The LFS forecasts will be an important and ongoing part of the Integrated Resource Planning process.

By this timeframe, the Joint System anticipates having the Flickertail Wind Farm placed into operation to support renewable energy goals. Additionally, if it is demonstrated to be beneficial for the Joint System members, progress will continue on developing a natural gas facility and advancing Project Tundra's carbon capture project as part of a diversified and reliable portfolio.

SECTION 14
Large Loads

Sudden Addition of a Large Load

To ensure the Joint System can reliably serve significant new loads, Minnkota follows a structured and proactive Large Load Interconnection Process. Any new large industrial or commercial addition (such as a data center or major manufacturing facility) is evaluated in numerous areas, including power supply, transmission capacity and local distribution infrastructure.

This interconnection process includes coordinated engineering studies, detailed analysis and close collaboration with member utilities to verify that appropriate resources are in place or can be developed in a timely manner. By completing these evaluations well ahead of a new load coming online, Minnkota and its members can confidently plan for growth while maintaining system reliability.

Sudden Loss of a Large Load

Minnkota's Large Load Interconnection Process is specifically designed to protect the Joint System and its legacy members from financial exposure related to the sudden loss of a large load. Through comprehensive engineering studies, cost allocation reviews and contractual safeguards, Minnkota ensures that all new infrastructure and resource needs required to serve a large load are fully funded by that new consumer. This includes generation, transmission and local delivery upgrades, as well as any associated development costs.

Large Load Interconnection Process

To effectively manage the growing interest in large-scale electric service connections, Minnkota has established a formal Large Load Interconnection Process. These projects are evaluated separately from traditional member load requests due to their size, complexity and potential impact on the transmission and distribution system. The interconnection process ensures that all required system upgrades and associated costs are fully identified, assigned and recovered from the large-load customer through every step of the process. This protects traditional member-consumers by ensuring that they do not bear the financial responsibility for infrastructure investments driven solely by these major facilities. In addition, the growth associated with large loads is measured and assessed independently from Minnkota's regular Load Forecast Study, ensuring that system planning, resource adequacy and reliability remain well coordinated. Minnkota's Large Load Interconnection form and additional information can be found on its public website: https://minnkota.com/our-programs/large-load-interconnection-process

Data Centers and Artificial Intelligence

In recent years, Minnkota and its members have experienced an increase in interest from large-scale data center and digital asset mining operations seeking to interconnect within its service area. These facilities, which include high-performance computing for artificial intelligence applications and large-scale blockchain mining, represent a new class of load that is distinct from traditional industrial or commercial customers. Their energy demands are continuous, high-density, and in many cases approach hundreds of megawatts when fully developed. While these loads offer substantial economic opportunity in the form of increased wholesale energy sales and system utilization, they also require rigorous planning and assessment.

To address these developments, Minnkota utilizes its formal Large Load Interconnection Process, previously described, which is designed to protect the reliability of the transmission and distribution system while providing clarity for prospective developers. This process requires a series of technical studies to determine system impacts and identify the infrastructure upgrades necessary to accommodate the proposed load. Costs associated with these studies and the upgrades are assigned directly to the interconnecting facility, ensuring that the Minnkota member cooperatives, NMPA municipals and end-use consumers are not burdened with expenses arising from new industrial development.

Minnkota has developed a new wholesale rate class specifically for high-demand electric consumers, structured around cost-of-service principles. This schedule ensures that fixed generation and transmission costs are fully recovered, while provisions related to load factor encourage steady and predictable consumption patterns. The structure also includes exit protections, reducing the risk of stranded costs should a facility cease operations prematurely. Together, these rate mechanisms provide Minnkota with the tools necessary to manage both the financial and operational risks of these new loads.

Core Scientific

Core Scientific operates a large-scale digital asset mining facility within the Minnkota member service area in Grand Forks, N.D. The 100-MW site, which came online in 2021, represents one of the first high-density computing loads interconnected to the Minnkota member systems. To accommodate Core Scientific's interconnection, Minnkota conducted extensive system impact studies and identified the need for substation and transmission upgrades. This facility currently operates as a load modifying resource, which means that it can be curtailed up to a designated number of hours each year. Current contracts with Core Scientific extend through 2026.

Applied Digital

Applied Digital began construction in September 2025 on a $3 billion artificial intelligence (AI) data center near Harwood, N.D. The new 280-megawatt campus, known as Polaris Forge 2, is scheduled to begin operations in 2026 and reach full capacity by early 2027.

Once complete, the facility will be the largest single load interconnected to the cooperative's system. Its focus on AI and cloud-based computing services highlights the growing diversification of digital energy demand beyond digital asset mining.

Minnkota continues to work closely with Applied Digital during the interconnection process, performing detailed engineering studies to assess the impacts on transmission and substation

infrastructure. System upgrades and necessary power supply resources dedicated to this load will be paid for by Applied Digital. The facility is served under Minnkota's dedicated rate for data centers, which provides cost-of-service alignment and financial protections for the membership.

Resource Options Available in the Event of Generation Shutdown

Resource diversity is a foundational priority of the Joint System's long-term planning efforts. Maintaining a balanced mix of resources enhances reliability, supports affordability and reduces exposure to operational and regulatory risks. This is why the Joint System is pursuing additional wind resources such as the Flickertail Wind Farm, as well as evaluating the development of a natural gas facility that can provide dispatchable generation when renewable output is limited. Together, these resources strengthen the Joint System's ability to serve member needs under a wide range of conditions.

In the event of the loss of a major generation unit for a year or less, Minnkota would seek to secure replacement power through bilateral agreements with neighboring utilities or through purchases from the MISO energy market. These options provide short-term flexibility while permanent solutions are evaluated.

If the generator outage resulted in the need for long-term replacement, Minnkota would be required to purchase power and capacity for the full duration required to install new generation. The time necessary to construct new resources is currently impacted by supply chain and inflationary pressures.

A complete shutdown of the Joint System's coal-based generation would have significant financial and operational consequences. The Joint System would be responsible for the ongoing debt service of the retired units, the costs associated with purchasing replacement power and the capital investment required to build new generation all at the same time. This scenario would place a substantial financial burden on end-use consumers.

Summary

Minnkota is taking a steady, measured approach to managing this new wave of large electric loads. Through its formal Large Load Interconnection Process, the cooperative ensures that every project is evaluated for its technical, financial and operational impact before moving forward. Costs for new infrastructure are assigned directly to the developers, not to existing members or consumers. By maintaining this structure, Minnkota is protecting the reliability of its system and the financial integrity of its membership.

SECTION 15
Environmental Costs

Environmental costs are an important part of every resource decision. As a not-for-profit electric cooperatives and municipals, the organization carefully evaluates environmental risks to avoid stranded investments or assets that could increase costs for members.

The MN PUC has adopted environmental externality values for selected air emissions, which includes carbon dioxide (CO_2), sulfur dioxide (SO_2), nitrous oxide (NO_X), particulate matter 10 microns and less (PM-10) and volatile organic compounds (VOCs). These values are used to help understand the potential impacts of different generation options, but they do not represent direct costs to consumers. Natural gas generation is being evaluated as part of future planning, though no specific projects are under development at this time. If fossil-fuel-based generation is added to the portfolio, environmental costs will be assessed according to regulatory requirements.

No near-term environmental compliance challenges are expected, but carbon management may be part of the industry's future. Project Tundra provides a potential path to lower emissions while maintaining reliable and affordable power for cooperative members.

SECTION 16
Public Participation

Public participation in the Integrated Resource Planning process was provided by the governing boards of the member systems, which represent end-use consumers. Their ideas and concerns were solicited as part of the overall resource planning process. A meeting and input session was held with the Northern Municipal Power Agency on October 22. A meeting and input session was held with representatives from all 11 Minnkota member cooperatives was held on November 14.

Date		**Location**
Northern Municipal Power Agency	October 22, 2025	Thief River Falls, MN
Beltrami Electric Cooperative	November 14, 2025	Grand Forks, ND
Cass County Electric Cooperative	November 14, 2025	Grand Forks, ND
Cavalier Rural Electric Cooperative	November 14, 2025	Grand Forks, ND
Clearwater-Polk Electric Cooperative	November 14, 2025	Grand Forks, ND
Nodak Electric Cooperative	November 14, 2025	Grand Forks, ND
North Star Electric Cooperative	November 14, 2025	Grand Forks, ND
PKM Electric Cooperative	November 14, 2025	Grand Forks, ND
Red Lake Electric Cooperative	November 14, 2025	Grand Forks, ND
Red River Valley Cooperative Power Assoc.	November 14, 2025	Grand Forks, ND
Roseau Electric Cooperative	November 14, 2025	Grand Forks, ND
Wild Rice Electric Cooperative	November 14, 2025	Grand Forks, ND
Minnkota Power Cooperative, Inc.	November 14, 2025	Grand Forks, ND

At these meetings, individual members of the Board of Directors of the member systems were given the opportunity to participate in the IRP process and to provide their input, ideas and comments were solicited and received. Their board resolutions are included in Appendix H.

SECTION 17
Plan is in the Public Interest

Maintain or Improve the Adequacy of Utility Service

The IRP maximizes the use of existing resources by maintaining and extending the useful life of its assets where it is practical and economically justifiable.

Keep Customers' Bills and Utility Rates as Low as Practical, Given Regulatory and Other Constraints

The IRP documents how the Joint System will evaluate energy-efficiency programs and resource options and select those that are the most cost-effective.

Minimize Adverse Socioeconomic Effects and Adverse Effects Upon the Environment

The Joint System intends to meet any federal and state environmental requirements. This goal is implicit in the IRP.

Enhance the Utility's Ability to Respond to Changes in the Financial, Social and Technological Factors Affecting its Operations

The Joint System recognizes the importance of maintaining flexibility in its resource portfolio to effectively navigate evolving regulatory, operational and market conditions. This flexibility is reflected in the Joint System's diversified mix of generation resources, including three baseload facilities, a well-established and extensive demand response program, and numerous transmission interconnections with neighboring utilities. As an active participant in the MISO market, the Joint System is also able to take advantage of regional energy opportunities that support system reliability and affordability.

Looking ahead, the Joint System is continuing to expand its resource diversity by adding the Flickertail Wind Farm and evaluating the development of natural gas generation that can provide firm, dispatchable reliability to complement renewable resources. These strategic actions further strengthen the Joint System's ability to serve member systems and their end-use consumers in a reliable and cost-effective manner amid changing energy demands.

Limit the Risk of Adverse Effects on the Utility and its Customers from Financial, Social and Technological Factors that the Utility Cannot Control

The Joint System is mindful of the many risks that the electric industry faces. It is continually evaluating those risks as it analyzes the natural gas and wind generation options that are presently available. The IRP outlines the concerns about these risks and discusses how the risks may be avoided or minimized.

Summary

The IRP fulfills the requirements of Minnesota statutes and rules. Minnkota and NMPA believe that it presents a clear and concise picture of how the Joint System intends to satisfy the electrical requirements of its members (and their consumers) in a cost-effective and reliable manner while meeting federal and state environmental requirements.

SECTION 18
Cross Reference Guide

Cross Reference of Resource Plan Requirements

Rule or Statute		Reference Section
216B.1691 *Subdivision 2*	Report on plans, activities, and progress with regard to the renewable energy objectives.	7
216B.2422		
Subdivision 3	Utility must use the environmental cost values, along with other socioeconomic factors, in selecting resources.	15
Subdivision 6	Utility should state if it intends to site or construct a large energy facility.	4
7843.0300 *Subparagraph 5*	Submit 15 copies of the plan to the Commission, and copies to the Department, Attorney General, MEQB, and other interested parties	See Service List
7843.0400 *Subparagraph 1*	Include a copy of the latest advance forecast to the DOC and MEQB.	See Appendix A
Subparagraph 3	Description of the process and analytical techniques used in developing the plan.	5
Subparagraph 3	Include a five-year action plan with a schedule of key activities and regulatory filings.	13
Subparagraph 3	Include a narrative of why the plan is in the public interest.	17
Subparagraph 4	Include a nontechnical summary not to exceed 25 pages in length.	1
Notice	Submit an original copy of the filing as an unbound, one-sided document on 8½-by-11 paper with no tabbed dividers.	Enclosed with PUC Filing

Cross Reference to 2022 Integrated Resource Two-Year Action Plan

Section

A.	A Load Forecast Study (LFS) will be completed for each of the 11 member systems and Minnkota in 2023. The LFS will track the growth in the demand and energy requirements of the member systems.	**Completed**
B.	Discussions and meetings will continue to take place between the member systems, the NMPA municipals and Minnkota. These meetings will focus	**Completed**

on strategies to reduce energy costs to the end-use customers.

C. Minnkota staff will continue to study and forward recommendations to the Minnkota Board of Directors concerning modifications or additions needed to the Wholesale Power Rate Schedule. These efforts will continue to focus on developing a rate philosophy that is fair and equitable to the members and reflects the applicable power supply expenses. **Ongoing**

D. Minnkota staff will continue to analyze the cost-effectiveness of integrating demand side management programs and renewable energy resources into the Joint System power supply resource mix. **Ongoing**

Cross Reference to 2022 Integrated Resource Five-Year Action Plan

Section

A. A Load Forecast Study (LFS) will be completed for each of the 11 member systems and Minnkota in 2025 and 2027. These studies will track the growth in the demand and energy requirements of the member systems. The LFS forecasts will be an important and ongoing part of the Integrated Resource Planning process. **Ongoing**

B. Minnkota staff will continue to analyze and forward recommendations to the Minnkota Board of Directors on the best methods of promoting and enhancing Demand Response activities. **Ongoing**

C. Minnkota staff will continue to analyze the cost-effectiveness of integrating demand side management programs and renewable energy resources into the Joint System power supply mix. **Ongoing**

D. Future Integrated Resource Plans will be completed as required. **Ongoing**