Minnkota Power Cooperative, Inc.

– and –

Northern Municipal Power Agency

2022 INTEGRATED RESOURCE PLAN

2022 – 2036

Submitted to the

Western Area Power Administration

– and the –

Minnesota Public Utilities Commission

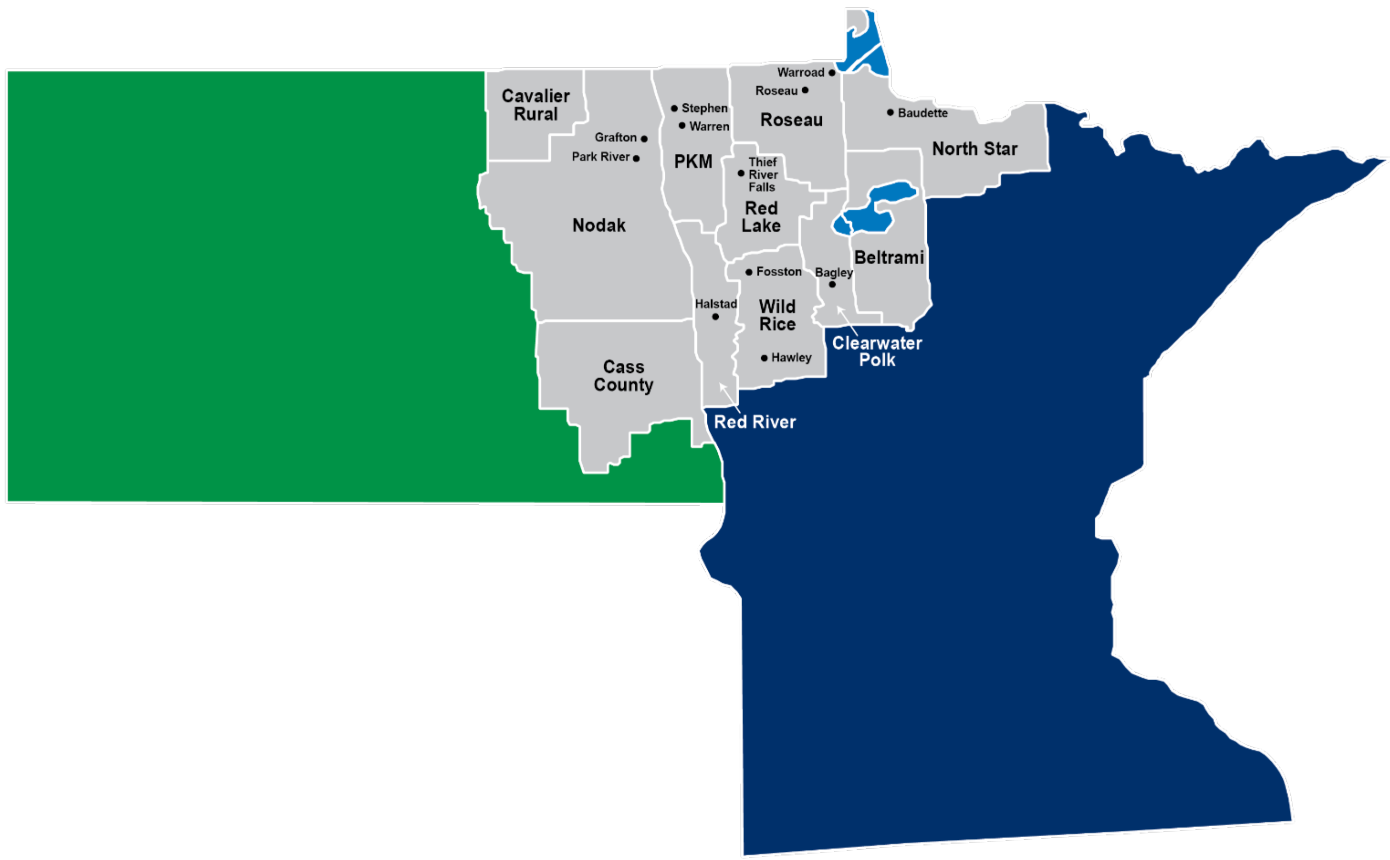
PUBLIC DOCUMENT – TRADE SECRET DATA HAS BEEN EXCISED

Minnkota Power COOPERATIVE

A Touchstone Energy® Cooperative

Northern Municipal POWER AGENCY

SERVICE AREA



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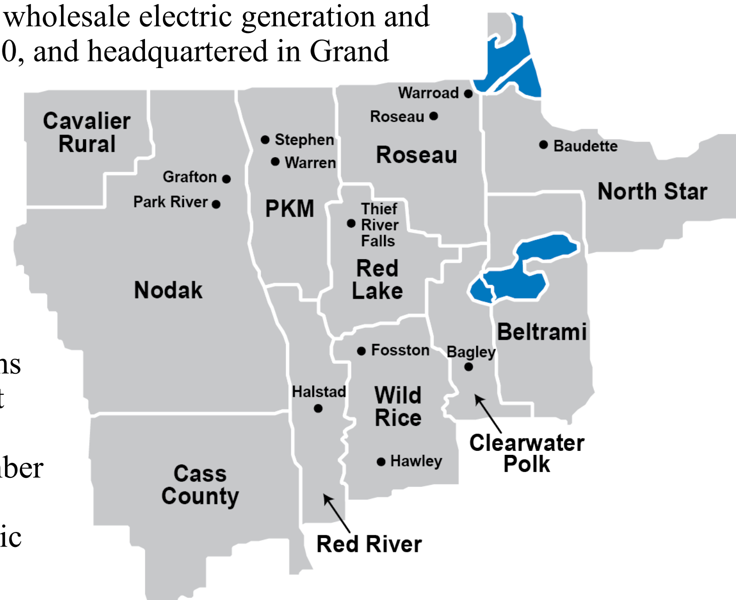
SECTION 1
Introduction

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 366,000 people. The member systems serve approximately 146,500 customers. The primary function of the member systems is to provide the total electrical requirements of their own member-owner 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 a Wholesale Power Contract with each of the 11 member systems until Dec. 31, 2058, and thereafter until terminated with six months' written notice of either party. 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.

The Wholesale Power Rate Schedule is structured so as 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 member systems. Directors are elected annually at a delegate 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 15,800 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 a ratio of NMPA's load to the Joint System load. Minnkota is the operating agent for NMPA.

Minnkota Membership

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 membership 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 390 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 210 employees operate out of the general headquarters in Grand Forks, N.D. Approximately 180 are employed at the Milton R. Young Station located near Center, N.D.

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

Minnkota is a market participant in the MISO energy market. This allows Minnkota to purchase energy from or sell energy into the MISO energy market. This MISO market is another source for the Joint System's energy requirements.

SECTION 2
Resource Plan Summary

Introduction

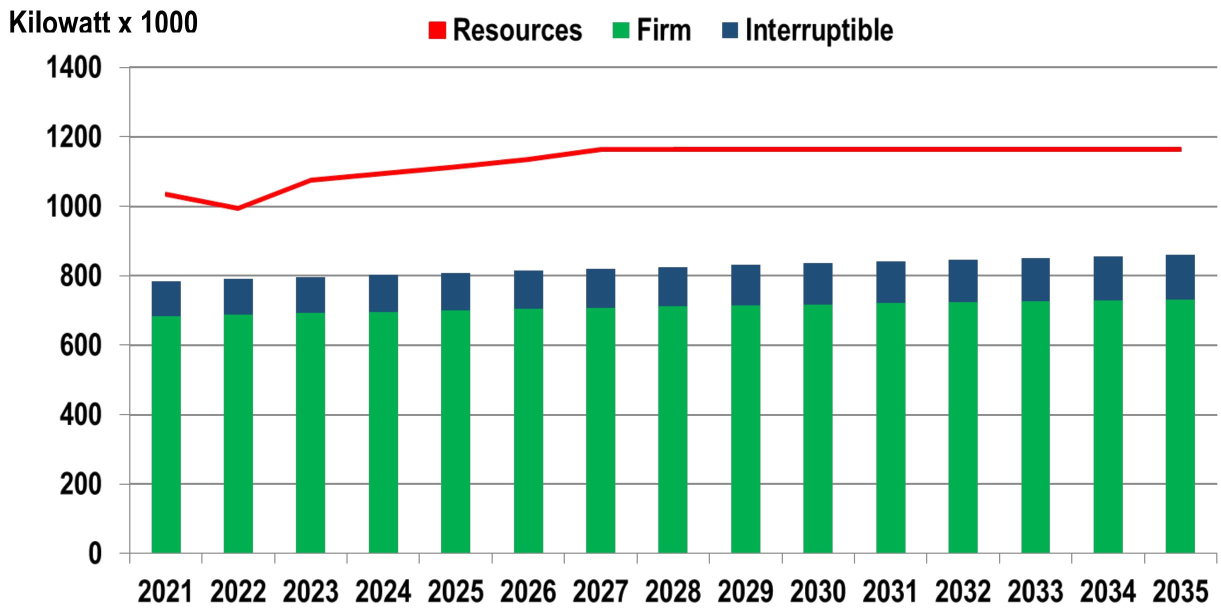
Minnkota and NMPA together submit this 2022 Integrated Resource Plan (IRP). This document has been prepared to fulfill the IRP requirements of WAPA and the Minnesota Public Utilities Commission.

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 customers, maintain low electric rates, minimize environmental impacts and minimize the risk of adverse effects from financial and technological impacts.

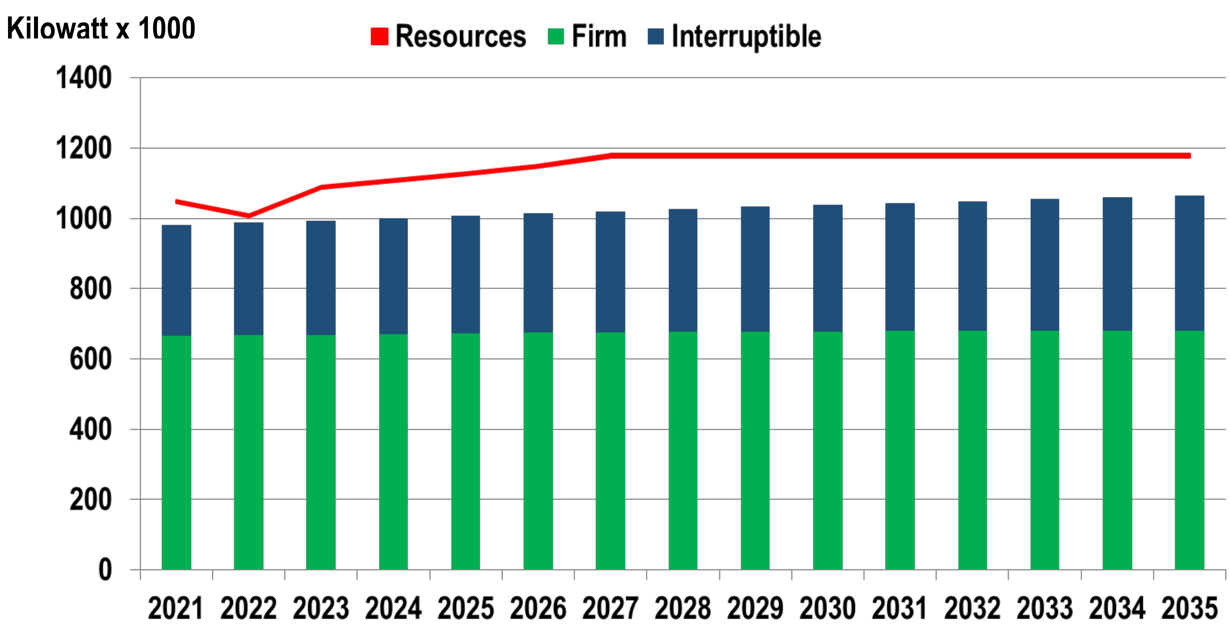
Load Forecasts

The Joint System energy requirements are forecasted to increase at a rate of 0.7% 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. This is based on the 30-year projections from the 2021 Load Forecast Study. 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.

Summer Capacity vs. Load



Winter Capacity vs. Load



As seen in the above tables, the Joint System has more than sufficient resource capacity to serve its firm load during the next 15 years.

Energy Considerations

The amount of energy that the Joint System needs to procure from generation resources not under its control is another important factor in long-term generation expansion planning.

The Joint System has diverse energy resources as detailed in Section 4. The Young 1, Young 2, and Coyote generating units are all baseload generation. The Joint System also utilizes Minnkota's firm power allocation and the NMPA firm power allocations from WAPA to fulfill its energy requirements. Minnkota also has a number of power purchase agreements for wind-derived energy.

The majority of the Joint System's future energy requirements will be supplied from the resources listed above. The energy requirements not fulfilled by the Joint System's resources will most likely be purchased from the MISO energy market.

From an analysis of the forecasted Joint System energy requirements and the expected output of its generation resources, WAPA firm power allocations, and power purchase agreements, it is forecasted that the Joint System purchases from the MISO energy market will range from a low of 0.3% to a high of 2.4% of its total annual energy requirements.

Since the amounts of energy forecasted to be purchased from the MISO energy market are minor, there is no need for additional generation additions from an energy supply perspective. A more detailed explanation of projected MISO energy purchases can be found in Section 7.

Summary

From both a resource capacity perspective and an energy requirements perspective, the Joint System does not need additional generation resources in the 2022-2035 timeframe.

SECTION 3
Demand Response Program

Historical Perspective

Beginning in 1973, Minnkota and the member systems instituted a comprehensive and effective Demand Response (DR) program. Currently about 55,000 end-use consumers participate in this important program. 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.

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-user, 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 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 miscellaneous loads.

Winter and Summer Interruptible Load Forecasts

Winter Season	Interruptible Load - MW
2022	350
2023	355
2024	360
2025	365
2026	370
2027	375
2028	380
2029	385
2030	390
2031	395
2032	400
2033	405
2034	410
2035	415
2036	420

Summer Season	Interruptible Load - MW
2022	100
2023	102
2024	104
2025	106
2026	108
2027	110
2028	112
2029	114
2030	116
2031	118
2032	120
2033	122
2034	124
2035	126
2036	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 variety of existing resources that economically and reliably fulfill the energy requirements of the end-use customers of its member systems and the NMPA municipals.

Existing resources consist of baseload, diesel, hydro allocations, biomass, and wind generation.

Minnkota and eight of the NMPA municipals have firm power allocations from WAPA. These firm power allocations supply varying amounts of capacity and energy throughout the year.

Existing Generation

MILTON R. YOUNG UNIT 1

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

COYOTE PLANT

The Coyote Plant is a 427 MW lignite-fired generating plant located southwest of Beulah, N.D., and is operated by Otter Tail Power Company (OTP). NMPA owns a 30 percent share (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

The Langdon Wind Project is comprised of two separate wind farms located near Langdon, N.D.

The first wind farm, Langdon I, consists of 106 turbines, of which 79 are owned by NextEra and 27 are owned by OTP. The turbines are 1.62 MW General Electric machines with a total capacity of 171.7 MW. OTP owns 43.74 MW and NextEra owns 127.98 MW of the turbine capacity of Langdon I. Minnkota has a long-term power purchase agreement with NextEra for 99 MW of capacity and energy.

The second wind farm, Langdon II, consists of 27 turbines, all of which are owned by NextEra. These turbines are also 1.5-MW General Electric machines with a repower total capacity of 40.5 MW. Minnkota has a long-term power purchase agreement with NextEra for all the capacity and energy produced by Langdon II.

ASHTABULA WIND

The Ashtabula Wind Project is comprised of two separate wind farms located near Pillsbury, N.D.

The first wind farm, Ashtabula I, consists of 131 turbines, of which 99 are owned by NextEra and 32 are owned by OTP. The turbines are 1.5 MW General Electric machines with a total capacity of 196.5 MW. NextEra owns 148.5 MW of the turbine capacity of Ashtabula I. Minnkota has a long-term power purchase agreement with NextEra for 148.5 MW of capacity and energy.

The second wind farm, Ashtabula II, consists of 113 turbines, of which 80 are owned by NextEra and 33 are owned by OTP. These turbines are also 1.5 MW General Electric machines with a total capacity of 169.5 MW. NextEra owns 120.0 MW and OTP owns 49.5 MW of the turbine capacity of Ashtabula II. Minnkota has a long-term power purchase agreement with NextEra for the output of 69.0 MW of capacity and energy.

OLIVER III WIND

The Oliver III Wind Project consists of 43 GE 2.10 MW wind turbine generators and 5 GE 1.79 MW wind turbine generators owned by NextEra, with a total capacity of 99.3 MW, in Morton County and Oliver County, N.D. Minnkota has a long-term power purchase agreement with NextEra for the output of 99.3 MW of capacity and energy.

INFINITY WIND

Minnkota's Infinity Wind Program consists of two 0.900 MW wind turbines, one located near Valley City, N.D., and one located near Petersburg, N.D. The Valley City turbine commenced operation on Jan. 25, 2002. The Petersburg turbine became operational on July 12, 2002. Both units are expected to produce approximately 2,800 MWh annually.

THIEF RIVER FALLS HYDRO PLANT

Thief River Falls, a 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. 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.

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 72.632 MW and 358,303 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.

Sales

Basin Electric Power Cooperative Sales

2022 Annual	100 MW	March 2022 – May 2022

Montana-Dakota Utilities

Minnkota has a sales agreement with Montana-Dakota Utilities for the following amounts of capacity from the Joint System:

2021-2022	Annual	75MW	June-May
2022-2023	Annual	90MW	June-May
2023-2024	Annual	30MW	June-May
2024-2025	Annual	30MW	June-May
2025-2026	Annual	30MW	June-May

Transmission Facilities

Minnkota's transmission facilities consist of 464 miles of 345 kV, 444 miles of 230 kV, 284 miles of 115 kV and 2,158 miles of line up to and including 69 kV. Additionally, Minnkota completed a 250-mile 345 kV transmission line between Center, N.D., and Grand Forks, N.D., in the summer of 2014.

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.

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

SECTION 5
Load Forecast

Overview

The primary function of the IRP is to demonstrate how a utility plans on supplying the energy requirements of its end-use consumers over the next 15 years. The IRP documents the resource and demand side options that best fit the utility's forecasted energy requirements.

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

Resource Plan 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.

Load Forecast Study

Rural Utilities Service (RUS) defines a Load Forecast Study (LFS) as a "thorough study of a borrower's electric loads and the factors that affect those loads in order to determine, as accurately as practical, the borrower's future requirements for energy and capacity. The LFS of a power supply borrower includes and integrates the LFSs of its member systems." The LFS must meet the guidelines and procedures outlined in Title 7 Part 1710 Subpart E of the Code of Federal Regulations, which defines the purposes, basic policies, requirements and criteria that must be met before RUS will approve a LFS.

LFS Approach

Econometric modeling was the primary forecasting technique utilized in the member systems' LFS. Econometric modeling identifies relationships between energy use and economic, demographic and system trends. The models are based upon 30 years of historical data and utilize such factors as population, employment, income, weather, electricity prices, alternate fuel prices, agricultural economic conditions, as well as other factors pertinent to model development. The studies specifically determined and quantified the factors that historically had impacts on electrical usage.

Econometric models were developed to forecast the number of residential consumers, residential energy usage, the number of small commercial consumers and small commercial usage.

Forecasts for the number of large commercial customers and usage were developed judgmentally, based on input from the member systems.

Judgment and trend analysis were utilized to forecast irrigation sales, street lighting, sales to public authorities, sales for resale, own usage and losses for each of the member systems.

Models were developed using the ordinary least squares approach to regression analysis. All of the models and their resulting forecasts were selected on the basis of theoretical and statistical validity and reasonableness of results.

Load Forecast

The Joint System load forecast is comprised of the Minnkota Load Forecast Study and a load forecast of the 12 NMPA municipal systems.

The member-owner distribution cooperatives and Minnkota are required to complete a Rural Utilities Service (RUS)-approved Load Forecast Study. The LFS is on a two-year cycle, meaning that new studies of the individual member-owners and Minnkota are completed every other year. The latest LFSs were completed in 2021.

Minnkota's LFS was developed in a bottom-up manner. The individual member system's energy and capacity requirements forecasts were summated to form Minnkota's base forecast. A forecast of Minnkota's transmission losses was also developed.

The municipal members of NMPA are not required to complete a LFS. However, a load forecast utilizing a linear regression analysis of the historical period 2005 through 2020 was completed for each of the members of NMPA.

The forecast of the Joint System's energy requirements is the sum of the forecasts of Minnkota's energy requirements, NMPA's energy requirements, and transmission losses. The forecasts of the winter and summer peak demands are based on historical trending.

Data Mining-Processing

Minnkota has seen data mining/processing industrial loads develop in its service territory in 2021 and will see more load developing in 2022. However, the data mining/processing loads have been excluded from the LFS because the loads are special interruptible loads that are registered with MISO (Midcontinent Independent System Operator) as load modifying resources and are under either three-year or five-year electric service contracts. Because reporting requirements differ between RUS, MISO, and member systems/municipal systems (NMPA), the data mining/processing loads were included in an updated Executive Summary that is located in Appendix G of the attached LFS. The narrative and tables project the impact of Minnkota's interruptible data mining/processing loads, which is used for MISO and Module E reporting.

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: (LFS Table 4.3)

Median Load Growth Forecasts

Year	Energy Requirements MWH	Winter Peak MW	Summer Peak MW
2022	4,687,225	985	789
2023	4,744,149	994	796
2024	4,788,853	1,001	802
2025	4,834,014	1,007	808
2026	4,875,355	1,014	814
2027	4,915,579	1,020	819
2028	4,959,010	1,027	825
2029	5,001,694	1,033	831
2030	5,038,686	1,038	836
2031	5,077,416	1,044	841
2032	5,115,597	1,049	846
2033	5,148,414	1,054	850
2034	5,186,007	1,059	855
2035	5,224,654	1,065	860
2036	5,256,383	1,069	864

The Joint System's median forecast of annual energy requirements is projected to increase at a rate of 0.7% per year. The winter peak demand is projected to increase at a rate of 0.6% per year and the summer peak demand is projected to increase at a rate of 0.7% per year. These numbers are based on the 30-year projections from the 2021 Load Forecast Study.

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

Analysis was done 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
2022	4,573,332	963	698
2023	4,571,602	960	733
2024	4,557,003	956	756
2025	4,539,401	949	762
2026	4,560,053	952	765
2027	4,580,782	956	768
2028	4,601,588	959	772
2029	4,622,472	963	775
2030	4,643,433	966	778
2031	4,659,268	968	779
2032	4,675,147	971	780
2033	4,691,070	973	782
2034	4,707,038	976	783
2035	4,723,051	978	784
2036	4,736,069	978	786

The Joint System's low load growth scenario forecasts an increase of 0.85% 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
2022	4,801,117	985	807
2023	4,916,695	994	824
2024	5,020,704	1,001	839
2025	5,131,980	1,007	864
2026	5,198,495	1,014	871
2027	5,265,731	1,020	877
2028	5,333,696	1,027	884
2029	5,402,397	1,033	890
2030	5,471,842	1,038	897
2031	5,538,678	1,044	906
2032	5,606,204	1,049	916
2033	5,674,427	1,054	926
2034	5,743,353	1,059	935
2035	5,812,990	1,065	945
2036	5,878,164	1,069	953

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 6
Resource Adequacy

Discussion

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 customer 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 customer 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.

SECTION 7
Energy Requirement Considerations

Introduction

Another important consideration in generation planning is the degree to which the Joint System will be dependent on market-based resources to meet its load requirements. The Joint System has the Young 1, Young 2, and Coyote coal-fired generators, NMPA WAPA allocations, Minnkota's WAPA allocation, and power purchase agreements for wind energy from the Langdon, Ashtabula and Oliver III wind projects to fulfill its energy requirements.

However, since the coal-fired generating units require periodic maintenance during which time they are not generating energy, and since wind is intermittent by nature, the Joint System has to purchase energy to serve its load requirements from the wholesale electricity market. During those times when the Joint System doesn't have the generation resources to fulfill its energy requirements, it almost always purchases that energy from the MISO energy market.

A financial danger exists in depending too greatly on the MISO energy market, 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.

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 contains the forecasts of the Joint System's annual energy requirements for the low growth, median growth, and the high growth scenarios. (LFS Table 4.3)

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
2022	4,573,332	4,687,225	4,801,117
2023	4,571,602	4,744,149	4,916,695
2024	4,557,003	4,788,853	5,020,704
2025	4,539,401	4,834,014	5,131,980
2026	4,560,053	4,875,355	5,198,495
2027	4,580,782	4,915,579	5,265,731
2028	4,601,588	4,959,010	5,333,696
2029	4,622,472	5,001,694	5,402,397
2030	4,643,433	5,038,686	5,471,842
2031	4,659,268	5,077,416	5,538,678
2032	4,675,147	5,115,597	5,606,204
2033	4,691,070	5,148,414	5,674,427
2034	4,707,038	5,186,007	5,743,353
2035	4,723,051	5,224,654	5,812,990
2036	4,736,069	5,256,383	5,878,164

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
2022	45,733	46,872	48,011
2023	91,432	94,883	98,334
2024	45,570	47,889	50,207
2025	45,394	48,340	51,320
2026	45,601	48,754	51,985
2027	45,808	49,156	52,657
2028	46,016	49,590	53,337
2029	46,225	50,017	54,024
2030	46,434	50,387	54,718
2031	46,593	50,774	55,387
2032	46,751	51,156	56,062
2033	46,911	51,484	56,744
2034	47,070	51,860	57,434
2035	47,231	52,247	58,130
2036	47,361	52,564	58,782

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 generation resources, power purchase agreements and extensive demand response program will meet the forecasts for peak demand and energy requirements. The Joint System is expected to have adequate resources to meet the capacity and energy requirements of its members/customers and will have a minimal dependence on the MISO energy market. Therefore, there is no need for future generation additions and no need for additional power purchase agreements in the next 15-year timeframe. Even with adequate resources, Minnkota continues to evaluate new opportunities with its neighboring utilities, as well as the development of new technologies.

SECTION 8
Minnesota Renewable Energy Standard and Greenhouse Gas Emissions

8.1 Renewable Energy Standard Objectives Discussion

Minnesota Statute § 216B.1691 addresses the Renewable Energy Standard, which requires utilities to generate or procure certain amounts of renewable generation.

During the 2007 Legislative session, the statute was amended, in part, to establish a Renewable Energy Standard (RES) with specified mandated renewable energy goals beginning in 2010 and amended the definition of an eligible energy technology.

Each electric utility, other than those that owned a nuclear generating facility as of Jan. 1, 2007, shall generate or procure sufficient electricity generated by an eligible energy technology to provide its Minnesota retail customers or the retail members of a distribution utility to which the electric utility provides wholesale electric service, so that at a minimum the following percentages of the electric utility's total electric sales to retail customers in Minnesota are generated by eligible energy technologies by the end of the year as follows:

- 2010 7%
- 2012 12%
- 2016 17%
- 2020 20%
- 2025 25%

The definition of an eligible energy technology was changed to one that:

Generates electricity from the following renewable energy sources: (1) solar; (2) wind; (3) hydroelectric with a capacity of less than 100 megawatts; (4) hydrogen provided that after Jan. 1, 2010, the hydrogen must be generated from resources listed in this clause; or (5) biomass, which includes, without limitation, landfill gas, an anaerobic digester system, and an energy-recovery facility used to capture the heat value of mixed municipal solid waste or refused-derived fuel from mixed municipal solid waste as a primary fuel.

Minnkota purchases small amounts of energy from a landfill gas generator located in Fargo, N.D. Minnkota also owns two 0.9 MW wind generators, one located near Valley City, N.D., and the other located near Petersburg, N.D. Since the outputs of these generators are comparatively small relative to Minnkota's large renewable resources, this section will only focus on the large renewable resources. The smaller resources were only noted so that the reader has knowledge of the full extent of the Joint System's renewable energy efforts.

Minnkota has power purchase agreements with NextEra, a wind developer, for portions of its Langdon, Ashtabula and Oliver III wind projects located in North Dakota. From the Langdon wind project, Minnkota has rights to the output of 93 wind turbines with a nameplate capacity of 139.5 MW. From the Ashtabula wind project, Minnkota has rights to the output of 145 wind turbines with a nameplate capacity of 217.5 MW. From the Oliver III wind project, Minnkota has rights to the output of 48 wind turbines with a nameplate capacity of 100 MW.

Between the Langdon, Ashtabula and Oliver III wind projects, Minnkota has rights to the output of 286 wind turbines with a nameplate capacity of 457 MW. For study purposes, it was assumed that the annual capacity factor would be 42% at the Langdon and Ashtabula facilities and 50% at the Oliver III facility, which translates to approximately 1,751,500 MWh of wind energy for the Joint System.

The following table documents the Joint System's Minnesota RES given its long-term energy forecast and the percent required to be generated by renewable resources. Also displayed in the table are the amounts of wind energy forecasted to be generated by the portions of the Langdon and Ashtabula wind projects for which Minnkota has power purchase agreements. (MPC Req Summary 2019 Table 3.17 / Summary 3).

Year	Joint System Minnesota Retail Sales MWH	% Required For MN RES	Energy Requirement For MN RES MWH	Langdon, Ashtabula and Oliver III Wind Energy Production MWH
2022	2,184,555	20	436,911	1,688,753
2023	2,210,534	20	442,107	1,688,753
2024	2,232,526	20	446,505	1,688,753
2025	2,256,240	25	564,060	1,688,753
2026	2,279,506	25	569,876	1,688,753
2027	2,302,144	25	575,536	1,688,753
2028	2,328,354	25	582,088	1,688,753
2029	2,352,797	25	588,199	1,688,753
2030	2,375,752	25	593,938	1,688,753
2031	2,400,706	25	600,176	1,688,753
2032	2,422,827	25	605,707	1,688,753
2033	2,442,925	25	610,731	1,688,753
2034	2,468,399	25	617,100	1,688,753
2035	2,489,506	25	622,377	1,688,753
2036	2,509,172	25	627,293	1,688,753

From the above tables, it can be seen that the Joint System purchases from renewable energy resources are significantly greater than its requirements.

These tables demonstrate the Joint System's strong dedication to fulfilling its Minnesota RES requirements.

8.2 Greenhouse Gas Emissions

Discussion

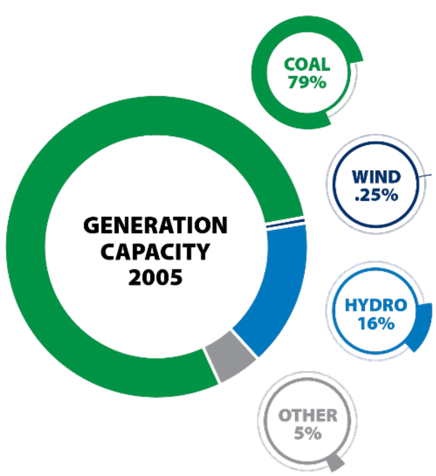
Minnesota Statute 216H.02 addresses Minnesota's greenhouse gas emissions-reduction goal, which states that it is the goal of the State to reduce statewide greenhouse gas emissions across all sectors producing those emissions to a level at least 15 percent below 2005 levels by 2015, to at least 30 percent below 2005 levels by 2025, and to a level at least 80 percent below 2005 levels by 2050.

Minn. Stat. § 216H.01, Subd. 2, defines statewide greenhouse gas emissions as follows:

> "Statewide greenhouse gas emissions" include emissions of carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride emitted by anthropogenic sources within the state and from the generation of electricity imported from outside the state and consumed in Minnesota. Carbon dioxide that is injected into geological formations to prevent its release to the atmosphere in compliance with applicable laws, and carbon dioxide associated with the combustion of fuels other than coal, petroleum, and natural gas are not counted as contributing to statewide greenhouse gas emissions.

The Joint System does not own any sources of generation located in Minnesota. All of the Joint System's generation resources are located in North Dakota. As noted in the two charts below, since 2005, the Joint System has seen a significant increase in its wind generation capacity.

Generation Mix Changes



Illustrated below are the following tables which demonstrate the calculation of Joint System's CO_2 emission reductions. Table 1 shows the Joint System's projected MWhs generated by coal fired generators which can serve Joint System's load. Table 2 shows emission statistics for coal generation resources which served Joint System's Minnesota load for 2005, and possible emission projections for 2022 thru 2040. Table 3 compares CO_2 emissions for 2005 to CO_2 emissions for 2022 thru 2040 levels.

Table 1

Year	Member MN (MWh)	NMPA MN (MWh)	TOTAL MN (MWh)	MN RES Mandate	Fossil Fuel (MWh)
2005	1,406,229	384,515	1,790,744	0	1,790,744.00
2014	1,623,674	392,176	2,015,850	12%	1,773,948.11
2015	1,515,319	378,173	1,893,492	12%	1,666,273.06
2016	1,494,552	372,330	1,866,882	12%	1,642,856.50
2017	1,498,450	367,600	1,866,050	17%	1,548,821.68
2018	1,522,570	376,250	1,898,820	17%	1,576,020.60
2019	1,531,624	370,681	1,902,305	17%	1,578,913.15
2020	1,484,380	367,379	1,851,759	20%	1,481,407.20
2021	1,505,347	375,761	1,881,108	20%	1,504,886.11
2022	1,526,347	377,883	1,904,230	20%	1,523,384.00
2023	1,539,241	379,694	1,918,935	20%	1,535,147.69
2024	1,552,245	381,220	1,933,465	20%	1,546,772.13
2025	1,563,085	382,397	1,945,482	25%	1,459,111.61
2026	1,570,575	383,321	1,953,896	25%	1,465,422.28
2027	1,580,057	384,055	1,964,112	25%	1,473,084.00
2028	1,590,217	384,562	1,974,779	25%	1,481,084.45
2029	1,599,941	384,717	1,984,658	25%	1,488,493.71
2030	1,607,442	384,734	1,992,176	25%	1,494,132.05
2031	1,614,338	384,531	1,998,869	25%	1,499,151.68
2032	1,621,277	384,145	2,005,422	25%	1,504,066.51
2033	1,626,402	383,557	2,009,959	25%	1,507,468.92
2034	1,633,300	382,843	2,016,143	25%	1,512,107.12
2035	1,641,395	381,954	2,023,349	25%	1,517,512.02
2036	1,645,438	381,028	2,026,466	25%	1,519,849.45
2037	1,649,211	379,971	2,029,182	25%	1,521,886.80
2038	1,654,721	379,002	2,033,723	25%	1,525,291.96
2039	1,657,742	378,010	2,035,752	25%	1,526,814.10
2040	1,661,298	377,019	2,038,317	25%	1,528,737.49

Column descriptions for Table 1

- **Member MN (MWh)** = Total MN member MWh sales plus 4% transmission losses
- **NMPA MN (MWh)** = Total MN MWh sales to NMPA members plus 4% transmission losses
- **Total MN (MWh)** = Member MN (MWh) + NMPA MN (MWh)
- **MN RES Mandate** = MN renewable mandate
- **Fossil Fuel (MWh)** = TOTAL MN (MWh) * (1 – MN RES Mandate)

Table 2

Year	Young 1 CO_2 emissions lb/MWh	Young 2 CO_2 emissions lb/MWh	Coyote CO_2 emissions lb/MWh	Weighted Average	Fossil Fuel MWh	MN annual CO2 emissions in tons
2005	2,345	2,464	2,374	2,394	1,790,744	2,143,689
2014	2,074	2,154	2,404	2,211	1,773,948	1,960,741
2015	2,193	2,166	2,405	2,255	1,666,273	1,878,563
2016	2,382	2,141	2,281	2,268	1,642,857	1,862,782
2017	2,282	2,199	2,339	2,273	1,548,822	1,760,344
2018	2,308	2,199	2,319	2,275	1,576,021	1,792,720
2019	2,199	2,131	2,319	2,216	1,578,913	1,749,515
2020	2,118	2,179	2,292	2,196	1,481,407	1,626,925
2021	2,165	2,182	2,331	2,226	1,504,886	1,674,891
2022	2,165	2,182	2,331	2,226	1,523,384	1,695,479
2023	2,165	2,182	2,331	2,226	1,535,148	1,708,571
2024	2,165	2,182	2,331	2,226	1,546,772	1,721,509
2025	2,165	2,182	2,331	2,226	1,459,112	1,623,946
2026	1,516	218	2,331	954	1,465,422	699,225
2027	1,516	218	2,331	954	1,473,084	702,881
2028	1,516	218	2,331	954	1,481,084	706,699
2029	1,516	218	2,331	954	1,488,494	710,234
2030	1,516	218	2,331	954	1,494,132	712,924
2031	1,516	218	2,331	954	1,499,152	715,319
2032	1,516	218	2,331	954	1,504,067	717,664
2033	1,516	218	2,331	954	1,507,469	719,288
2034	1,516	218	2,331	954	1,512,107	721,501
2035	1,516	218	2,331	954	1,517,512	724,080
2036	1,516	218	2,331	954	1,519,849	725,195
2037	1,516	218	2,331	954	1,521,887	726,167
2038	1,516	218	2,331	954	1,525,292	727,792
2039	1,516	218	2,331	954	1,526,814	728,518
2040	1,516	218	2,331	954	1,528,737	729,436

Table 3

Year	2005 CO_2 Emissions, Tons	Projected CO_2 Emissions, Tons	Percent reduction of CO_2 from 2005
2014	2,143,689.25	1,960,741	-8.5%
2015		1,878,563	-12.4%
2016		1,862,782	-13.1%
2017		1,760,344	-17.9%
2018		1,842,867	-14.0%
2019		1,713,255	-20.1%
2020		1,673,409	-21.9%
2021		1,695,835	-20.9%
2022		1,717,712	-19.9%
2023		1,736,197	-19.0%
2024		1,756,070	-18.1%
2025		1,658,524	-22.6%
2026		878,629	-59.0%
2027		887,415	-58.6%
2028		896,290	-58.2%
2029		905,252	-57.8%
2030		914,305	-57.3%
2031		923,448	-56.9%
2032		932,682	-56.5%
2033		942,009	-56.1%
2034		951,429	-55.6%
2035		960,944	-55.2%
2036		970,553	-54.7%
2037		980,163	-54.3%
2038		989,772	-53.8%
2039		999,381	-53.4%
2040		1,008,991	-52.9%

The CO_2 emissions are based on the MWh generation needed to serve Minnesota load from Young 1, Young 2 and Coyote only. Young 1, Young 2, and Coyote CO_2 emissions are used as a weighted average (from Table 2) and multiplied by Fossil Fuel MWhs (from Table 1) needed to serve Minnesota load.

As described in Section 12 of Joint System's IRP, Minnkota is pursuing Project Tundra, which is estimated to capture 90% of the CO2 emissions from Young 2 and additional capture from Young 1. If the project moves forward, Minnkota currently anticipates construction to initiate in 2022-2023, with an in-service date of 2025-2026.

Accordingly, the Joint System submits Table 3 showing Joint System CO2 emissions in 2005 at 2,143,689 tons. Upon the successful completion of Project Tundra, Joint System CO_2 emissions would be significantly reduced as demonstrated in 2026 in Table 3.

The Commission's Order requested that the Joint System include scenarios that do not assume approval and success of carbon sequestration. At present, Minnkota has completed the Department of Energy-sponsored Front-End Engineering and Design study and is confident in the technology and anticipates final permits to be issued in Q3 of 2022.

Minnkota currently has the largest fully-permitted CO_2 storage facility in the United States. In January of 2022, Minnkota received its Class VI injection well permit from the State of North Dakota. Further, it received approval of its Monitoring, Reporting and Verification plan from the EPA.

In light of the above information, the Joint System is confident that its significant generation mix changes from 2005 to the present as noted above, coupled with Minnkota's continued progress towards development of Project Tundra, as well as the growing support for Carbon Capture and Storage at every level of government will satisfy the Commission's inquiry as to the Joint System's progress towards meeting its greenhouse gas emissions reduction goals.

If it were to be determined that Project Tundra is not plausible by 2025, the Joint System is in position with its generation mix to meet Minnesota's goal of offsetting greenhouse gas emissions from the generation of electricity imported from outside the state and consumed in Minnesota by at least 30 percent from 2005 levels.

It is the intent of the Joint System to comply with all applicable federal and state requirements regarding reducing carbon emission once those requirements are identified going forward.

SECTION 9
Energy Efficiency and Conservation Program

Discussion

Energy conservation and efficiency strategies play significant roles for Minnesota cooperatives and municipals in the Joint System’s service territories. State law requires Minnesota electric utilities to invest a portion of their revenues each year in conservation improvement programs that promote energy-efficient technologies and practices to their consumers.
In order to meet the state’s requirements, the PowerSavers program was formed to help business and residential consumers become more efficient energy users and to also improve Minnkota’s own efficiency as an energy provider. The program offers incentives to both residential and business end-use customers.

The residential program includes several incentives for electric heating, ventilation and air conditioning (HVAC), lighting and ENERGYSTAR® appliances.

The business program offers several incentives for HVAC, lighting, motors, adjustable speed drives, refrigeration and compressed-air technologies commonly used by businesses.

The table below shows the annual kWh savings totals reached through the PowerSavers program from 2014 to 2021.

PowerSavers Program Summary of kWh Savings			
2014	27,209,892 kWh	2018	21,538,490 kWh
2015	27,678,829 kWh	2019	18,343,689 kWh
2016	33,330,584 kWh	2020	18,529,409 kWh
2017	27,628,406 kWh	2021	19,418,632 kWh

The Joint System has met the Minnesota energy efficiency and conservation requirements since the inception of the PowerSavers CIP program and will continue to strive to meet the requirements in the future.

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 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.

9.2 Development

As part of the Next Generation Energy Act of 2007 (Act), the Minnesota Legislature revised the Conservation Improvement Program (CIP) and renamed it the Energy Efficiency and Conservation (EE&C) Program. The modifications to the Act transitions the program from one that focused on the amount of money spent on conservation to one that focuses on calculated energy savings.

The EE&C Program established an annual energy savings goal of 1.5% of annual retail energy sales. The energy savings are based on the average of the prior three-year weather-normalized retail sales.

In the development of the conservation and energy efficiency programs, staff of Minnkota's Minnesota member-owner distribution cooperatives and participating NMPA municipals realized that it would be significantly more beneficial if all the members collaborated as a group to develop ideas and implement consistent energy-saving programs for their consumers. The group has compiled ideas and resources under the PowerSavers name and logo.

The group organized under the name PowerSavers, which originally included Beltrami Electric Cooperative, Clearwater-Polk Electric Cooperative, North Star Electric Cooperative, PKM Electric Cooperative, Red River Valley Cooperative Power Association, Red Lake Electric Cooperative, Roseau Electric Cooperative, Wild Rice Electric Cooperative, Bagley Public Utilities, Baudette Municipal Utilities, Fosston Municipal Utilities, Halstad Municipal Utilities, Hawley Public Utilities, Roseau Municipal Utilities, Stephen Municipal Utilities, Thief River Falls Municipal Utilities and Warren Municipal Utilities.

It was also apparent that help from outside sources was needed to get the various programs off the ground. To that end, Franklin Energy Services (Franklin) of Port Washington, Wisc., was chosen to develop a comprehensive set of conservation and efficiency improvement programs to help residential and low income consumers, as well as small and large businesses.

One of the first steps taken by PowerSavers and Franklin was to develop a set of goals for the new endeavor. The five goals were: 1) consistent programs between all the members; 2) effective retail marketing; 3) business ally support; 4) customer behavior modification; and 5) energy efficiency education.

PowerSavers and Franklin developed a program portfolio consisting of five residential and three business programs. The residential programs consist of 1) Prescriptive Incentive; 2) Low Income; 3) Direct Installation; 4) Energy Behavior Use Change; and 5) Existing Homes.

The Residential Prescriptive Incentive Program is designed to support end-use customers choosing high-efficiency equipment at the time normal equipment is replaced or during major renovations. Recommendations for replacement equipment include heating, ventilation and air conditioning (HVAC) equipment, hot water heaters and ENERGYSTAR® appliances.

The Residential Low-Income program utilizes direct installation services to address domestic hot water, lighting, energy use and weatherization in low income housing. The low-income program targets participants with an income at or below 200% of the federal poverty level. Eligible households are contacted through direct mail and install services.

The Residential Direct Installation program is designed to make an immediate impact on home electric energy usage through the installation of high-efficiency measures. These measures include LEDs, low-flow faucet aerators, showerheads, pre-rinse sprayer valves and water heater temperature turndown. An auditor performs an energy assessment and provides feedback to the homeowner regarding their energy usage.

The Residential Existing Homes program provides homeowners with information, access to qualified contractors and financial incentives to improve energy efficiency for their homes. An auditor conducts a thorough energy assessment as a basis to provide recommendations for efficiency improvements. These assessments often use equipment such as a blower door, which measures the extent of air leaks in the building, and infrared cameras, which reveal heat loss and pinpoint the need for additional insulation.

The Residential Energy Behavior Use Change program is designed to help customers 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. Turning off lights, turning down water heaters and using a programmable thermostat are just a few examples.

The business programs are 1) Prescriptive Incentive; 2) Custom; and 3) Direct Installation.

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.

Legislation was passed in May 2017, which removed the CIP requirements for cooperatives with fewer than 5,000 members and municipals with fewer than 1,000 consumers.

This reduced the participating cooperatives and municipals to the following:

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

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

In May 2021, the Energy Conservation and Optimization Act (ECO Act) was signed into law by Governor Walz. It is the first significant update to the CIP program since the Next Generation Act of 2007.

Summary of the ECO Act bill as it pertains to the Minnkota cooperatives and municipal systems

- Retains the mandated 1.5% savings goal
    - 0.95% of goal must be met with energy conservation measures.
    - 0.55% of goal can be met with additional conservation measures, EUI measures, and fuel-switching measures.
    - Utility can request a reduction of minimum savings goal to as low as 0.95%.
- Spending on fuel-switching improvements must not exceed 0.55% until July 1, 2026.
- Spending requirement of 1.5% has been eliminated unless a utility falls short of the minimum savings goal for three consecutive years.
- Low-income spending requirement of 0.2% remained the same.
    - Up to 15% of low-income spending can be spent on pre-weatherization measures.
    - Can contribute money to the Healthy AIR Account to provide pre-weatherization measures that count toward the low-income spending goal (up to 15%).

SECTION 10
Region Transmission Operator (RTO) Participation

Discussion

Minnkota occasionally performs studies to analyze RTO membership. Minnkota has strong transmission connections to Southwest Power Pool (SPP) and MISO, making them the logical options. Minnkota is presently a MISO market participant, which allows the purchase or sale of energy within the MISO energy market.

To date, the studies have shown that it is not in Minnkota's best interest to join an RTO, and Minnkota therefore does not presently have plans to do so.

SECTION 11
Transmission Planning

Introduction

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' customers. 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 Renewable Energy Standard.

SECTION 12
Environmental Compliance

General

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, a subsidiary of Allete. 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 (35%), Northern Municipal Power Agency (Minnkota serves as operating agent) (30%), Montana-Dakota Utilities (25 percent), and Northwestern Energy (10%). Otter Tail operates the plant, rated at 427 MW, on behalf of the owners. Coyote began commercial operation in 1983. Coyote 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.

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.

The MRYS and Coyote CCR disposal sites maintain compliance with the provisions of the CCR Rule. In addition to the federal requirements, the MRYS and Coyote waste disposal sites are permitted and inspected by the North Dakota Department of Environmental Quality (NDDEQ).

Significant challenges in maintaining compliance with the CCR Rule at MRYS or Coyote Station are not anticipated.

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 a proposed rule in the Federal Register that revises again the definition of "Waters of the United States." The proposal puts back into place the pre-2015 definition, updated to reflect consideration of recent Supreme Court decisions. The agencies intend to consider further revisions in a second rule in light of additional stakeholder engagement and implementation considerations, scientific developments, and environmental justice values. This effort will also be informed by the experience of implementing the pre-2015 rule, the 2015 Clean Water Rule, and the 2020 Navigable Waters Protection 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 at electric generating units (EGUs) was published in November 2015, and provides additional regulatory standards for wastewater discharged to surface waters. These standards are incorporated into facility North Dakota Pollutant Discharge Elimination System (NDPDES) permits.

This 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.

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 for the Coyote Station.

The draft NDDEQ State Implementation Plan (SIP) has been issued for EPA and Federal Land Manager comments. The Executive Summary of the SIP states:

> *North Dakota is currently projected to meet its 2028 visibility goals and is projected to remain on track to meet the 2064 visibility goals (below the adjusted glidepath). Continuing to remain below the adjusted glidepath and showing improvement on the most impaired days for each planning period will accomplish the 2063 end goals. North Dakota has determined that the additional controls evaluated will not have a meaningful impact on the 2028 visibility projections. Therefore, the Department determined that it is not reasonable to require additional controls during this planning period."*

The NDDEQ held a public comment period on the draft SIP during spring 2022, which closed June 2, 2022. A hearing was also held on June 1, 2022. NDDEQ will review and address substantive comments prior to submittal of the final SIP to EPA. The timeline for submittal is August 2022. Minnkota recognizes the possibility of EPA not accepting the state's conclusion "that it is not reasonable to require additional controls." EPA may reject the SIP, and issue a Federal Implementation Plan (FIP), which, if upheld, may require additional controls at MRYS and Coyote Station by December 31, 2028. The timing of a final decision on any additional controls is undetermined, since administrative process and possible litigation will affect the process.

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, 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 MRYS and Coyote have maintained compliance since that date.

Various EPA actions on MATS have occurred since implementation. The latest action is an EPA proposed rule published in the Federal Register on February 9, 2022. The proposal is to reaffirm the Appropriate and Necessary Finding, and solicit information on the cost and performance of new or improved technologies to control HAP emissions, including improved operation and risk-related information. It is possible that this proposed rule could result in a final rule that will increase expectations for additional HAP controls at MRYS and Coyote.

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. The EPA has clarified to states that there is no requirement for submittal of state implementation plans under either the ACE rule or the CPP. Instead, EPA has indicated most recently that a new rulemaking on greenhouse gas for existing EGUs will be issued in late 2022 or early 2023.

Oral arguments were held at the Supreme Court of the United States on February 28, 2022, to determine whether EPA has limited authority under the Clean Air Act to issue rules and standards of performance that could potentially reshape the country's transmission grids and unilaterally decarbonize any sector of the economy. A decision from the Court is anticipated in June 2022 and may result in establishing the breadth of EPA's authority in designing a program for regulating CO_2. Minnkota intends to continue closely following the development of these rulemakings.

Project Tundra

Minnkota recognizes that the potential exists for future stringent CO_2 regulations for existing coal-fired EGUs. Despite carbon capture, utilization and storage (CCUS) technology not being adequately demonstrated to assume nationwide viability, the MRYS facility is situated in a unique geographical location in close proximity to secure geologic CO_2 storage sites (deep saline aquifers). This is not the case for many (or most) EGUs, and thus MRYS is in a unique situation where CCUS may be commercially viable. Additionally, the project would provide a low-carbon source of dispatchable electric capacity that provides grid stability and reliability to Minnkota's member-owners.

For these reasons, Minnkota has sponsored studies for the retrofit of a carbon capture system on the MRYS facility, with sequestration in the form of geological sequestration in saline aquifers located directly below the MRYS facility (Project Tundra). Project Tundra's design targets the capture of 12,978 short tons of CO_2 per day from the flue gas from Unit 2 and Unit 1 (in varying percentages) at the MRYS. The project will capture and sequester an annual average of 4 million tonnes/year of CO_2.

The project builds upon prior federal investment by scaling up the application to process more flue gas, apply the technology to a cold weather climate, and utilize steam and electrical energy provided by the coal units. The ultimate goal is to create a new benchmark – a large-scale, integrated demonstration of a "plant-based" approach, where flue gas and steam from more than one unit will be integrated in the CO_2 capture process. Once demonstrated, the process can be commercially and economically replicated across the region, the country, and the world.

Project Tundra has received important bipartisan support, and has partnered with federal and state of North Dakota entities to advance its research and development. The project is presently completing a Front-End Engineering Design (FEED) study, including advanced amine solvents, economic modeling and aerosol mitigation and management. In addition, Minnkota has partnered with the state of North Dakota and Fluor Enterprises to conduct the final body of engineering, with the goal to produce construction-ready engineering, scheduling, and pricing terms by the end of 2022. Importantly, Minnkota has received its Class VI CO_2 storage facility permits and EPA approval of the Monitoring, Reporting and Verification (MRV) plan for the storage site.

Minnkota is currently seeking outside investment in the project from entities that can harness applicable tax credits for carbon capture projects, so that the financial risk to Minnkota members will be limited. Tax equity investment interest in the project is strong, as multiple investors capable of consuming 100% of the tax equity have signed non-disclosure agreements with Minnkota.

Ultimately, Project Tundra would result in ~450 net MW of near-zero carbon power produced with limited or no increase in cost, while enabling continued use of North Dakota's abundant, reliable and low-cost lignite coal resources, and ensuring the capital investment in MRYS can continue to be utilized.

Minnkota recognizes that CO_2 regulations present a longer-term risk to maintaining affordable and reliable resources that emit CO_2. If constructed, Project Tundra could help provide continued reliability and affordability of electricity. Using a technology-driven solution will help to reduce the risk to our member-owners, given the uncertainty of future CO_2 regulations. More details on Project Tundra can be found at www.projecttundrand.com.

SECTION 13
Two-Year Action Plan

The Joint System will take the following actions during the 2022 to 2023 time frame 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 2023. 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 reduce energy costs to the end-use customers.

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

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.

SECTION 14
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 2024-2026 time frame as part of its ongoing efforts in Integrated Resource Planning.

A Load Forecast Study will be completed for the Joint System 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.

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.

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.

Future Integrated Resource Plans will be completed as required.

SECTION 15
Contingencies

Sudden Addition of a Large Load

The sudden unexpected appearance of a new large load is a situation that many utilities face. If this were to occur in the Joint System service territory, the Joint System would most likely arrange the purchase of short-term generation capacity to serve the new load. The purchase would allow the necessary time to complete an analysis of the alternatives or options for long-term capacity commitments. Minnkota would utilize short-term capacity purchases rather than prematurely commit to a long-term obligation without having completed a detailed analysis.

Sudden Loss of a Large Load

The sudden loss of a large load is also a situation that many utilities face. If this would occur to the Joint System, Minnkota would market the energy that normally would have been sold to the large load into the MISO energy market.

Resource Options Available in the Event of Facilities Shutdown

The Joint System would have a limited number of resource options available in the event that it was forced to shut down its lignite generation facilities. The Joint System currently has no surplus generation resources standing idle and ready to be placed into service other than costly standby diesel generators. In our view, the Joint System's options, upon loss of an existing resource, would be similar to what other utilities have available to them.

The range of options varies with the severity of the shutdown scenario being evaluated. The economic impact (rate increases) to the end-use customer would increase as the severity of the shutdown scenarios increases.

If only one of the Joint System's lignite-fired generators was shut down for a limited period of time (less than a year), Minnkota would likely purchase replacement power from the MISO market and neighboring utilities until the unit was returned to service. The cost of the replacement energy would be dictated by the market conditions at the time of the outage and the length of time replacement energy had to be secured.

If the generator that was shut down had to be replaced with a new coal-fired or gas-fired generator, replacement power would have to be purchased for a longer period of time. The longer time period would make it more problematic for Minnkota to purchase replacement power and capacity. It is difficult to estimate the likelihood of successfully purchasing replacement power and capacity for the length of time needed to install new generation capacity. However, it would take two to three years to install new simple-cycle gas-fired generation and three to five years to install a new combined cycle combustion turbine. Given the current regulatory climate, it is unlikely new coal-fired generation could be constructed.

If all of Joint System's coal-fired generation were shut down, the financial impact on the Joint System, and consequently the end-use customer, would be disastrous. The Joint System and its members/customers would carry the financial burden of the debt service for the shutdown generators, shoulder the costs for replacement power and, at the same time, finance new generation capacity.

SECTION 16
Environmental Costs

In theory, environmental costs are defined as impacts on the environment from electric generation, which are not included in utility costs or customer rates. 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).

Electric utilities in Minnesota are required to use the externality values in conjunction with other factors for generation capacity options reviewed or approved by the MN PUC. However, environmental externality values are not to be applied to unit commitment, dispatch or other operating decisions.

Unlike environmental abatement costs (compliance costs, fees, taxes, etc.), environmental externality values do not represent actual direct costs to end-use customers. Results of any environmental externality analyses should be compared with the socioeconomic impacts, project cost payback, net present value or other non-quantifiable impacts and costs.

The MN PUC has required economic analyses be conducted considering environmental externality values when considering generation options.

At the present time, the Joint System has no plans for adding generation capacity.

SECTION 17

Renewable Resource Scenarios – 50% and 75%

The Joint System currently has 459MW installed wind nameplate capacity to serve the energy needs for Minnesota and North Dakota members/customers. Currently, North Dakota does not impose a renewable energy requirement. So long as North Dakota does not impose such a requirement, a 50% or 75% renewable requirement would not require additional new renewable resources from the Joint System. However, a 50% or 75% renewable requirement in Minnesota without a renewable requirement in North Dakota, would likely force the Joint System to develop separate Minnesota and North Dakota wholesale power rates. Under these scenarios, they would likely lead to a significantly higher rate and cost to the Minnesota cooperative and municipal system end-use members/customers.

Any resource option under Minn. Stat. § 216B.2422, Subd. 2(c), requiring either 50% or 75% of all energy needs from facilities through a combination of conservation and renewable energy resources will be significantly more costly than the base case option because of the intermittence of renewable resources. Under the alternative resource options, backup generation, such as a new natural gas turbine, would be needed to serve firm load when renewable resources are not producing energy.

The Joint System does not believe that the 50% and 75% renewable resource options represent a viable or cost-effective method of meeting its future energy and generation capacity needs.

SECTION 18
Public Participation

Public participation in the integrated resource planning process was provided by the governing boards of the member systems, which represent end-use customers. Their ideas and concerns were solicited as part of the overall resource planning process. Shown below is a list of the dates and locations at which presentations of the draft IRP report were given.

Date		**Location**
Beltrami Electric Cooperative	May 23, 2022	Bemidji, MN
Cass County Electric Cooperative	April 26, 2022	Fargo, ND
Cavalier Rural Electric Cooperative	April 25, 2022	Langdon, ND
Clearwater-Polk Electric Cooperative	April 27, 2022	Bagley, MN
Nodak Electric Cooperative	April 12, 2022	Grand Forks, ND
North Star Electric Cooperative	March 30,2022	Grand Forks, ND
PKM Electric Cooperative	April 26, 2022	Warren, MN
Red Lake Electric Cooperative	May 25, 2022	Red Lake Falls, MN
Red River Valley Cooperative Power Assoc.	April 25, 2022	Halstad, MN
Roseau Electric Cooperative	April 27, 2022	Roseau, MN
Wild Rice Electric Cooperative	May 31, 2022	Mahnomen, MN
Northern Municipal Power Agency	April 20, 2022	Thief River Falls, MN
Minnkota Power Cooperative, Inc.	May 26, 2022	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 19
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 need to be flexible in matters concerning these factors. This flexibility is evident in that the Joint System has its generation resources diversified into three different baseload plants, has a well-established and extensive Demand Response program, has numerous transmission ties with various area utilities, is a MISO market participant, and has 459 MW of wind capacity through power purchase agreements. The Joint System will continue to maintain flexibility in those areas that affect its ability to serve its customers in a cost-effective manner.

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 various generation options that are presently available. It is also evaluating the advantages, disadvantages, and risks involved in becoming a member of a regional transmission organization such as MISO. 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 customers in a cost-effective and reliable manner while meeting federal and state environmental requirements.

SECTION 20
Cross Reference Guide

Cross Reference of Resource Plan Requirements

Rule or Statue		Reference Section
216B.1691 *Subdivision 2*	Report on plans, activities, and progress with regard to the renewable energy objectives.	8
216B.2422 *Subdivision 2*	Include least-cost plans for meeting 50 percent and 75 percent of all new and refurbished capacity needs with conservation and renewable energy.	17
Subdivision 3	Utility must use the environmental cost values, along with other socioeconomic factors, in selecting resources.	16
Subdivision 6	Utility should state if it intends to site or construct a large energy facility.	2
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.	7
Subparagraph 3	Include a five-year action plan with a schedule of key activities and regulatory filings.	14
Subparagraph 3	Include a narrative of why the plan is in the public interest.	19
Subparagraph 4	Include a nontechnical summary not to exceed 25 pages in length.	2
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 2019 Integrated Resource Plan Two-Year Action Plan

Section

A. A Load Forecast Study (LFS) will be completed for each of the 11 member systems and Minnkota in 2019. 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 on strategies to reduce energy costs to the end-use customers. **Completed**

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 2019 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 2019 and 2021. 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**

APPENDIX A

Minnesota Electric Utility Annual Report

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0120 REGISTRATION

ENTITY ID#	69
REPORT YEAR	2020

Number of Power Plants	4

UTILITY DETAILS

UTILITY NAME	Minnkota Power Coop
STREET ADDRESS	5301 32nd Ave S
CITY	Grand Forks
STATE	ND
ZIP CODE	58201-3312
TELEPHONE	701-795-4000
	Scroll down to see allowable UTILITY TYPES
* UTILITY TYPE	COOP

CONTACT INFORMATION

CONTACT NAME	JAMIE OVERGAARD
CONTACT TITLE	RATES, LOAD AND PLANNING MANAGER
CONTACT STREET ADDRESS	5301 32nd Ave S
CITY	Grand Forks
STATE	ND
ZIP CODE	58201-3312
TELEPHONE	701-795-4219
CONTACT EMAIL ADDRESS	jovergaard@minnkota.com

UTILITY OFFICERS

NAME	TITLE
LES WINDJUE	CHAIRMAN
STEVE ARNESEN	VICE CHAIRMAN
COLETTE KUJAVA	SECRETARY-TREASURER
ROBERT MCLENNAN	PRESIDENT & CEO

PREPARER INFORMATION

PERSON PREPARING FORMS	JAMIE OVERGAARD
PREPARER'S TITLE	RATES, LOAD AND PLANNIBG MANAGER
DATE	7/1/2021
PREPARER'S EMAIL ADDRESS	

COMMENTS

ALLOWABLE UTILITY TYPES

Code*

Private

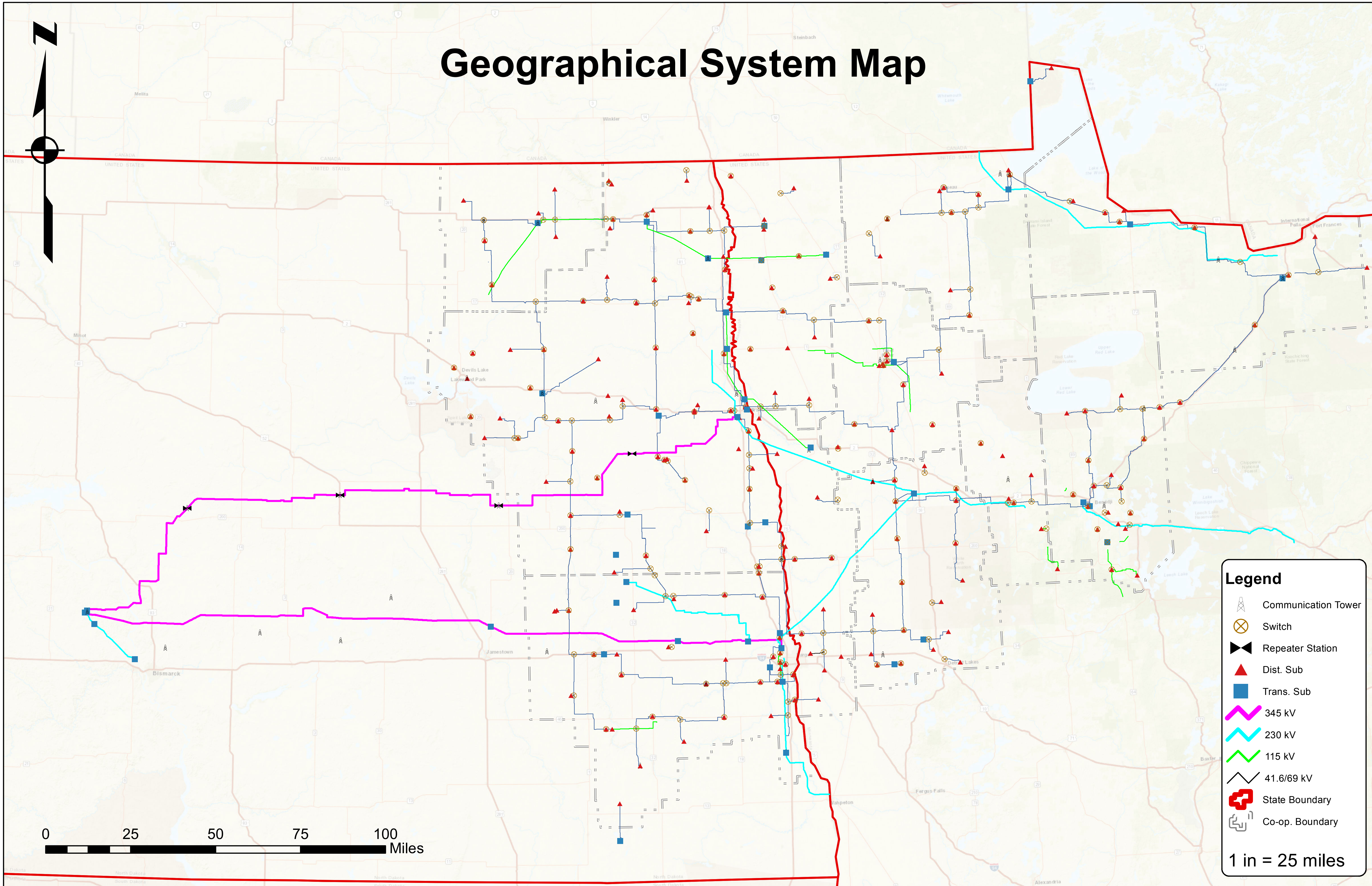
Public

Co-op

APPENDIX B

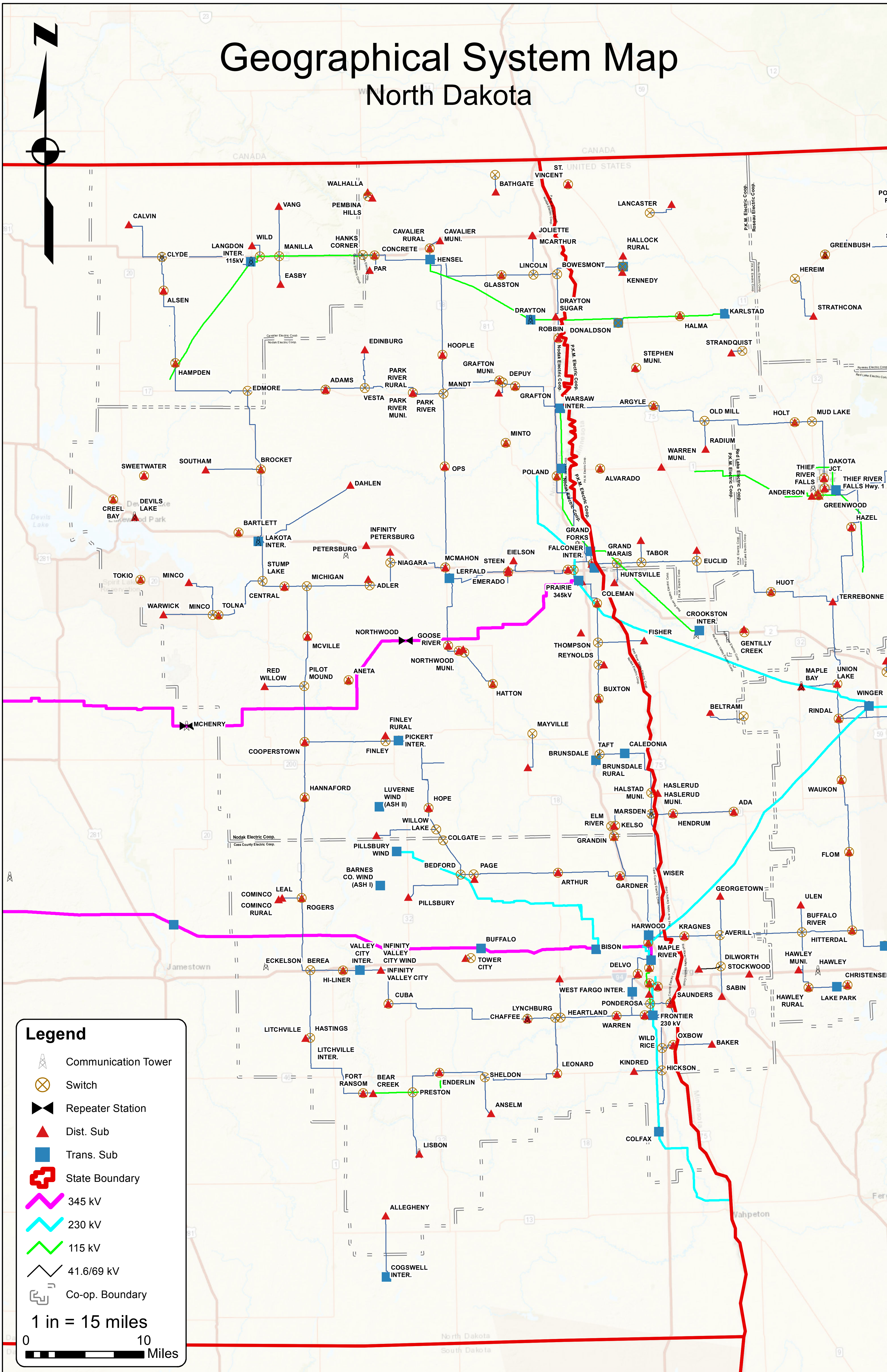
Minnesota Service Area Maps

Geographical System Map

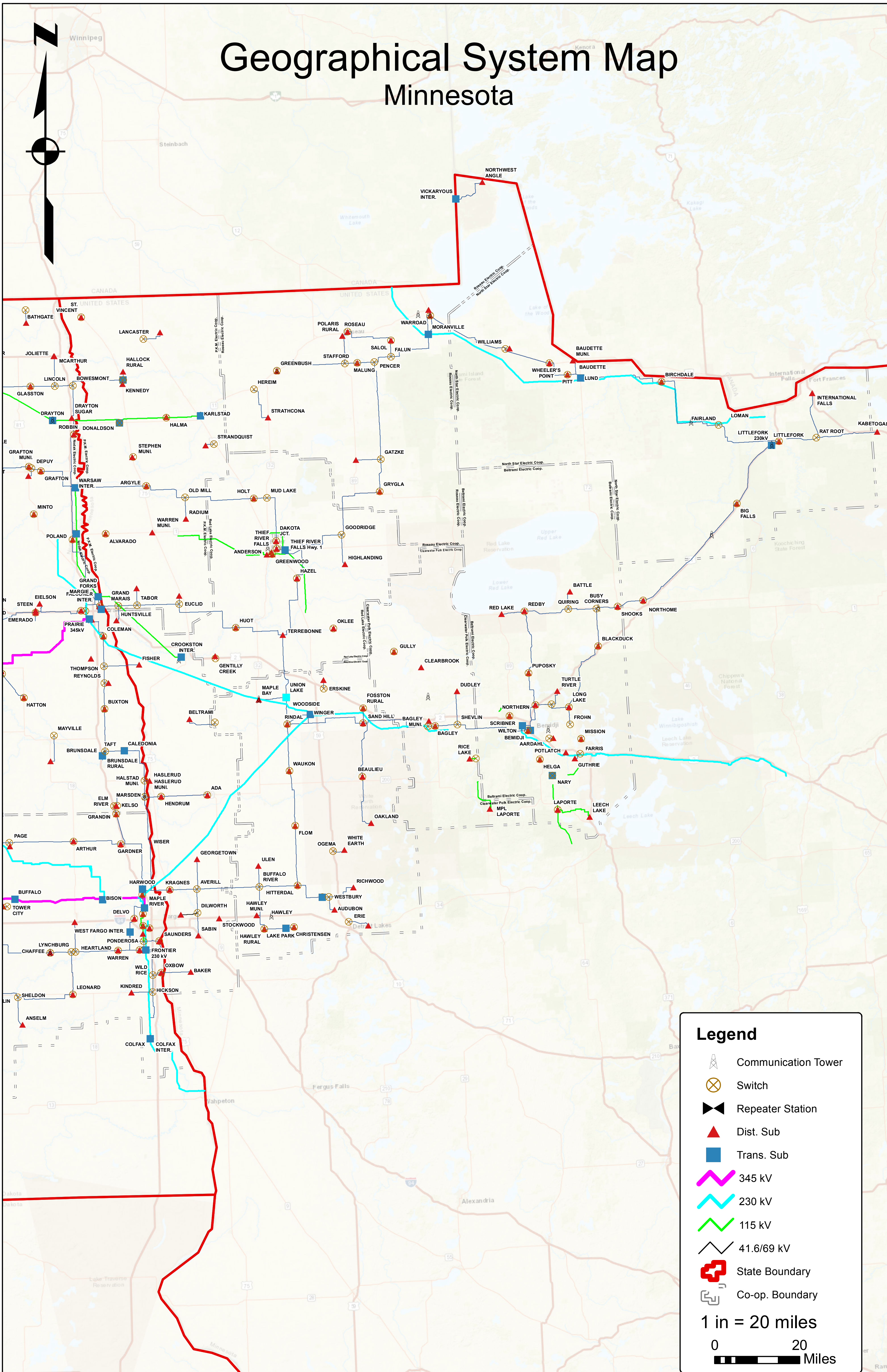


Geographical System Map

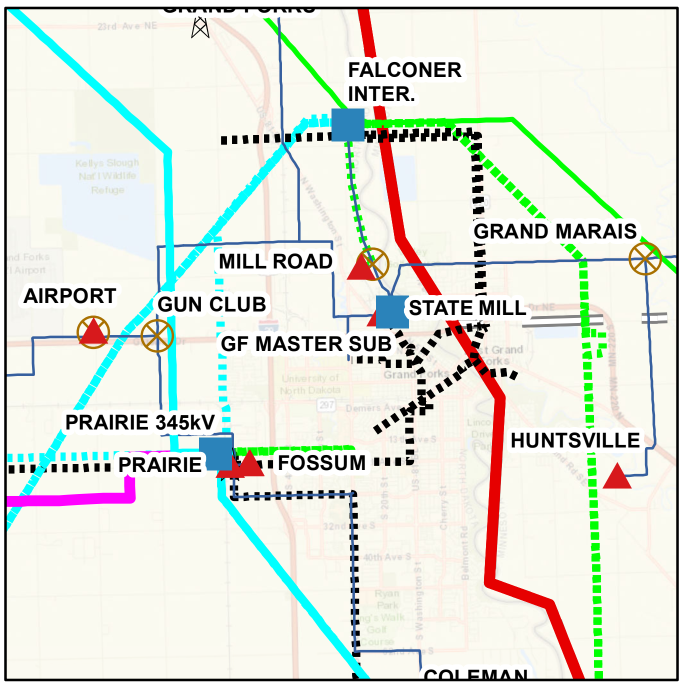
North Dakota



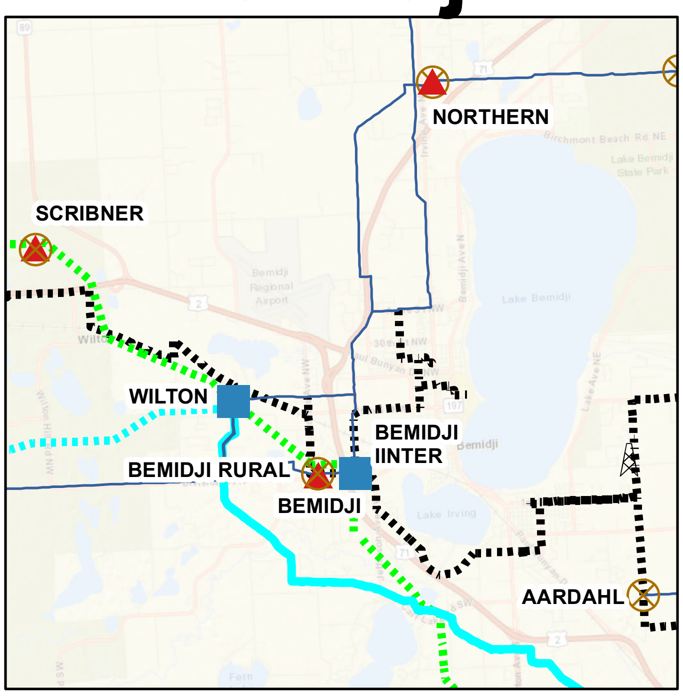
Geographical System Map
Minnesota



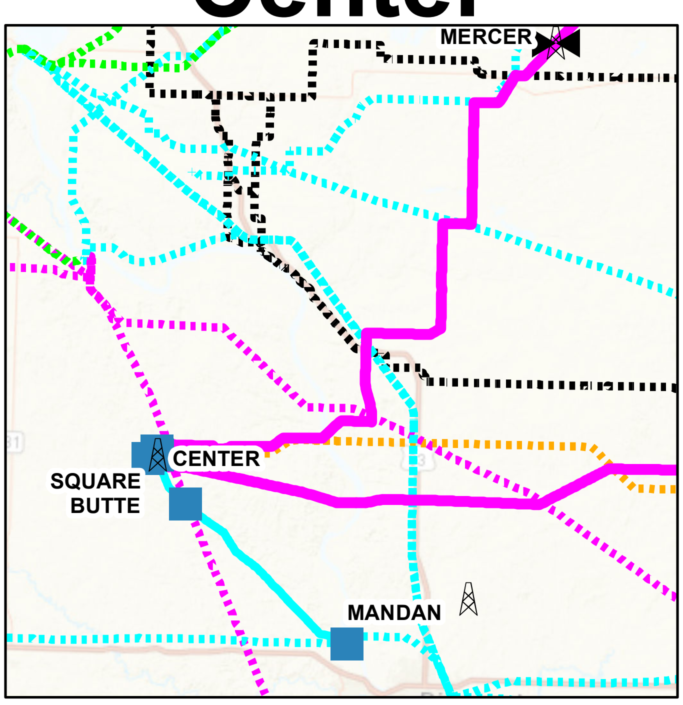
Grand Forks



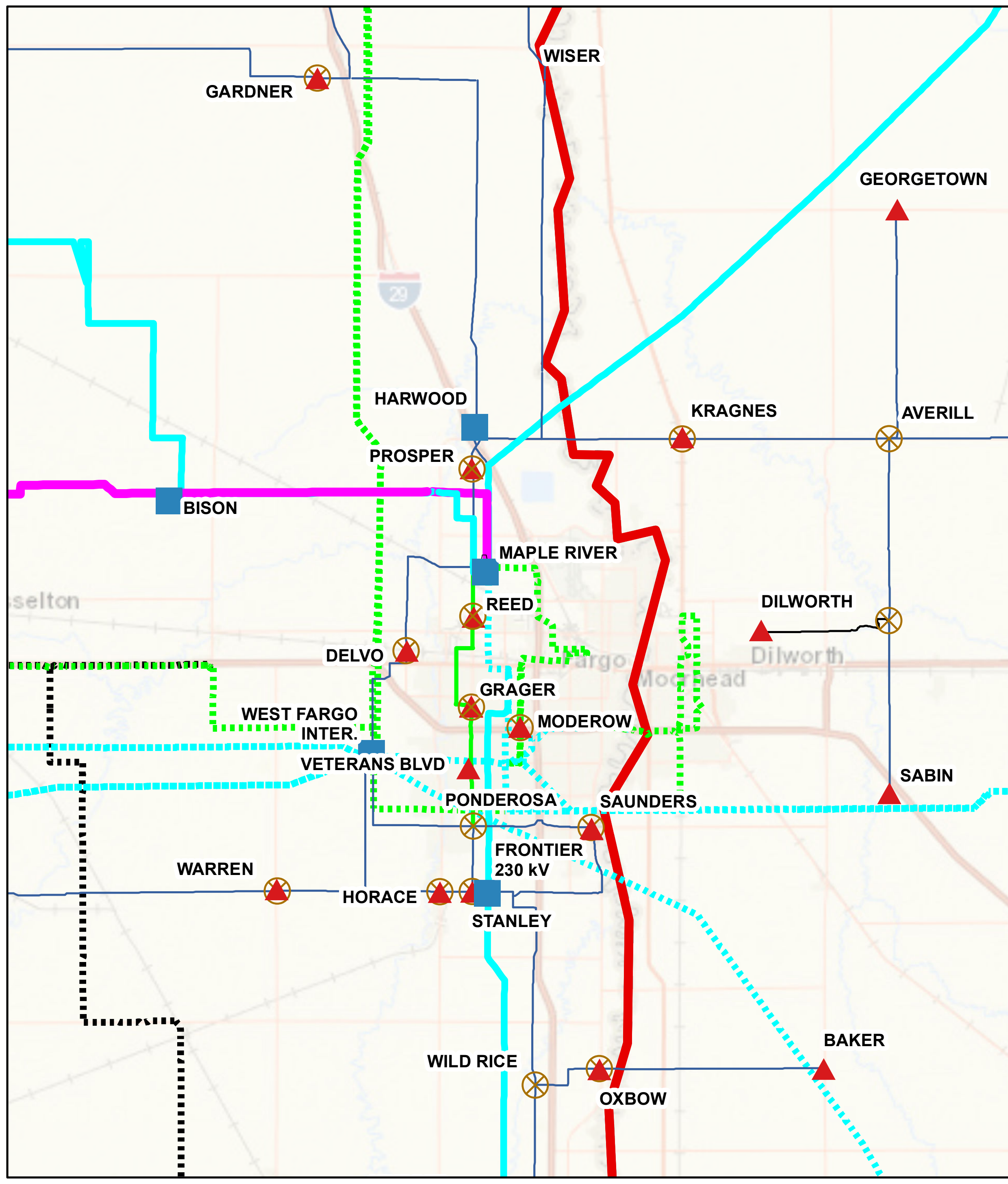
Bemidji



Center



Fargo



Thief River Falls