January 3, 2022

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. ET6/RP-22-312

Dear Mr. Seuffert:

Attached are the comments of the Minnesota Department of Commerce, Division of Energy Resources (Department) in the following matter:

Minnkota Power Cooperative, Inc.'s Submittal of its 2022-2036 Integrated Resource Plan

Jamie Overgaard, Rates, Load & Planning Manager with Minnkota Power Cooperative, Inc., filed the Petition on June 30, 2022.

The Department recommends the Minnesota Public Utilities Commission (Commission) **accept Minnkota Power Cooperative, Inc.'s 2022-2036 Integrated Resource Plan** and is available to answer any questions the Commission may have.

Sincerely,

/s/ CHRISTOPHER WATKINS
Public Utilities Rates Analyst

CW/ja
Attachment

Before the Minnesota Public Utilities Commission

Comments of the Minnesota Department of Commerce
Division of Energy Resources

Docket No. ET6/RP-22-312

I. INTRODUCTION

A. OVERVIEW OF THE FILING

Electric utilities in Minnesota are required to file proposed integrated resource plans (IRPs) every two years pursuant to Minnesota Rules 7843.0100 to 7843.0600. Minnkota Power Cooperative, Inc. (Minnkota or the Cooperative) and Northern Municipal Power Agency (NMPA) filed their last Joint System IRP for the period 2019 to 2033 on June 28, 2019 in Docket No. ET6/RP-19-416.

On July 11, 2022 Minnkota and NMPA submitted their IRP for the period 2022 to 2036.

B. ORGANIZATIONAL STRUCTURE AND JOINT SYSTEM BACKGROUND

Minnkota is a wholesale electric generation and transmission cooperative headquartered in Grand Forks, North Dakota. The Cooperative provides wholesale electric service to 11 retail distribution customers whose service areas cover 34,500 square miles and a population of approximately 366,000 people. Minnkota's member systems provide service to approximately 146,500 customers across northwestern Minnesota and eastern North Dakota, with eight of Minnkota's 11 members located in Minnesota. Minnkota is governed by a Board of Directors consisting of one director from each of the 11 Class A member systems. In addition, several Class B and Class C members contract with Minnkota for short-term power purchases and are represented by nonvoting delegates attending membership meetings.

The Northern Municipal Power Agency (NMPA) is a Class B member of Minnkota and selects a nonvoting liaison to attend Minnkota's Board of Directors' meetings. NMPA consists of 12 municipal utilities – 10 in northwestern Minnesota and 2 in eastern North Dakota – and serves approximately 15,800 customers. NMPA owns a 30% share of the 427 MW generating plant in Beulah, North Dakota as well as an undivided interest in Minnkota's transmission system determined by the ratio of NMPA's load to the total Joint System load.

Minnkota and NMPA together form a Joint System due to Minnkota's status as operating agent for NMPA and joint ownership of transmission facilities. The Joint System capacity and energy requirements are served by an aggregation of Minnkota's generation, NMPA generation, and Minnkota and NMPA's Western Area Power Administration (WAPA) allocation. Both Minnkota's and NMPA's member systems purchase electric capacity and energy requirements under similar Wholesale Power Rate Schedules, which are structured so Minnkota stays in compliance with requirements laid out in an Indenture of Mortgage between Minnkota and the United States acting through the Administrator of the Rural Utilities Service. As a MISO market participant, Minnkota is also eligible to meet the Joint System's energy requirements via energy sales and purchases in the MISO energy market.

Table 1 below shows the generating resources currently available to the Joint System, which have not changed since Minnkota's 2019 IRP.

Table 1: Joint System's Available Generating Resources

Name	Type	Nameplate Capacity	Owner	% Joint System	Available to Joint System
Milton R. Young 2	Lignite Baseload	455 MW	Square Butte Co-op	78%	355
Milton R. Young 1	Lignite Baseload	250 MW	Minnkota	100%	250
Ashtabula I	Wind	196.5 MW	Minnkota PPA	76%	148.5
Coyote	Coal Baseload	427 MW	NMPA	30%	128.1
Langdon 1	Wind	171.7 MW	Minnkota PPA	58%	99
Oliver III	Wind	99.3 MW	Minnkota PPA	100%	97
WAPA Minnkota	Hydro	76.632 MW	Minnkota Allocation	100%	72.632
Ashtabula II	Wind	169.5 MW	Minnkota PPA	41%	69
Langdon 2	Wind	40.5 MW	Minnkota PPA	100%	40.5
WAPA NMPA	Hydro	40.6 MW Winter/36.2 MW Summer	NMPA Allocation	100%	38
Cass County	Diesel	21.98 MW	Cass County Co-op	100%	21.98
NMPA	Diesel	13.536 MW	Minnkota Lease	100%	13.536
Infinity	Wind	1.8 MW	Minnkota	100%	1.8
Fargo Landfill Gas	Landfill Gas	0.925 MW	Minnkota PPA	100%	0.925
Thief River Falls	Hydro	0.5 MW	Thief River Falls	100%	0.5

The Joint System also currently has approximately 350 MW and 100 MW of interruptible load in the winter and summer seasons, respectively. The Joint System projects these interruptible loads will increase to 420 MW during the winter season and 128 MW during the summer season by 2036. Table 2 below shows the Joint System interruptible load forecasts throughout the planning period.

Table 2: Joint System's Winter and Summer Interruptible Load Forecasts

Year	Interruptible Load (MW)	
	Winter Season	Summer Season
2022	350	100
2023	355	102
2024	360	104
2025	365	106
2026	370	108
2027	375	110
2028	380	112
2029	385	114
2030	390	116
2031	395	118
2032	400	120
2033	405	122
2034	410	124
2035	415	126
2036	420	128

C. JOINT SYSTEM'S PLANNING PROCESS

1. Key Assumptions of the Planning Process

Minnkota used commercially available software packages to conduct its load forecast database development and analysis. First, Minnkota entered data into Excel 365 for conducting the necessary calculation and transformations. Next, Minnkota imported the results into EViews software to perform regression analysis and develop the forecasts based on selected regression equations. The Cooperative used the following key assumptions in creating its forecast models and analysis:

a. Minnkota used univariate, multivariate, and qualitative statistical methods to create the econometric modeling, giving greater weight to multivariate forecasting (ordinary least squares regression analysis) to develop the following forecasts:
    i. Number of residential customers
    ii. Residential energy usage
    iii. Number of small commercial consumers
    iv. Small commercial usage
b. Where developing a model was not practical, Minnkota used judgment and trend analysis to forecast the following variables:
    i. Irrigation sales
    ii. Street lighting
    iii. Sales to public authorities

    iv. Sales for resale
    v. Own usage and losses for each member system
c. The Cooperative used the following data sources to prepare its forecast:
    i. Woods and Poole Economics, Inc. Complete Economic and Demographic Data Series (CEDDS), 2021.
    ii. Midwestern Regional Climate Center. Online database for select Minnesota and North Dakota Weather Stations.
    iii. U.S. Department of Energy (DOE). Annual Energy Outlook, 2021.
    iv. U.S. DOE. *Monthly Energy Review*, various issues.
    v. Minnkota Residential Surveys. Conducted in 1988, 1990, 1993, 1996, 1999, 2005, 2010, and 2015.
d. Economic and demographic growth assumptions
    i. Employment growth expected to grow 0.9% per year
    ii. Per capita income expected to grow 1.4% per year
    iii. Total population in Minnkota's service territory expected to grow 0.5% per year

2. Planning Process

Minnkota used the following approach in its 2022-2036 IRP planning process:

a. Contracted with Clearspring Energy Advisors, LLC to consult the Cooperative in forecasting the Joint System energy and demand through 2050.
b. Developed the Joint System load forecast by aggregating the individual member system's energy and capacity requirements.
c. Used linear regression analysis of the historical period 2005-2020 to complete a load forecast for NMPA municipal members who are not required to complete a Rural Utility Service (RUS)-approved Load Forecast Study (LFS).
d. Created a forecast for the Joint System's total energy requirements by combining the Minnkota and NMPA energy requirements with the Joint System's transmission losses.
e. Determined resource needs to meet the projected energy and capacity requirements based on parts a through d.
f. Used base projections to create future scenarios showing the impacts of changing assumptions regarding future weather and economic growth patterns. Alternative scenarios include:
    1. Severe weather, normal economic growth
    2. Mild weather, normal economic growth
    3. Normal weather, rapid economic growth
    4. Normal weather, slow economic growth
g. Used results from alternative scenario analysis to develop recommended low, median, and high planning ranges to provide uncertainty analysis and risk management to the Joint System total energy requirements and peak demand through 2050. Minnkota used a Monte Carlo simulation to identify the most-probable high and low ranges for selected years (2025, 2030, 2035, 2040, 2045, and 2050).

3. Preferred Plan

After comparing the Joint System's generation resources, power purchase agreements, projected demand response program performance, and minimal purchases from the MISO energy market against the identified energy and capacity requirements for the years 2022-2036, the Cooperative determined it has sufficient resources to meet demand without procuring additional generation resources or power purchase agreements.

The Joint System's Two-Year Action Plan contains the following activities:[1]

- Complete a LFS for the Joint System in the fall of 2023.
- Continue discussions with member systems and NMPA municipals to identify strategies to reduce energy costs to customers.
- Continue to analyze the Wholesale Power Rate Schedules and provide recommendations to the Board of Directors to ensure rates remain fair and equitable for members.
- Continue to analyze cost-effectiveness of further integration of demand-side management programs and renewable energy resources into the Joint System's energy resource portfolio.

The Joint System's Five-Year Action plan contains the following activities in addition to those identified in the Two-Year Action Plan above:[2]

- Conduct a LFS for the Joint System in 2025 and 2027.
- Further focus staff efforts in analyzing and recommending changes to the Board of Directors to promote and enhance Demand Response offerings and continue integrating demand-side management programs and renewable energy resources.

II. DEPARTMENT ANALYSIS

In its analysis, the Department reviewed:

a. The Joint System's forecast,
b. Joint System's historical energy conservation achievements,
c. Whether the Joint System's proposed plan would provide a reliable system,
d. Joint System's compliance with the Renewable Energy Standard,
e. Joint System's progress in meeting Minnesota's greenhouse gas reduction goal.

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[1] Minnkota Power Cooperative, Inc. and Northern Municipal Power Agency 2022 Integrated Resource Plan (2022 IRP). *In the Matter of Minnkota Power Cooperative, Inc. Integrated Resource Plan.* Docket No. ET6/RP-22-312. July 11, 2022, page 46.
[2] 2022 IRP, page 47.

A. ASSESSMENT OF ENERGY AND DEMAND FORECAST

1. Joint System's Forecast

Minnkota used a bottom-up approach to develop the Joint System's energy and demand forecasts for the IRP planning period as described above. In this approach, Minnkota aggregated the member-owner distribution cooperatives' and Minnkota's Rural Utilities Service (RUS)-approved Load Forecast Studies with each of the NMPA members' forecasts[3] and the forecasted system transmission losses.

Table 3 below summarizes the forecasted energy requirements and summer and winter peak demand for the Joint System throughout the IRP planning horizon.[4]

Table 3. Joint System Median Energy and 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 anticipates its annual energy requirements will increase 0.7% per year through 2036, and projects winter and summer peak demand will increase 0.6% and 0.7% per year, respectively.[5]

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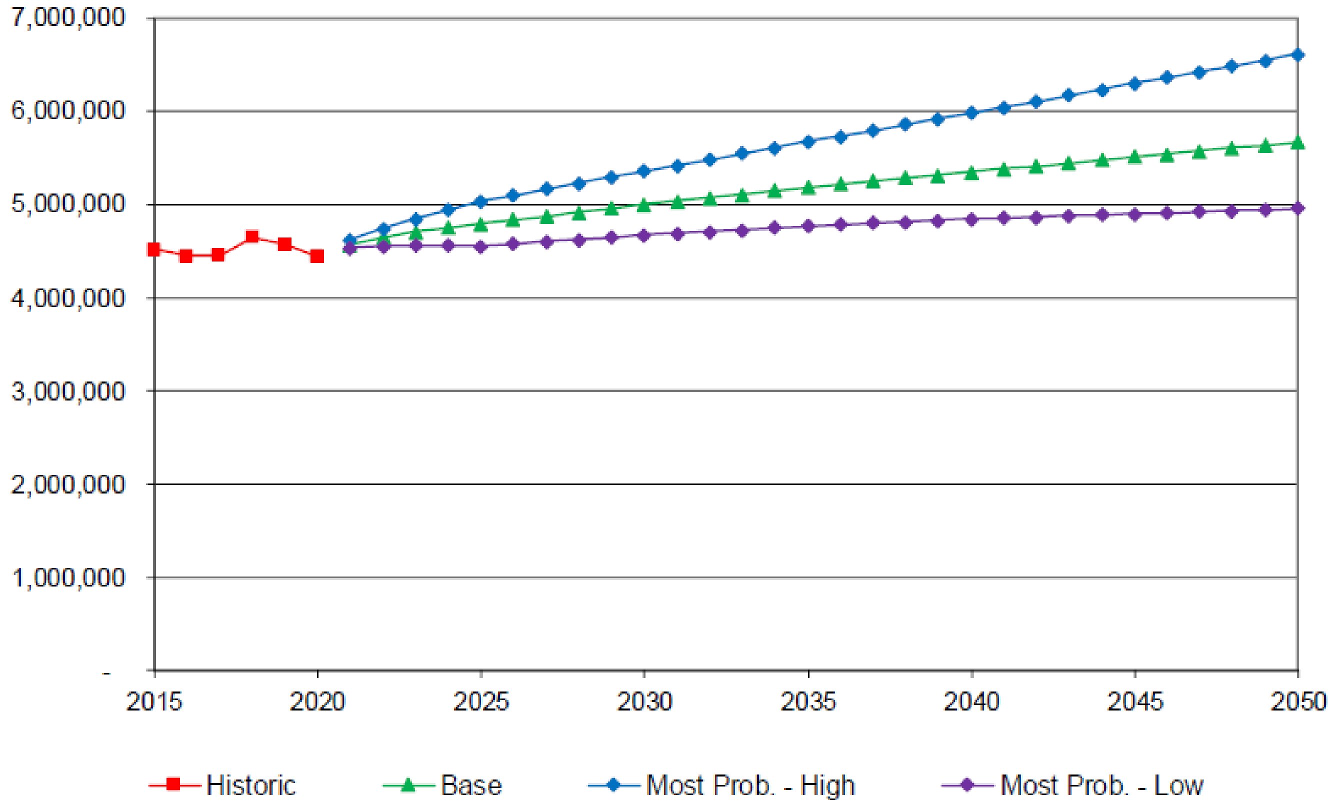
[3] NMPA members have no requirement to complete a RUS LFS, Minnkota completed a linear regression analysis of the historical period 2005 – 2020 to create load forecasts for each NMPA member.
[4] 2022 IRP, page 20.
[5] 2022 IRP, page 20. Growth rates based on the 30-year projections from the 2021 Load Forecast Study.

Figure 1 below depicts the Joint System's forecasted planning ranges from 2015 to 2050.[6]

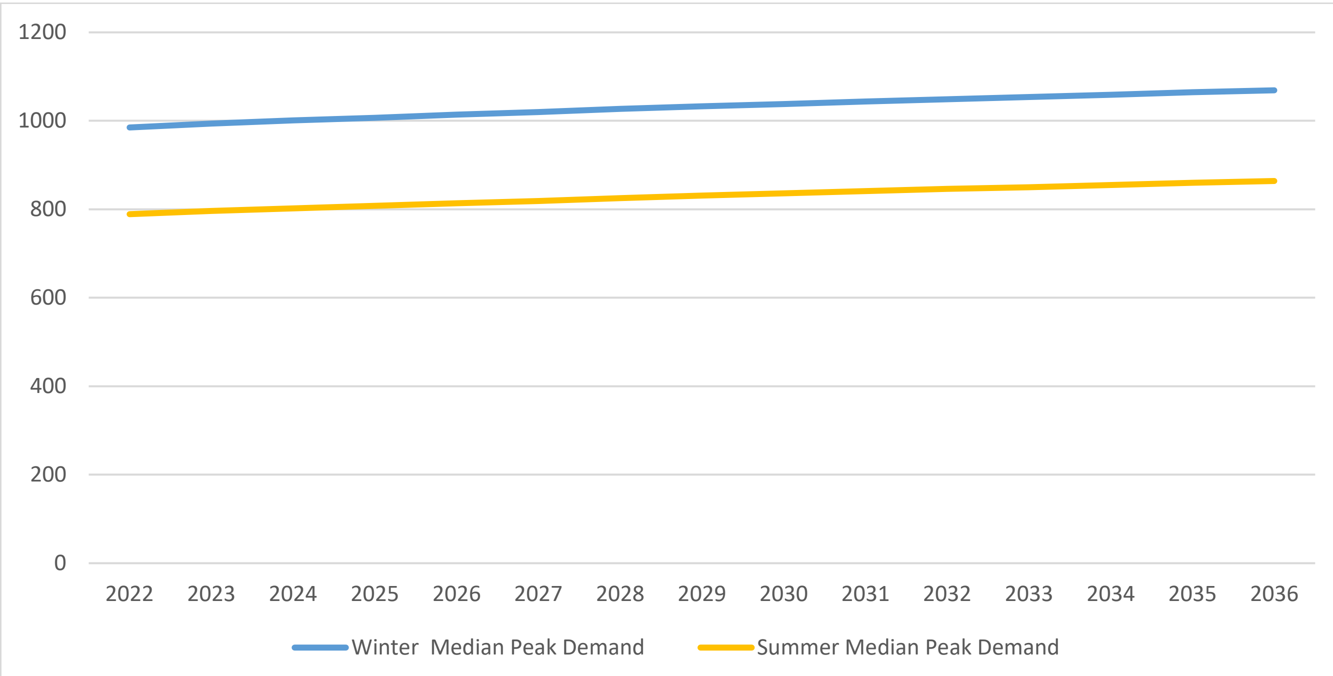
Figure 1. Joint System Forecast – Most Probable Ranges (MWh)



[6] 2022 IRP, Appendix C, Load Forecast Study, page E-8.

Figure 2 below shows the Joint System's projected winter and summer peak demand over the IRP planning period of 2022 – 2036.

Figure 2. Median Forecasts for Joint System Winter and Summer Peak Demands (MWs)



The Joint System anticipates its peak demands for the winter and summer to increase 0.6% and 0.7% per year, respectively.[7]

3. Department Analysis

To determine its confidence level in the Joint System's energy and demand forecasts provided in the 2022 IRP the Department conducted a cursory analysis of the Joint System's historical accuracy in projecting energy and demand requirements by comparing past IRP projections against actual data as reported in the 2022 IRP. The Department found the Joint System has consistently forecasted higher winter demand and annual energy requirements than occurred in a given year, and slightly underestimated summer peak load.

[7] 2022 IRP, page 20.

Table 4 below shows the percentage difference between the seasonal demand forecasts and actual annual peak seasonal demand from the Joint System's past four IRPs, with positive numbers representing an over-forecasting error and negative numbers representing under-forecasted errors. Numbers highlighted in red identify the years in which the actual seasonal demand fell outside the Joint System's most probable low or high planning range.

Table 4. Percentage by Which Forecasted Seasonal Demand Deviated from Actual Demand

Forecast Year	IRP Forecast Performance by IRP Filing Year							
	2006		2010		2014		2019	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
2006	-1.19%	2.04%						
2007	-1.15%	2.61%						
2008	2.54%	-6.95%						
2009	6.32%	-5.78%						
2010	-3.48%	4.35%	-2.79%	10.58%				
2011	-1.22%	1.45%	1.57%	8.25%				
2012	-2.35%	4.36%	-1.01%	9.94%				
2013	-0.83%	3.46%	-0.17%	8.21%				
2014	2.68%	11.07%	2.17%	15.03%	-2.68%	7.34%		
2015	0.00%	19.57%	-1.43%	22.78%	-6.51%	13.88%		
2016	5.05%	19.84%	2.61%	22.04%	-2.44%	12.99%		
2017	2.32%	24.03%	-0.62%	25.67%	-5.88%	15.83%		
2018	4.95%	21.23%	1.08%	22.01%	-4.18%	12.18%		
2019	5.87%	22.36%	2.63%	22.47%	-3.09%	11.78%	-4.79%	3.63%
2020	3.18%	34.32%	-2.46%	33.37%	-7.96%	21.23%	-9.99%	11.79%
2021			-3.24%	36.49%	-9.17%	23.22%	-11.57%	13.15%
Average	1.51%	10.53%	-0.14%	19.74%	-5.24%	14.81%	-8.78%	9.53%

The Department notes that over the past four IRPs, the Joint System has, on average, under-forecasted its summer peak demand by 3.16% and over-forecasted its winter peak demand by 13.65%. However, while the winter demand forecast deviations are trending towards actual realized demand, the Joint System's projections for its summer demand are trending away from the actual realized values. The Department requests the Joint System provide an explanation for this trend in their Reply Comments.

Table 5 below shows a similar analysis the Department performed, looking at the forecasted and actual annual energy requirements for the Joint System from its past five Load Forecast Studies.

Table 5. Percentage by Which Forecasted Energy Requirements Deviated from Actual Energy Requirements

Forecast Year	2011 Forecast	2013 Forecast	2015 Forecast	2017 Forecast	2019 Forecast
2011	1.59%				
2012	4.19%				
2013	-3.66%	-5.11%			
2014	-4.72%	-6.26%			
2015	1.66%	-0.14%	5.95%		
2016	4.30%	2.72%	8.90%		
2017	6.79%	1.41%	8.77%	3.84%	
2018	4.40%	-0.71%	7.00%	1.74%	
2019	6.71%	1.12%	8.81%	3.18%	1.93%
2020	12.25%	6.26%	14.09%	7.90%	8.18%
Average	3.35%	-0.09%	8.92%	4.17%	5.05%

Due to the Department's current constraint on forecasting resources, it did not complete a detailed analysis of the Joint System's forecast methodology for the 2022 IRP and determined the forecast is reasonable for planning purposes. Given that Minnkota is not projecting a need for additional resources through 2036 and the winter-peaking Joint System's tendency to historically over-forecast its winter demand and annual energy requirements the Department has determined that the current conservative forecasting methodology will ensure a reliable system throughout the planning period.

In its May 20, 2020 Order accepting Minnkota's 2019 IRP, the Commission ordered Minnkota and NMPA to provide information about the extent to which any member cooperatives are supplying up to five percent of their energy and capacity requirements from sources other than Minnkota.[8] The Department was unable to locate any information responsive to this requirement in the Joint Systems' 2022 IRP and requests that the Joint System include a discussion of the topic in its Reply Comments in the instant docket.

C. ASSESSMENT OF HISTORICAL CONSERVATION ACHIEVEMENTS

1. Introduction

Minnesota's Conservation Improvement Program (CIP) statutes (Minn. Stat. § 216B.241) were changed in 2007 to require utilities to meet an energy-savings goal equal to 1.5% of a utility's retail sales.

[8] Minnesota Public Utilities Commission. ORDER ACCEPTING RESOURCE PLAN AND MODIFYING FUTURE FILING REQUIREMENTS. *In the Matter of Minnkota Power Cooperative, Inc. and Northern Municipal Power Agency's 2019 Resource Plan.* May 20, 2020. Docket No. ET6/RP-19-416. Order Point 5, page 8.

The CIP statutes were again changed in 2021 upon the passage of the Energy Conservation and Optimization Act (ECO Act) to reflect the legislature's finding that "optimizing the timing and method used by energy consumers to manage energy use provides significant benefits to the consumers and to the utility system as a whole" and to emphasize the potential of load management programs to meet state policy goals.[9] The ECO Act also increased the state's annual energy savings goal from 1.5% to 2.5% of annual retail energy sales of electricity and natural gas.

In addition, Minn. Stat. § 216B.2403 states:

> Each individual consumer-owned utility subject to this section has an annual energy-savings goal equivalent to 1.5 percent of gross annual retail energy sales, to be met with a minimum of energy savings from energy conservation improvements equivalent to at least 0.95 percent of the consumer-owned utility's gross annual retail energy sales.

2. Historical Performance

Table 6 below summarizes the Joint System's realized annual energy savings as a percentage of retail sales to Minnesota customers.

Table 6. Joint System's Actual Energy Savings as a Percent of Retail Sales

Year	Retail Sales	kWh Savings	Percentage
2010	1,645,135,382	25,872,370	1.57%
2011	1,645,135,382	25,050,178	1.52%
2012	1,779,332,334	35,420,330	1.99%
2013	1,764,679,372	27,446,537	1.56%
2014	1,718,746,166	30,507,492	1.77%
2015	1,748,260,864	43,111,834	2.47%
2016	1,794,803,833	33,330,584	1.86%
2017	1,467,985,277	27,628,406	1.88%
2018	1,261,946,444	21,538,490	1.71%
2019	1,222,912,595	17,359,340	1.42%
2020	1,235,293,939	14,094,972	1.14%

The Joint System attributes the decrease in energy savings occurring after 2018 to a 2017 amendment to Minn. Stat. § 216B.241, subd. 1b, which provided an exemption from CIP requirements for municipals with fewer than 1,000 customers and cooperatives with fewer than 5,000 customers. This legislation reduced the number of municipal utilities and cooperatives participating in the Joint System's PowerSavers Program from 17 to 12, with the following members participating in the program:[10]

[9] Minn. Stat. § 216B.2401(a)
[10] 2022 IRP, page 36. NOTE: Starred utilities are exempt from CIP but continue to participate in PowerSavers voluntarily.

*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

The Joint System has historically met Minn. Stat. § 216B.241's energy savings requirements even though it consistently holds a surplus of supply-side resources. The Cooperative projects it will continue to obtain annual energy savings of 1.5% of its retail sales.

The Department requests Minnkota provide additional discussion regarding the decrease in energy savings performance after member municipal and cooperative utilities left the PowerSavers program in Reply Comments. This discussion should include a narrative of the plans the Joint System has to expand the program or otherwise provide new energy saving offerings to its members to get the Joint System back on track to meeting Minnesota's goals of annual energy savings of 1.5% of retail sales.

D. MINNKOTA'S COMPLIANCE WITH THE RENEWABLE ENERGY STANDARD

1. Introduction

Prior to the 2007 Legislative Session, Minn. Stat. § 216B.1691 required utilities to make a good faith effort to obtain 15% of their Minnesota retail sales from eligible energy technologies by 2015, and to obtain 0.5% renewable energy from biomass technologies. The 2007 Minnesota Legislature amended Minn. Stat. § 216B.1691 to include a Renewable Energy Standard (RES) beginning in 2010. As amended, Minn. Stat. § 216B.1691, subd. 2 sets forth the Renewable Energy Objective in place through 2010 and requires:

> Each electric utility shall make a good faith effort to generate or procure sufficient electricity generated by an eligible energy technology to provide its retail customers or the retail customers of a distribution utility to which the electric utility provides wholesale electric service so that commencing in 2005, at least one percent of the electric utility's total retail electric sales to retail customers in Minnesota is generated by eligible energy technologies, and seven percent of the electric utility's total retail electric sales to retail customers in Minnesota by 2010 is generated by eligible energy technologies.

Minn. Stat. § 216B.1691, subd. 2a established the Renewable Energy Standard utilities must meet through 2025 and specifically requires:

> Each electric utility shall generate or procure sufficient electricity generated by an eligible energy technology to provide its retail customers in Minnesota, or the retail customers of a distribution utility to which the

> electric utility provides wholesale electric service, so that at least the following standard percentages of the electric utility's total retail electric sales to retail customers in Minnesota is generated by eligible energy technologies by the end of the year indicated:
>
> - 2012 12 percent
> - 2016 17 percent
> - 2020 20 percent
> - 2025 25 percent

The statute no longer requires a portion of the renewable energy generation come from biomass technologies. Minn. Stat. § 216B.1691, subd. 1 defines an eligible energy technology as follows:

> Generates electricity from the following energy sources: (1) solar; (2) wind; (3) hydroelectric with a capacity of less than 100 megawatts; (4) hydrogen, provided that after January 1, 2010, the hydrogen must be generated from the 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 refuse-derived fuel from mixed municipal solid waste as a primary fuel.

Minn. Stat. § 216B.1691, subd. 2(d) directs the Commission to "issue necessary orders detailing the criteria and standards by which it will measure an electric utility's efforts to meet the renewable energy objectives of subdivision 2 to determine whether the utility is making the required good faith effort."

After taking comments from affected parties, the Commission issued several Orders setting forth the criteria for determining compliance with the RES Statute.[11] Among the resources the Commission determined ineligible for meeting the RES are 1) resources used for green pricing, 2) resources that do not meet the statutory definition of eligibility, and 3) generation assigned to compliance for other regulatory purposes such as another state's Renewable Portfolio Standard Requirements (RPS).

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[11] *In the Matter of Detailing Criteria and Standards for Measuring an Electric Utility's Good Faith Efforts in Meeting the Renewable Energy Objectives Under Minn. Stat. §216B.1691,* Docket No. E999/CI-03-869, Initial Order Detailing Criteria and Standards for Determining Compliance with Minn. Stat. §216B.1691 and Requiring Customer Notification by Certain Cooperative, Municipal, and Investor-Owned Distribution Utilities. (June 1, 2004) *In the Matter of Detailing Criteria and Standards for Measuring an Electric Utility's Good Faith Efforts in Meeting the Renewable Energy Objectives Under Minn. Stat. §216B.1691,* Docket No. E999/CI-03-869; *In the Matter of a Commission Investigation into a Multi-State Tracking and Trading System for Renewable Energy Credits,* Docket No. E999/CI-04-1616, Second Order Implementing Minn. Stat. §216B.1691, Opening Docket to Investigate Multi-State Program for Tracking and Trading Renewable Credits and Requesting Periodic Updates from Stakeholder Group; (October 19, 2004) *In the Matter of Detailing Criteria and Standards for Measuring an Electric Utility's Good Faith Efforts in Meeting the Renewable Energy Objectives Under Minn. Stat. §216B.1691,* Docket No. E999/CI-03-869, Order After Reconsideration (August 13, 2004)

The 2007 amendment to Minn. Stat. § 216B.1691, subd. 4 required the Minnesota Public Utilities Commission to 1) establish a program for tradable Renewable Energy Credits (RECs) by January 2008, and 2) require all electric utilities to participate in a Commission-approved REC tracking system once such a system was in operation.

The Commission subsequently adopted the use of the Midwest Renewable Energy Tracking System (M-RETS), a multi-state REC tracking system, as the REC tracking system under Minn. Stat. § 216B.1691, subd. 4(d) and required Minnesota utilities to participate.[12] Specifically, the Commission required utilities to complete the online registration process and sign the Terms of Use agreement with the M-RETS system administrator APX, Inc., and receive account approval from APX by January 1, 2008. In addition, the Commission directed utilities to make a substantial and good faith effort to create a system account and sub-accounts for its organization, and to register its generation units/facilities in the M-RETS system by March 1, 2008.

In its December 18, 2007 *Order Establishing Initial Protocols for Trading Renewable Energy Credits,* the Commission adopted a four-year shelf life for all renewable energy credits to be used for compliance with the Minnesota RES. A four-year shelf life allows a REC to be retired towards MN RES compliance in the year of generation and during the four years following the year of generation.

Finally, in its December 3, 2008 *Third Order Detailing Criteria and Standards for Determining Compliance under Minn. Stat. §216B.1691 and Setting Procedures for Retiring Renewable Energy Credits*, the Commission directed utilities to begin retiring RECs equivalent to 1% of their Minnesota annual retail sales for the 2008 and 2009 compliance year by May 1 of the following year. Upon retirement, RECs are transferred into a specific Minnesota RES retirement account and are no longer available to meet other state or program requirements, thus addressing the statutory prohibition against double counting the RECs and promoting the environmental benefits of renewable energy. The Commission further directed the utilities to submit a compliance filing demonstrating their RES compliance by June 1 of each year.

2. Minnkota's RES Requirement During Forecast Period

In Section 8.1 of its IRP, the Joint System discussed its plan for compliance with Minnesota's RES.[13] Table 7 below compares the Joint System's RES requirements over the 15-year planning period to the projected wind energy production from its Langdon, Ashtabula, and Oliver III wind generation facilities. In calculating its wind facilities' energy production, the Joint System assumed a capacity factor of 42% at the Langdon and Ashtabula facilities and 50% at the Oliver III facility.[14]

[12] *In the Matter of a Commission Investigation into a Multi-State Tracking and Trading System for Renewable Energy Credits,* Docket No. E999/CI-04-1616, Order Approving Midwest Renewable Energy Tracking System (M-RETS) Under Minn. Stat. §216B.1691, Subd. 4(d), and Requiring Utilities to Participate in M-RETS (October 9, 2007)
[13] 2022 IRP, pages 27 – 28.
[14] 2022 IRP, page 28.

Table 7. Joint System's Projected Compliance with Minnesota Renewable Energy Standard

Year	Joint System Minnesota Retail Sales (MWh)	% Renewables Required for MN RES	Renewable Energy Required for MN RES (MWh)	Langdon, Ashtabula and Oliver III Wind Energy Production (Mwh)	Excess/(Undersupply) of Renewable Energy to Comply with MN RES (MWh)
2022	2,184,555	20%	436,911	1,688,753	1,251,842
2023	2,210,534	20%	442,107	1,688,753	1,246,646
2024	2,232,526	20%	446,505	1,688,753	1,242,248
2025	2,256,240	25%	564,060	1,688,753	1,124,693
2026	2,279,506	25%	569,876	1,688,753	1,118,877
2027	2,302,144	25%	575,536	1,688,753	1,113,217
2028	2,328,354	25%	582,088	1,688,753	1,106,665
2029	2,352,797	25%	588,199	1,688,753	1,100,554
2030	2,375,752	25%	593,938	1,688,753	1,094,815
2031	2,400,706	25%	600,176	1,688,753	1,088,577
2032	2,422,827	25%	605,707	1,688,753	1,083,046
2033	2,442,925	25%	610,731	1,688,753	1,078,022
2034	2,468,399	25%	617,100	1,688,753	1,071,653
2035	2,489,506	25%	622,377	1,688,753	1,066,376
2036	2,509,172	25%	627,293	1,688,753	1,061,460

As shown in the table above, the Joint System continues to generate sufficient energy from renewable sources to satisfy the Minnesota RES requirements in each year of the IRP planning period.

3. Renewable Generation Resources

Minnkota has registered its renewable generation facilities with the Midwest Renewable Energy Tracking System (M-RETS). Currently the Joint System has procured or contracted for renewable generation resources that are projected to generate 1,688,753 Renewable Energy Credits (RECs) annually, accruing an average of 1,299,781 RECs annually over the years 2022 – 2025.[15] Minnkota has been active in the wholesale REC market in the preceding two calendar years, selling 700,000 and 830,000 RECs in 2020 and 2021, respectively.[16]

[15] Minnkota Power Cooperative & Northern Municipal Power Agency 2021 Annual REC Retirement and Biennial Green Pricing Report. Docket No. E999/PR-22-12. May 27, 2022.
[16] *Id.*

The Joint System's existing renewable resources and power purchase agreements will allow the Joint System to maintain compliance with the Minnesota RES through 2045. The Department concludes the Joint System – with wind generation resources accounting for over 30% of its member's annual retail sales – has a reasonable plan to meet the energy policy goals of Minnesota's RES.

E. PROVIDING A RELIABLE SYSTEM

1. New issues that could impact Minnkota's reliability

On August 31, 2022, the Federal Energy Regulatory Commission (FERC) accepted the Midcontinent Independent System Operator's (MISO) proposed tariff revisions establishing a seasonal resource adequacy construct. The revisions include 1) moving Schedule 53 resources[17] from an annual auction to a seasonal auction cadence, 2) creating a two-tiered weighting structure to calculate Seasonal Accredited Capacity of Schedule 53 resources, 3) implementing an "Effective Load Carrying Capability (ELCC) adjusted by Resource Adequacy (RA) hours," and 4) increasing the number of required interruption commitments for Load Modifying Resources – Demand Response resources from 10 to 16 per planning year for resources to qualify as capacity resources in MISO's market.

2. Impact on Minnkota

The Joint System currently has wind generation resources accounting for 34% of its total owned or contracted generation capacity. These wind generation facilities are Schedule 53 resources, and therefore their accredited capacity to meet the Joint System's resource adequacy requirements is likely to change as MISO shifts from annual to seasonal resource assessments and auctions. MISO's transition to a new ELCC by RA hours methodology also has the potential to significantly change the capacity accreditation for the Joint System's wind resources, as capacity credits will now be assigned based on historical unit-level data calculated using a two-tiered weighting to reflect the individual resource's seasonal availability during all hours besides RA hours (Tier 1 hours) and RA hours (Tier 2 hours).

As the Department noted in its Initial Comments in the Joint System's 2019 IRP, Minnkota calculated its available capacity to meet its MISO resource adequacy requirements assuming a capacity factor for its wind resources rather than MISO's capacity accreditation value for these wind resources.[18] The Department provided Table 8 below in its comments to show the impact of using MISO's 21.5% wind capacity accreditation for the Joint System's wind resources rather than the Joint System's assumed 42% capacity factor.

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[17] Schedule 53 resources are those resources designed to satisfy Resource Adequacy Requirements and are defined as capacity resources that are either Demand Response or Generation Resources, but are not Dispatchable Intermittent Resources, Electric Storage Resources, External Resources, or Use Limited Resources.

[18] Initial Comments of the Minnesota Department of Commerce, Division of Energy Resources. *In the Matter of Minnkota Power Cooperative, Inc.'s 2019 Integrated Resource Plan.* Docket No. ET6/RP-19-416. November 7, 2019, page 7.

Table 8. Minnkota Supply-Side Resource Nameplate and Unforced Capacity (UCAP)[19] MW

Generation Plant	Energy Source	Nameplate MW	Unforced Capacity (UCAP)[5] MW
Young 1	Coal	250	240.4
Young 2	Coal	355	315.9
Coyote	Coal	128	108.6
Various Wind	Wind	459	99
Minnkota WAPA	Hydro	49	42.7
NMPA WAPA	Hydro	36	35.2
Municipal Diesels	Diesel	14	15.7
Cooperative Diesels	Diesel	20	20.7
Total		**1311**	**878.2**

The exact values of the weighted two-tiered capacity credits for the Joint System's wind resources are not known at this time. The values will be calculated based upon each resources' performance over the past three years, so at this time the Department is unable to ascertain the magnitude of impacts to the Joint System's resource adequacy. The Department issued an Information Request (IR) to Minnkota asking whether and how MISO's tariff revisions will affect the Joint System's forecasting methodology and market participating beginning in the 2023/2024 Planning Year. Minnkota responded the changes to the methodology for calculating Seasonal Accredited Capacity and the transition to seasonal capacity auctions in the MISO market would not change the Joint System's load forecasting or resource planning processes for 2023-2024 due to timing constraints.[20]

3. Department Recommendations

The Department understands the complexities inherent in the transition to MISO's seasonal resource accreditation construct and acknowledges that FERC approved MISO's proposed tariff after Minnkota filed its 2022 IRP, making it difficult to conduct the analyses required to ascertain the impacts of MISO's tariff revisions in the near term. The Department recommends the Commission order the Joint System to include the following in its next IRP: 1) relevant data showing how these tariff revisions impacted the Joint System's accredited capacity, and 2) a detailed discussion of the resulting changes to the assumptions Minnkota made or methodology it employed in planning to meet future resource adequacy requirements.

[19] The unforced capacity value is equal to the installed capacity of the unit multiplied by (1- unit's EFORd). Equivalent Demand Forced Outage Rate (EFORd) is a measure of the probability that a generating unit will not be available due to a forced outage or forced derating when there is a demand on the unit to generate.
[20] Minnkota Response to DOC IR #3.

Lastly, the Department notes the Commission's Order Point 3 from it's Order accepting Minnkota and NMPA's 2019 IRP which states:

> 3. In its next resource plan, the Joint System shall update the Commission on the impact of the Regional Haze Rule on the Coyote Plant's operations and accordingly on the Joint System's resource needs.[21]

The Department was unable to locate information provided in the Joint System's 2022 IRP that specifically addresses this requirement. Minnkota acknowledged that North Dakota Department of Environmental Quality (NDDEQ) would be filing its final State Implementation Plan (SIP) with the Environmental Protection Agency (EPA) in August of 2022, and provided an excerpt from the draft SIP Executive Summary which reads in part:[22]

> 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.

While the Joint System acknowledged that the EPA may reject North Dakota's SIP and issue a Federal Implementation Plan (FIP) requiring additional controls at Coyote Station by December 31, 2028, it did not provide any updates for the Commission regarding the Joint System's current thinking or planned operational and resource adequacy responses that would be required should the EPA reject the NDDEQ SIP. The Department notes that the deadline for the Joint Systems instant IRP was extended to provide Minnkota time to coordinate its response with Otter Tail Power's current ongoing IRP, and requests that the Joint System provide a detailed update of its correspondence with Otter Tail Power regarding the planned future of Coyote Station and any contingency plans already identified by the Joint System for implementation should the EPA enforce the Regional Haze Rule FIP on North Dakota.

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[21] Minnesota Public Utilities Commission. ORDER ACCEPTING RESOURCE PLAN AND MODIFYING FUTURE FILING REQUIREMENTS. *In the Matter of Minnkota Power Cooperative, Inc. and Northern Municipal Power Agency's 2019 Resource Plan.* May 20, 2020. Docket No. ET6/RP-19-416. Order Point 4, page 8.

[22] 2022 IRP, page 43.

E. ASSESSMENT OF PROGRESS IN MEETING MINNESOTA'S GREENHOUSE GAS REDUCTION GOALS

1. Introduction

Minn. Stat. § 216H.02 subd. 1 states Minnesota has a goal to reduce statewide greenhouse gas (GHG) emissions across all sectors to at least 15% lower than 2005 levels by 2015, at least 30% below 2005 levels by 2025, and at least 80% below 2005 levels by 2050.

In 2013, the Minnesota Legislature passed amendments to Minnesota Statutes § 216B.2422, subd. 4, which states (new language underlined):

> The commission shall not approve a new or refurbished nonrenewable energy facility in an integrated resource plan or a certificate of need, pursuant to section 216B.243, nor shall the commission allow rate recovery pursuant to section 216B.16 for such a nonrenewable energy facility, unless the utility has demonstrated that a renewable energy facility is not in the public interest. <u>The public interest determination must include whether the resource plan helps the utility achieve the greenhouse gas reduction goals under section 216H.02, the renewable energy standard under section 216B.1691, or the solar energy standardunder section 216B.1691, subdivision 2f</u>.

On August 5, 2013, the Minnesota Public Utilities Commission issued a Notice of Information in Future Resource Plan Filings (Commission's Letter). The Commission Letter states, in part:

> **PLEASE TAKE NOTICE** that the Commission expects utilities to include in their resource plans filed after August 1, 2013 an explanation how the resource plan helps the utility achieve the greenhouse gas reduction goals, renewable energy standard, and solar energy standard as listed in the above-referenced legislation.Parties should also be prepared to discuss the matter in comments.

In Section 8.2 of its IRP,[23] the Joint System discussed how its preferred resource plan would allow the utility to achieve the greenhouse gas reduction goals identified in Minn. Stat. § 216H.02.

2. Minnkota's GHG Emissions Accounting Methodology for this IRP

For its 2022 IRP, the Joint System estimated the annual GHG emissions resulting from forecasted retail energy sales using the same methodology provided in its Reply Comments from its 2019 IRP.[24] To calculate its annual emissions through 2036, the Joint System summed its total retail sales in Minnesota to Minnkota and NMPA members plus 4% transmission losses and subtracted the retail

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[23] 2022 IRP, pages 29 – 33.
[24] Minnkota Power Cooperative Reply Comments. *In the Matter of Minnkota Power Cooperative, Inc.'s 2019 Resource Plan.* Docket No. ET6/RP-19-416. January 8, 2019.

sales from renewable generation sources as required by Minnesota's RES mandate. The remaining sales from energy produced at Young 1, Young 2, and Coyote coal plants were multiplied by a weighted average of the three unit's CO_2 lbs/MWh emissions profile to determine the total carbon dioxide emissions resulting from energy generated for sale in the state of Minnesota. The Joint System provided a table in its IRP (reproduced here as Table 9 below) showing a comparative analysis of the historical and projected emissions for the years 2014 – 2040 against the baseline year of 2005.[25]

Table 9. Joint System Emission Reductions from 2005 Levels

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%

[25] 2022 IRP, page 32.

The Department notes the significant decrease in annual projected CO_2 emissions beginning in calendar year 2026 resulting from the assumed in-service date of carbon capture technologies installed at Young 1 and Young 2 as a part of Minnkota's Project Tundra. This project is estimated to have the potential to capture 90% of the carbon emissions at Young 2 (reducing the lbs CO_2/MWh from 2,182 to 218) and approximately 30% at Young 1 (reducing lbs CO_2/MWh from 2,165 to 1,516).[26]

In its May 20, 2020 Order accepting Minnkota's 2019 IRP, the Commission ordered Minnkota and NMPA to include scenarios in its GHG reduction forecasting that do not assume approval and success of carbon sequestration technologies deployed as a part of Project Tundra.[27] Order Point 4 states the following:

> In its next resource plan, the Joint System shall comply with the Commission's August 5, 2013 letter regarding resource plan requirements and submit an evaluation of the Joint System's progress towards meeting Minnesota's greenhouse gas emissions reduction goal, including comparing its actual 2015 CO2 emissions and projected 2025 emissions to the Joint System's actual 2005 CO2 emissions. The Joint System should include scenarios that do not assume approval and success of carbon sequestration.

The Joint System explained it has completed the Department of Energy-sponsored Front-End Engineering and Design study for Project Tundra, anticipating issuance of final permits in Q3 of 2022, and Minnkota currently operates the largest fully-permitted carbon dioxide storage facility in the United States.[28] The Joint System also noted it received its Class VI injection well permit from North Dakota in January of 2022, and also was granted approval of its Monitoring, Reporting, and Verification plan from the Environmental Protection Agency. Achieving these project milestones and continuing to accumulate relevant experience in carbon capture and sequestration in its operating facilities has the Joint System confident in the ultimate success of Project Tundra in meeting the forecasted GHG reductions presented in its 2022 IRP. Therefore, it did not provide scenario analyses of a future without Project Tundra, but rather included a qualifying statement, "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."[29]

[26] 2022 IRP, page 31, Table 2.
[27] Minnesota Public Utilities Commission. ORDER ACCEPTING RESOURCE PLAN AND MODIFYING FUTURE FILING REQUIREMENTS. *In the Matter of Minnkota Power Cooperative, Inc. and Northern Municipal Power Agency's 2019 Resource Plan.* May 20, 2020. Docket No. ET6/RP-19-416. Order Point 4, page 8.
[28] 2022 IRP, page 33.
[29] *Id.*

3. Department Analysis

The Department notes the Joint System's progress towards certification and approval of Project Tundra is promising. However, the discussion provided in the 2022 IRP does not meet the requirements of the Commission's Order Point 4 that seeks to ascertain the impacts to the Joint System's GHG emissions profile should Project Tundra fail to come online or perform as anticipated.

Therefore, the Department requests the Joint System provide an alternate assessment of projected emissions reductions – in a similar format to Table 3 in its IRP – without Project Tundra in Reply Comments. This will allow the Commission to confirm the Joint System's assertion it will be able to achieve emissions reductions of at least 30% from 2005 levels through 2040 should Project Tundra fail to provide the projected reductions at Young 1 and 2.

As it did in its Initial Comments in Southern Minnesota Municipal Power Agency's (SMMPA) 2022 IRP, the Department notes the Commission has not approved a specific GHG accounting methodology for Minnesota utilities to use in their IRPs to determine whether they are progressing towards meeting the state's GHG emissions reduction goals. The Department had several discussions with parties before recommending the following approach in SMMPA's 2013 IRP:[30]

- Start with emissions from utility-owned generation;
- Add emissions from utility purchases; and
- Subtract CO_2 emissions from sales from utility-owned generation.

Since the emissions from utility purchases is unknown (unless a bilateral contract exists), the Department recommended that utilities use the 2005 average emissions per MWh for the Midwest Reliability Organization (MRO) West region 2005 purchases, and the 2009 average emissions per MWh for the MRO West region for 2015 and 2025.

The Department recommended this method because it considers what GHG emissions the utilities' customers are causing. The Department continues to use this method to account for GHG emissions in electric utilities' IRPs.

In February 2015 the Department gathered the following parties to further discuss how to measure progress towards the state's greenhouse gas reduction goal:

- Basin Electric Cooperative
- Dairyland Power Cooperative
- Great River Energy
- Interstate Power and Light
- Large Power Intervenors
- Minnesota Municipal Power Agency

[30] Docket No. ET9/RP-13-1104.

- Minnesota Pollution Control Agency
- Minnesota Power
- Minnesota Public Utilities Commission
- Missouri River Energy Services
- Otter Tail Power
- Southern Minnesota Municipal Power Agency
- Xcel Energy

Based on discussions at and after the meeting, the Department developed a set of guiding principles presented to the parties in November 2015.

Although the Joint System's analysis of its GHG emissions does not comply with the proposed retail ratepayer methodology, the Department considers them reasonable for planning purposes at this time. However, the Department is concerned that the fact that Minnesota's utilities are using different methodologies undermines any attempts to measure the state's progress in achieving greenhouse gas reduction goals.

The Department recommends the Commission accept the Joint System's analysis of its progress towards meeting Minnesota's GHG reduction goal for this IRP. In addition, the Department continues to recommend 1) parties convene in 2023 to try and reach consensus on how to analyze an electric utility's progress toward meeting Minnesota's GHG reduction goal, and 2) the Commission adopt a uniform method for assessing GHG reduction projections for use in future IRPs, whether or not parties reach consensus.

III. DEPARTMENT RECOMMENDATIONS

The Department makes the following requests and recommendations to the Joint System and Commission:

- **The Department requests the Joint System provide the following in Reply Comments:**
    - **An explanation of the assumptions or methodological choices the Joint System made in forecasting its seasonal demand that caused its forecasted summer peak demand to increasingly under-forecast actual system demand.**
    - **Information about the extent to which any Minnesota member cooperatives are supplying up to five percent of their energy and capacity requirements from other sources.**
    - **A detailed explanation of the Joint System's plan to increase its annual energy savings to meet Minnesota energy policy goals after the departure of some of its member municipal and cooperative utilities from the PowerSavers program.**
    - **An update on the impact of the Regional Haze Rule on the Coyote Plant's operations and the Joint System's resource needs.**
    - **An updated table showing the anticipated GHG reductions achievable throughout the IRP planning period without including Project Tundra's anticipated impacts.**

- **Provided the Joint System's Reply Comments include responses to the above inquiries, the Department recommends the Commission accept Minnkota Power Cooperative, Inc.'s 2022-2036 Integrated Resources Plan.**

- **The Department continues to recommend:**
  1) **parties convene in 2023 to try and reach consensus on how to analyze an electric utility's progress toward meeting Minnesota's GHG reduction goal, and**
  2) **the Commission adopt a uniform method for assessing GHG reduction projections for use in future IRPs, whether or not parties reach consensus.**

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Comments

Docket No. ET6/RP-22-312

Dated this **3rd** day of **January 2023**

/s/Sharon Ferguson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_22-312_RP-22-312
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_22-312_RP-22-312
Jamie	Overgaard	jovergaard@minnkota.com	Minnkota Power Cooperative, Inc.	5301 32nd Ave S Grand Forks, ND 58201	Electronic Service	No	OFF_SL_22-312_RP-22-312
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_22-312_RP-22-312
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_22-312_RP-22-312