MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	**August 24, 2023**	**Agenda Item 2****
Company	Minnkota Power Cooperative, Inc. and Northern Municipal Power Agency (Joint System)	
Docket No.	ET6/RP-22-312 **In the Matter of the Minnkota Power Cooperative, Inc. and Northern Municipal Power Agency (collectively, the Joint System) 2022-2036 Integrated Resource Plan**	
Issues	Should the Commission accept the Joint System's 2022 Integrated Resource Plan? Should the Commission adopt a uniform method for assessing greenhouse gas reduction projections for use in future resource plans?	

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✓**Relevant Documents**	**Date**
Minnkota Power Cooperative, Initial Filing	**July 1, 2022**
Minnkota Power Cooperative, Appendices A-H (Public and Non-Public)	**July 11, 2022**
Department of Commerce, Comments	**January 3, 2023**
Minnkota Power Cooperative, Reply Comments	**March 13, 2023**

BACKGROUND

I. Introduction

A. Procedural History

On July 1, 2022, Minnkota Power Cooperative, Inc. (Minnkota) and Northern Municipal Power Agency (NMPA) (collectively, the Joint System) filed its 2022 Integrated Resource Plan (IRP), covering the 2022-2036 planning period.

On January 3, 2023, the Department of Commerce, Division of Energy Resources (the Department or DOC) filed Initial Comments recommending that the Commission accept the Joint System's IRP. The Department's Initial Comments also sought additional, clarifying information for the Joint System to provide in Reply Comments.

On March 14, 2023, the Joint System filed Reply Comments, which included responses to the Department's inquiries.

B. Resource Planning

Minn. Stat. § 216B.2422, subds. 1–2 requires electric utilities capable of generating at least 100 megawatts (MW) of power and serving 10,000 retail customers in Minnesota, directly or indirectly, to periodically file an IRP with the Commission. For cooperatives and municipal utilities such as the Joint System, the Commission's role in resource planning is advisory.

Minn. R. 7843.0500, subp. 3 states that resource plans must be evaluated on their ability to:

A. maintain or improve the adequacy and reliability of utility service;
B. keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints;
C. minimize adverse socioeconomic effects and adverse effects upon the environment;
D. enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and
E. limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.

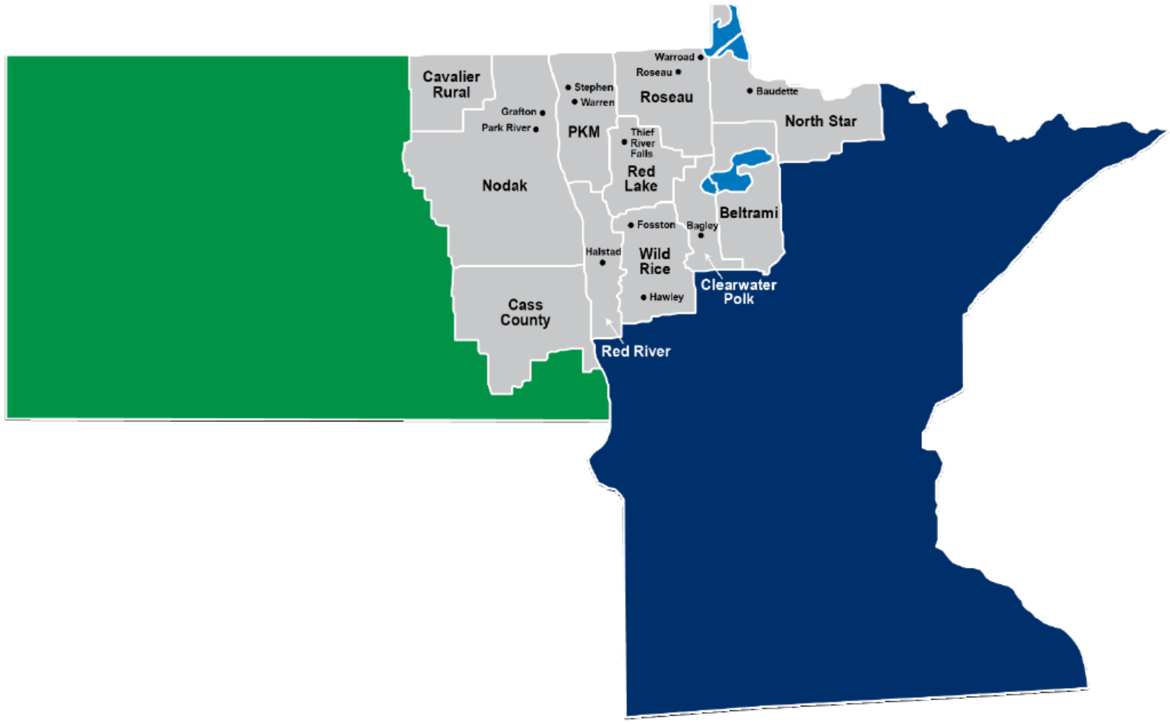
This is the seventh IRP that Minnkota and NMPA have filed jointly with the Commission.

II. Organizational Structure

A. Minnkota

Minnkota is a wholesale electric generation and transmission (G&T) cooperative headquartered in Grand Forks, North Dakota. Minnkota provides wholesale electric service to 11 retail distribution cooperatives, which are the members and owners of Minnkota, serving approximately 152,000 retail customers in a 34,500-square-mile area across northwestern

Minnesota and eastern North Dakota. This service area is depicted by the map below:



Member-systems are cooperative associations made up of residential, commercial, and industrial consumers within a contiguous geographic area. They provide retail electric service to their own member consumers through wholesale purchases of capacity and energy from Minnkota, which is delivered through the member-systems' electrical distribution facilities. Minnkota has wholesale power contracts with each of the 11 member systems though December 31, 2058. Of note, members may elect to purchase up to 5% of their requirements from sources other than Minnkota.

B. NMPA

Minnkota also serves as operating agent for Northern Municipal Power Agency (NMPA), headquartered in Thief River Falls, Minnesota. NMPA is a municipal power agency serving 12 municipal utilities—ten located in northwestern Minnesota and two in eastern North Dakota. NMPA's 12 municipal utilities serve the electrical requirements of approximately 15,800 customers.

C. Operating as a Joint System

Minnkota and NMPA effectively form a Joint System through:

- Operating agreements and joint ownership of transmission facilities.[1]

[1] NMPA owns an undivided interest in Minnkota's transmission system, which is based on a ratio of NMPA's load to the Joint System load.

- Generation and Western Area Power Administration (WAPA) allocations that are collectively utilized to serve the Joint System capacity and energy requirements.

- Obligations to conform to MISO's Resource Adequacy requirements.

III. Existing Resources

The largest generating resources in the Joint System are the coal-fired Milton R. Young Station and Coyote Station, hydropower WAPA allocations, and full or partial shares of the wind output from the Langdon, Ashtabula, and Oliver III wind farms. Notably, the Joint System does not own any sources of generation located in Minnesota—all generation is located in North Dakota.

Some details of the Joint System's resource mix include:

- Milton R. Young Station is a two-unit, lignite coal-fired power plant located near the town of Center, North Dakota. Minnkota owns and operates Young 1 (250 MW) and operates Young 2 (455 MW) on behalf of its owner, Square Butte Electric Cooperative.[2]

- Coyote Station (427 MW) is a lignite coal-fired mine mouth facility located near Beulah, North Dakota. NMPA owns 30% of Coyote Station (128 MW), and Minnkota acts as NMPA's agent for scheduling capacity and energy. Otter Tail Power owns 35% of Coyote Station and is the plant's operating agent. The other co-owners are Montana-Dakota Utilities and NorthWestern Energy.

- Langdon, Ashtabula, and Oliver III wind are all located in North Dakota. In total, Minnkota has rights to the output of 457 MW of wind (in nameplate capacity).

- Minnkota and eight NMPA municipals have WAPA firm power allocations. Minnkota's WAPA allocation provides firm capacity and energy to the Joint System of 72.6 MW and 358,303 MWh per year. NMPA's allocations provide firm capacity and energy to the Joint System of 40.6 MW winter/36.2 MW summer and 174,311 MWh per year.

- Minnkota's Infinity Wind Program consists of two 900 kW wind turbines, one located near Valley City, North Dakota, and one located near Petersburg, North Dakota. Both turbines commenced operation in 2002, and both produce about 2,800 MWh annually.

- Smaller-sized resources include:
  - Thief River Falls owns and operates a 500 kW hydro plant that has been in operation since 1927.
  - Minnkota leases 10 diesel generating units for Cass County Electric Cooperative, which have a total capacity rating of 18.28 MW.

[2] Both Young Station units are fueled by lignite coal obtained from the adjacent Center Mine, which is operated by BNI Coal, Ltd, a subsidiary of Allete.

- Three of the NMPA municipal members, Thief River Falls, Grafton, and Halstad, have diesel generators leased to Minnkota, which total 13.54 MW.

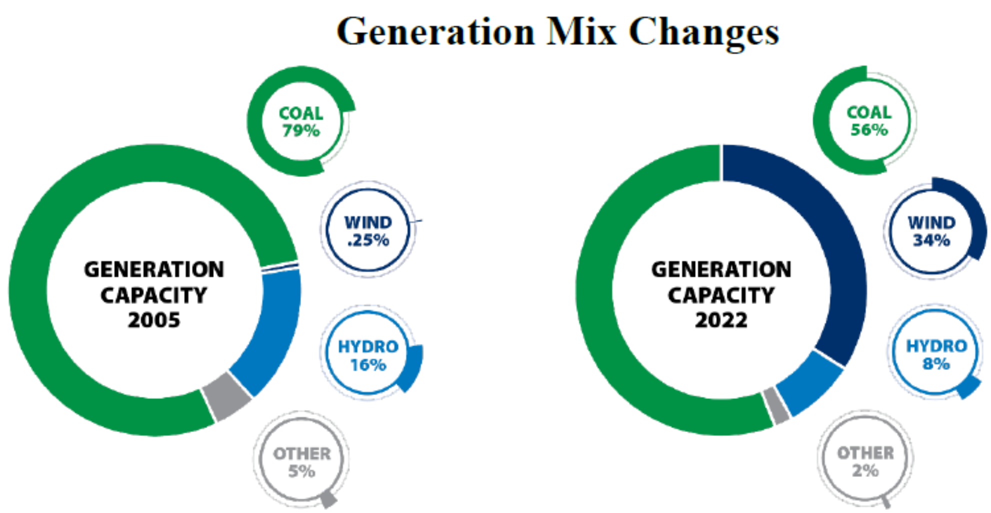
Table 1 below (also Table 1 of the Department's Initial Comments) is a summary of the Joint System's generating resources:

Table 1
DOC-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	Minnkota PPA	58%	99
Oliver III	Wind	99.3	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

In 2022, the Joint System's capacity mix was mostly coal (56%) and wind (34%). This is depicted on the right-side of the "Generation Mix Changes" figure below.[3] This is in stark contrast to the left-side of the figure, which shows that in 2005, the Joint System was about 80% coal and just 0.25% wind.

[3] IRP Petition, p. 29.



The Joint System is also pursuing the development of Project Tundra, a carbon capture and storage (CCS) project estimated to capture 90% of carbon dioxide (CO_2) emissions from Young 2 and additional capture from Young 1. According to the Joint System, Project Tundra would result in about 450 MW of near-zero carbon power produced with limited or no increase in cost, while enabling continued use of North Dakota's lignite coal resources. At the time of the filing, construction was expected to start in 2022-2023, with an in-service date of 2025-2026.

Regarding its transmission infrastructure, the Joint System operates and maintains more than 3,340 miles of transmission line and 252 substations, including a recently-completed 250-mile, 345 kV transmission line between Center, North Dakota and Grand Forks, North Dakota. In total, the transmission infrastructure consists 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.

OVERVIEW OF ACTION PLAN

I. Resource Need

As noted above, the Joint System's available resources are comprised of generating resources, plus the WAPA firm power allocations, plus power purchases, minus power sales. Energy requirements and summer and winter peak demands are based on Minnkota's 2021 Load Forecast Study (LFS) and a load forecast of the 12 NMPA municipal systems. From this comparison, the Joint System determined that it "has more than sufficient resource capacity to serve its firm load during the next 15 years."[4] Therefore, the Joint System proposes no additional generation resources in its IRP.

[4] IRP Petition, p. 12.

The Joint System described its "two-year action plan" (2022-2023) and "five-year action plan" (2024-2026) as follows:

Table 2
Summary of Sections 13 and 14 of the IRP: Two- and Five-Year Action Plans

Two-Year Action Plan (2022-2023)	1. Update the Load Forecast Study in 2023. 2. Develop strategies to reduce energy costs. 3. Decide whether modifications are needed in the Wholesale Power Rate Schedule. 4. Analyze cost-effective demand-side management strategies.
Five-Year Action Plan (2024-2026)	1. Update its Load Forecast Study in 2025 and again in 2027. 2. Enhance demand response activities. 3. Identify cost-effective demand-side management programs and renewable energy resources.

II. Meeting the Commission's Resource Planning Criteria

Table 3 below summarizes the Joint System's explanation regarding how its IRP will meet the Commission's five factors to consider in evaluating resource plans:

Table 3
Meeting the Commission's Five Factors to Consider under Minn. R. 7843.0500, subp. 3 (A-E)

Evaluation Factor	How the IRP Meets Each Factor
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	The IRP evaluates energy-efficiency programs and resource options and selects those that are the most cost-effective.
Minimize Adverse Socioeconomic and Environment Effects	The IRP meets all federal and state environmental requirements.
Ability to Respond to Financial, Social and Technological Change	The Joint System is flexible because generation is 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 457 MW of wind.
Limit Risk of Adverse Effects that the Utility Cannot Control	The Joint System considers many risks the electric industry faces. As one example, Minnkota continues to evaluate the advantages, disadvantages, and risks involved in becoming a member of an RTO such as MISO, and the IRP outlines the concerns about these risks.

CONTENTS OF THE IRP

I. Reliability

A. MISO Tariff Revisions

Currently, Minnkota is not a member of a Regional Transmission Organization (RTO), although Minnkota is a load-serving entity and market participant in MISO. As such, Minnkota, as the Joint System, must conform to MISO's Resource Adequacy requirements, and MISO annually prescribes the Joint System's planning reserve margin.

Since the Joint System filed its 2022 IRP, the Federal Energy Regulatory Commission (FERC) accepted MISO's tariff revisions establishing a seasonal resource adequacy construct. These revisions include, among other things, moving from an annual auction to a seasonal auction and creating a new structure to calculate seasonal accredited capacity for Schedule 53 resources.[5] The Department's comments noted that wind resources – which are Schedule 53 resources –

[5] 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.

account for 34% of the Joint System's total owned or contracted generation capacity.

In discovery, the Department inquired about the impact of MISO's tariff revisions; in response to Department Information Request No. 3, the Joint System stated that 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. Therefore, the Department recommends that in the next IRP, the Joint System should include more information on transitioning to MISO's seasonal resource accreditation construct.

B. Load Forecasting

The Joint System's load forecast is comprised of Minnkota's 2021 LFS, which is completed every other year, and a load forecast of the 12 NMPA municipal systems. The Joint System's baseline forecast projects energy requirements to increase at a rate of 0.7% per year. The summer and winter peak demands are forecasted to increase at 0.7% and 0.6% per year, respectively.

The Joint System examined low and high sensitivities, which adjusted variables such as weather, economic conditions, and fuel prices, that produced the following results:

- The low load growth scenario forecasts 0.85% growth in annual energy requirements. Both winter and summer peak demand increase at 0.45% per year.

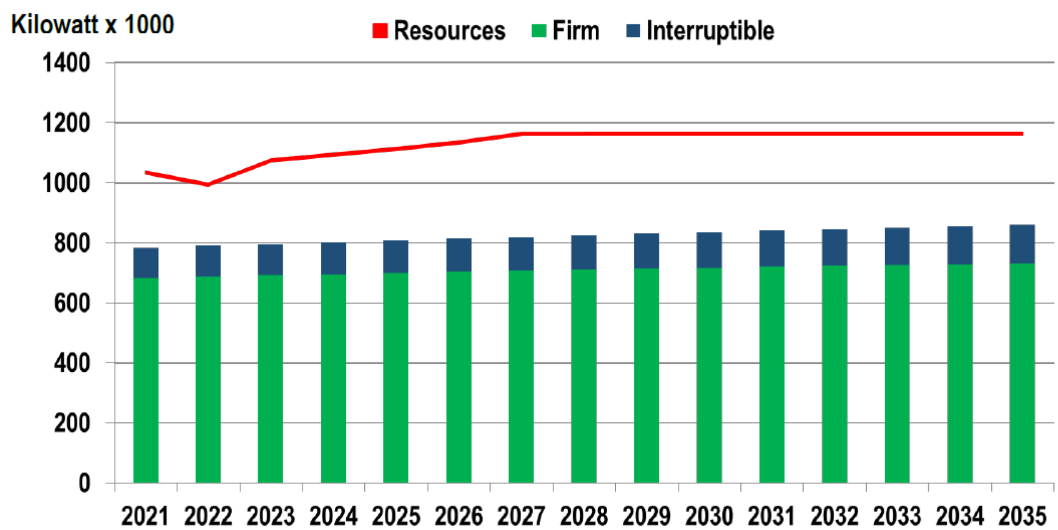
- The high load growth scenario forecasts 1.8% growth in annual energy requirements. Winter peak demand increases at a rate of 1.3% per year, and summer peak demand increases at 1.2% per year.

The Joint System noted that it has recently seen data mining/processing industrial loads develop in its service territory, but these loads are not included in the LFS for two main reasons. First, data mining loads are typically under either three- or five-year electric service contracts. Second, data mining loads are special interruptible loads that are registered with MISO as load-modifying resources.

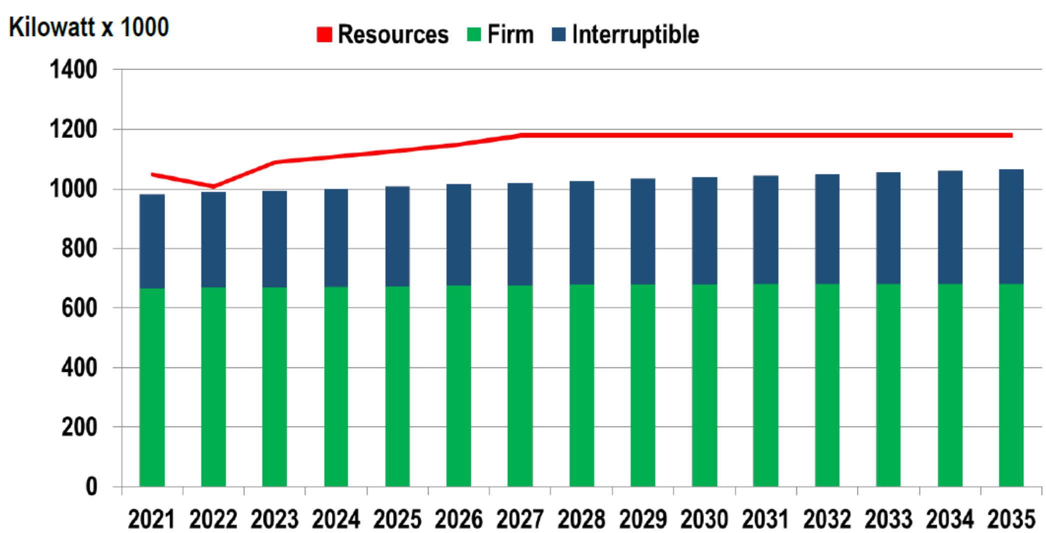
C. Available Resources

As noted above, the Joint System expects existing resources will sufficiently cover demand and energy requirements over the 2022-2036 planning period, and therefore no additional generation is proposed in this IRP. To illustrate this, the following charts display the winter and summer peak demands, separated into the firm (green bar) and interruptible (blue bar) components. This total load is then compared to total available resources (red line). Note that "Resources" (the red line) accounts for the Joint System's near-term capacity sales to Basin and Montana-Dakota Utilities, which vary in their amount over the 2022-2026 timeframe.

Summer Capacity vs. Load



Winter Capacity vs. Load



Minnkota must occasionally purchase energy from or sell energy into the MISO energy market when it is economical to do so—for instance, when coal-fired facilities require periodic maintenance, or wind is unavailable. However, due to the financial risk associated with relying too heavily on MISO energy markets, the Joint System plans to meet its energy requirements from owned or PPA resources to the extent practicable. According to its IRP analysis, the Joint System estimates that energy market purchases will be minor during the planning period, ranging from a low of 0.3% to a high of 2.4% of total annual energy.

D. Capacity Sales

As noted above, Minnkota has capacity sales arrangements with Basin and Montana-Dakota Utilities, which are subtracted from total available resources in the need assessment. Minnkota capacity sales are provided in the table below:

Table 4
Minnkota Capacity Sales, 2022-2026

Basin Electric Power Cooperative			
2022	Annual	75 MW	June-May
Montana-Dakota Utilities			
2022-2023	Annual	90 MW	June-May
2023-2024	Annual	30 MW	June-May
2024-2025	Annual	30 MW	June-May
2025-2026	Annual	30 MW	June-May

E. Demand-Side Resources

1. Demand Response

For the winter season, the Joint System's demand response (DR) program utilizes dual heating systems, water heaters, slab storage heating, thermal storage heating, electric transportation, and miscellaneous loads.

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.

2. Energy Savings

The Joint System formed its PowerSavers program to help business and residential consumers become more efficient energy users, as well as improve the system's own efficiency as an energy provider. Since the inception of PowerSavers, the Joint System has been able to meet all Conservation Improvement Program (CIP) requirements, and the Joint System intends to continue to do so for this IRP.

Notably, energy savings decreased after 2018 as a result of an 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 members.[6] Following this amendment, three of the Joint System's cooperatives, who according to the Joint System played key roles in promoting PowerSavers, withdrew participation in CIP.

[6] Minn. Stat. § 216B.241, subd. 1b.

In addition, the Joint System argued that since technologies are becoming increasingly efficient, there is less available incremental energy savings that can be realized through efficiency programs. This creates another challenge in keeping up with historical energy savings achievement levels.

However, the Joint System intends to take advantage of the flexibility of the Energy Conservation and Optimization Act (ECO Act), which will allow the Joint System to "meet [its] annual energy savings goal through a combination of programs delivering energy conservation, efficient fuel-switching, load management and other measures [that] should eliminate some of the barriers [the Joint System has] experienced in the past."[7]

F. Project Tundra

While not a new resource proposal, the Joint System continues to pursue Project Tundra, a CCS retrofit of Milton R. Young Station. The Joint System explained that Milton R. Young Station is in close proximity to secure geologic CO_2 storage sites (deep saline aquifers), which makes the power plant in a unique situation where CCS technology may be commercially viable.

According to the Joint System, Project Tundra can capture an estimated 12,978 short tons of CO_2 per day from the flue gas at Young Unit 2 and Unit 1 (in varying percentages). In total, the project will capture and sequester 4 million tonnes per year of CO_2 on average.

Project Tundra has received bipartisan support, and the project is presently completing a Front-End Engineering Design (FEED) study, including advanced amine solvents, economic modeling and aerosol mitigation and management. At the time of the IRP filing, Minnkota and various partners were in the final stages of engineering, with the goal to produce construction-ready engineering, scheduling, and pricing terms by the end of 2022.

Minnkota is currently seeking outside investment in the project from entities that can harness applicable tax credits for CCS 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.

II. RES and GHG Reduction Goal

A. Renewable Energy Standard

As discussed previously, Minnkota has PPAs for portions of the Langdon, Ashtabula and Oliver III wind farms in North Dakota. In total, Minnkota purchases the output from 457 MW (nameplate) of wind, which translates to approximately 1,751,500 MWh of wind energy.[8]

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[7] Joint System Reply Comments, p. 4.

[8] 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.

Table 5 documents the Joint System's estimated compliance with the Minnesota Renewable Energy Standard (RES). The table includes: (1) a retail sales forecast; (2) the percent of sales required to be generated by renewable resources (20% or 25%); (3) the amount of energy (in MWH) required to meet the RES; and (4) forecasted energy output from Minnkota's wind PPAs. The takeaway from the table is that "purchases from renewable energy resources are significantly greater than [the Joint System's] requirements."[9]

Table 5
Excerpt of Joint System Renewable Energy System Compliance Table

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

B. Greenhouse Gas Emissions

Tables 1-3 of the IRP present CO_2 emissions-related information. Table 3 shows CO_2 emissions by year relative to 2005 levels. Table 3 begins in 2014 and continues through 2040.

Notably, upon completing Project Tundra, Joint System CO_2 emissions would reduce from 1,658,835 tons in 2025 (a 22.6% reduction relative to 2005 levels) to 878,629 tons in 2026 (a 59% reduction relative to 2005 levels). Staff inserted the green line to show the decrease in CO_2 emissions once Project Tundra is incorporated. The Joint System explained that if Project Tundra is not operational by 2025, it can still reduce emissions in Minnesota by at least 30% from 2005 levels.

[9] IRP Petition, p. 28.

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 next sections will summarize the Department's comments and the Joint System's. This will provide more discussion of the Joint System's CO_2 reductions.

DEPARTMENT COMMENTS

The Department's analysis reviewed the Joint System's:

1. forecast;
2. historical energy conservation achievements;
3. reliability needs;
4. RES compliance; and
5. progress towards meeting Minnesota's greenhouse gas reduction goal.

I. Forecasting

The Department reviewed the Joint System's forecast by looking at past forecasts for historical accuracy. This revealed that the Joint System has consistently underestimated summer peak load (meaning the actual summer peak was higher than forecasted) and over-forecasted winter demand and annual energy requirements (meaning the actual winter peak was lower than forecasted).

The table below presents the Department's analysis of the percentage by which forecasted seasonal demand deviated from actual seasonal demand over the Joint System's past four IRPs. Positive numbers represent over-forecasting error, and negative numbers represent under-forecasting errors. This shows that the Joint System's summer forecast was generally well-below actuals, while the winter forecast was well-above actuals.

Table 6
Excerpt of DOC-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
Average	1.51%	10.53%	-0.14%	19.74%	-5.24%	14.81%	-8.78%	9.53%

The Department also noted the following trends:

- In the summer, forecasted demand is trending away from the actual realized value (i.e., error has been increasing).
- Conversely, in the winter, forecasted demand is trending towards actual realized demand (i.e., error has been shrinking).

Despite the Department's concerns, the Department determined that the Joint System's forecast is reasonable for planning purposes. The Department reasoned that, since the Joint System is not projecting a need for additional resources through 2036, and winter demand and annual energy requirements have historically been over-forecast, reliability will be ensured throughout the planning period.

The final forecasting issue involves the amount of members' capacity and energy supplied by sources other than Minnkota. The Department noted that the Commission's May 20, 2020, Order accepting the Joint System's 2019 IRP asked the Joint System to provide information about the extent to which any member cooperatives are supplying up to five percent of their energy and capacity requirements from other sources. The Department was unable to locate any information responsive to this requirement in the Joint System's 2022 IRP, so the Department requested that the Joint System include this information in Reply Comments.

A. Joint System Response on Forecasting

The Joint System's forecasting consultant, Clearspring Energy, assisted in developing a response to the Department's forecasting concerns.

The Joint System provided two main reasons to explain deviations between actual and forecasted values:

One explanation for the error is that historic data in the models is based on <u>observed</u> data. If a given year was hotter than normal weather (at the time of peak setting), then the forecast would underpredict the actual peak. For the 2017-2022 time period, 5 of the 6 summers were warmer than the average value (meaning the forecast would underpredict), and 4 of the 6 winters were average or colder than average (meaning the forecast would tend to overpredict).

A second explanation involves Minnkota's <u>winter load control</u>. The amount of load control at the time of peak is inherently included in the coincident peak demand data and thus incorporated into the model. If actual load control exceeds what the model assumes, then that could lead to an over-prediction of winter demand.

The Joint System stated it would take the Department's forecasting comments into account when preparing its 2023 LFS.

Finally, in response to the question about members who supply up to five percent of their energy and capacity from other sources, the Joint System stated that two member cooperatives have small community solar garden (CSG) facilities that fall under Minnkota's five percent provision—Cass County Electric Cooperative's Prairie Sun CSG and Beltrami Electric Cooperative's Northern Solar CSG.

II. Energy Savings

The Department examined the Joint System's historical performance in meeting CIP requirements. Table 7 (DOC-Table 6) below summarizes the Joint System's realized annual energy savings as a percentage of retail sales to Minnesota customers from 2010-2020. The table shows that the Joint System has consistently realized above 1.5% energy savings; however, there has been a decline in energy savings beginning around 2018.

Table 7
DOC-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%

As discussed previously, the Joint System attributed the decrease in energy savings to an 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. The Department requested that the Joint System provide in Reply Comments a discussion about the decrease in energy savings performance as well as plans to provide new energy saving offerings to its members.

A. Joint System Response on Energy Savings

According to the Joint System, DOC-Table 6 failed to include the carry-forward provision in the statute that utilities may access to reach their CIP requirements. Thus, according to the Joint System, DOC-Table 6 misrepresents the Joint System's ability to meet CIP requirements for years 2019 and 2020 because it does not take these savings into account. Once the carry-forward savings are included, the Joint System meets the 1.5% CIP requirement in all years. The revised table with carry-forward savings are in the table below. Staff highlighted the carry-forward savings and percentages with a red box.

Table 8
Joint System Corrected DOC-Table 6, with Carryforward Savings included

Year	Retail Sales	kWh Savings	Carryforward 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	984,349	1.50%
2020	1,235,293,939	14,094,972	4,434,437	1.50%
2021	1,294,575,466	19,186,892	231,740	1.50%

III. Reliability

The Department acknowledged the challenges brought upon by MISO's new seasonal resource accreditation construct and recognized that FERC approved MISO's proposed tariff after the Joint System filed its IRP. Therefore, the Department recommends the Commission order the Joint System to include the following information regarding MISO tariff revisions 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.

The Department highlighted the impact of seasonal accreditation requirements on wind resources. Table 9 (DOC-Table 8) shows the impact of using MISO's 21.5% wind capacity accreditation for the Joint System's wind resources instead than the Joint System's assumed 42% capacity factor.[10] Note that under a 21.5% capacity accreditation for wind, the amount of capacity that can be used for resource adequacy requirements drops significantly.

[10] Staff notes that the Joint System's "42% capacity factor" assumption refers to the energy output assumption from Minnkota's wind PPA, which is used to calculate energy for RES compliance. The Department appears to refer to 42% capacity factor in the context of MISO seasonal accredited capacity.

Table 9
DOC-Table 8: Minnkota Supply-Side Resource Nameplate and Unforced Capacity, MW

Generation Plan	Energy Source	Nameplate MW	Unforced Capacity (UCAP) 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	Diesels	14	15.7
Cooperative Diesels	Diesels	20	20.7
Total		**1,311**	**878.2**

IV. Renewable Energy Standard

Table 10 (excerpt of DOC-Table 7) 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. For space, Staff includes only the five-year action plan beginning with 2024 (the takeaway is the same throughout the planning period).

Table 10
Excerpt of DOC-Table 7. Joint System 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)
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

The Department determined "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."[11] In fact, the Department found that, through existing renewable resources and PPAs, the Joint System can maintain compliance with the Minnesota RES through 2045.[12]

11 Department January 3, 2023, comments, p. 15.

12 Department January 3, 2023, comments, p. 16.

V. Minnesota Greenhouse Gas Reduction Goal

The Department observed a significant decrease in annual projected CO_2 emissions beginning in 2026, due to the assumed in-service date of Project Tundra. The Joint System estimates that Project Tundra could capture 90% of the carbon emissions at Young 2 and approximately 30% at Young 1. This results in a decrease in the carbon intensity at those units of:

- Young 2 decreases its carbon intensity from 2,182 lbs. CO_2/MWh to 218 lbs. CO_2/MWh
- Young 1 decreases from 2,165 lbs. CO_2/MWh to 1,516 lbs. CO_2/MWh.

In its May 20, 2020, Order accepting the Joint System's 2019 IRP, the Commission ordered the Joint System to include scenarios in its GHG reduction forecasting that do not assume approval and success of Project Tundra. Order Point 4 stated:

> 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 Department agreed with the Joint System that Project Tundra's progress towards certification and approval is promising; however, the 2022 IRP does not meet the requirements of the Commission's Order Point 4, which 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 requested the Joint System provide projected emissions reductions without Project Tundra.

A. Joint System Response to the Department

The Joint System explained in its July 1, 2022, IRP Filing that a Class VI injection well permit was received from North Dakota. Moreover, the EPA approved the Joint System's Monitoring, Reporting, and Verification plan. The Joint System expected all final permits by the end of 2022, which would make the Milton R. Young Station facility "the largest fully-permitted carbon dioxide storage facility in the United States."[13] (Staff is unaware of the final permitting status.)

By achieving these project milestones and continuing to accumulate relevant experience in carbon capture and sequestration, the Joint System is confident in the ultimate success of Project Tundra. Therefore, the Joint System did not initially provide scenario analyses in the IRP of a future without Project Tundra. Instead, the Joint System stated that if Project Tundra is not plausible by 2025, the Joint System would still be in position to offset GHG emissions from electricity consumed in Minnesota by at least 30% relative to 2005 levels.

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[13] IRP Petition, p. 33.

Nevertheless, as requested, the Joint System provided a table in Reply Comments showing projected CO_2 emissions and the percent reduction of CO_2 from 2005 levels without Project Tundra. For space, Staff includes years 2022-2030 only:

Table 11
Joint System CO_2 emissions without Project Tundra, 2022-2030[14]

Year	2005 CO_2 Emissions, Tons	Projected CO_2 Emissions, Tons	Percent Reduction of CO_2 from 2005
2022	2,143,689	1,737,193	-19.0%
2023		1,750,643	-18.3%
2024		1,763,943	-17.7%
2025		1,663,997	-22.4%
2026		1,651,152	-23.0%
2027		1,659,820	-22.6%
2028		1,668,854	-22.2%
2029		1,677,241	-21.8%
2030		1,683,622	-21.5%

VI. Uniform Greenhouse Gas Accounting

The Department argues that any attempts to measure the State's progress in achieving GHG reduction goals are undermined because Minnesota's utilities are using different methodologies to assess GHG reductions. Therefore, the Department recommends that:

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.

In February 2015, the Department convened a stakeholder meeting to discuss how to measure progress towards the State's GHG reduction goal. Based on discussions at and after the meeting, the Department developed a set of guiding principles, which was presented to stakeholders in November 2015. The Department recommended a method that:

1. Starts with emissions from utility-owned generation;
2. Adds emissions from utility purchases; and
3. Subtracts CO_2 emissions from sales from utility-owned generation.

[14] Joint System Reply Comments, p. 6.

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

The Joint System's calculation of its GHG emissions did not comply with the Department's proposed retail ratepayer methodology; nevertheless, the Department considers the Joint System's calculation reasonable for planning purposes at this time.

VII. Regional Haze

Order Point 3 of the Commission's order accepting the Joint System's 2019 IRP 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.[15]

The Department was unable to locate information provided in the Joint System's 2022 IRP that specifically addresses this requirement. However, the Joint System did state that it expected the North Dakota Department of Environmental Quality (NDDEQ) to file its final State Implementation Plan (SIP) with the EPA in August 2022, after the IRP filing date. The Joint System cited the draft SIP Executive Summary, which stated that "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)."[16]

However, the Joint System also 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, <u>but the Joint System did not provide any contingency plan if EPA were to reject the NDDEQ SIP</u>.

A. Joint System Response on Regional Haze

The Joint System provided the response below on Regional Haze compliance:

> North Dakota Department of Environmental Quality (NDDEQ) prepared a well-supported plan for making reasonable progress toward the national visibility goal. The State Implementation Plan (SIP) is consistent with the applicable laws and guidance, and it includes reasoned analysis to justify the state's policy determinations. [On] August 10, 2022 NDDEQ officially submitted the state approved North Dakota Regional Haze State Implementation Plan Revision for

[15] 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.

[16] IRP, p. 43.

Round 2 of the visibility protection program.

Specific to the Coyote Station, NDDEQ undertook a rigorous "four factor" reasonable progress analysis for the facility, consistent with the Clean Air Act (CAA) and Environmental Protection Agency (EPA) requirements. North Dakota reasonably concluded that the costs associated with additional controls for Coyote could not be justified on the basis of the minimal, if not meaningless, visibility improvements that would result from installing and operating those controls.

The NDDEQ's SIP analysis shows that the emission controls at Coyote, along with recent and forthcoming facility shutdowns and other on-the-books controls required by various Clean Air Act and state regulatory programs, place North Dakota well on the way to complete elimination of manmade visibility impairment, as required by the regional haze program. The SIP has the state already achieving more progress than called for by EPA's "uniform rate of progress" to natural visibility by the year 2064. Considering the four-factor analyses alongside the visibility improvement results, consistent with the law and EPA rules and guidance, confirms that no controls are required for Coyote Station or other facilities during this planning period.

EPA Region 8 Administrator Becher sent letter of SIP Completeness Determination on August 23, 2022. On August 30, 2022, EPA issued Findings of Failure for 15 states, including amongst others Minnesota, Missouri, Iowa, Illinois, and Nebraska. We are not otherwise aware of a timeline for determination from the EPA on the SIP.[17]

JOINT SYSTEM REPLY COMMENTS

The previous section included the Joint System's response to specific categories of the Department's analysis. In this section, Staff attempts to summarize the Joint System's Reply Comments in a single table, which sets the Department's concerns alongside the Joint System's response to the Department.

[17] Joint System Reply Comments, p. 5.

Table 12
Department Requests for Information and Joint System Reply

Department Request	Joint System Reply
Under- and over-forecasting	According to Clearspring Energy, the Joint System's forecasting consultant, there are several possible causes for the variations, but two main factors could be: (1) actual versus normal weather, in which summers are hotter than expected and (2) load control, in which actual load control in a given winter exceeds what is assumed in the model.
Member systems supplying up to five percent of energy and capacity from other sources.	Two member cooperatives, Cass County Electric Cooperative and Beltrami Electric Cooperative, have CSGs that fall under Minnkota's five percent provision.
Increasing annual energy savings after members' departure from PowerSavers.	The Department does not account for the carryforward provision that allows utilities to reach their CIP requirements. Therefore, the Department misrepresents Minnkota falling short of their CIP regulatory requirements for years 2019 and 2020.
GHG reductions without Project Tundra	If Project Tundra is not implemented, Minnkota would likely retire Renewable Energy Credits from existing wind farms to meet state and federal regulations/obligations.
Regional Haze Rule's impact on Coyote Station	NDDEQ prepared a SIP that is consistent with the applicable laws and guidance for the visibility protection program. NDDEQ also undertook an analysis of Coyote Station that is consistent with the Clean Air Act and EPA requirements. North Dakota concluded that the costs for emissions control equipment for Coyote, or any other facility, are not justified.

STAFF DISCUSSION

I. Staff Recommends the Commission Accept the Joint System's Resource Plan

The Commission's May 20, 2020, Order accepting the Joint System's 2019 IRP stated:

> The Commission finds that the Joint System's resource plan meets the requirements and purpose of the resource planning statute and rules by addressing how it will meet its customer needs throughout the planning period and adequately explaining its analysis. The Commission will therefore accept the Joint System's 2019 resource plan.[18]

[18] Docket No. ET-6132/RP-19-416, Commission Order (May 20, 2020), p. 6.

The record in the 2022 IRP proceeding is similar; the Department (the sole intervenor) recommends the Commission accept the Joint System's IRP by concluding that:

- the forecast is reasonable for planning purposes, and the Joint System will have no additional resource needs over the planning period;
- the Commission should accept the Joint System's analysis of its progress towards meeting Minnesota's GHG reduction goal for this IRP (although the Department raised concerns about utilities in the State using different methodologies to measure the State's progress); and
- the Joint System "has a reasonable plan to meet the energy policy goals of Minnesota's RES."[19]

Staff largely agrees with the Department's analysis, and Staff recommends the Commission's order in this proceeding mirror its decision in the Joint System's last IRP proceeding. Put another way, Staff supports Decision Option 1, which states:

- **Decision Option 1**: The Commission accepts the Minnkota Power Cooperative, Inc. and Northern Municipal Power Agency (the Joint System) 2022-2036 Integrated Resource Plan. The Commission accepts the Joint System's forecast for planning purposes.[20]

II. The Department's Additional Recommendations

In addition to recommending the Commission accept the Joint System's 2022-2036 IRP, the Department made additional recommendations pertaining to (1) the MISO seasonal construct (Decision Options 2.a. and 2.b.) and (2) GHG accounting (Decision Options 3.a. and 3.b.). Staff supports the Department's recommendation regarding MISO's new tariff revisions, but not uniform GHG accounting across electric utilities.

A. MISO Recommendations

The following Decision Options reflect the Department's recommendations for the Joint System to incorporate, into its next IRP, MISO's tariff revisions establishing a seasonal resource adequacy construct.

Decision Option 2: In the next IRP, the Joint System shall include:

- 2.a. relevant data showing how MISO tariff revisions impacted the Joint System's accredited capacity, and

- 2.b. a detailed discussion of the resulting changes to the assumptions Minnkota made or methodology it employed in planning to meet future resource adequacy requirements.

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[19] Department January 3, 2023, comments, p. 16.

[20] Staff notes that this language is the same as Order Point 1 of the Commission's order in Minnkota's 2019 IRP, except Staff replaced "2019" with "2022 -2036."

Staff supports the Department's recommendation that the Joint System's next IRP include information regarding MISO's Seasonal Resource Adequacy Construct and revisions to its non-thermal capacity accreditation method. While clarifications to the Department's terms "relevant data" and "detailed discussion" might be needed, the Department's request for analysis of the impacts of MISO's tariff revisions is reasonable.

B. Greenhouse Gas Accounting

The Department recommends that:

- **Decision Option 3:** Parties shall convene in 2023 to try and reach consensus on how to analyze an electric utility's progress toward meeting Minnesota's GHG reduction goal.
- **Decision Option 4:** The Commission should adopt a uniform method for assessing GHG reduction projections for use in future IRPs, whether or not parties reach consensus.

Staff does not oppose participating in meetings on analyzing progress toward the Minnesota GHG reduction goal; however, given workload constraints, and considering that there are several IRPs that are either open or soon-to-be-filed, Staff questions whether a broad stakeholder group is the best use of resources in 2023. As an alternative, it might be more useful to address GHG accounting methods for each utility in their respective IRPs. In this case, the Department concluded that the Joint System's GHG accounting method is "reasonable for planning purposes at this time," and Staff believes that is as far as the Commission needs to go on this issue.

The Department's comments explain that the Department has already convened parties on this issue in February 2015, and based on these discussions, the Department developed a set of guiding principles that were presented to the parties in November 2015. It is not clear if the Department intends to repeat these meetings, or why the Commission needs to require them.

Regarding the second part of the Department's recommendation, Staff has two reservations with applying GHG accounting methodologies uniformly:

First, the Department's GHG accounting methodology involves: (1) starting with emissions from utility-owned generation, (2) adding emissions from utility purchases, then (3) subtracting CO_2 emissions from sales from utility-owned generation. The Joint System's method incorporates emissions from <u>utility-owned generation only</u>. This means the Department is suggesting the Joint System make additional calculations for purchases and sales, which is complicated because Minnkota is a North Dakota-headquartered, wholesale electric G&T that is not rate-regulated by the Commission and has a number of power purchase and sales contracts. To the extent GHG emissions have a direct or implied financial value (which is the case in Minnesota proceedings), Staff is unsure of the Joint System's willingness to impose societal costs on purchases and sales. The Joint System did not comment on this issue in Reply Comments.

Second, asking the Commission to adopt a uniform GHG accounting method does not seem to be meaningfully actionable at this juncture. It appears that the Department is asking the Commission to commit utilities to a set of guiding principles made in 2015, without noticing the issue for comments from other parties to whom the decision would affect. At the same time, the Department concluded that the Joint System's GHG accounting method is "reasonable for planning purposes at this time."

It is worth noting that the Department made the same GHG accounting recommendations in the SMMPA IRP, but the Commission declined to either convene parties on analyzing progress toward Minnesota's GHG reduction goal or establish a uniform GHG accounting method.

C. Energy Savings and Carry-forward Savings

Minn. Stat. 216B.2403, subp. 4(b) states:

> (b) The energy-savings goals specified in this section must be calculated based on weather-normalized sales averaged over the most recent three years. <u>A consumer-owned utility may elect to carry forward energy savings in excess of 1.5 percent for a year to the next three years</u>, except that energy savings from electric utility infrastructure projects may be carried forward for five years. A particular energy savings can only be used to meet one year's goal.

Table 13 (JS-Table 6, Reply Comments) shows the carry-forward savings in 2019-2021:

Table 13
Revised Table 6 (excerpt, 2018-2021) – Joint System Reply Comments

Year	Retail Sales	kWh Savings	Carryforward Savings	Percentage
2018	1,261,946,444	21,538,490		1.71%
2019	1,222,912,595	17,359,340	984,349	1.50%
2020	1,235,293,939	14,094,972	4,434,437	1.50%
2021	1,294,575,466	19,186,892	231,740	1.50%

The statute allows a consumer-owned utility – in this case, the Joint System – to elect to carry forward energy savings for a year to the next three years. Therefore, Staff agrees with the Joint System's response that the Joint System demonstrated it will be able to achieve CIP regulatory requirements for years 2019 and 2020.

D. Filing Date for the Next IRP

The table below shows the current IRP schedule for Minnesota utilities filing resource plans.

Table 14
Upcoming IRP Schedule

Utility	Date of Next IRP Filing
Xcel Energy	February 2024
SMMPA	December 2024
Minnesota Power	March 2025
MMPA	August 2025
Great River Energy Otter Tail Power Basin, Dairyland O-IRPs	Current IRPs are Pending Review

If the Commission wishes to continue to stagger IRP filings, while maintaining the generally-accepted practice of requiring IRP filings about every three years, then Staff offers as a starting point for discussion a December 1, 2025, filing date for the Joint System's next IRP.

DECISION OPTIONS

1. Accept the Minnkota Power Cooperative, Inc. and Northern Municipal Power Agency (the Joint System) 2022 Integrated Resource Plan, and accept the Joint System's forecast for planning purposes. (Joint System, Department, Staff)

Filing Requirements for Next IRP

2. In the Joint System's next IRP, require the Joint System to include:

   A. relevant data showing how the tariff revisions relating to MISO's Seasonal Resource Adequacy Construct impacted the Joint System's accredited capacity, and

   B. a detailed discussion of the resulting changes to the assumptions Minnkota made or methodology it employed in planning to meet future resource adequacy requirements. (Department, Staff)

Greenhouse Gas Accounting

3. Require the parties to convene in 2023 to try to reach consensus on how to analyze an electric utility's progress toward meeting Minnesota's GHG reduction goal. (Department)

4. Adopt a uniform method for assessing GHG reduction projections for use in future IRPs, whether or not parties reach consensus. (Department)

Filing Date for Next IRP

5. Require the Joint System to file its next IRP by December 1, 2025. (Staff option)