July 13, 2026 **PUBLIC DOCUMENT**

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

RE: **PUBLIC** Comments of the Minnesota Department of Commerce
Docket No. E015/CN-25-111

Dear Ms. Bergman:

Attached are the **PUBLIC** comments of the Minnesota Department of Commerce (Department) in the following matter:

In the Matter of the Application of Minnesota Power and American Transmission Company, LLC for a Certificate of Need and Route Permit for the Iron Range – St. Louis County – Arrowhead 345 kV Transmission Project

The Department recommends that the Minnesota Public Utilities Commission (Commission) consider the impacts detailed in the Environmental Report, and, if the impacts are acceptable, **grant the Certificate of Need**. The Department is available to answer any questions the Commission may have.

Sincerely,

/s/ DR. SYDNIE LIEB
Assistant Commissioner of Regulatory Analysis

RP/LH/ad
Attachment

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Before the Minnesota Public Utilities Commission

PUBLIC Comments of the Minnesota Department of Commerce
Division of Energy Resources

Docket No. E015/CN-25-111

I. INTRODUCTION

Minnesota Power (MP) and American Transmission Company, LLC by and through its corporate manager ATC Management Inc. (ATC) (collectively, the Applicants) submitted an application to the Commission for a Certificate of Need (CN) and Route Permit (application) to construct the Iron Range – St. Louis County – Arrowhead 345 kilovolt (kV) Transmission Project (the project or ISA project). The proposed project was selected as part of the Midcontinent Independent System Operator, Inc.'s (MISO) Long Range Transmission Plan (LRTP) Tranche 2.1 portfolio. The proposed project, along with the rest of the portfolio, was selected by MISO to support the reliability of the regional transmission system, particularly in northern Minnesota and northwest Wisconsin. It will provide additional transmission capacity and regional transfer capability to reliably integrate new renewable generation, meet growing electrical demand, and strengthen the bulk power system.

A. NOTICE AND EXEMPTION PETITIONS

On August 7, 2025, MP and ATC submitted their Request for Exemption from Certain Certificate of Need Application Data Requirements (Exemption Petition). The Exemption Petition requested the Applicants' proposal to be exempted from certain CN application data requirements.

Also on August 7, 2025, the Applicants submitted their Notice Plan Petition (Notice Petition). The Notice Petition provided the Applicants' plan to notify potentially affected members of the public about the CN application under Minnesota Rules 7849.2550.

On August 27, 2025, Comments on the Exemption Petition and the Notice Petition were filed by the Department. Reply comments were filed by the Applicants.

On November 18, 2025, the Commission issued an Order approving the Exemption Petition and the Notice Petition.[1]

B. CERTIFICATE OF NEED APPLICATION

Several weeks before the CN was filed, the Department completed an informal courtesy review of a draft version of the application.

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[1] *In the Matter of the Application for a Certificate of Need for the Iron Range – St. Louis County – Arrowhead 345 kV Transmission Line Project, Order*, Docket No E015/CN-25-111, November 18, 2025, (eDockets) 202511-225041-01.

On January 5, 2026, the Applicants filed their Combined Certificate of Need and Route Permit Application for the Iron Range – St. Louis County – Arrowhead 345 kV Transmission Line Project (application).

On January 15, 2026, Commission Energy Infrastructure Permitting Staff (PUC EIP) filed comments on application completeness.

On January 23, 2026, the Commission issued an Order finding the CN application complete.[2]

On June 11, 2026, the Commission issued its Notice of Comment Period on the Merits of the Certificate of Need Application (Notice). The Notice established due dates and stated that the following topics are open for comment:

- Are there any contested issues of fact with respect to the representations made in the certificate of need application?
- Should the Commission remove the 800 MVA limit on the Arrowhead Substation?
- Should the Commission grant a certificate of need for the proposed project?
- Are there other issues or concerns related to this matter?

On July 1, 2026, the Commission issued an Order authorizing Commission staff to prepare an Environmental Assessment Addendum, adopting the Draft Scoping Decision, requesting that an Administrative Law Judge preside over public hearings, and issuing a Draft Route Permit.[3]

Below are the comments of the Department regarding the application and the issues specified in the Notice.

[2] In the Matter of the Application for a Certificate of Need for the Iron Range – St. Louis County – Arrowhead 345 kV Transmission Line Project, Order, Docket No E015/CN-25-111, January 23, 2026, (eDockets) 20261-227318-01.
[3] *In the Matter of the Application for a Certificate of Need for the Iron Range – St. Louis County – Arrowhead 345 kV Transmission Line Project, Order*, Docket No E015/CN-25-111, July 1, 2026, (eDockets) 20267-233654-01.

II. PROPOSED PROJECT

In the application, the Applicants request the Commission approve a CN for a proposed project that would consist of the following elements:[4]

The proposed project consists of three major segments:

- Segment 1: A new, approximately 32.7-mile-long, single-circuit 345 kV line on double-circuit capable structures from MP's Iron Range Substation to MP's St. Louis County Substation;
- Segment 2: Replacement of approximately 33.3 miles of existing 230 kV line with new double-circuit 345 kV structures and conductor from north of the St. Louis River in St. Louis County to MP's St. Louis County substation. One circuit in this segment will be operated at 345 kV and the other circuit will continue to operate at 230 kV;[5]
- Segment 3: A new approximately 1.5-mile-long, double-circuit 345 kV transmission line from MP's St. Louis County substation to ATC's Arrowhead Substation.

The proposed project will also require the following:

- Modifications of the Iron Range Substation to accommodate one additional 345 kV line entrance and associated high voltage equipment;
- Expansion of the St. Louis County Substation to accommodate three additional 345 kV line entrances and associated high voltage equipment;
- Expansion of the existing ATC Arrowhead Substation to accommodate two additional 345 kV line entrances and associated high voltage equipment.

The proposed project is located along existing high-voltage transmission line right-of-way for 92% of its length, thus qualifying for Standard Review. The Applicants' estimated cost to construct the proposed project is between $444.1 million and $519.3 million (2024 dollars).[6]

[4] *In the Matter of the Application of Minnesota Power and American Transmission Company, LLC for a Certificate of Need for the Iron Range - St. Louis County - Arrowhead 345 kV Transmission Project,* Minnesota Power, American Transmission Company, Combined Certificate of Need and Route Permit Application for the Iron Range – St. Louis County – Arrowhead 345 kV Transmission Line Project, January 5, 2026, Docket No. E015/CN-25-111, (eDockets) 20261-226460-03, (hereinafter "Initial Application").

[5] The 230 kV circuit will operate on the 345 kV double-circuit structures and will use the new 345 kV conductor but will be operated at 230 kV. The 230 kV circuit will be upgraded to 345 kV at a future date, and the Applicants will obtain any necessary approvals.

[6] The MISO Board of Directors approved the project as part of the LRTP Tranche 2.1 portfolio in December 2024 at a cost of $428 million (2024 dollars).

III. DEPARTMENT ANALYSIS

Minnesota Statutes § 216B.2421, subd. 2(2) includes in its definition of large energy facility (LEF) "any high-voltage transmission line with a capacity of 300 kilovolts or more and greater than one mile in length in Minnesota." Since the proposed project is 345 kV and 63 miles long, it qualifies as a LEF. Minnesota Statutes § 216B.243, subd. 2 states that "no large energy facility shall be sited or constructed in Minnesota without the issuance of a certificate of need by the commission pursuant to sections 216C.05 to 216C.30 and this section and consistent with the criteria for assessment of need." Therefore, a CN application must be approved by the Commission before the proposed project can be sited or constructed.

There are several factors to be considered by the Commission in making a determination in CN proceedings. In general, these factors are in different sections of Minnesota Statutes. Some of the general statutory criteria are reflected more specifically in Minnesota Rules 7849.0120. However, some statutory criteria do not appear to be reflected in rules. To clarify the analysis, the Department groups all relevant statutory and rule criteria into five categories:

A. Need Analysis,
B. Alternative Analysis,
C. Socioeconomic Analysis,
D. Other Permits,
E. Policy Analysis.

The Department addresses each of the statutory and rule criteria below. A cross index showing where the various provisions of Minnesota Statutes and Minnesota Rules are addressed is provided in Attachment 1.

The Department notes that the Commission's Energy Infrastructure Permitting (EIP) unit will prepare the environmental report (ER) for the proposed project. The ER discusses the potential impacts of the proposed project and alternatives on the natural and socio-economic environments. The Department recommends the Commission consider the ER in making its determination.

A. NEED ANALYSIS

Minnesota Rules 7849.0120 establishes the criteria governing issuance of a certificate of need. Under subpart A, the Commission must determine whether "the probable result of denial would be an adverse effect upon the future adequacy, reliability, or efficiency of energy supply to the applicant, to the applicant's customers, or to the people of Minnesota and neighboring states." In making that determination, the rule directs the Commission to evaluate five specific considerations. The Department addresses each of the five considerations below.

A.1. Accuracy of the Forecast

A.1.1. Background

Minnesota Rules 7849.0120.A.1 states that, in assessing need, the Commission shall evaluate "the accuracy of the applicant's forecast of demand for the type of energy that would be supplied by the proposed facility."[7] The Commission's September 23, 2021 *Order Granting Certificate of Need and Issuing Site Permit and Route Permit* (Plum Creek Order) in Docket Nos. IP6697/CN-18-699, IP6697/WS-18-700, and IP6697/TL-18-701 clarified this criterion:

Plum Creek did not use data from a PPA, IRP, or biennial transmission project report to demonstrate demand for the Project. However, under Minnesota statute and rules, there is no requirement that Plum Creek present a PPA, IRP, biennial transmission project report, or any other specific data to demonstrate demand. The Legislature contemplated that independent power producers would construct such projects and did not require them to enter into power purchase agreements before obtaining a certificate of need. Rather, the Commission may evaluate demand using any data it finds persuasive, on a case-by-case basis. Furthermore, because Plum Creek is an independent power producer and not a utility, the Commission granted it certain variances to provide alternative data when more appropriate, and the data provided is sufficient to demonstrate demand.

In this case, Plum Creek showed that utilities and commercial and industrial customers have reported strong clean energy goals above and beyond RES [Renewable Energy Standard] requirements, and additional renewable energy sources will be needed to meet that demand. Furthermore, utilities plan to retire coal-based generating units across the region in the coming years, and renewable energy sources are expected to fill some of the resulting capacity needs. These established goals and plans are strong evidence of a utility's intention for future energy development and can be used to demonstrate demand, especially when consistent with stated public policy goals. Citation omitted.

Based on longstanding practice, the Commission found in the above docket that additional renewable energy resources will be needed to meet growing demand, above and beyond what is needed for the carbon-free standard (Minn. Stat. 216B.1691 subd. 2g). The Department considered this guidance in formulating the analysis of the Applicants' forecast of demand for the type of energy that would be supplied by the proposed project.

In the application, the Applicants defined the scope of the project need as follows: "the Project, as part of the LRTP Tranche 2.1 portfolio, is needed to enhance grid reliability in the Upper Midwest as grid operating conditions become more variable, increase grid efficiency as energy is transferred from where it is produced to where it is needed, and meet the growing demand for reliable clean energy in the Upper Midwest."[8] Therefore, the stated need for the proposed project relates to needed grid reliability and increased transfer capability, rather than an individual utility's peak demand.

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[7] Note that Minnesota Statutes § 216B.243 subd. 3(1) requires the Commission to evaluate the accuracy of the long-range energy demand forecasts on which the necessity for the facility is based.
[8] Initial Application at 145.

A.1.2 MISO's Analysis

MISO prepared a range of updated Futures scenarios to develop the overall LRTP Tranche 2.1 portfolio, which corresponded to different load growth forecasts and changing generation mix. The three Futures that MISO identified are explained in the *2023 MISO Futures Report* (Futures Report), which is discussed in Chapter 3.3.7 of the application.
Beginning in 2021, MISO created three Planning Futures for use in bulk power system planning, such as the LRTP Tranche 1 portfolio of projects. MISO developed these Futures over the course of the 18-month planning process known as the 2021 MISO Transmission Expansion Plan (MTEP21). In 2022, MISO underwent a "refresh" of the MTEP21 Futures, known as "Series 1A Futures," which incorporated new information while keeping the original assumptions largely intact. The Tranche 2.1 portfolio relied on the planning scenarios presented in Futures 1A, particularly the planning scenario of Future 2A.

For the Series 1A Futures, MISO explains that, due to the rapid changes in the energy industry, key federal and state legislation, and public policy drivers, they needed to update the assumptions around energy load growth and changing generation:

Compared to the MTEP21 Futures, the Series 1A Futures demonstrate an accelerating pace of transformation in the industry and, as a result, accelerating need for transmission to support a reliable transition. A summary of the key assumptions for each Series 1A Future is shown in Figure 9 and Figure 10. MISO focused its evaluation and development of Tranche 2 on Future 2A and Future 1A.[9]

On pg. 27 of the Futures 1A refresh, MISO highlights the different growth rates for energy and demand, before energy efficiency and distributed energy resources (DERs) were selected by MISO's resource planning model:

1) Future 1A assumed an annual energy growth rate of 0.63% and a peak demand growth of 0.77%. The scenario included low-base EV growth and low electrification, mainly from plug-in electric vehicles (PEVs).
2) Future 2A assumed an annual energy growth rate of 1.25% and a peak demand growth of 1.14%. The scenario assumes 30% total energy growth by 2040, driven by higher household electrification with PEVs, as well as residential and commercial and industrial (C&I) electrification.
3) Future 3A assumed an annual energy growth rate of 1.95% and a peak demand growth rate of 1.63%. The scenario assumes 50% total energy growth by 2040, driven by additional electrification across many sectors.[10]

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[9] *Id*., at 41.
[10] MISO, *MISO Futures Report Series 1A,* (November 1, 2023), Available at https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf, at 3. (Hereinafter "2023 MISO Futures Report")

The Futures Series 1A Report at Figures 18 and 19 highlights both the Futures Series 1 (from an earlier Futures process undertaken in 2021) and Futures Series 1A (from the 2023 Futures Report), to show the energy and demand compound annual growth rates (CAGR) for the three scenarios:

- Future 1A: 0.63% CAGR for energy; 0.77% for coincident peak demand growth
- Future 2A: 1.25% CAGR for energy growth; 1.14% CAGR for coincident peak demand growth
- Future 3A: 1.95% CAGR for energy growth; 1.63% for coincident peak demand growth[11]

MISO used Futures Series 1A in the LRTP process. As laid out in the MTEP24 Final Report, MISO conducted multiple modeling runs with different scenarios to validate Futures 2A and 1A for appropriateness. Following setting Futures 2A and 1A as appropriate benchmarks, MISO then ran four core load cases to develop planning models. As laid out in Table 2.1 of the MTEP24, the load cases are as follows:

- Case 1: Summer Peak Load, which features high coincident renewable output in the summer, between 90 and 100% of the annual peak demand, with storage off.
- Case 2: Winter Peak Load, which features peak winter demand with high coincident renewable output in the winter between 90% and 100% of the annual winter peak demand, with storage discharging at 50% of nameplate.
- Case 3: Average Load, which features high coincident renewable output between 70% and 80% of the annual peak demand, with storage charging at 60% nameplate.
- Case 4: Light Load, which features high coincident renewable output to test ability of the system to absorb reactive power, with storage charging at 60% nameplate. [12]

The rationale for the proposed project is described in the LRTP MTEP24 Report:

The 345 kV projects in Northern Minnesota (indicated by the dashed red lines in the map below) resolve more than 50% of the constraint violations for both the 200 kV above and below systems. The Northern Minnesota group provides outlets to North Dakota generation, resolves constraint violations in this area and connects to Tranche 1 lines. Congestion in Northern Minnesota is reduced and the increased generation outlet in North Dakota, South Dakota and Minnesota shifts congestion to new flowgates, which are addressed with the portfolio.[13]

[11] *Id.*, at 27.
[12] MISO, *MTEP24 Full Report, 2024 MISO Transmission Expansion Plan (MTEP24),* (2024). At 32-33. Available at https://www.misoenergy.org/planning/transmission-planning/mtep/#nt=%2Fmtepstudytypenew%3AMTEP%20Reports&t=10&p=0&s=FileName&sd=desc (Hereinafter "MTEP24 Report").
[13] *Id.,* at 98.

The stated need for the proposed project is thus to resolve more than 50% of the constraint violations for above and below 200 kV systems. In addition to resolving a number of violations, the proposed project also reduces the percentage of line loadings.[14] For example, as identified in the MTEP24 Report, two overloaded elements studied by MISO, [MP] Hibbard – Winter St. 115 kV and [MP] Dahlberg – Stinson 115 kV, faced initial worst loading conditions of 243% and 211%, respectively, which would largely be mitigated by the proposed project.[15]

Thus, the transmission needs addressed by the proposed project are not tied to an individual utility need or a specific summer peak demand. The proposed project's need rests on improving system reliability and mitigating voltage violations on the existing lower voltage transmission system.

A.1.3 The Department's Analysis

As the proposed project meets a regional need, the Department's analysis extends beyond just MP and includes an analysis of other utilities in the region.

First, the Department calculated the compound annual growth rate (CAGR) for each of the rate-regulated investor-owned utilities (IOUs), as well as Great River Energy, a wholesale electric power co-op which files advisory-only resource plans. These four major utilities serve load in Minnesota as well as in other states, which provides an adequate proxy for the need forecast of Minnesota and neighboring states.

Minnesota Power and ATC, as Applicants, provided their applicable forecasts in their application for the proposed project in Appendix K (Trade Secret). Minnesota Power reported that the documents were uploaded to eDockets using Docket No. 25-11. For the purpose of analyzing need relative to annual electric utility forecasts, the Department used the trade secreted versions of the "2024 Forecast Report" Excel spreadsheets for MP, Xcel, OTP, and GRE from Docket No. E999/M-25-11.

American Transmission Company did not present annual electric forecast (AFR) data in Docket No. 25-11. However, in the application, ATC provided a 10-year peak demand forecast from 2024-2034. The Department calculated that the weighted summer peak demand CAGR for the Applicants (MP and ATC, respectively) from 2024-2034 (comparing MP's 1st through 10th forecasted year to ATC's 10-year forecast) is 2.13%, which is larger than the Futures 2A forecast for demand growth.

The Department calculated the CAGR from 2026 to 2039 for both the annual energy forecast and the summer peak demand for MP, Xcel, OTP, and GRE. The CAGRs for each utility were then weighted by the forecasted 2026 energy and demand to calculate the weighted average CAGR for energy and demand, respectively, for the utilities serving Minnesota and neighboring states.

The weighted average energy CAGR from the 1st forecast year to 13th forecast year, 2026 to 2039, for all four utilities based on their total system energy forecast is 2.17%, and 2.41% for the Minnesota

[14] *Id.*, at 99.
[15] *Ibid.*

portion of their electrical system. Both the system-wide and Minnesota-specific weighted average CAGRs for the four utilities are higher than the Futures 2A energy forecast.

Similarly, the weighted average CAGR for demand for the four utilities (MP, Xcel, OTP, and GRE) is 0.38%, which is reported as a system peak demand, which for MISO is a summer peak demand. The peak demand for the four utilities is significantly lower than the peak demand CAGR identified by MISO in Futures 2A at 1.14%. Using a 13-year outlook with the four major utilities' base summer peak demand, the end year forecast would be roughly 1,386 MW higher summer peak demand in Minnesota in 2039 under the Futures 2A CAGR compared to the four Minnesota utilities' growth rate.

For ease of comparison across utilities, the Department provides Table 1, which lists systemwide energy forecast, Minnesota-specific energy forecast, and peak demand forecast by utility, based on their 2025 AFR data.

Table 1: Energy and Demand Forecasts from Docket No. 25-11 (AFR Dockets)

Utility	System-wide Energy Forecasted CAGR (2026-2039)	Minnesota-Specific Energy Forecasted CAGR (2026-2039)	Summer Peak Demand CAGR (2026-2039)
	[TRADE SECRET HAS BEEN EXCISED]		
MP			
Xcel			
OTP			
GRE			
Total	2.17%	2.41%	0.38%

Second, the Department reviewed the Commission's orders in the utilities' most recent resource plans (IRPs) for additional forecast-related information. At the time of this analysis, the relevant Commission-approved IRPs for the major utilities in Minnesota appear in the following dockets: Minnesota Power (E015/RP-21-33), Xcel Energy (E002/RP-24-67), Otter Tail Power (E017/RP-21-339), and Great River Energy (ET2/RP-22-75).

Minnesota Power's 2021-2035 resource plan (E015/RP-21-33) included in its long-term forecast numerous plant retirements, as well as new resource additions that reflect MP's stated goal of transitioning its resource mix. The Commission's Order stated that stakeholders agreed about the accuracy and modeling approach to MP's forecasting:

The parties largely agree that the modeling conducted by Minnesota Power was reliable, the assumptions reasonable, and the calculations accurate. The remaining points of contention are related to the dates for closing Boswell Units 3 and 4 and how much additional renewable energy to add at specific junctures, considering cost, reliability, community, and environmental impacts.[16]

Likewise, the Commission's Order found that Minnesota Power had needs for renewable procurement to comply with the state's renewable portfolio standard and meet industrial customer demand. The Order directed MP to acquire the following resources, following dispatchable resource retirements:

- Acquiring at least 300 and up to 400 MWs of wind,
- Acquiring up to 300 MWs of regional/in MP's service territory net-zero solar,
- Implementing battery storage demonstrations between 100 and 500 MWh,
- Ceasing operations at Boswell Unit 3 by December 31, 2029 and Unit 4 by 2035, including incorporating consideration of MISO's Long-Range Transmission Plan (LRTP) into future MP IRPs.[17]

Similarly, Xcel's most recent IRP settlement (E002/RP-24-67), which combined a resource acquisition for 800 MW of firm, dispatchable resources and the 2024-2040 IRP, saw Xcel's demand increase from new large data center loads, EV deployment, and beneficial electrification:

The settlement agreement reasonably supports energy adequacy, reliability, and affordability and minimizes adverse socioeconomic and environmental impacts, all while accounting for significant anticipated load growth and compliance with the state's carbon-free goals.[18]

The Commission approved a select portfolio of resource acquisition, including a new 420 MW combined cycle turbine in Lyon County, a 300 MW, 4-hour battery storage at the Sherco Generating Station, and numerous power purchase agreements (PPAs) for both new renewable and existing dispatchable generation resources. The Commission approved the following five-year action plan targets for new resource addition:

- 3,200 MW of wind by 2030, 2,800 MW of which will use the Minnesota Energy Connection Line,
- 400 MW of solar, reusing the King Interconnection
- 600 MW of storage by 2030, using the Minnesota Energy Connection,

[16] In the Matter of Minnesota Power's 2021 2035 Integrated Resource Plan, Order Approving Plan and Setting Additional Requirements, Docket No. E015/RP-21-33, January 9, 2023, (eDockets) 20231-191970-01 (Hereinafter "MP IRP Order").
[17] *Id.,* at 9.
[18] *In the Matter of Xcel Energy's 2024–2040 Upper Midwest Integrated Resource Plan*, *Order Approving Settlement with Modifications*, April 11, 2025, E002/RP-24-67, (eDockets) 20254-217941-01 (Hereinafter "Xcel IRP Order") at 8.

- Extending Monticello Nuclear Generating Plant to 2050, and extending Prairie Island Nuclear Generating Plant Units 1 and 2 to 2053 and 2054, respectively.[19]

In OTP's most recent IRP (E017/RP-21-339), the Commission approved a settlement agreement after multiple versions of resource plans, following key federal and regional transmission organization changes. These changes included both resource retirements and additions to meet the utility's obligation under the carbon-free standard:

- Remove all jurisdictional allocation to its Minnesota ratepayers for the Coyote Station Generating Plant,
- Adding liquid natural gas (LNG) storage at the Astoria Station,
- At least 200 and up to 300 MW of solar resources with a commercial operation date by November 1, 2027,
- No less than 150 MW and up to 200 MW of wind achieving commercial operation dates by December 31, 2029,
- No less than 20 MW and up to 75 MW of 4-hour BESS or longer duration.[20]

Lastly, the Commission approved Great River Energy's last IRP on June 11, 2024 (ET2/RP-22-75). The Commission found that GRE's forecast did not appropriately model increasing demand due to growing EV adoption:

First, the Commission concurs with the Department that the shortcomings in GRE's demand forecast may not require the Commission to reject GRE's plan outright, but they render the forecast insufficient to support any claim for a Certificate of Need—so the Commission will make that finding. Second, the Commission will recommend that GRE, when it models scenarios for its next resource plan, include a range of demand forecasts for electric vehicles. Finally, the Commission will recommend that GRE work with the Department to address forecasting issues before GRE develops its next resource plan.[21]

The Department notes that, though the proposed project's stated need does not relate to peak demand and instead to broader regional reliability and voltage violation mitigation, the 2024 AFR for Minnesota Power may not incorporate some recently announced expected load growth in MP's service territory. MP submitted their 2024 Annual Electric Utility Forecast Report on August 1, 2025.[22] The utility has since announced a planned data center in Hermantown, MN.[23] There is an open comment

[19] *Id.*, at 9.
[20] *In the Matter of Otter Tail Power's 2023 2037 Integrated Resource Plan, Order Modifying Otter Tail Power's 2023- 2037 Integrated Resource Plan*, July 22, 2024, E017/RP-21-339, (eDockets) 20247-208805-01.
[21] *In the Matter of Great River Energy's 2023– 2037 Integrated Resource Plan, Order Accepting 2023-2037 Resource Plan and Setting Future Filing Requirements*, June 11, 2024, ET2/RP-22-75, (eDockets) 20246-207588-01.
[22] *Minnesota Power's 2025 Annual Electric Utility Forecast Report*, Minnesota Power, 2024 Annual Report (.xlx), August 1, 2025, Docket No. E-999/PR-25-11, (eDockets) 20258-221641-02.
[23] *In the Matter of the Petition for Approval of an Electric Service Agreement between Google and Minnesota Power*, Minnesota Power, Petition, March 26, 2026, Docket No. E-015/M-26-159, (eDockets) 20263-229694-01.

period relating to the Electric Service Agreement (ESA) for that data center project (Docket No. E015/M-26-159). A qualified data center load coming onto MP's system between 2026 and 2039 would likely increase the energy and demand CAGR for MP. As noted in the Department's analysis, the peak demand for Applicants, as well as the weighted average energy CAGRs for MP, Xcel, OTP, and GRE all exceed the MISO Futures 2A scenario growth rates. The application already establishes growth rates in excess of the MISO scenario growth rates, the Department estimates that an updated forecast would only further increase the weighted average CAGR for both energy and peak demand for the Applicants, demonstrating increased need.

If the Commission is interested in exploring the interaction between the proposed data center and the forecast analysis for the proposed project, the Department notes the Commission may order the Applicants to provide an updated forecast for 2026 to 2039 which factors in the energy and peak demand growth attributed to the proposed data center.

A.2 Conservation Impacts

Minnesota Rules 7849.0120.A.2 states that the Commission must consider "the effects of the applicant's existing or expected conservation programs and state and federal conservation programs."[24]

The stated need for the proposed project is to enhance grid reliability in the Upper Midwest and to increase regional transfer capability.[25]

Therefore, the impact of conservation programs is of lesser importance, as conservation would perform a peak-demand shaving role, and peak demand is not the principal concern for the stated need of the proposed project.

The application discusses Minnesota Power's demand-side management and conservation programs in Appendix L:

Minnesota Power filed its 2024 Energy Conservation and Optimization Plan with the Commission on April 1, 2025 in Docket No. E015/M-25-48. A copy of the "Summary" section and the "Status Report" section of this filing is provided in this appendix. Minnesota Power filed its 2025 Integrated Resource

[24] Note that Minnesota Statutes § 216B.243 subd. 3 states that "No proposed large energy facility shall be certified for construction unless the applicant can show that demand for electricity cannot be met more cost effectively through energy conservation and load-management measures…"
Minnesota Statutes § 216B.243 subd. 3(2) requires the Commission to evaluate the "effect of existing or possible energy conservation programs under sections 216C.05 to 216C.30 and this section or other federal or state legislation on long-term energy demand."
Minnesota Statutes § 216B.243 subd. 3(6) requires the Commission to evaluate "possible alternatives for satisfying the energy demand or transmission needs including but not limited to potential for increased efficiency and upgrading of existing energy generation and transmission facilities, load-management programs, and distributed generation."
Minnesota Statutes § 216B.243 subd. 3(8) requires the Commission to evaluate "any feasible combination of energy conservation improvements, required under section 216B.241, that can (i) replace part or all of the energy to be provided by the proposed facility, and (ii) compete with it economically."
[25] Initial Application at 8, 33.

Plan ("IRP") ("2025 IRP") with the Commission on March 3, 2025 in Docket No. E015/RP-25-127. Appendix B of the 2025 IRP filing contained information regarding Minnesota Power's planning and strategies for demand-side management, Energy Efficiency, and CIP.[26]

The application at Appendix F describes MISO's approach to transmission planning considering energy efficiency and other conservation programs. As part of the development of the Futures scenarios, MISO develops forecasts that feature three categories of demand-side additions, which were Demand Response (DR), Energy Efficiency (EE) and Distributed Generation (DG). MISO includes its forecasts for these categories in the 2023 Futures Report. For the Futures 1A, 2A, and 3A, different amounts of the above demand-side management blocks were chosen, based on the assumed levels of deployment of demand-side resources for the 20-year outlook.

MISO performed resource modeling using EGEAS software for each of the three Futures scenarios (1A, 2A, and 3A) and various blocks of EE, DR, and DG. The EGEAS model creates 20 years of load shape forecasts for each Future scenario for both coincident peak load (GW) and annual energy (GWh). MISO stated in their 2023 Futures Report that "the evolution of each Future load shape is shown, comparing the final input load shape for year 2042 from AEG that includes electrification assumptions against the 2042 load shape post modeling of each scenario that nets out EE programs selected."[27] Thus, MISO prepares the load shapes both with the demand-side resources and the load shape adjusted down to account for the model selecting expected DR, EE, or DG.

Thus, the net load shapes that MISO forecasts for each Future scenario already have the energy efficiency amounts included (and netted), to demonstrate that the net load growth forecasts are accretive beyond what energy efficiency would provide. The LRTP Tranche 2.1 portfolio then plans the transmission expansion, assuming the above amounts of demand-side resource acquisition.

Likewise, Appendix L also includes a summary of MP's Energy Conservation and Optimization (ECO) Program filing from April 1, 2025.[28] The report states that in 2024 MP achieved energy savings of 3.0% of gross annual retail sales, which is "above the 1.75% minimum energy-savings goal set in the 2021 Energy Conservation and Optimization Act," achieving 105% of MP's energy-savings goal for the year.[29]

The Department concludes that the regionally approved MISO planning process includes the effects of the Applicants' existing or expected conservation programs and that conservation programs cannot address the proposed project's need.

[26] *In the Matter of the Application of Minnesota Power and American Transmission Company, LLC for a Certificate of Need for the Iron Range - St. Louis County - Arrowhead 345 kV Transmission Project,* Minnesota Power, American Transmission Company, Appendices F Through N (PUBLIC), January 5, 2026, Docket No. E015/CN-25-111, (eDockets) 20261-226460-06 at Appendix L, pg. 3.
[27] 2023 MISO Futures Report at 35.
[28] Initial Application, Appendix L, at 11.
[29] *Ibid.*

A.3 Promotional Practices

Minnesota Rules 7849.0120.A.3 states that the Commission must consider "the effects of promotional practices of the applicant that may have given rise to the increase in the energy demand, particularly promotional practices which have occurred since 1974."[30]

The initial application at Chapter 3.9 states that "the Applicants have not conducted any promotional activities or events that have triggered the need for the Project. Rather, the Project is driven by regional reliability related to the clean energy transition and meeting public policy objectives."[31]

The Department agrees and finds no evidence that the Applicants have conducted promotional practices that have triggered the need for the proposed project. The Department further notes that the stated need for the proposed project relates to regional reliability and regional transfer capability, and that the Applicants' promotional practices have not created the reliability needs brought on by the changing resource mix and transfer capability to bring low-carbon resources from their generation source to load centers.

A.4 Non-CN Facilities Analysis

Minnesota Rules 7849.0120.A.4 states that the Commission is to consider "the ability of current facilities and planned facilities not requiring certificates of need to meet the future demand."[32]

As laid out in the MISO Business Practice Manual 20 on Transmission Planning (BPM 020), transmission owners (TOs) "are responsible for submitting data for their existing and approved transmission facilities."[33] TOs submit granular data to MISO about their existing transmission topology, which becomes the base case for any long-range transmission plan proposals. MISO describes its process for evaluating the system performance of Tranche 2.1 as "comparing the dynamic performance of the system with the final portfolio against a base case scenario without the portfolio."[34] MISO thus includes all existing, built transmission infrastructure in the base case of its transmission planning methodology, which indicates that the proposed reliability benefits, voltage violation reductions, and increased transfer capability identified from the proposed project would not be possible with the existing transmission system. Therefore, "the ability of current facilities and planned facilities not requiring certificates of need to meet future demand" has already been considered in MISO's transmission models.

[30] Minn. R. 7849.0120, subp. A.3. Note that Minnesota Statutes § 216B.243 subd. 3(4) requires the Commission to evaluate promotional activities that may have given rise to the demand for this facility.
[31] Initial Application at 74.
[32] Note that Minnesota Statutes § 216B.243 subd. 3(6) requires the Commission to evaluate alternatives for satisfying the energy demand or transmission needs including but not limited to upgrading of existing energy generation and transmission facilities and distributed generation.
[33] MISO, *Business Practice Manuals, BPM 020 – Transmission Planning*, MISO (July 2025), at 52. Available at https://www.misoenergy.org/legal/rules-manuals-and-agreements/business-practice-manuals/.
[34] MTEP24 Report at 42.

The Department concludes that current facilities and planned facilities not requiring certificates of need would not be able to meet the future demand.

A.5 Efficient Use of Resources

Minnesota Rules 7849.0120.A.5 states that the Commission is to consider "the effect of the proposed facility, or a suitable modification thereof, in making efficient use of resources."

The initial application states that the proposed project plans to use existing right-of-way for approximately 62.5 miles, or 92% of the proposed transmission route.[35] The proposed project would make efficient use of the existing high-voltage transmission right-of-way and not tie up additional land rights.

In summary, the Department concludes that the proposed project makes efficient use of resources.

A.6 Department Conclusion

Based on the analysis of the five considerations in Minnesota Rules 7849.0120, subpart A, the Department concludes that the probable result of denying the certificate of need would be an adverse effect upon the future adequacy, reliability, or efficiency of energy supply to the Applicants, to the Applicants' customers, and to the people of Minnesota and neighboring states.

B. ALTERNATIVES ANALYSIS

Minnesota Rules 7849.0120.B requires the Commission to determine "a more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence on the record." The rule then lists four specific considerations. The Department addresses each consideration separately below.

B.1. Size, Type, and Timing

Minnesota Rules 7849.0120.B.1 states that the Commission must consider "the appropriateness of the size, the type, and the timing of the proposed facility compared to those of reasonable alternatives."

B.1.1. Size

Regarding size, the Department discussed the definition of size (as well as type and timing) in the context of transmission lines in the Department's January 28, 2013 comments in Docket No. ET6675/CN-11-826. In that proceeding, the Department defined "size" as referring to "the quantity of power transfers that the transmission infrastructure improvement enables." The Department maintains this interpretation.

[35] Initial Application at 11.

Table 13 of the application shows that the proposed project would result in an increase in north-to-south transfer capability by 105 MW, and as part of the larger LRTP Tranche 2.1 portfolio, the proposed project would increase transfer capability by an additional 101 MW. Table 15 of the application shows that the proposed project would result in an increase in Minnesota to Wisconsin (west to east) transfer capability by 134-182 MW. The application discusses the need for regional transmission buildout to move power to "…regional load centers, to relieve congestion, support the generation fleet transition, and meet growing electrical demand." From this discussion, the Department concludes that the size of the proposed project matches the indicated need.
Section 4.4.1 of the application considers lower voltage alternatives to the proposed project. The Applicants state that three 230 kV lines or eleven 115 kV lines would be needed to achieve the same impedance as one 345 kV line. This would increase right-of-way and cost requirements substantially. In section 4.4.2, the Applicants consider higher voltage alternatives including new 765 kV and 500 kV lines. These voltages would increase costs substantially, because extensive substation requirements would be required to step down the voltage at the Iron Range, St. Louis County, and Arrowhead substations. Given the increased right-of-way, operational complexities and higher costs, the Department agrees that neither lower nor higher voltages are reasonable alternatives to the proposed project.

In section 4.6.4 of the application, the Applicants consider the scenario where the 800 MVA limit through the Arrowhead substation is maintained. Here, the Department analyzes the alternative scenario where the 800 MVA limit is maintained, and in doing so, addresses the second notice topic. Maintaining the 800 MVA limit would require modifying the configuration of the project such that power flow through the substation into Wisconsin can still be controlled at less than or equal to 800 MVA. The Applicants identify two approaches to achieve this alternative configuration:

1. Removing the proposed St. Louis County – Arrowhead 345 kV double-circuit transmission line from the project scope,
2. Modifying the configuration of this line so that it bypasses the Arrowhead substation and connects the St. Louis County substation to a different endpoint in Wisconsin.

The Applicants explain that the first approach would force all regional 345 kV power flows onto the 230 kV system which would cause congestion, erode regional reliability and transfer capability, and be inconsistent with the project need.[36] Additionally, the Applicants explain that the second approach would require new transmission construction that was not originally approved as a part of the LRTP Tranche 2.1 Portfolio, increasing costs and requiring a MISO Variance Analysis. The second approach, however, would achieve the regional transfer capability benefits consistent with the project need, but would be inconsistent with the MISO project definition.[37] The Department agrees that maintaining the 800 MVA limit at the Arrowhead substation would impose unnecessary costs and not address the reliability and transfer capability needs of the region.

[36] Initial Application at 85.
[37] *Id.,* at 86.

In summary, the Department agrees that the Applicants' proposed size is reasonable and the 800 MVA limit at the Arrowhead substation should be removed.

B.1.2 Type

As noted above, the Department discussed the definition of type in the context of transmission lines in the Department's January 28, 2013 comments in Docket No. ET6675/CN-11-826. In that proceeding, the Department interpreted "type" as referring to "the transformer nominal voltages, rated capacity, surge impedance loading (SIL), and nature (AC or DC) of power transported." The Department maintains this interpretation.

Regarding nominal voltages, 345 kV is the standard high voltage used in Minnesota for long-distance transfer projects. Over the past two decades, several 345 kV lines have been utilized in Minnesota, including some of the transmission corridors associated with other LRTP Tranche 2.1 projects. There are two 765 kV projects from Tranche 2.1 that are currently before the Commission. This project was ultimately approved at 345 kV because substantial upgrades would need to be made to the project substations in order to accommodate higher voltages.

The Department agrees with the Applicants' conclusion that 345 kV is preferable in this case.

The Applicants analyzed the alternative of upgrading existing facilities in the area instead of the proposed project. The findings were that some of the lines within the area have a post-contingent loading of more than two times the rated capacity. This means that even if upgrades were carried out on these lines, they would not be able to meet the capacity and transfer capabilities that the proposed project would provide. Additionally, Table 20 of the application shows that upgrading the lines would be a much more costly alternative.[38]

The Department agrees with the Applicants' conclusion that the Project as proposed would best serve capacity.

In Section 4.4 of the initial application, impedance of alternative voltage lines was discussed. This impedance can be correlated to SIL, in that 345 kV is more optimal compared to lower voltage lines. While there was no comparison in the application of impedance of higher voltage transmission lines, the application stated a higher voltage would be infeasible due to cost constraints and requirements for the MISO LRTP Tranche 2.1 portfolio.

Regarding the nature of power transported, alternating current (AC) is to be used for the proposed project. The application states the following about the advantages of AC over high voltage direct current (HVDC) in this case:

> As a rule of thumb, HVDC becomes a cost-effective alternative to AC transmission when the total line length is greater than 350-400 miles. In addition, the Project is designed to

[38] Initial Application at 78.

> support the underlying AC transmission system now and in the future by being interconnected to the Benton County Substation and being designed for a future interconnection at the Cuyuna Series Compensation Station. These connections to the underlying AC system would not be feasible with an HVDC solution.

The Department agrees with the Applicants' conclusion that AC is preferable to HVDC in this case.

In summary, the Department concludes that the Applicants' proposed type is reasonable.

B.1.3. Timing

As noted above, the Department discussed the definition of timing in the context of transmission lines in the Department's January 28, 2013 comments in Docket No. ET6675/CN-11-826. In that proceeding, the Department interpreted "timing" as referring to "the on-line date for the transmission infrastructure improvements." The Department maintains this interpretation.

Section 1.4 of the application states that the project will have an in-service date of no later than 2032.

The Department concludes that the Applicants' proposed timing is reasonable.

B.1.4 Size, Type, and Timing Summary

Overall, the Department agrees with the Applicants that the size, type, and timing of the proposed project are reasonable when compared to those of the available alternatives.

B.2 Cost Analysis

Minnesota Rules 7849.0120.B.2 states that the Commission is to consider "the cost of the proposed facility and the cost of energy to be supplied by the proposed facility compared to the costs of reasonable alternatives and the cost of energy that would be supplied by reasonable alternatives."

As noted above, there are no viable alternatives that could meet the Project's need in terms of size, type, and timing. The Applicants conducted a cost analysis of an upgrade alternative in Table 20 of the application. Not only was this alternative not viable in terms of capacity, but it was also more expensive. Based upon this analysis, the Department concludes that the Applicants' proposed project is the least-cost alternative.

B.3 Natural and Socioeconomic Environments Analysis

Minnesota Rules 7849.0120.B.3 states that the Commission is to consider "the effects of the proposed facility upon the natural and socioeconomic environments compared to the effects of reasonable alternatives."

The Applicants explained the impact of the LRTP Tranche 2.1 Portfolio as follows:[39]

> The portfolio alleviates congestion and enables interconnection of approximately 116 GW of new generation resources [citation omitted] to meet projected load, public policy objectives, and planning reserve margins. As a result, the portfolio is anticipated to reduce Midwest carbon dioxide ("CO2") emissions by 127 to 199 million metric tons over 20 to 40 years to help states like Minnesota comply with decarbonization laws. [citation omitted]

The Department sent an information request (IR 5) to the Applicants requesting information on Project-specific carbon emission reductions. The Applicants submitted a response stating that Project-specific analyses for carbon reductions were not conducted, as it was part of the larger Tranche 2.1 of LRTP.

Given there are no viable alternatives in terms of size, type and timing, and that this project is selected by MISO as part of a larger portfolio, the Department believes no analysis of the impact of alternatives on the natural and socioeconomic environments is necessary.

B.4 Reliability Analysis

Minnesota Rules 7849.0120.B.4 states that the Commission is to consider "the expected reliability of the proposed facility compared to the expected reliability of reasonable alternatives."

The goal of the proposed project is to improve reliability. As discussed above, the application considered several alternatives such as generation, demand-side management, different voltages, non-CN alternatives, DC lines, and a no-build alternative. In information requests (IRs 12, 13 & 14), the Department requested the Applicants conduct a screening test for three alternatives: (1) BESS, (2) BESS with APFC, and (3) advanced reconductoring.

The Applicants' response was that these three alternatives were not viable to meet the multiple factors of demand that MISO requires for this project. The two BESS options would not provide the transmission capacity required for the rest of Tranche 2.1. The reconductoring would also not meet the capacity for the Project. The Applicants confirmed the proposed project is designed to use an Advanced Power Flow Control (APFC)at the Stinson 115 kV substation in Wisconsin, the ultimate destination for the project (IR 2 and IR 14).

In the application, the Applicants described that they would utilize double-circuit capable structures for the project, per MISO's definition of the project under LRTP. Additionally, Applicants in Chapter 2.5.2 describe how they will also use the proposed future second circuit position initially for rebuilding the existing Iron Range-Arrowhead 230 kV line in segment 2 to enhance the resiliency of the 230 kV network. This co-location would normally cause a decrease in reliability with exposure to additional contingencies, such as a simultaneous outage. The Applicants state that the simultaneous outage of these lines would not violate any reliability standards for MISO. Given the benefits of co-locating versus

[39] Initial Application at 44.

the potential reliability issues, the Applicants believe the co-location of Segment 2 with the existing 230 kV line to be the most prudent.

Based upon a review of the Applicants' application, the Department concludes that the proposed project would result in greater expected reliability compared to the expected reliability of reasonable alternatives.

B.5 Department Conclusion

Based upon this analysis, the Department concludes that a more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence on the record.

C. PROTECTING THE NATURAL AND SOCIOECONOMIC ENVIRONMENTS

Minnesota Rules 7849.0120.C requires the Commission to determine "by a preponderance of the evidence on the record, the proposed facility, or a suitable modification of the facility, will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including human health." The rule then lists four specific considerations. The Department addresses each consideration separately below.

C.1 Overall State Needs

Minnesota Rules 7849.0120.C.1 states that the Commission shall evaluate "the relationship of the proposed facility, or a suitable modification thereof, to overall state energy needs."[40]

Regarding this, section 1.2 of the application states that the proposed project:

> … is needed to enhance grid reliability in the Upper Midwest as grid operating conditions become more variable, to increase grid efficiency and regional transfer capability as energy is transferred from where it is produced to where it is needed, and to meet the growing demand for reliable clean energy in the Upper Midwest.[41]

The Department agrees with the Applicants that the proposed project was designed by MISO as part of the LRTP to address reliability needs across the MISO footprint and that the proposed project individually will benefit state energy needs.

[40] Minn. R. 7849.0120, subd. C.1. Note that Minnesota Statutes § 216B.243 subd. 3(3) requires the Commission to evaluate the relationship of the proposed facility to overall state energy needs.
[41] Initial Application at 7.

C.2 Effects on Natural and Socioeconomic Environments

Minnesota Rules 7849.0120.C.2 states that the Commission shall evaluate "the effects of the proposed facility, or a suitable modification thereof, upon the natural and socioeconomic environments compared to the effects of not building the facility."[42]

As noted above, the Department relies on the ER for its socioeconomic analysis in a CN proceeding. The ER provides information related to the effects of the proposed facility upon the natural and socioeconomic environments compared to the effects of not building the facility. The Department recommends that the Commission consider the ER filed by PUC EIP staff in the Commission's decision in this matter.

C.3 Induced Development

Minnesota Rules 7849.0120.C.3 states that, in assessing need, the Commission shall evaluate "the effects of the proposed facility, or a suitable modification thereof, in inducing future development."[43]

As noted above, the Department relies on the ER for its socioeconomic analysis in a CN proceeding. The ER provides information related to inducing future development. The Department recommends that the Commission consider the ER filed by PUC EIP staff in the Commission's decision in this matter.

The Department also notes that the initial application discusses additional load serving potential that would be made possible from the proposed project and the LRTP Tranche 2.1 portfolio. The initial application states that the proposed project increases the northern Minnesota voltage stability system operating limit (SOL) "by approximately 970 MW, resulting in 1,250 MW of increased load serving potential in northern Minnesota compared to the WNF pre-portfolio case."[44] Given the previously noted planned large load addition in Hermantown, the Commission may order Applicants to provide a discussion of how they plan to ensure that the planned data center complies with Minn. Stat. 216B.1622 which requires that all costs attributable to a very large customer, including a customer that benefits from greater transmission headroom for interconnection, be paid by that customer.

C.4 Socially Beneficial Uses

Minnesota Rules 7849.0120.C.4 states that, in assessing need, the Commission shall evaluate "the socially beneficial uses of the output of the proposed facility, or a suitable modification thereof, including its uses to protect or enhance environmental quality."[45]

As noted above, the Department relies on the ER for its socioeconomic analysis in a CN proceeding. The ER provides information related to enhancing environmental quality. The Department

[42] Minn. R. 7849.0120, subd.C.2
[43] Minn. R. 7849.0120, subd. C.3.
[44] Initial Application at 56.
[45] Minn. R. 7849.0120, subd.C.4. Note that Minnesota Statutes § 216B.243 subd. 3(5) requires the Commission to evaluate benefits of this facility, including its uses to protect or enhance environmental quality, and to increase reliability of energy supply in Minnesota and the region.

recommends that the Commission consider the ER filed by PUC EIP staff in the Commission's decision in this matter.

D. OTHER PERMITS

Minnesota Rules 7849.0120.D requires the Commission to determine if "the record does not demonstrate that the design, construction, or operation of the proposed facility, or a suitable modification of the facility, will fail to comply with relevant policies, rules, and regulations of other state and federal agencies and local governments."[46] This rule does not list any specific considerations.

Chapter 8 of the application discusses numerous permits and approvals that may be required for the proposed project. The Department reviewed the information on potentially required permits. Regarding the permits required by other agencies, the Department presumes that the various agencies will review and confirm that the Applicants are in compliance prior to granting their permits. The Department relies upon these other agencies to enforce their requirements. Of course, should any necessary permits be denied, the proposed project may not be constructed, regardless of the Commission's decision regarding the application.

Based upon the above discussion, the Department concludes that the record does not demonstrate that the design, construction, or operation of the proposed facility, or a suitable modification of the facility, will fail to comply with relevant policies, rules, and regulations of other state and federal agencies and local governments.

E. POLICY ANALYSIS

There are several remaining criteria in statutes and rules that are applicable to a CN but do not closely fit into the rule decision criteria discussed above. Therefore, these criteria are grouped into a final category of policy considerations.

E.1 Robustness of the Transmission System

Minnesota Statutes § 216B.243, subd. 3(9) states that the Commission shall evaluate "with respect to a high-voltage transmission line, the benefits of enhanced regional reliability, access, or deliverability to the extent these factors improve the robustness of the transmission system or lower costs for electric consumers in Minnesota."

The proposed project will have several benefits related to the regional transmission system. The application discusses the following benefits:[47]

[46] Note that Minnesota Statutes § 216B.243 subd. 3(7) requires the Commission to evaluate the policies, rules, and regulations of other state and federal agencies and local governments.
[47] Initial Application at 43 and 44.

- Reliability Issues – The portfolio relieves significant levels of transmission line overloads, including 961 unique overloads identified in power flow modeling, in addition to voltage violations, stability limits, and other reliability constraints across the Midwest.
- Economic Issues – The portfolio reduces significant generation curtailments, economic price separation between MISO regions, system losses, and severe wide-area congestion, including thousands of hours of uneconomic grid operation caused by nearly 250 unique needs identified in economic planning simulations of future-year conditions.
    - Cost Effectiveness – The $21.8 billion portfolio has a benefit-to-cost ratio of 1.8 to 3.5. This means that every dollar invested in transmission will result in economic benefits of $1.80 to $3.50. Per MISO's analysis, the LRTP Tranche 2.1 Portfolio is expected to provide net economic savings of $23.1 billion to $72.4 billion over the first 20 years of service.

- Generation Transition and Public Policy – The portfolio alleviates congestion and enables interconnection of approximately 116 GW of new generation resources to meet projected load, public policy objectives, and planning reserve margins. As a result, the portfolio is anticipated to reduce Midwest carbon dioxide ("CO2") emissions by 127 to 199 million metric tons over 20 to 40 years to help states like Minnesota comply with decarbonization laws. In addition to Minnesota, Illinois and Michigan have enforceable decarbonization standards, and Wisconsin has a decarbonization goal.

MISO's MTEP24 LRTP Tranche 2.1 Report (Appendix I of the application) states that the proposed project, along with other projects from the Tranche 2.1 portfolio, will reduce curtailments in the area by 13.2% (15.5 million MWh) and reduce congestion by 16.2% ($977,000/MW).[48]

The Department concludes that the proposed project will have substantial benefits in terms of enhanced regional reliability and lowering costs for electric consumers in Minnesota.

E.2 Renewable Preference

There are two sections of Minnesota Statutes that provide a preference for renewable resources in resource planning and resource acquisition decisions. First, Minnesota Statutes § 216B.243, subd. 3a[49] states that:

> The Commission may not issue a certificate of need under this section for a large energy facility that generates electric power by means of a nonrenewable energy source, or that transmits electric power generated by means of a nonrenewable energy source, unless the applicant for the certificate has demonstrated to the Commission's satisfaction that it has explored the possibility of generating power by means of renewable

[48] Appendix I of the Initial Application at 81.
[49] Note that Minnesota Statutes § 216B.243 subd. 3(11) also requires the Commission to evaluate whether an applicant has made the demonstrations required under this subdivision.

> energy sources and has demonstrated that the alternative selected is less expensive (including environmental costs) than power generated by a renewable energy source. For purposes of this Subdivision, "renewable energy source" includes hydro, wind, solar, and geothermal energy and the use of trees or other vegetation as fuel.

Second, Minnesota Statutes § 216B.2422, subd. 4 states that:

> 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.

The Department notes that the proposed project would not interconnect any particular generation resource. Moreover, the proposed project is not needed to transmit power from a particular new generation resource. Rather, the proposed project would transmit electricity from the existing bulk power system to the northern Minnesota area. Therefore, it could reasonably be stated that these renewable preference statutes do not apply.

In summary, the Department concludes that this statutory requirement does not apply.

E.3 Renewable Energy Standard Compliance

Minnesota Statutes § 216B.243, subd. 3(10) states that the Commission shall evaluate "whether the applicant or applicants are in compliance with applicable provisions of sections 216B.1691 …" In turn, Minnesota Statutes § 216B.1691, subd. 2a states that each electric utility shall provide retail customers in Minnesota with the following percentages of total retail electric sales from energy generated by renewable energy technologies:

(1) 2012 12 percent
(2) 2016 17 percent
(3) 2020 20 percent
(4) 2025 25 percent
(5) 2035 55 percent.

The Department reviews historical compliance with the RES statute in a biennial report to the legislature. The most recent report was the *Minnesota Renewable Energy Standard Utility Compliance* (RES Report), filed January 15, 2025.[50] The RES Report concluded that all utilities demonstrated compliance with the 2023 RES obligation and appear able to comply into the future (except for fourteen municipal utilities). MP, therefore, has complied with the RES standard.

[50] Minnesota Renewable Energy Standard Utility Compliance

Regarding future compliance, the Department notes that Table 3 of the RES Report estimates MP can comply through 2039.

E.4 Carbon Free Standard Compliance

Minnesota Statutes § 216B.243, subd. 3(10) states that the Commission shall evaluate "whether the applicant or applicants are in compliance with applicable provisions of 216B.1691…" In turn, Minnesota Statutes § 216B.1691, subd. 2g states that each electric utility must generate or procure sufficient electricity generated from carbon-free energy technology to provide the electric utility's retail customers in Minnesota with the following percentages of the electric utility's total retail electric sales to retail customers in Minnesota by the end of the year indicated:

(1) 2030 80 percent for public utilities; 60 percent for other electric utilities
(2) 2035 90 percent for all electric utilities
(3) 2040 100 percent for all electric utilities.

The Department reviews compliance with the CFS statute in MP's most recent integrated resource plan. In the 2025-2039 IRP, MP states they have established a plan to deliver an annual energy portfolio that is 80 percent renewable by 2030 and 90 percent renewable by 2035. MP will also "continue evaluating technology options and economic pathways to develop an annual energy portfolio that is compliant with the 100 percent by 2040 milestone in the CFS without sacrificing reliability, and while ensuring incremental cost increases to support the infrastructure buildout required to meet the state's clean energy goals are transparent and reasonable."[51]

In initial comments on MP's 2025-2039 IRP, the Department notes that 2040 is outside of the 15-year planning period for the IRP, so MP is only required to demonstrate compliance with the 2030 and 2035 standards. The Department concluded that MP's IRP is compliant with future CFS requirements.

E.5 Local Job Impacts

Minnesota Statutes § 216B.2422, subd. 4a states:

> The commission must consider local job impacts and give preference to proposals that maximize the creation of construction employment opportunities for local workers, consistent with the public interest, when evaluating any utility proposal that involves the selection or construction of facilities used to generate or deliver energy to serve the utility's customers, including but not limited to an integrated resource plan, a certificate of need, a power purchase agreement, or commission approval of a new or refurbished electric generation facility. The commission must, to the maximum extent possible,

[51] *In the Matter of Minnesota Power's 2025-2039 Integrated Resource Plan*, Minnesota Power, Initial Filing, March 3, 2025, E015/RP-25-127, (eDockets) 20253-215986-11 at 4.

> prioritize the hiring of workers from communities hosting retiring electric generation facilities, including workers previously employed at the retiring facilities.

Section 6.2.3 of the application states that the workforce required for construction of the proposed project's facilities is estimated to be about 75 to 150 construction workers, depending on the construction sequencing and time of the year. The application also states that "Applicants will work with local contractors, to the extent practicable, in the Project area to identify potential opportunities to complete this work using contractors local to the Project area."[52] Additionally, the Applicants state that they have strong relationships with the Building Trades and are committed to working with organized labor on the project, including paying prevailing wages.

Additionally, in Section 2.1.4.2.1 of Appendix E of the application, the Environmental Assessment, the Applicants state that they will send out a Request for Proposal to contractors with a preference for use of local, union labor. Where there is a need for specialty work, exceptions are expected to be made to this, as specialized local labor may not be available.

The Department concludes that the Applicants have adequately addressed this statutory requirement.

E.6 Domestic Content Preference

Minnesota Statutes § 216B.2422, subd. 4b states "The commission may give preference in resource selection to projects utilizing energy technologies produced domestically by entities who received an advanced manufacturing tax credit for those technologies under section 45X of the Internal Revenue Code, as allowed under the federal Inflation Reduction Act of 2022, Public Law 117-169."

IR 8 requested the Applicants provide a response to this requirement. The Applicants state:

> Section 45X of the Internal Revenue Code applies to the following technologies: photovoltaic cells, wind energy components, torque tubes, structural fasteners, photovoltaic wafers, solar grade polysilicon, polymeric backsheet, solar modules, inverters, electrode active materials, battery cells, battery modules, and applicable critical minerals. The Iron Range – St. Louis County – Arrowhead 345 kV Project ("ISA Project") involves the construction of new transmission facilities and not new generation resources. Therefore, Minn. Stat. § 216B.2422, subd. 4b does not apply to this proceeding.

The Department agrees with the Applicants' interpretation of Section 45X and concludes this statutory requirement has been satisfactorily addressed.

[52] Initial Application at 112.

E.7 Federal Tax Credits and Programs

The Commission's September 12, 2023 *Order Setting Requirements Related to Inflation Reduction Act* in E,G999/CI-22-624 at point 1 states:

> The utilities shall maximize the benefits of the Inflation Reduction Act in future resource acquisitions and requests for proposals in the planning phase, petitions for cost recovery through riders and rate cases, resource plans, gas resource plans, integrated distribution plans, and Natural Gas Innovation Act innovation plans. In such filings, utilities shall discuss how they plan to capture and maximize the benefits from the Act, and how the Act has impacted planning assumptions including (but not limited to) the predicted cost of assets and projects and the adoption rates of electric vehicles, distributed energy resources, and other electrification measures. Reporting shall continue until 2032.

In addition to the IRA, the Department is interested generally in any federal financing mechanisms such as grants, loans or tax credits that the Applicants may have taken advantage of to help fund the project.

IR 9 requested the Applicants provide a response to the IRA requirement and the Department's general interest. The Applicants stated:

> At this time, the Applicants have not identified any opportunities for capturing specific benefits. While no such opportunities have been identified at this time for the ISA Project, the Applicants continue to evaluate whether opportunities may become available.

The Department concludes that the Applicants have adequately addressed this statutory requirement.

F. CONDITIONS

The application at section 2.4.3.1 states that the four major Minnesota utility local balancing authorities (MP, NSP, GRE, and OTP) will "collectively be allocated approximately 18% of the total costs for the Project, with the rest of the costs being allocated to load in the remaining MISO Midwest subregion."[53]

Following Table 4 in the initial application, the Department remade the table for the four major utilities who are local balancing authorities (LBAs) for MISO cost allocation. Table 2 confirms the approximately 18% allocation of the proposed project's costs, which is part of the overall LRTP Tranche 2.1 Portfolio costs that Minnesota's utilities will be accountable for.

[53] Initial Application at 25.

Table 2: Minnesota Local Balancing Authority % of Tranche 2.1 Portfolio

Minnesota LBA	Cost Allocation Zone	LBA Allocation (%)
GRE	1	2.9 %
MP	1	2.3 %
NSP	1	9.3 %
OTP	1	3.3 %
	Total	17.8 %

The cost of the proposed project will be allocated according to each local balancing authority (LBA) based upon the load ratio share (LRS) of each load serving entity. The annual revenue requirement for the proposed project is assessed based on actual monthly energy consumption by customers.

If there is an increase in an individual utility's load ratio share (monthly energy consumption), then it will pay more for the proposed project and resulting portfolio. That utility will also have an increased ratepayer base to spread the larger load ratio share percentage over.

Purdue University's State Utility Forecasting Group published a report, *2022 MISO Energy and Peak Demand Forecasting for System Planning*, which estimates that Minnesota makes up almost 98% of Local Resource Zone 1 (LRZ1).[54] Therefore, Minnesota's ratepayers are exposed to the costs allocated to LRZ 1 that will materialize from the LRTP Tranche 2.1 portfolio, not solely the proposed ISA project.

Utility Applicants for certificates of need provide cost estimates for their proposed projects and create a strong basis for the Commission to hold Applicants accountable for costs they represent for facilities. Prior review of CN proceedings indicates that the Commission has generally not allowed "blank check" approval for cost recovery in riders when the actual project costs are higher than estimated costs that utilities have represented in regulatory proceedings.[55]

The Department notes that the Commission has several tools for ratepayer protection, once the Commission determines the costs of the proposed project based on route alternatives. The Department recommends conditioning approval of the proposed project on inclusion of the following ratepayer protection mechanisms, requiring MP and ATC (Applicants) to:

1) File in this docket a final cost estimate or cost cap amount within 60 days of any Commission Order determining the final route. Include with the final cost estimate a detailed justification

[54] Lu, Liwei, Kain, Andrew E., Gotham, Douglas J., et. al., Purdue University State Utility Forecasting Group, *2022 MISO Energy and Peak Demand Forecasting for System Planning*, (November 2022) Available at [Independent Energy and Peak Demand Forecasts to the Midcontinent Independent System Operator (MISO)] at 16.
[55] For a detailed discussion of this issue see the November 7, 2018 *Direct Testimony and Attachments of Mark A. Johnson* in Docket No. E002, ET6675/CN-17-184, available at: [201811-147664-02]

for any upward departure from the cost estimate in the initial application, as well as the initial MISO MTEP24 approved costs.

2) Beginning with the first calendar year after issuance of the certificate of need, and annually thereafter until all associated LRTP Tranche 2.1 portfolio projects are placed in service, file in this docket a report that:
    a. identifies the current cost estimate for each project in the LRTP Tranche 2.1 portfolio, as reflected in MISO's most recent cost tracking and any MTEP variance requests, compared against the costs approved in MTEP24;
    b. states the resulting aggregate portfolio cost and any changes from the initial approved portfolio cost; and
    c. estimates the share of any portfolio cost increase allocable to MP ratepayers based on MP's load ratio share.
3) Wait until the first rate case after the proposed project is placed in-service to recover any cost overruns from Minnesota ratepayers.

G. COMMISSION NOTICE

G.1 Contested Facts

The first topic open for comment is "Are there any contested issues of fact with respect to the representations made in the certificate of need application?"

The Department does not identify any contested issues of fact with respect to the application.

G.2 800 MVA Limit

The second topic open for comment is "Should the Commission remove the 800 MVA limit on the Arrowhead substation?"

Based on the Department's analysis, maintaining the 800 MVA limit on the Arrowhead substation is not a reasonable alternative to the proposed project. The Department recommends that the Commission remove the 800 MVA limit on the Arrowhead substation.

G.3 Grant the CN

The third topic open for comment is "Should the Commission grant a certificate of need for the proposed project?"

Based upon the above analysis, should the Commission find, after consideration of the ER, that the proposed facility "will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including human health," the Department recommends that the Commission grant a CN to the Applicants with the cost protection conditions outlined in Section F of this analysis.

G.4 Other Issues

The fourth topic open for comment is "Are there other issues or concerns related to this matter?"

The Department does not have any other issues or concerns.

IV. DEPARTMENT RECOMMENDATION

Based upon the above analysis, the Department

- **Recommends** that the Commission remove the 800 MVA limit on the Arrowhead substation**.**
- **Recommends** that the Commission grant a CN to the Applicants should the Commission find, after consideration of the ER, that the proposed facility "will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including human health."
- **Recommends** the Commission require the Applicants as a condition of the CN approval to:
  a. File in this docket a final cost estimate or cost cap amount within 60 days of any Commission Order determining the final route. Include with the final cost estimate a detailed justification for any upward departure from the cost estimate in the initial application, as well as the initial MISO MTEP24 approved costs.
  b. Beginning with the first calendar year after issuance of the certificate of need, and annually thereafter until all associated LRTP Tranche 2.1 portfolio projects are placed in service, file in this docket a report that:
     i. identifies the current cost estimate for each project in the LRTP Tranche 2.1 portfolio, as reflected in MISO's most recent cost tracking and any MTEP variance requests, compared against the costs approved in MTEP24;
     ii. states the resulting aggregate portfolio cost and any changes from the initial approved portfolio cost; and
     iii. estimates the share of any portfolio cost increase allocable to MP ratepayers based on MP's load ratio share.
  c. Wait until the first rate case after the proposed project is placed in-service to recover any cost overruns from Minnesota ratepayers.

Regulatory Criteria	**Where Addressed in these Comments**
Minn. R. 7849.0120, Subpart A (1)	Section III, A, 1
Minn. R. 7849.0120, Subpart A (2)	Section III, A, 2
Minn. R. 7849.0120, Subpart A (3)	Section III, A, 3
Minn. R. 7849.0120, Subpart A (4)	Section III, A, 4
Minn. R. 7849.0120, Subpart A (5)	Section III, A, 5
Minn. R. 7849.0120, Subpart B (1)	Section III, B, 1
Minn. R. 7849.0120, Subpart B (2)	Section III, B, 2
Minn. R. 7849.0120, Subpart B (3)	Section III, B, 3
Minn. R. 7849.0120, Subpart B (4)	Section III, B, 4
Minn. R. 7849.0120, Subpart C (1)	Section III, C, 1
Minn. R. 7849.0120, Subpart C (2)	Section III, C, 2
Minn. R. 7849.0120, Subpart C (3)	Section III, C, 3
Minn. R. 7849.0120, Subpart C (4)	Section III, C, 4
Minn. R. 7849.0120, Subpart D	Section III, D
Minn. Stat. § 216B.243, Subd. 3(9)	Section III, E, 1
Minn. Stat. §§ 216B.243, Subd. 3a and 216B.2422, Subd. 4	Section III, E, 2
Minn. Stat. §§ 216B.243, subd. 3(10) and 216B.1691 Subd. 2a	Section III, E, 3
Minn. Stat. §§ 216B.243, subd. 3(10) and 216B.1691 Subd. 2g	Section III, E, 4
Minn. Stat. §§ 216B.2422, subd. 4a	Section III, E, 5
Minn. Stat. § 216B.2422, subd. 4b	Section III, E, 6
Commission Order in E,G999/CI-22-624	Section III, E, 7