BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	**Chair**
Hwikwon Ham	**Commissioner**
Audrey C. Partridge	**Commissioner**
Joseph K. Sullivan	**Commissioner**
John A. Tuma	**Commissioner**

In the Matter of the Application for a Certificate of Need for the "Power on Midwest" 765kVHigh Voltage Transmission Line Project	DOCKET NO. ET3, E002/CN-25-117 CN-25-118, CN-25-119, CN-25-120

OVERLAND – CERTIFICATE OF NEEDINITIAL COMMENT

On February 9, 2026, the Public Utilities Commission issued a Notice of Comment Period for the above-captioned Certificate of Need transmission line application that was filed on February 3, 2026. PUC Dockets ET3/ E002/CN-25-118, CN-25-119 and CN-25-120 were consolidated into the CN-25-117 docket, hence this filing in only CN-25-117, but these comments are intended to be applicable to all.

FULL DISCLOSURE: At this time, I am filing this Initial Comment as an individual, an attorney representing intervenors in multiple transmission proceedings since the Arrowhead-Weston transmission project in 1999. I have heard from two clients thus far on other matters who have received notice that they are in the project area, but as we're not sure of impact, we're waiting to determine whether their agricultural parcels are under consideration for routing.

The "need" for this line is not apparent and has not been demonstrated by the Applicants. MISO "approval" is not a demonstration of need under Minn. Stat. §216B.243. There are also issues of fact justifying a contested case, and a joint proceeding for the Certificate of Need docket and the yet to be applied for Route Permit docket. Minn. Stat. §216B.243, Subd. 4, which states:

> Unless the commission determines that a joint hearing on siting and need under this subdivision and chapter 216I is not feasible or more efficient, or otherwise not in the public interest, a joint hearing under this subdivision and chapter 216I must be held.

Applicants have not shown need for this transmission project, improperly rely on MISO for their nee claim, the cost estimates and cost/benefit analysis are skewed, and there are system alternatives that would be better for the State of Minnesota and communities that would have to live with this transmission line. As a pass through for export, this project(s) does little for Minnesota other than, with extreme environmental impacts, shift costs to landowners, ratepayers, communities, and the State.

I. NOTICE OF THIS COMMENT PERIOD WAS NOT PROVIDED TO PROJECT AREA LANDOWNERS WHO WERE SENT PROJECT NOTICE BY UTILITIES

At the outset, it should be noted that the affected landowners, who did receive a notice card mailer of the pending applications and utility open houses from the applicants, did not receive a Notice of Comment Period from the Public Utilities Commission[1]. It's difficult to be a participant when there is no notice. Failure to provide notice means that there is no opportunity to participate – people cannot know what they do not know.

The Commission must correct this failure of notice. Because failure of notice is also an issue in the Maple River-Cuyuna docket CN-25-109, and the Power on Midwest docket CN-25-117, 118, 119, and 120, this is a systemic failure of Commission process and procedure, which must also be corrected.[2] Rulemaking could correct this, but the Commission threw out years of

[1] See Notice of Comment Period, February 9, 2026, 20262-227934-01.

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work on Minnesota Rules ch. 7849 and 7850.[3]

At this time I ask that notice be provided to those landowners in the project area and the Comment Period be extended at least two weeks beyond the date those notice are received.

II. THE CERTIFICATE OF NEED APPLICATION ARGUABLY CONTAINS THE INFORMATION REQUIRED, BUT MORE INFORMATION IS NEEDED.

The Tranche 2.1 transmission line projects are the first of a kind in Minnesota. This particular consolidated docket is a very long connected project at an unprecedented voltage rate and capacity in Minnesota and the five state area. This is a regulatory arena where we need more information in the application, and not less.

The Commission gave the Applicants everything they asked for in its November 26, 2025 Order. While the Certificate of Need does arguably contain the information required as exempted by the Commission's Order, due to the extreme number of, and content of, exemptions granted by the Commission, much additional information is necessary to determine if the project is indeed needed and in the public interest -- information that is not yet provided. While it is clear the Commission's Order is applicable only to the Application, and does not limit the information that could be provided by the Applicants for the record to be considered by the Commission, Exemptions are a subtle shift in the burden of production to participants and intervenors who are typically unfunded and short on resources and in knowledge of how to participate and obtain the missing information.[4]

The information exemptions cover areas where more information is needed, and that information is needed because there are underlying contested issues of fact.

[3] See R-12-1248, Rulemaking for ch. 7849 and 7850.

[4] Commerce tacitly admits the distinction between "application requirements" and provision of information during the review process in the final paragraph of its recommendation for 7849.0260 C(3). See Application, Appendix B, p. B-16.

This is a 765kV transmission line, a very high voltage long transmission line, a type new to Minnesota, and yet despite the issues of first impression, the Commission exempted the Applicants from 11 of the rules with subparts specifying contents of a Certificate of Need application. These 765kV projects in southern Minnesota are exactly the types of projects over which the Commission should exercise a watchful regulatory eye.

Specifically, the exemptions granted by the Commission, on recommendations of Commerce, for this group of consolidated projects are not warranted. Exemption by exemption:

- **Minn. R. 7849.0230:** The Commission "varied" this not-application-content rule for environmental review, using a more recent and more robust procedure, with notice, opportunities for public participation. This is a welcome shift and we agree with Commerce and Commission's assessment, but we note that this is no substitute for the necessary iterative review of a full EIS in the routing docket.

- **Minn. R. 7849.0260 A(3) and C(6)** were exempted. System losses are no substitute for knowing the losses expected from each specific project, because line losses are expected from long transmission lines, and are a cost that must be considered. For example, when the Commission directed Xcel to disclose the expected line loss for the "MN Energy Connection" (CN-22-131 and TL-22-132) the expected line loss was estimated at 10-12%. The cost of line loss must be considered in the project's cost/benefit analysis. Using Applicant's argument that "the requested exemptions are consistent with several prior exemption requests approved by the Commission in other CN transmission line dockets, and Commerce citing the "gen-tie lines" with the disclosed 10-12% line loss is surprising, and disingenuous given the Commission's rightful concern about line loss. The total mileage of these consolidated projects and the inherent line loss is stunning.

- **Minn. R. 7849.0260 B(4) and (8)** were not fully exempted, and Commerce notes that "it is not recommending a wholesale exemption from Minn. R. 7849.0260 B(8), " in "providing the data required." Minn. R. 7849.0260 B(8) is "any reasonable combinations of the alternatives listed in subitems (1) to (7)" and see also Minn. Stat. §216B.243, Subd. 3(8). Again, this is application requirements, not exemptions from provision of the information by applicants or others and consideration by the Commission.

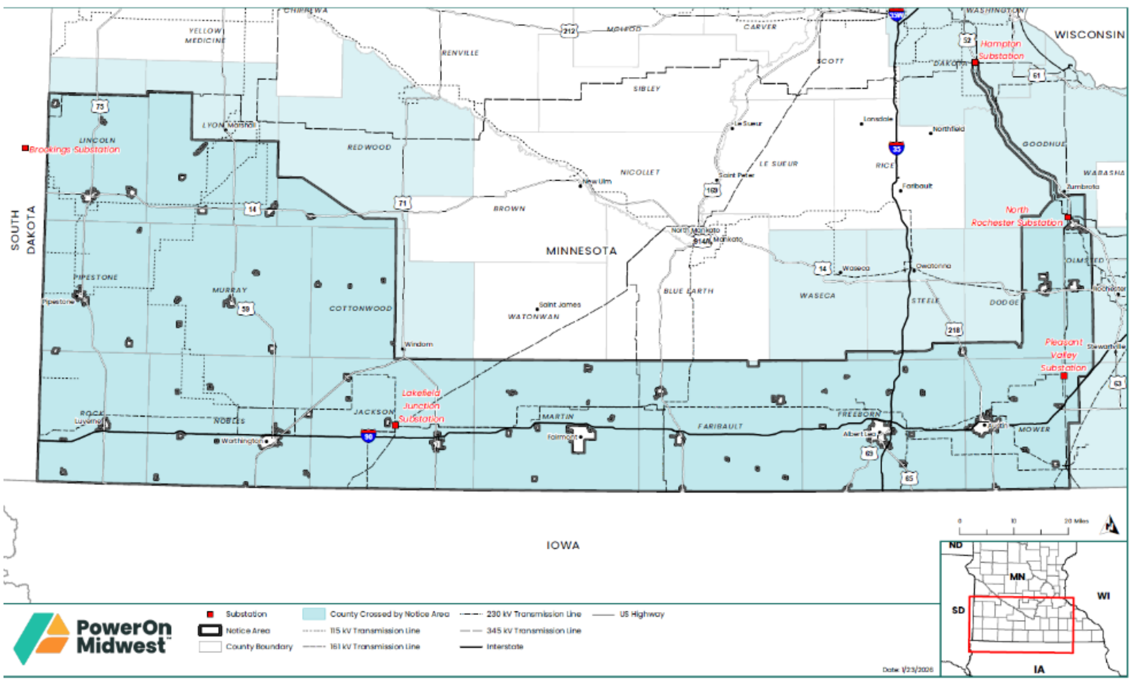
- **Minn. R. 7849.0260 C(5)** covers the impact of the effect on rates systemwide and in Minnesota, related to the project. A fact often left out is that the allocation of these MISO projects to Minnesota utilities, hence ratepayers, is for the entire Tranche, not just this specific project. The Applicants should provide not just the rate impacts of this specific project, but the impacts of the entire Tranche 2.1 projects allocated to

Minnesota utilities. Minnesota ratepayers will be paying for projects not in Minnesota but for which Minnesota receives, according to MISO, some benefit. Will this lower costs for Minnesota "consumers?" Minn. Stat. §216B.243, Subd. 3(9). A confounding factor is the challenge of MISO's cost allocation by North Dakota in a Complaint to FERC which is ongoing – the Minnesota Public Utilities Commission has intervened in that docket.[5]

- **Minn. R. 7849.0260 D** requires a **<u>system</u>** map. The description of the alternative map Applicants proposed, and Commerce and the Commission agreed is sufficient, is grossly deficient. What was approved was "high voltage transmission lines within the proposed Notice Area." This is the approved "Notice Plan" map showing the area with high voltage transmission lines in the area:

Chapter 1: EXECUTIVE SUMMARY

Figure 1.8-1: PowerOn Midwest Notice Area



25 February 2026 [6]

The "Notice Area" map above is insufficient to gain an understanding of the project in relation to the electrical system in Minnesota and the region. The "system" is far more than the "proposed Notice Area" and this limitation is odd when transmission, as we know, is "all connected."

As for inclusion of "high voltage transmission lines," Minn. Stat. §216B.2421 defines "high voltage" as:

[5] See *North Dakota Pub. Serv. Comm'n v. Midcontinent Indep. Sys. Operator, Inc., Complaint of the Concerned Commissions and Requests for Expedited Action and Fast Track Processing*, Docket No. EL25-109-000 (July 30, 2025).

[6] Application, Figure 1.8-1, p. 25.

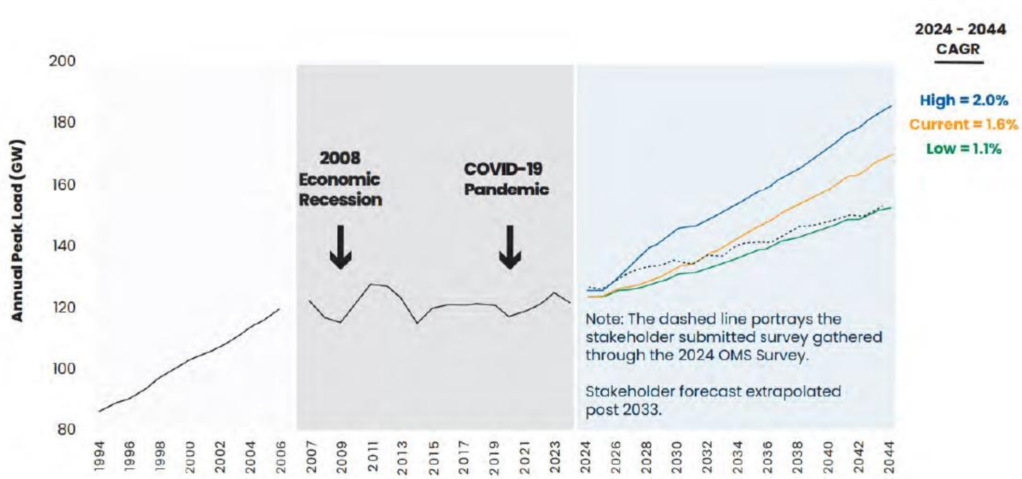
(2) any high-voltage transmission line with a capacity of 300 kilovolts or more and greater than one mile in length in Minnesota;

(3) any high-voltage transmission line with a capacity of 100 kilovolts or more with more than ten miles of its length in Minnesota;

To comply with Minn. R. 7849.0260 D, the Application must include a map of all high voltage lines over 100kV in Minnesota, South Dakota, Iowa (particularly in light of ITC lines – MVP 3, 4 and 5) and Wisconsin, with visible designation of voltages, substations, of all the regional transmission projects, i.e., all tranche 2.1 projects, and the projects leading up to Tranche 2.1, in permitting process and/or under construction, including SW MN 345kV (EQB Docket 01-1958; CapX 2020; MISO's MVP 17 project portfolio, Tranche 1, and the MN Energy Connection Lyon Co. to Sherco. A determination of "need" cannot be made without consideration of the broad overview. This map is essential for an understanding of the transmission system and these consolidated projects.

- **Minn. R. 7849.0270, Subps. 1-5.** This is an important information requirement for a need proceeding and should not be exempted. The Applicant/MISO's vision of peak demand and annual consumption is a contested fact. The notion of exemption for peak demand and annual consumption, instead to require systemwide peak demand forecasts and reliance on MISO information is contrary to the mandate of the Minnesota Public Utilities Commission and responsibility to the ratepayers. We must not forget the example of CapX 2020 and the extreme forecast of 2.49% annual demand increase[7], and the resulting overcapacity. MISO's demand forecasts are based on outdated 2024 information in our Trump administration world. In this application, Figure 5.3-1, page 100 of the Application, is a graph showing flat peak belying the extreme overstatement of the CapX demand forecast, yet predicting extreme increase:

Figure 5.3-1: MISO Region Net Peak Load Expectations Over Time (1994 to 2044)[138]



[7] Why would the applicants raise the grossly overestimated CapX 2.49% annual increase forecast, p. 11. when the Figure 5.3.1 shows how misguided that forecast proved to be?

Note the time frames of the increase in demand on Application pages 101-104. Over a 20 year period, the increase predicted is not extreme.

A look at MISO's "Long-Term Load Forecast" from December 2024[8] also uses this chart above to depict "Net Peak Load Expectations Over Time (1994-2044).[9] This report identifies "five" key drivers, though it lists six, most of which are not credible:

Building Electrification: Federal and state policies are driving the electrification of heating systems and appliances, increasing energy demand by 36-43 TWh by 2044.

Artificial Intelligence (AI) Revolution and Data Centers: The expansion of data centers, fueled by AI and cloud-based applications, will raise MISO's energy demand by 149-241 TWh by 2044.

Electric Vehicles (EV): The growth of EVs, driven by federal incentives and declining battery costs, is projected to add 54-91 TWh of demand by 2044, with rapid adoption between 2030-2040.

New Industry Development and Reshoring: Electrification of oil and gas industries and reshoring efforts are expected to increase energy demand by 21-105 TWh by 2044.

Green Hydrogen: Green hydrogen production, supported by federal incentives, could increase MISO's energy demand by 26-95 TWh by 2044, contingent on sustained policy support.

Distributed Energy Resources (DERs): The rise of rooftop solar, energy storage and other DERs is expected to contribute 69-78 TWh of capacity to MISO's system by 2044.

This report is from December 2024, and so much has changed, and the future looks to be equally volatile. The "drivers" from 2024 are prior to the current administrations intentional decimation of the U.S. economy and revocation and elimination of "green energy" policies established by prior administrations. We now see promotion of fossil fuels, elimination of loan guarantees and grants for renewable generation, and elimination of most of the subsidies and tax credits that had been available for the "energy transition."[10]

For example, **"Building Electrification"** (p. 15) should reflect the increasing energy efficiency of electric heating systems and appliances, which decreases peak demand. Its placement as a key driver is dependent on "replacement of fossil fuel-based heating systems" and "Federal incentives, such as IRA rebates." "Fossil fuel-based heating systems" are replaced not only by electric, but increasing deployment of geothermal for heating and air conditioning. Also, this does not take into account this administration's efforts to resurrect fossil fuel.[11]

[8] See fn 25, p. 13, MISO. December 2024, Demand Forecast Whitepaper. Available at: https://cdn.misoenergy.org/MISO%20Long-Term%20Load%20Forecast%20Whitepaper_December%202024667166.pdf
[9] Id, p. 4.
[10] Executive Order 14386, STRENGTHENING UNITED STATES NATIONAL DEFENSE WITH AMERICA'S BEAUTIFUL CLEAN COAL POWER GENERATION FLEET, https://federalregister.gov/d/2026-03156
[11] Id.

AI Revolution and Data Centers (p. 17) is another 2024 notion that is shifting, with increasing projections of an AI bubble burst in 2026.[12] Though one data center is making permitting and electrification progress to the immediate north of Pine Island, across Hwy. 52 from the North Rochester substation[13], data center proposals are being challenged, proposals are being withdrawn, and similarly to wind in the interconnection queue, while there are many proposed projects, it is unknown how many will actually be permitted and built.

Electric Vehicles (EV) (p. 19) is also not likely to increase peak demand, as EV's are typically charged off peak and are system support as storage.[14]

New Industry Development and Reshoring (p. 23) may have had promise in the 2024 analysis, but in 2026, following 2025, and the economic downturn, this is also not a likely contributor to higher demand.[15]

Green Hydrogen (p. 26) development is, as noted in the report, supported by federal incentives, incentives that have been withdrawn in 2025.[16]
Distributed Energy Resources (DERs), rather than create demand for transmission, reduce need for transmission by generating electricity at or near load.[17] "Distributed generation can significantly impact inter-zonal transmission flows… At moderate levels, distributed generation adoption could cause certain

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[12] See, e.g. **AI Bubble May Burst, Wiping Out $40 Trillion From Nasdaq. Here's What To Do** https://www.forbes.com/sites/petercohan/2025/10/15/ai-bubble-may-pop---wiping-out-40-trillion-learn-what-could-happen-and-what-to-do/; **The AI boom has all 4 classic bubble signs — and it could pop in 2026 if interest rates rise, a top economist says** https://www.businessinsider.com/ai-boom-has-4-bubble-signs-could-burst-2026-economist-2025-12?op=1; **Anatomy of an AI reckoning https://www.weforum.org/stories/2026/01/how-would-the-bursting-of-an-ai-bubble-actually-play-out/**

[13] The data center is proposed to be served by a short 345kV line from the North Rochester substation across Hwy 52 to the data center on the east side of Hwy 52.

[14] See e.g., **EVs Are Essential Grid-Scale Storage: Before long, there will be more EV battery capacity than the grid can use** https://spectrum.ieee.org/electric-vehicle-grid-storage**; Electric vehicles as quasi-stationary energy storage devices** https://www.ifam.fraunhofer.de/en/magazine/electric-vehicles-as-quasi-stationary-energy-storage-devices.html**; The Smart Grid Connection: How Energy Storage in EVs Contributes to Grid Stability and Flexibility** https://qmerit.com/blog/the-smart-grid-connection-how-energy-storage-in-evs-contributes-to-grid-stability-and-flexibility/

[15] See e.g., **Administration's Proposed Cuts to Non-Defense R&D Pose Long-Term Risk to Rising Living Standards** https://www.cbpp.org/research/federal-budget/administrations-proposed-cuts-to-non-defense-rd-pose-long-term-risk-to; **Federal Research and Development (R&D) Funding: FY2026** https://www.congress.gov/crs-product/R48694; **Why America's Decline In R&D Funding Might Challenge The Future Of Small Business** https://www.forbes.com/sites/nataliemadeiracofield/2025/05/22/why-americas-decline-in-rd-funding-might-challenge-the-future-of-small-business/

[16] See e.g., **Trump administration defunds Northwest hydrogen hub, Spokane grid project, WSU research in cuts targeting 'the Left's climate agenda'** https://www.spokesman.com/stories/2025/oct/02/trump-administration-defunds-northwest-hydrogen-hu/, **Trump Administration announces targeted energy funding terminations including California's multi-billion dollar hydrogen hub** https://keyt.com/news/california/2025/10/03/trump-administration-announces-selective-terminations-of-hydrogen-projects-nationwide/; **US slashes funding for hydrogen projects** https://drivinghydrogen.com/2025/10/24/us-slashes-funding-for-hydrogen-projects/

[17] See e.g., **Distributed Generation Resources and Implications for Transmission,** p. 27 (3 pages missing, may not be public) https://www.wecc.org/sites/default/files/documents/meeting/2024/Muhs-StS-ESIG%20DERs%20and%20Transmission.pdf**;**

inter-zonal transmission investments to be delayed or avoided."[18]

- **Minn. R. 7849.0280, Subps. (B) through (I).** The Commerce Comments stated:

  > The Department agrees with the Applicants that the Commission has approved exemptions to Minn. R. 7849.0280, subps. (B) through (I) in similar circumstances and for similar reasons. Therefore, the Department recommends that the Commission approve the requested exemption to Minn. R. 7849.0280, subps. (B) through (I).[19]

  The Commerce Exemption recommendations were adopted by the Commission -- Commerce and the Commission rely on the "we've done it before, so let's do it again" theory. That's insufficient rationale for exemption.

- **Minn. R. 7849.0290** Efficiency and energy conservation have done much to keep the peak demand down, and based on the technology changes over the last decade,, rapidly changing technology will have an even greater impact on lowering energy demand and peak demand. Further information is needed from the applicants. Commerce and the Commission should require it from the applicants rather than push the work onto "interested parties" to pursue. The Commission is the regulator.

- **Minn. R. 7849.0300 and 7849.0340.** Applicants claim they will address impacts to congestion relief and request a variance from the portions of these rules that require the examination of delay to incorporate the three specific levels of demand. Shouldn't this be relevant given the grossly overstated demand predictions for CapX 2020? Commerce and the Commission again rely on the "we've done it before, so let's do it again" theory. That's insufficient.

- **Minn. R. 7849.0330 G** How is the region of the likely area for routes between the endpoints different from the project area? What is in the region that Applicants do not want considered? This exemption request should not have been approved, and now we should be looking carefully at the "region" and search for important "major features."

The Commission too readily accepts Exemption Requests and in doing so, little by little abdicates its regulatory responsibility, which is particularly concerning for a project of this magnitude. An application missing important information, though "exempted," has the effect of shifting the burden of production onto the state agency that approved the exemptions, on

[18] Id.
[19] Order, p. 21 of 30, Commerce Exemption recommendations, p. 10202512-226131-01 December 23, 2025.

informal participants with little subject knowledge and administrative procedural experience, and Intervenors with limited resources. As for the Applicants, through failure to provide credible and reliable information, and by making exemption requests based on MISO portfolio information rather than Minnesota and project specific information, and worse, repeatedly offering the "we've done it before, so let's do it again" theory, the lack of relevant information renders the application incomplete.

III. THERE ARE MANY CONTESTED ISSUES OF FACT

The primary contested fact is fundamental to a Certificate of Need docket – whether the line is needed based on the Minnesota Certificate of Need criteria, and in particular, whether the MISO determined cost and the MISO cost/benefit analysis using 2024 data remains credible in 2026. This is an issue because the application relies on the MISO Tranche 2.1 process, analysis, forecasting, and cost/benefit analysis for the substance of its need claim. In 2025 and 2026, the economy of the U.S. and economics of the MISO Tranche 2.1 project have changed dramatically. The 2024 cost estimates and the cost/benefit analysis on which Tranche 2.1 relies are no longer valid.

The Commission is the regulator. The applicants' need claim relies on MISO's Tranche 2.1, not Minnesota Certificate of Need criteria, and MISO is not the regulator. The interests of the Public Utilities Commission and MISO are distinct, and in some ways are not compatible. Approval of this and any project must be a careful evaluation through the Certificate of Need process as defined by law.

A. Outdated economic modeling assumptions aren't sufficient to demonstrate need.

This project, and all the Tranche 2.1 projects, are using outdated 2024 economic assumptions in a 2026 application, in an unprecedented time of supply limitation, cost increasing tariffs, and economic uncertainty -- cost increases so extreme that that at least one transmission project, so far, revealed cost increases totaling 43%, which requires a MISO Tariff FF variance analysis triggered at a 25% increase.

> At the time the Board approved the LRTP Tranche 1 portfolio, MISO estimated the Project cost to be $969,900,000 (in 2022 dollars). As part of the Q2 2025 MTEP Quarterly Project updates, GRE and MP's combined estimated costs for the Project are projected to be $1,389,895,000 (in 2022 dollars, an increase of approximately 43%).
>
> GRE and MP attribute the 43% cost increase to three factors:
>
> - 25% - Material and construction cost escalations
>   - Initial estimated costs for the project were developed in 2022. Since then, there has been an increase in electrical component costs such as substation equipment, steel, and labor causing an increase to the project cost.
> - 18% - Routing and engineering design refinements
>   - Transmission line routing is determined by the Minnesota Public Utilities Commission which has the authority to select the route that best aligns with state statute, balancing land, environmental, and community impacts with costs. The Commission's approved route increased the overall Project costs.
>   - Substation facilities' scopes of work were refined upon further engineering design. [20]

The conditions leading to the cost increase of the estimated 43% for that one project are not isolated because current economic conditions are global, literally, and costs have risen exponentially. Not only have costs risen, but materials and supplies may be difficult, if not impossible, to procure. A similar scenario occurred during COVID, where shipping limitations and market upheaval upended construction and cost for energy projects – in two instances, with the developers filing Notice of Force Majure and the projects brought to a screeching halt.[21] Each transmission project before the Commission should be carefully scrutinized and cost increases identified, MISO Variance Analysis as appropriate. This project is no exception.

B. MISO's cost/benefit analysis must use current numbers to determine whether a project is feasible, mush less conveys a benefit.

The MISO "approval" is predicated on a cost/benefit analysis showing that Tranche 2.1

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[20] MISO Notice of Variance Analysis, filed in PUC dockets CN-22-416 and TL-22-415, filed December 15, 2025, PUC eDockets ID 202512-225901-01.

[21] See Notices of Force Majure in Badger Hollow and Two Creeks solar in Wisconsin: **Impact of COVID on energy projects**, legalectric.org/weblog/19714/, March 30th, 2020.

portfolio would have economic benefits greater than the costs for each MISO zone. When the cost rises, the ratio of benefits to cost changes. If the cost rises exponentially, or if the cost rises "just" 25% or more triggering a "MISO variance analysis" under the MISO Tariff FF, that means MISO is exercising due diligence to assure the portfolio remains economically sound. This project, and all projects based on 2024 economic assumptions must be reanalyzed. Does the project make economic sense in 2026? The Applicants have not demonstrated the economics work in this climate. The Commission must also exercise due diligence and assure that this individual project, and all of the MISO Tranche 2.1 projects are economically sound in 2026.

C. The "Power on Midwest" transmission line does not provide benefits for the proposed transmission corridors.

Whether the project provides benefits to the transmission corridor is a contested issue of fact. The Application does not specify any benefits. The application does state there would be a "benefit", that the cost benefit ratio is 1.8-3.5, and does state that "For an average electrical consumer, MISO estimates that the LRTP Tranche 2.1 Portfolio is estimated to cost about $5 per 1,000 kWh of energy used while providing $10 to $18 of value over that same amount of usage per month in value."[22] MISO members, the applicant utilities and others, are the benefactors, and there is no specific claim of benefits to those in the project corridor.

Will the project provide electricity to the area? Is there a substation where the 765kV will be dropped down to a useable voltage and distributed locally? Is there a benefit to landowners whose land will be taken for this project? Is there a benefit to local governments who may lose property tax revenue due to decreased property values? How much Utility Personal Property Tax will be received by the local governments and school districts, and does that tax revenue offset

[22] Application, p. 6-7, fn. 8: "Net savings are 20-year net present value (NPV) in $-2024 (Id., Page 125, Figure 2.137)"

property tax revenue decrease due to devaluation at or near the transmission easement?[23] How are environmental costs determined and considered? How are socioeconomic costs determined and considered? These are among the issues of fact to be addressed in a contested case.

D. MISO's Independent Market Monitor has raised questions about cost, alternatives, and challenges the MISO claimed need for Tranche 2.1. Minnesota's Commission should as well.

Need and cost are the primary issues in a Certificate of Need docket. It is the job of the Public Utilities Commission to regulate utilities, and in this case, to review the Applicant's proposal for Tranche 2.1 transmission in Minnesota. The concerns of the MISO Independent Market Monitor raise issues of fact.

It is the job of MISO's Independent Market Monitor to monitor the direction and decisions of MISO. MISO's IMM has called into question the economic wisdom and responsibility of proceeding with Tranche 2.1 in both its Comments to the MISO Board[24] and in its Intervention[25] in a FERC docket where North Dakota and other Commissions are challenging MISO's cost allocation for the MISO Tranche 2.1 projects. [26] Is the Commission considering the concerns if the Independent Market Monitor?

Concern about costs of transmission and overbuilding is not limited to the MISO system. Similar issues have been raised in PJM, particularly regarding "rapidly evolving circumstances and incomplete assumptions," raised by the Deputy Consumer Advocate in Pennsylvania, in a January 21, 2026 letter,[27] stating:

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[23] It is presumed that local governments will receive Utility Personal Property Tax on the project's physical structures, but that amount is unknown.
[24] MISO IMM Comments on LRTP Tranche 2 Benefit Metrics, May 29, 2024.
[25] MISO IMM Motion to Intervene, September 9, 2025.
[26] See *North Dakota Pub. Serv. Comm'n v. Midcontinent Indep. Sys. Operator, Inc., Complaint of the Concerned Commissions and Requests for Expedited Action and Fast Track Processing*, Docket No. EL25-109-000 (July 30, 2025).
[27]Correspondence to PJM, from Melanie Joy El Atich, Deputy Consumer Advocate, Counsel to Pennsylvania Consumer Advocate, Darryl Lawrence.

> It is not clear, at this time, whether or how PJM's recent downward adjustments to data center demand in its 2026 load forecast, released on January 14, 2026, would impact the accommodated data center load growth in PPL's zone.[28]
>
> It is not clear, at this time whether or how the recent leadership directions from the White House, PJM Governors, and PJM Board, as announced on January 16, 2026, would impact the siting and building of generation that may obviate the need for all or part of Project 237.

These are practical concerns and issues of fact for consideration in relation to any transmission proposal, and in particular, a proposal of MISO's Tranche 2.1 magnitude.

E. Many transmission lines have been proposed and permitted in the area with similar or identical beginning and endpoints that call the "need" for this project into question.

Newly permitted transmission lines across southern Minnesota into Wisconsin and Iowa calls the Applicants need claim into question, whether more transmission is needed and where it is needed, and for what purpose. Some of the transmission build-out applied for and/or permitted in southern Minnesota to be considered for a big picture review are:

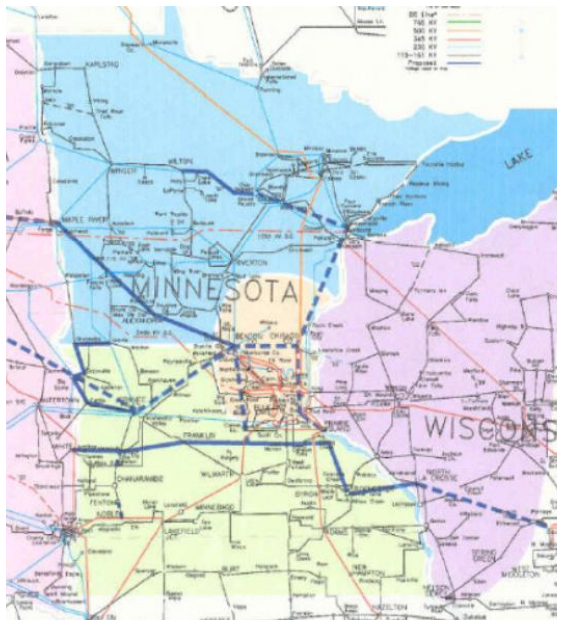
- Tranche 2.1's "Gopher to Badger" transmission project
- Mankato-Mississippi 345kV Wilmarth/North Mankato through North Rochester to Mississippi/Tremval to Columbia
- 2nd circuit Brookings-Lyon County & Helena -Hampton - PUC CN-23-200; TL-08-1474
- Lyon County to Sherco 345kV transmission with 800MW in new gas generation in Lyon County, a line with over 2,000 MVA capacity and 10-12% line loss
- MVP Portfolio – ITC's 345kV Lines 3, 4 in southern MN and IA, and 5 Badger-Coulee LaX to Cardinal on north and Hickory Creek to Cardinal on the south
- CapX 2020 – 345kV Brookings to Hampton and Hampton to La Crosse (CapX 2020) into Wisconsin
- SW MN 345kV Transmission – Split Rock to Lakefield Jct. beginning the southern Minnesota transmission corridor

These projects, notably the CapX, MISO MVP Portfolio, and Tranche 1 and Tranche 2.1, are obviously connected, but are segmented, with artificial beginning and end points, and

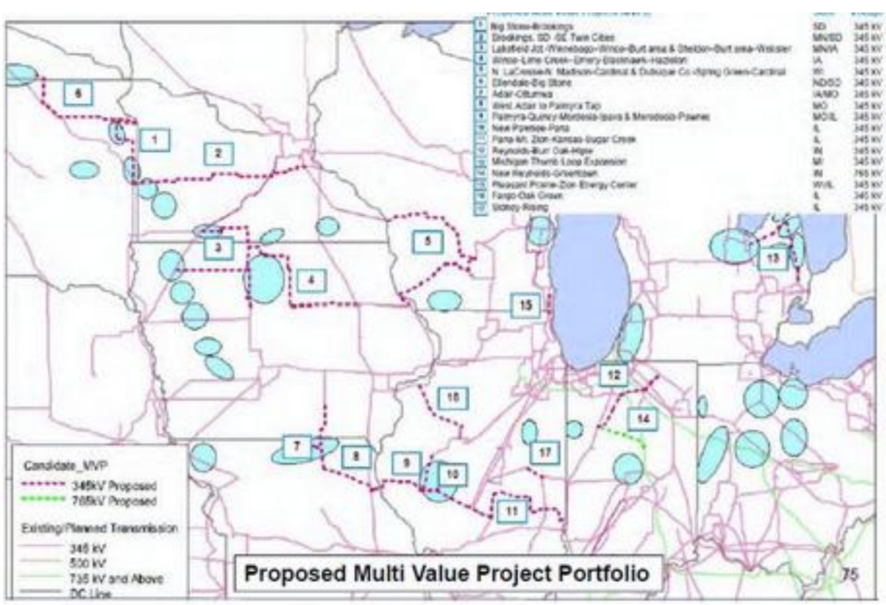
[28] MISO's Tranche 2.1 analysis and this application do not include data centers, which though discussed, are speculative. See Application, §5.3, fn. a, Table 1.1-1, and in the other 13 mentions of data centers in the application.

particularly for the southern Minnesota projects beginning at the South Dakota Border, extending through Minnesota and also into Iowa (CN-25-117, 118, 119, 120) and Power on Midwest's connection to the Gopher to Badger project at the existing or new North Rochester substation.

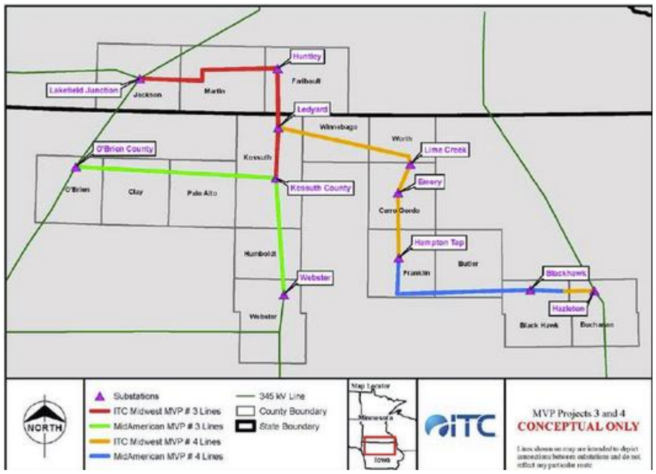
When these lines are put on a map, the result in southern Minnesota is an extensive web of transmission, before Tranche 2.1 is added. Tranche 2.1 is duplicative of several of these lines.



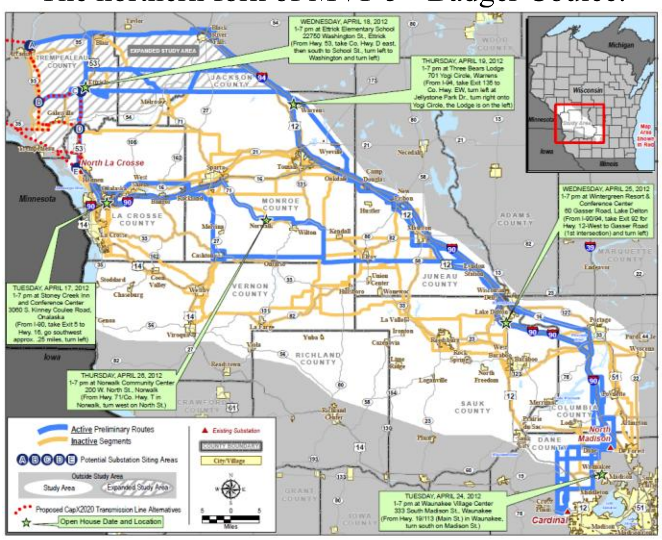
MVP projects 3, 4 through southern Minnesota and into Iowa, and 5, the northern part from La Crosse to Cardinal called Badger Coulee, and from Dubuque to Cardinal, Cardinal-Hickory Creek:



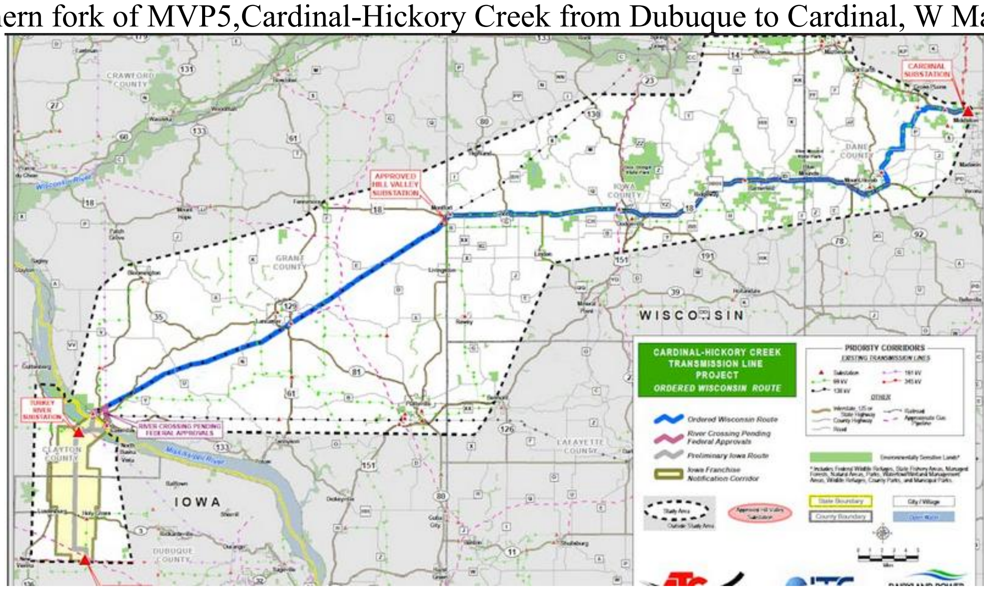
MVP 3 and 4 in southern Minnesota and Iowa; 5 Badger Coulee & Cardinal-Hickory Creek:



The northern fork of MVP 5 - Badger Coulee:



Southern fork of MVP5,Cardinal-Hickory Creek from Dubuque to Cardinal, W Madison:



F. **Reasonable and available system alternatives, individually or in combination, may obviate the "need" for this project.**

System alternatives proposed essentially must, under the Certificate of Need law, have the same beginning and endpoints. Whether alternatives are reasonable and available is contested.

i. The 345kV lines in southern Minnesota have not been upgraded in decades, particularly the Wilmarth, King-Eau Claire-Arpin, and Prairie Island-Byron-Adams transmission lines. If these lines were updated, much transmission capacity would be gained and system stability and support increased.

ii. Batteries are a viable and cost effective alternative and substitute for transmission. See IV. System Alternatives, A (i) below.

iii. Direct current lines are a more efficient (less line loss over distance) alternative, particularly in long lines with no AC step down for local service.

iv. Undergrounding DC transmission in highway and railway rights of way and easements is a reasonable, available, and utilized system alternative. For years underground projects have been proposed and some permitted. See Minn. Stat. § 216I.05, Subd. 11(e); and section IV. System Alternatives, A (ii) below.

v. Existing and planned transmission projects with the same or similar beginning and end points, as described above, have not been fully disclosed, and may be a reasonable and available system alternative.

G. **The Applicants' claim that "consumers" will be responsible for only a small portion of the cost of this project is contested.**

The cost of this transmission project to Minnesota is an issue of fact. The cost to Minnesota is claimed in the application to be comparably low, which is because cost is apportioned among the utilities in MISO that will benefit from the project – the greater the benefit, the higher the cost for that utility. Two things are demonstrated in this equation.

Applicants claim that the benefit-cost ratio for the entire portfolio is 1.8-3.5, and that the cost to "consumers" is roughly $5 per 1,000kW used,[29] but "consumers" are not defined, and are different from ratepayers. The Application does not identify "consumers" nor does it disclose the benefit-cost ratio for this specific, or any specific project. Benefits go to MISO members, the utilities, and not ratepayers. The benefit for this project is an issue of fact that must be clarified, as well as the current cost and the impact of cost increases on the benefit-cost ratio.

If Minnesota utilities, and ultimately Minnesota ratepayers, will pay only a small share of the cost of this project, that means there is not much benefit to Minnesota, comparably, and that Minnesota MISO members are not receiving must of the benefit of this project. Second, costs for ALL of the Tranche 2.1 projects are apportioned among ALL the utilities, which means that Minnesota utilities will be allocated costs from ALL the projects and this cost of ALL the Tranche 2.1 projects that will be put on utilities, therefore ratepayers. The entire cost of Tranche 2.1 transmission to Minnesota, must be identified, acknowledged by the Commission, be integrated into this proceeding, and a cost benefit analysis for each discrete transmission project foisted on Minnesota utilities and ratepayers to determine whether it is worthwhile for Minnesota.

The claimed benefit-cost ratio for this project is a contested issue of fact. The Commission is the regulator, and these costs for the many projects will accrue – the Commission had best account for the entire cost of MISO Tranche 2.1 and the other "portfolios" in Schedule 26A[30] as a part of this docket, as the projects in other states that add cost to Minnesotans will not otherwise be addressed by the Commission.

H. Costs of individual projects are in 2024 dollars, with extreme cost increases

[29] Application, §1.4.2, p. 6-7. The section is headed "Local Minnesota Drivers" but the benefit-cost information provided is not local to Minnesota or the project area
[30] MISO Schedule 26A Indicative Annual Charges, released September 30, 2025.The Commission should be mindful that Schedule 26A is based on wholesale transactions, not retail customers.: https://cdn.misoenergy.org/Schedule%2026A%20Indicative%20Annual%20Charges106365.xlsx

expected.

Cost of the project is another issue of fact. As above in paragraph A, economics in the U.S. have changed dramatically from 2024 to the present, most notably in the last year, and any cost estimate based on 2024 dollars needs to be revisited. This has become an issue in one of the Tranche 2.1 projects, where MISO is requiring a "Variability Analysis" for project. The cost of the Gopher to Badger line in Minnesota is $979 million to $1.373 billion, and the MISO cost estimate, for a larger section of "project 26, from North Rochester to Columbia, has a cost estimate of $1.924 billion. What's the cost estimate from the River to Bell Creek and from Bell Creek to Columbia, the remainder of project 26? It looks like this project also has cost increases. To what extent? MISO's "approval" of the project is dependent on the cost-benefit ratio, therefore the cost estimate. The Commission needs an updated cost estimate and updated cost/benefit analysis. MISO likely must complete a variance analysis for this project and consider whether this project should be approved.

ID	Project Name	Predominate kV	Targeted ISD	Est. Cost ($M, 2024)
19	Bison - Alexandria	345	2032	$216
20	Maple River - Cuyuna	345	2033	$908
21	Iron Range - Arrowhead	345	2032	$428
22	Big Stone South - Brookings County - Lakefield Junction	765	2034	$1,459
23	Lakefield Junction - East Adair	765	2034	$1,375
24	Lakefield Junction - Pleasant Valley - North Rochester	765	2034	$1,195
25	Pleasant Valley - North Rochester - Hampton Corner	345	2032	$222
26	North Rochester - Columbia	765	2034	$1,924
27	Rocky Run - Werner - North Appleton	345	2032	$212
28	South Fond du Lac - Rockdale - Big Bend - Sugar Creek - Kitty Hawk	345	2033	$1,102
29	Bluemond - Arcadian - Waukesha - Muskego - Elm Road - Racine	345	2032	$731
30	Columbia - Sugar Creek	765	2034	$743
31	Sugar Creek - Collins	765	2034	$733
32	Ludington - Denver - Tittabawassee & Nelson Road	345	2032	$1,553
33	Greentown - Sorenson - Lulu	765	2033	$1,310
34	Oneida - Sabine Lake - Blackfoot & Majestic	345	2032	$600
35	Southwest Indiana-Kentucky	345	2032	$743
36	Southeast Indiana	345	2032	$578
37	Maywood - Belleau - MRPD - Sioux - Bugle	345	2032	$881
38	East Adair - Marshalltown - Sub T	765	2034	$1,583
39	Lehigh - Marshalltown - Franklin North & Montezuma	345	2032	$588
40	Sub T - Woodford County - Collins & Reynolds	765	2034	$2,298
41	Woodford County - Fargo & Radbourn	345	2032	$422
42	Burr Oak - Schahfer	345	2032	$68
	Total Portfolio Cost		Total	**$21,868**

[31]

It is difficult to attribute a cost to a MISO project, as several of the MISO projects, including this MISO project 26, North Rochester-Columbia, at $1,924 (million) is identified by MISO as North Rochester to Columbia, and is identified and applied for in Minnesota alternately as Gopher to Badger, running from North Rochester to the Mississippi, and as North Rochester-Marion-Bell Center. Cost is an issue of fact. 2026 cost is an issue of fact.

Benefits are also an issue of fact as benefits claimed are equally difficult to attribute to a particular project as MISO presents them only for the entire Tranche 2.1 portfolio of projects.

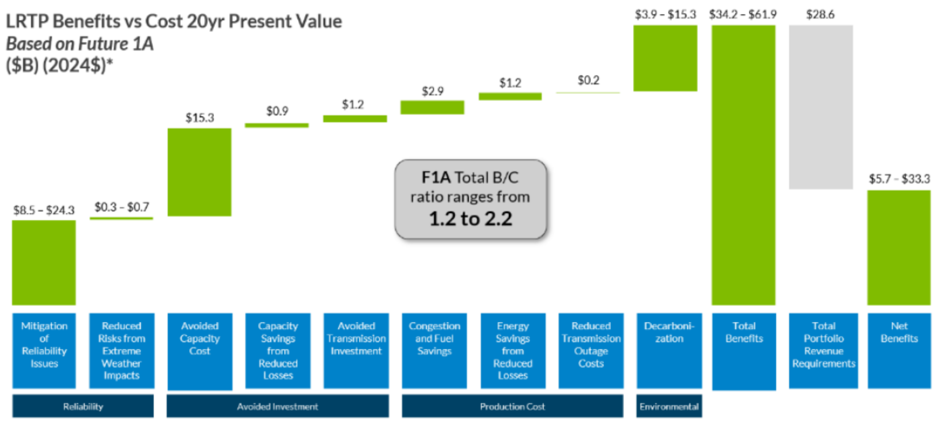


Figure 2.155: Tranche 2.1 Benefits based on Future 1A. [32]

Reliability Benefits	1. Mitigation of reliability issues	Value of alleviating reliability issues which, if unresolved, introduce a risk of unserved load
	2. Reduced risks from extreme weather events	Increases grid resilience and decreases the probability of major service interruptions
Avoided Investment Benefits	3. Avoided capacity costs	Avoids capital costs for local resource builds versus regional expansions defined in Futures
	4. Capacity Savings from Reduced Losses	Value of reducing transmission losses during peak capacity periods
	5. Avoided transmission investments	Avoids the need for facility replacement due to age and condition
Production Cost Benefits	6. Congestion and fuel savings	Enhances market efficiency and provides access to low-cost generation
	7. Energy Savings from Reduced Losses	Lower production costs to serve load with transmission facilities that reduce system losses
	8. Reduced transmission outage costs	Reduced transmission congestion during forced and planned transmission outages
Environmental Benefits	9. Decarbonization	Enables the economical dispatch of renewable resources to help reduce the carbon footprint

Table 2.28: Nine Benefit Metrics used for Tranche 2.1.

[31] MPTE2024, Tranche 2.1 cost, p. 162, *Table 2.35: Tranche 2.1 Portfolio Projects,* the costs used for cost/benefit analysis necessary for MISO "approval."

[32] MISO MTEP24, Benefit Metrics, p. 143

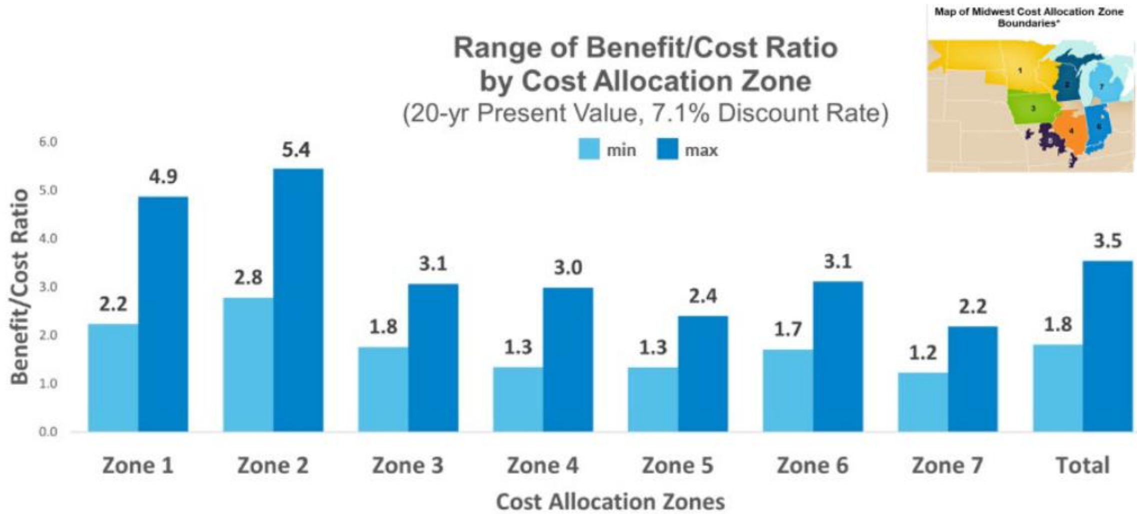


Figure 2.157: Tranche 2.1 Distribution of Benefits – Future 2A [33]

The Cost/Benefit ratio is calculated by "Cost Allocation Zone" and not project by project, which makes it impossible to consider the "benefit/cost ratio" for a specific project, and of the projects in Tranche 2.1, they are listed by MISO numbers which have been broken down into segments, not directly comparable with segmented Minnesota projects (and docket numbers). It's impossible to properly evaluate costs. Again, costs are an issue of fact. For the benefits claimed, are there other ways to harvest these benefits? Another issue of fact.

For example, the project in this docket is known as the "Power on Midwest" transmission line and runs from and to many different endpoints. This seems to be MISO projects 22, 23, 24 and 25, Big Stone Sout-Brookings-Lakefield Jct.; Lakefield Jct.-E Adair; Lakefield Jct.-Pleasant Valley-North Rochester-Hampton Corner, at a cost ranging estimated at \$3.327 billion to \$4.323 billion.[34] However, MISO's projects 22, 23, 24, and 25 have an estimated cost of \$4.751 billion in 2024 dollars.[35] That estimate includes the Minnesota portions of these projects but does not include the outstate of the projects as defined by MISO. How can these costs be compared?

[33] MTEP24, Benefits, Future 2A, p. 163
[34] Application, §1.7, p.22; Section 2.4 Project Costs.
[35] MTEP24, p. 162, Table 2.35.

Missing from the estimates are the South Dakota portion of MISO project 22, the Iowa portion of MISO project 23, the Lakefield Jct. to East Adair. The cost of the missing pieces of projects 22 and 23 must be identified for an evaluation of costs.

Table 1.7-2
Summary of Project Capital Cost Estimates (Base)

Project Component	SD/MN State Line to Lakefield Junction 765 kV ($2024)	Lakefield Junction to IA/MN State Line 765 kV ($2024)	Lakefield Junction to Pleasant Valley 765 kV ($2024)	Pleasant Valley to North Rochester 765 kV ($2024)	Pleasant Valley to North Rochester to Hampton 345 kV ($2024)
Transmission Lines	$582 million	$115 million	$813 million	$197 million	$233 million
Substations	$434 million	N/A	$393 million	$553 million	$7 million
Total	**$1.016 billion**	**$115 million**	**$1.206 billion**	**$750 million**	**$240 million**

I. The upper bound of capacity of this line, amps, MW and MVA, is a contested issue of fact.

At an open house in Caledonia, this writer was told that the capacity of the 765kV part of the Gopher to Badger project was 5,300 MVA. The application states:

> Each 765 kV line will utilize a six-conductor bundle per phase of 1192.5 thousand circular mil (kcmil) 45/7 aluminum conductor steel reinforced (ACSR) Bunting conductor, or a similar performing conductor, with 15-inch subconductor spacing and have a total capacity equal to or greater than 4,000 amperes (amps). The Applicants identified the 1192.5 45/7 Bunting as appropriate for the Project based on a study of 17 conductors. The conductor provides the requisite capacity for the Project, including meeting MISO's ampacity and surge impedance loading (SIL) requirements of 4,000 amps and of 2,400 MW, respectively.

Application, p. 33.

The expected and maximum ampacity at 765kV and 35kV segments is necessary to determine the capacity numbers expressed in MVA, and MVA for each segment should be identified. Expected and maximum capacity is a contested issue of fact.

J. Line losses for this individual project is an issue of fact.

As above, line losses can be considerable as line losses are accumulate over distance. For the "MN Energy Connection," Commission docket CN-22-131/132, the Commission's August 10, 2023 Order Authorizing Joint Procedures stated, that 2,200 MW of generation would deliver "approximately 1,996 MW to the Sherco Substation."[36] This presumes that "approximately" 204 MW line loss, at a rate of 11.33-12.75% for that project. What is expected line loss for these consolidated projects?

This project, presuming line loss of 11-12%, what will the cost be in lost energy? This is a material and contested issue of fact.

K. The Applicants' claim that the cost of Direct Current transmission generally and the cost of necessary converters is prohibitive -- that is an issue of fact.

Applicants claim that cost of Direct Current generally, underground, and the cost of converter stations render DC cost prohibitive. This is a contested issue of fact.

A DC project could be a reasonable and viable system alternative.[37] DC is used in northern Minnesota, Minnesota Power's 500MW Square Butte line from Center, ND to the Arrowhead substation is an uprated DC line claimed to be dedicated for wind. Minnesota's "CU" line from Coal Creek to Buffalo, Minnesota is a 400MW DC line, a line that could also be dedicated for wind IF the Coal Creek coal plant was retired.[38]

PJM recently approved a two-stage 185 mile underground transmission line with 6,000 MW capacity on Dominion right-of-way between Heritage substation near Freeman, Virginia and the Mosby substation near suburban Washington, D.C. in Aldie, Virginia[39], and two HVDC converters at each end of the line. This project is through a relatively congested area near

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[36] Commission Order Authorizing Joint Proceedings, **20238-198151-01**, August 10, 2023.
[37] See also **System Alternatives** below.
[38] See Wellstone & Casper's *Powerline: The First Battle of America's Energy War.*
[39] New HVDC Transmission Link from Heritage to Mosby - https://www.pjm.com/-/media/DotCom/planning/rtep-dev/expan-plan-process/ferc-order-1000/rtep-proposal-windows/2025-rtep-window-1-redacted-proposals/2025-w1-815.pdf

Washington, D.C. The comparative cost of undergrounding near a populated suburban and exurban Washington, D.C. compared with the rural project area for some or all of the "Power on Minnesota" projects is an issue of fact. The comparative cost of line loss is also an issue of fact, as the decreased line loss would also make up for some of the cost of DC versus AC. The dollar value of the decreased line loss should be considered in the AC v. DC calculation.

L. Applicants claim the cost of undergrounding DC is cost prohibitive.

Applicants' claim that the cost of undergrounding is cost prohibitive is a contested issue of fact. As above, PJM has approved a 185 mile underground direct current transmission line through a rural, suburban, and exurban area near Washington, D.C. The Soo Green line is a direct current line designed to be built underground utilizing railroad corridor and has been permitted by the Iowa Utilities Commission.[40] The cost of that project in a populated area should be compared with the cost of undergrounding in the rural project area, and compared with the cost of the Power on Minnesota project. The comparative costs of undergrounding DC versus the overhead AC of the many segments of these consolidated projects is a contested issue of fact.

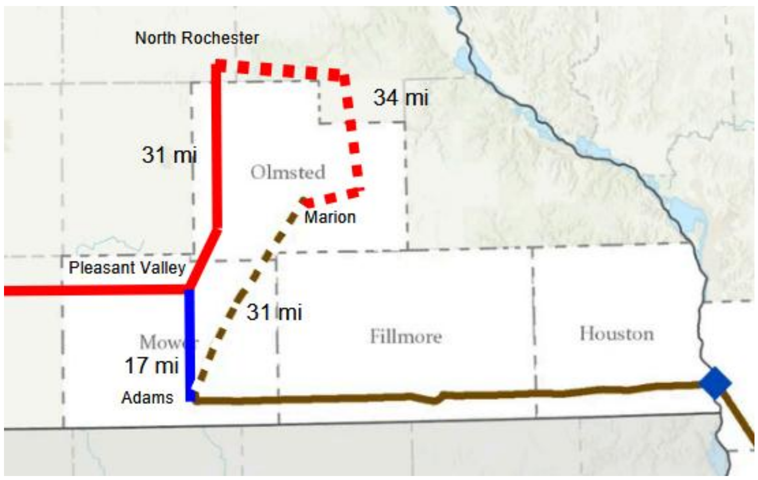
M. When need claim is based on desire for export capability, and the substations are set out as planned, "the project" could/should be a line across southern Minnesota.

The need for the project becomes an issue of fact when Applicants claim need for export. Whether export is a need for the project is an issue of fact. Focusing on export, are utilities overbuilding generation and building transmission for export when storage would solve any Minnesota "problem" with lower cost are additional issues of fact.

A logical system alternative suggested by Dale Thomford, addressing both the need claim outside the project, to the South Dakota and Wisconsin substations based on export, to reduce the

[40] See Application, pps. 174-176. And below, **System Alternatives**.

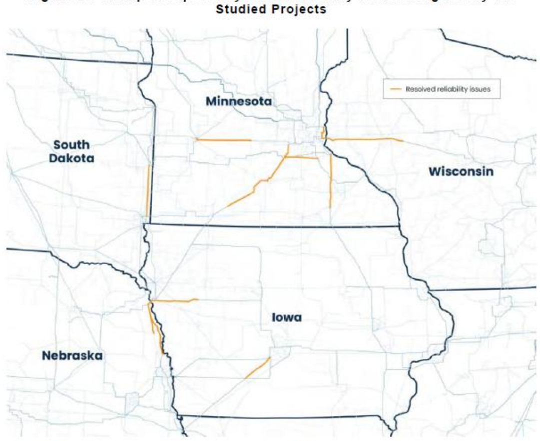
cost of the project, and to avoid New Haven township, is to eliminate 65 miles of frolic and detour on the eastward route from North Rochester to Marion and then down to Adams, cutting that transmission and substation from the cost, and to run a transmission line essentially across southern Minnesota to the Mississippi.[41] As provided by statute, Interstate 90 could provide a corridor from west to east.



N. Where 345kV support lines are "steady-state stability" problems, what is the support system if the 765kV system goes down?

The Applicants have identified a number of 345kV transmission lines that are necessary support for the 345kV system in the application that present "steady-state stability" issues.

Figure 6.3-1: Map of Top Steady-State Reliability Issues Mitigated by the Studied Projects



6.3.1.1 Supporting Local Reliability in Southern Minnesota

[41] Dale Thoforde, Initial Comment, 20262-228287-01, February 18, 2026.

If these 345kV lines supporting the 345kV system are a weak link, what happens if they are not reconductored/rebuilt/rehabilitated, the 765kV lines are built, and a 765kV line goes out? Is the 765kV system also reliant on the 345kV system for support? This is a material issue of fact. If those lines are upgraded, is the 765kV system needed? That's yet another issue of fact.

IV. THE COMMISSION SHOULD REFER THE CERTIFICATE OF NEED TO THE COURT OF ADMINISTRATIVE HEARINGS FOR JOINT CONTESTED CASE PROCEEDINGS.

The notice of comment period's Topics for Comment raises an odd choice, between that of "the Commission's informal process" or referral to the Court of Administrative Hearings. There is no citation in the notice for that "informal process." The Commission's Completeness Order of January 23, 2026 for the Iron Range to Arrowhead 345kV line "Authorized Reviewed the Certificate of Need using the informal comment and reply process under 7829.1200 to review the Certificate of Need."[42] There is no similar reference here.

Looking at procedure in the Commissions Ch. 7849 and 7829 reveals only one "informal process,"[43] found in Minn. R. 7829.1200, as Ordered in the Iron Range – Arrowhead project:

> **7829.1200 INFORMAL OR EXPEDITED PROCEEDING.**
>
> Subpart 1. **When appropriate.** Informal or expedited proceedings may be used when contested case proceedings are not required, for example, when:
>
> A. there are no material facts in dispute;
>
> B. the parties and the commission have agreed to informal or expedited proceedings; or
>
> C. informal or expedited proceedings are authorized or required by statute.

An "informal process" is wholly inappropriate for this application – there are material facts in dispute, there are no parties at this time to agree to informal or expedited proceedings, and informal or expedited proceedings are not authorized or required by statute.

[42] See Order, January 23, 2026, Order Point 2: "Authorized Reviewed the Certificate of Need using the informal comment and reply process under 7829.1200 to review the Certificate of Need." CN-25-111.
[43] Id.

The Commission must refer this application to the Court of Administrative proceedings. In addition to the contested case, there is a statutory preference for a joint Certificate of Need and Routing proceeding:

> Unless the commission determines that a joint hearing on siting and need under this subdivision and chapter 216I is not feasible or more efficient, or otherwise not in the public interest, a joint hearing under this subdivision and chapter 216I must be held.

Minn. Stat. §216B.243, Subd. 4.

As with the Maple River-Cuyuna 345kV project[44], a joint proceeding must be held for both dockets for the Gopher to Badger 765kV transmission project, and the Certificate of Need be put on hold until the Route Permit Application is submitted. The Commission must comply with the statute and refer both applications together to the Court of Administrative Hearings, and thus, if necessary, stay this Certificate of Need application until the Route application is received and the Certificate of need and Route proceed together. The Commission should follow the letter and spirit of the law.

V. ARE THERE ANY ADDITIONAL ISSUES OR CONCERNS RELATED TO THIS MATTER?

A thorough review of systems alternatives, environmental issues and impacts of the project, and comparing relative impacts with system alternatives in this Certificate of Need docket is imperative due to the novel proposal to add 765kV lines across hundreds of miles of Minnesota.

A. System Alternatives must be considered early in the Certificate of Need proceeding

System alternatives must be considered, and system alternatives need not satisfy all the claimed need, because different alternatives may work separately in tandem, in combination, to

[44] PUC Docket E015, ET2, E017/CN-25-109.

address different types of need, such as type of need and timing of need. System alternatives must also be incorporated early into environmental review, particularly because system alternatives may well have less of an environmental footprint than the project's 5,300MVA capacity 765kV transmission lines.

i. <u>Battery storage is a viable and cost recoverable alternative to transmission</u>.

Batteries are now regarded by FERC as a viable alternative to transmission. The value of battery storage has been growing over[45] recent years, and is playing a strong role in our energy transition. Jon Wellinghoff, former Chair and a Commissioner of the Federal Energy Regulatory Commission (FERC), testified regarding batteries, storage, other transmission alternatives and cost recovery for "advanced transmission technologies."[46] In his testimony, he notes the directive of FERC Order 890:

> *436…the Commission concludes that it is necessary to amend the existing pro forma OATT to require coordinated, open, and transparent transmission planning on both a local and regional level…* ***Through EPAct 2005 sec. 1223, Congress also directed the Commission to encourage the deployment of advanced transmission technologies in infrastructure improvements,*** *including among others optimized transmission line configurations (including multiple phased transmission lines), controllable load, distributed generation (including PV, fuel cells, and microturbines), and enhanced power device monitoring.*
> *437. Accordingly,* ***each public utility transmission provider is required to submit, as part of a compliance filing in this proceeding, a proposal for a coordinated and regional planning process that complies with the planning principles and other requirements in this Final Rule.***[4] [47]

[45] See Renewable-Storage Hybrids in a Decarbonized Electricity Supply, https://docs.nrel.gov/docs/fy23osti/84192.pdf
[46] Direct Testimony of Wellinghoff, Cardinal-Hickory Creek Transmission Project, ERF 370609 Ex.-DALC/WWF-Wellinghoff-9, Wisconsin PSC 5-CE-136. See also Energy Storage as a Transmission Asset, NARUC https://pubs.naruc.org/pub/87107D6D-C75A-2471-5F9D-68885685F3C2
[47] Id., p. 9.

Have MISO and the applicants "encourage[d] the deployment of advanced transmission technologies in infrastructure improvements." It does not appear that Alternative Transmission Solutions were properly assessed in developing its MTEP24 Tranche 2.1 and the Power on Minnesota transmission project.

ii. Utilizing Direct Current rather than Alternating Current is a viable alternative with lower line losses, providing a long term benefit – lower operational cost.

Using DC rather than AC is a viable system alternative that could utilize the same endpoints as proposed for the project. Direct Current benefits include:

1) High efficiency of transmission due to less line loss
2) Reduced corona discharge, related to lower line loss, and lower noise
3) EMF is lowered if not eliminated
4) Can be built underground, reducing impacts including environmental, visual, and health.

DC is a good alternative considering the distances between "endpoints" for the string of projects across Minnesota. It is an issue of fact whether DC is a viable system alternative, and whether these many projects across southern Minnesota are "all connected," making this a better candidate for use of DC. It is also an issue of fact whether the many projects provide step down service to local areas, and whether Minnesota is a pass through for export.

iii. Undergrounding is now a viable alternative to wires in the air and is encouraged by recent legislation.

The ability to underground transmission lines has become technically feasible and the cost has lowered sufficiently to make undergrounding a reasonable choice for routing a high voltage transmission line.

In 2024, the Minnesota legislature passed law encouraging use of highway and railroad rights of way for routing transmission. Minn. Stat. 216I.05, Subd. 11 (e).

Undergrounding a direct current line of similar capacity and endpoints would be a legitimate system alternative, and system alternatives are only raised in a Certificate of Need proceeding, though likely requiring routing adjustments to utilize highway and railroad rights of way. This system alternative should be reviewed as a system alternative in the Certificate of Need docket prior to consideration of routing.

Transmission underground in Minnesota is feasible. A study was prepared for the Minnesota Department of Transportation regarding undergrounding, with a Next Gen Highways workgroup that included staff of both Minnesota's Dept. of Commerce and Public Utilities Commission. The study's essential finding was that:

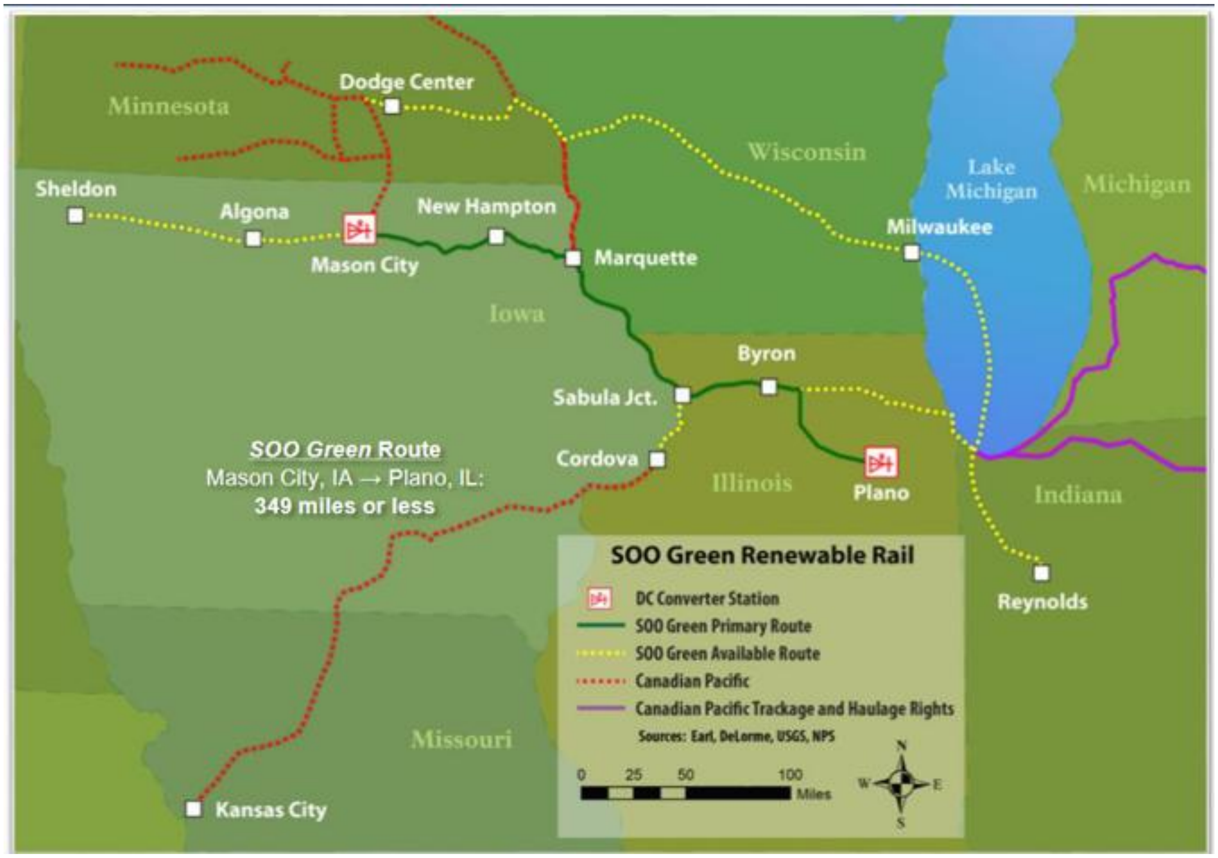
> **Conclusion**
>
> The findings from this study demonstrate that buried HVDC transmission can be cost-effective and that there is the potential to be sited in Interstate and highway ROW after making appropriate consideration of existing and future transportation system needs. Next steps are proposed to address the challenges identified over the course of this study.
>
> Buried fiber in the interstate and highway ROW shares many of the same challenges as buried HVDC transmission. Given the ability of state DOTs to co-locate buried fiber and HVDC transmission, it makes sense for them to consider the potential for future accommodation of buried HVDC transmission when installing fiber in interstate and highway ROW. [48]

In 2023, the Iowa Utilities Board approved the Soo Green transmission project, a proposal to move 2,100MW utilizing railroad easements for undergrounding, on easement secured from CP rail. Counties across Iowa have permitted the project. The Soo Green transmission project is expected to cost $3.2 billion.

[49]

[48] NextGen Highways Feasibility Study for the Minnesota Department of Transportation: Buried High-Voltage Direct Current Transmission https://nextgenhighways.org/wp-content/uploads/2023/01/NextGen-Highways-Feasibility-Study-Minnesota-DOT.pdf
[49] SOO Green Wins Final Iowa Approval, Clearing Path for $3.2B Underground Transmission Line, 2/6/2026 https://constructionreviewonline.com/soo-green-wins-final-iowa-approval-clearing-path-for-3-2b-underground-

The Soo Green line originally identified an "available route" in southeast Minnesota from Dodge Center to the Mississippi River, southward, and into Wisconsin, similar to the CapX 2020 route. It began in Dodge Center(the yellow dotted line) through Rochester, northeast to the CapX crossing then south to La Crosse and onward into Wisconsin, apparently towards Columbia:



A Soo Green presentation from 2018 stated the plan was to route under the Mississippi River, and also references five underground transmission lines in Germany.[50]

Another demonstration of the feasibility of underground was made public last week, when PJM approved a two-stage 185 mile underground transmission line with 6,000MW capacity on Dominion right-of-way between Heritage substation near Freeman, VA and Mosby

transmission-line/

[50] SOO Green Project Overview, October 24, 2018.

substation near suburban Washington, D.C. in Aldie, VA[51], and two HVDC converters at each end of the line:

Upgrade ID	Description	Cost Estimate ($M)	Designated Entity \ Transmission Owner	Cost Responsibility	Required IS Date
b4053.3	Construct a new bipolar +/- 525 kV HVDC link connecting Heritage and Mosby substations, where the link has a capability of transmitting 3,000 MW. The HVDC link, approximately 185 miles in length, will be fully routed underground between the two new proposed converter stations, one at Heritage and one at Mosby.	$2,271.70	VEPCO	**Load-Ratio Share Allocation:** AEC (1.63%) AEP (14.27%) APS (5.89%) ATSI (7.62%) BGE (3.96%) ComEd (12.47%) Dayton (2.04%) DEOK (3.12%) DL (1.62%) Dominion (14.85%) DPL (2.53%) EKPC (2.26%) JCPL (3.78%) ME (1.81%) Neptune (0.41%) OVEC (0.07%) PECO (5.04%) PENELEC (1.75%) PEPCO (3.62%) PPL (4.85%) PSEG (6.16%) RE (0.25%) **DFAX Allocation:** BGE (5.17%) DL (1.48%)	6/1/2032
b4053.4	Design and construct a new Voltage Source Converter (VSC) HVDC station at Heritage substation to support the new HVDC link.	$773.73	VEPCO	**Load-Ratio Share Allocation:** AEC (1.63%) AEP (14.27%) APS (5.89%) ATSI (7.62%) BGE (3.96%) ComEd (12.47%) Dayton (2.04%) DEOK (3.12%) DL (1.62%) Dominion (14.85%) DPL (2.53%) EKPC (2.26%) JCPL (3.78%) ME (1.81%) Neptune (0.41%) OVEC (0.07%) PECO (5.04%) PENELEC (1.75%) PEPCO (3.62%) PPL (4.85%) PSEG (6.16%) RE (0.25%) **DFAX Allocation:** BGE (5.17%) DL (1.48%) Dominion (87.78%) PEPCO (5.57%)	6/1/2032
b4053.5	Design and construct a new Voltage Source Converter (VSC) HVDC station at Mosby substation to support the new HVDC link.	$745.42	VEPCO	**Load-Ratio Share Allocation:** AEC (1.63%) AEP (14.27%) APS (5.89%) ATSI (7.62%) BGE (3.96%) ComEd (12.47%) Dayton (2.04%) DEOK (3.12%) DL (1.62%) Dominion (14.85%) DPL (2.53%) EKPC (2.26%) JCPL (3.78%) ME (1.81%) Neptune (0.41%) OVEC (0.07%) PECO (5.04%) PENELEC (1.75%) PEPCO (3.62%) PPL (4.85%) PSEG (6.16%) RE (0.25%) **DFAX Allocation:** BGE (5.17%) DL (1.48%) Dominion (87.78%) PEPCO (5.57%)	6/1/2032

[52]

Note the costs of the line and converter stations in comparison to the cost in the application of the Gopher to Badger line – just the Minnesota segment at $979 million to $1,273 million.

iv. A system alternative building on the "Thomforde alternative" above is to design that route across southern Minnesota as a direct current line.

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51 New HVDC Transmission Link from Heritage to Mosby - https://www.pjm.com/-/media/DotCom/planning/rtep-dev/expan-plan-process/ferc-order-1000/rtep-proposal-windows/2025-rtep-window-1-redacted-proposals/2025-w1-815.pdf

52 PJM 2026, Transmission Expansion Advisory Committee (TEAC) Recommendations to the PJM Board, p. 50-51, https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2026/20260203/20260203-pjm-board-whitepaper-february-2026.pdf

If there is a need for export direct current would be a better design to satisfy the need and eliminate some cost. Direct current alternative is ideal for a long line with few substations needing an expensive converter equipment. Using the "Thomforde alternative" would eliminate substations by going straight from South Dakota through Minnesota to the Wisconsin border and beyond.

v. A system alternative building on the "Thomforde alternative" would be to route the DC line in the Interstate 90 corridor.

The Minnesota legislature passed amendments to transmission law allowing, encouraging, promoting use of railroad and highway rights of way for routing transmission beyond the DOT's Policy of Accommodation.[53] The Interstate 90 right of way would provide a direct route to Wisconsin for export, design using direct current more suited due to elimination of substations on an export line and the long length of the line.

vi. The Wilmarth, King-Eau-Claire-Arpin, and Prairie Island-Byron Adams 345kV transmission lines should be updated.

As above, as system alternatives go, updating the lines identified as a system stability issue is an obvious one, and should have been done long ago. Applicants have included a "Map of top Steady-State Reliability Issues Mitigated by the Studied Projects" in the Application."[54] Half are not in Minnesota. Two of the problem lines originate near the Metro, and another is near, and because they are "all connected," they affect the project area. Heading directly northeast is the Wilmarth line; east is the King-Eau-Claire-Arpin 345kV transmission line, and heading directly south from the metro area is the Prairie-Island-Byron-Adams 345kV line. The Prairie Island-Byron-Adams 345kV line was placed in service on January 2, 1970, over fifty-five

[53] MnDOT Utility Accommodation and Coordination Manual, https://dot.state.mn.us/policy/operations/oe002.html
[54] Figure 6.3-1, p. 119.

years ago, and it has not been upgraded. The King-Eau Claire-Arpin[55] was placed in service on January1, 1960, sixty-five years ago, and it has not been upgraded. Neither of these two lines have not been upgraded since they were built.[56] The other lines shown in Minnesota as "Top Steady-State Reliability Issues" are also lines built decades ago. The Wilmarth line in southern Minnesota was reconductored to address a decades long sag problem, but more information is needed as it is identified as a "steady-state" stability problem..

The upgrade, reconductor, rebuild states of these lines is another issue of fact. If these lines are a steady-state reliability issue, why hasn't the problem been fixed? These lines appear to have been neglected for decades, and are now used as justification for this project. These lines supporting the 345kV system are identified as problem lines now, yet continue to be relied on to provide support for the 345kV system. These lines would also be expected to support the 765kV system? Without upgrades, this is foolhardy. All of these "Top Steady-State Reliability Issues" should be rectified, upgraded, reconductored, whatever is necessary to provide that needed steady-state reliability. If upgraded and no longer the "Top Steady-State Reliability Issues," what is the impact on need for the web of "Power on Minnesota" transmission projects? This is a contested issue of fact.

B. Environmental review early in this process is essential, as environmental review must address system alternatives.

A primary "other issue" is that of environmental review. Environmental review for a project, projects, of this magnitude should receive the full iterative review of an Environmental Impact Statement, required for a "Major" routing review. There are many system design and system

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[55] It was the King-Eau Claire-Arpin line that crashed on June 25, 1998, due to operator overloading above operating limits and failure to act on overload warnings, almost taking out the Eastern Interconnect. legalectric.org/f/2020/01/Northern-MAPP-Northwestern-Ontario-Disturbance-June-25-1988-FINAL-REPORT-1.pdf

[56] Attachment E, Information Requests 1 & 2, The Prehn Family and No CapX 2020, April 7, 2025, PUC Dockets E002/CN-22-532 and TL 23-157.

alternative impacts that need to be identified and considered in the Certificate of Need and demand environmental review, ideally in an Environmental Impact Statement. This should be a joint process as required by Certificate of Need statute and Major routing process. Minn. Stat. §216B.243, Subd. 4.

In Minnesota, there are no 765kV transmission lines – these southern Minesota Tranche 2.1 projects comprising "Power on Minnesota" are queued up to be the first. The environmental consequences of 765kV lattice towers through southern Minnesota cannot be overstated.

VI. CONCLUSION

This Certificate of Need application is essentially complete – information missing can be obtained through Information Requests, though this is a shift of the burden of production.

Several contested issues of fact that are focused on need, cost, and cost benefit have been raised, sufficient to justify referral to the Court of Administrative Hearings for a contested case proceeding.

An informal process of any sort is not appropriate, and the notion that an "informal process" as provided by Minn. R. 7829.1200 is absurd – it does not fit any of the three criteria.

Thorough environmental review is necessary, particularly where there are reasonable and available system alternatives.

Based on the above Comments, I request referral to CAH for a joint Contested Case process for the Certificate of Need and Route Applications, with multiple public hearings in the many counties along the route, an evidentiary hearing, and thorough environmental review as provided in an Environmental Impact Statement.

Thank you for the opportunity to file these comments in the "Power on Minnesota" transmission line dockets CN-25-117, CN-25-118, CN-25-119, and CN-25-120.

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