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February 25, 2026

Sasha Bergman
Executive Secretary via eFiling only
Public Utilities Commission
121 – 7th Place East
St. Paul, MN 55101

RE: Initial Comment – Completeness and Process
Gopher-Badger/Maribell Transmission Line
PUC Docket E015/CN-25-121

Dear Ms. Bergman:

On behalf of the North Route Group and NO765MN, attached please find Initial Comments on Completeness and Commission Process.

Please add to the Commission's Service List:

Suzanne Tomek
North Route Group
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Zumbro Falls, MN 55991

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John Pugleasa
NO765MN
3795 County 14
Caledonia, MN 55923

jjpugleasa@gmail.com

Thanks for your attention to this procedural matter.

Very truly yours,

Carol A Overland

Carol A. Overland
Attorney at Law

cc: North Route
Group NO765MN

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 Gopher to Badger Link 765kVHigh Voltage Transmission Line Project

DOCKET NO. ET3, E002/CN-25-121

CERTIFICATE OF SERVICE

INITIAL COMMENT OF NORTH ROUTE GROUP AND NO765MN

I, Carol A. Overland, hereby certify that I have this day served a true and correct copy of the attached North Route Group and NO765MN Initial Comment to all persons at the email addresses on the Public Utilities Commission eDockets service list by eFiling and eService.

February 25, 2026

Carol A. Overland

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INITIAL COMMENT OF NORTH ROUTE GROUP AND NO765MN

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 6, 2026.

The North Route Group and NO765MN offer the following Comments on the Commission's topics for comment. As an intervenor in the CapX 2020 routing dockets from Fargo to St. Cloud, Hampton to La Crosse 15 years ago, the North Route Group now confronts the proposal of a very similar route to the one that was soundly rejected by the Commission in 2012. NO765MN is a group of landowners. residents, farmers, and business owners in the southeastern tip of Minnesota, in Houston County, who live, farm, and work near the Mississippi River and the Minnesota-Wisconsin border along the 161kV transmission line that Dairyland has proposed to utilize as corridor for its 765kV transmission line through their community. The 161kV line is an older transmission line perched atop a ridge where routing an expanded easement for a transmission line would be "challenging" at best and the line would be visible for many miles.

The "need" for this line is not apparent and has not been demonstrated by the Applicants. There are also issues of fact justifying a contested case, a joint case of this Certificate of Need docket and the yet to be applied for Route Permit docket.

Both the North Route Group and NO765MN oppose this 765kV project and are participating in this docket to demonstrate that the Applicants have not shown need for this transmission project, that the cost estimates and cost/benefit analysis are skewed, and that there are system alternatives that would be better for the State of Minnesota and communities that would have to live with this transmission line.

I. NOTICE OF THIS COMMENT PERIOD WAS NOT PROVIDED TO LANDOWNERS AND PROJECT NOTICE NOT FULLY PUBLISHED

At the outset, it should be noted that the affected landowners, who did receive a notice of the pending application and utility open houses from the applicants, did not receive a Notice of Comment Period from the Public Utilities Commission. It's difficult to be a participant when there is no notice. Thankfully, there's word in the streets and cornfields, and some learned about this project, are sharing information, and will not miss this opportunity for participation.

There was another notice problems as well as it appeared that only those whose name, alphabetically, was "HALVORSEN,ANDREW J, HALVORSEN,MELISSA O" or before was sent the "Notice Plan" project mailing, and that names following alphabetically were not.[1] The Certificate of Service[2] mailing list reflects only A-Halvorsen, though names are a jumble of last names and first names alphabetically, i.e., Rep. Greg Davids is listed as "Gregory Davids," and he did receive notice.[3] The pattern of use of first or last names on the list is not apparent.

[1] Application, Attachment B, p. 100 where the list ends.
[2] Application, Attachment C, Certificate of Service.
[3] Application, Attachment B, p. 97.

However, on February 23, 2026 at 12:00 a.m., Applicants filed what appears to be the full notice list, and that those after "HALVERSON" were sent the Notice Plan mailer.

But it's not over. These are the newspapers on Applicants' list for publication of Notice:

Gopher to Badger Link

Application notice plan January newspaper ads: Run dates, affidavits and tear sheets

Media outlet	Run date
Austin Daily Herald	1/21/2026
Caledonia Argus	1/21/2026
Kenyon Leader	1/21/2026
Minnesota Star Tribune	1/19/2026
Preston Fillmore County Journal	1/19/2026
Rochester Post Bulletin	1/20/2026
Wabasha County Herald	1/20/2026

[4]

Missing are the Zumbrota News-Record[5] and the Red Wing Republican Eagle.[6]

Notice has been deficient in two ways – the notice of the Certificate of Need comment period was not provided to any landowner. The newspaper notices were deficient as at least two newspapers in the area of counties affected were not given the notice to publish.

The Commission must correct this failure of notice. Because failure of notice for the Completeness and Process comment period 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, it is also a systemic failure of Commission process and procedure, which must also be corrected.[7] How can these multiple failures of notice be corrected but for a do over providing the requisite notice?

II. THE CERTIFICATE OF NEED APPLICATION MAY CONTAIN THE INFORMATION REQUIRED, BUT MORE INFORMATION IS NEEDED.

While the Certificate of Need does arguably contain the information required as

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[4] Application, Attachment G, p. 1.

[5] The applicants held a well-attended open house in Zumbrota on January 12, 2026, yet no "Notice Plan" notice in the paper in January.

[6] The Republican Eagle did publish notice for the Power on Midwest on January 10, 2026.

[7] The landowners along the Iron Range-Arrowhead docket N-25-111, 112, did receive notice, though scoping meetings were cancelled and we're waiting for rescheduling.

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, information that is not yet provided. The Commission's Order is applicable only to the Application, and does not limit the information that should or must be provided by the Applicants for the record to be considered by the Commission.[8]

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

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 14 of the rules specifying contents of a Certificate of Need application. It's interesting that two of the southern Minnesota 765kV MISO Tranche 2.1 projects, consolidated MISO 22, 23, 24, & 25, and PUC Dockets CN-25-117, 118, 119, and 120; and this MISO project 26, PUC Docket CN-25-121 have extensive exemption requests, and those requests were all granted. The MISO Tranche 2.1 345kV projects just applied for in northern Minnesota, MISO project 20, PUC docket CN-25-109 and MISO project 21, PUC dockets CN-25-111 and TL.25-112 made very few exemption requests. The granting of such broad exemptions for the application requirements for these first of a kind long 765kV lines is neither reasonable or logical. The exemptions for two of the southern Minnesota 765kV MISO projects, consolidated 22, 23, 24, & 25, and PUC Dockets CN-25-117, 118, 119, and 120; and MISO project 26, PUC Docket CN-25-121 are excessive and unjustified.

Specifically, the exemptions granted by the Commission, on recommendations of

[8] 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.

Commerce, for PUC Docket CN-25-121 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.

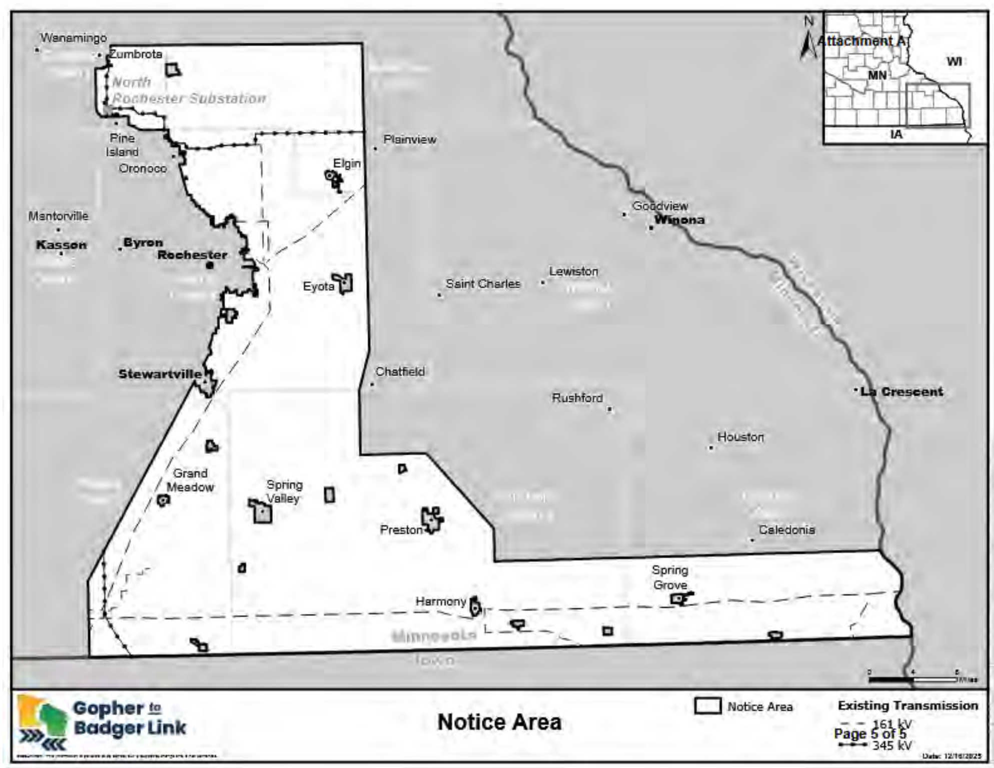
- **Minn. R. 7849.0260 B(4) and (8)** were not fully exempted, and Commerce notes that "it is not recommending a wholesale exemption from Minn. R. 7849.0260 B(8), " in "providing the data required." Minn. R. 7849.0260 B(8) is "any reasonable combinations of the alternatives listed in subitems (1) to (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.[9]

- **Minn. R. 7849.0260 D** requires a system 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

[9] 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).

proposed Notice Area." This is the approved "Notice Plan" map showing the area with high voltage transmission lines in the area:



[10]

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.2421defines "high voltage" as:

> (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;

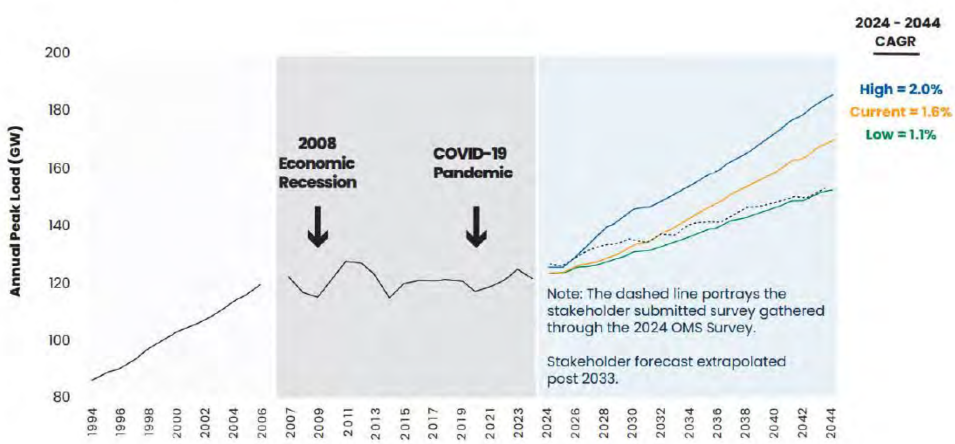
To comply with Minn. R. 7849.0260 D, the Application must include all high voltage lines in Minnesota and the five state area, with visible designation of voltages, substations, and all Tranche 1 and Tranche 2.1 projects. Need cannot be determined without consideration of the overview. This map is essential.

- **Minn. R. 7849.0270, Subps. 1-5.** The Applicant/MISO's vision of peak demand and annual consumption is contested. The notion of exemption for peak demand and

[10] Notice Plan Compliance Filing 20262-227889-01, February 5, 2026.

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 forecast of 2.49% annual demand increase, 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 77 of the Application, is a graph reminiscent of the extreme overstatement of the CapX demand forecast:

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



A look at MISO's "Long-Term Load Forecast" from December 2024[11] also uses this chart to depict "Net Peak Load Expectations Over Time (1994-2044).[12] This report identifies "five" key drivers, and 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.

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[11] See Application, fn. 18: MISO. December 2024, Demand Forecast Whitepaper. Available at: https://cdn.misoenergy.org/MISO%20Long-Term%20Load%20Forecast%20Whitepaper_December%202024667166.pdf
[12] Id, p. 4.

This report is from December 2024, and so much has changed. The "drivers" are prior to the 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."[13]

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." This does not take into account this administration's efforts to resurrect fossil fuel.[14]

AI Revolution and Data Centers (p. 17) is another 2024 notion that is shifting, with increasing projections of an AI bubble burst in 2026.[15] 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.[16]

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.[17]

Green Hydrogen (p. 26) development is, as noted in the report, supported by

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[13] See Executive Order 14386, STRENGTHENING UNITED STATES NATIONAL DEFENSE WITH AMERICA'S BEAUTIFUL CLEAN COAL POWER GENERATION FLEET, https://federalregister.gov/d/2026-03156

[14] Id.

[15] 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/

[16] 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/

[17] 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/

federal incentives, incentives that have been withdrawn in 2025.[18]
Distributed Energy Resources (DERs), rather than create demand for transmission, reduce need for transmission by generating electricity at or near load.[19] "Distributed generation can significantly impact inter-zonal transmission flows… At moderate levels, distributed generation adoption could cause certain inter-zonal transmission investments to be delayed or avoided."[20]

- **Summary – C.6.7** Use of the "alternative data" rather than the Applicants' data responsive to these rules demonstrates that this transmission project is not for Minnesota. Further, the "alternative data," which applicants' want to use, the MISO basis for demand forecasts, is materially flawed.

- **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).[21]

Commerce and the Commission again rely on the "we've done it before, so let's do it again" theory. That's insufficient rationale.

- **Minn. R. 7849.0290** Efficiency and energy conservation have done much to keep the peak demand down. 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.** Commerce and the Commission again rely on the "we've done it before, so let's do it again" theory. That's insufficient rationale.

- **Minn. R. 7849.0330 G** The applicants state that, "because the Project's specific route will be determined in future proceedings, they seek an exemption," but the excuses are disingenuous. There are routes on the map for viewing on the applicants' gophertobadgerlink.com site, and from there scroll down to the

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[18] 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/
[19] 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**;**
[20] Id.
[21] Order, p. 21 of 30, Commerce Exemption recommendations, p. 10, **202512-226131-01** December 23, 2025.

> "interactive map" page. At the open houses, there were several computers set up where people could ask to see their property with the transmission corridors drawn on the map. Because Commerce and Commission staff did not attend the applicants' open houses, perhaps they are not aware that there are lines drawn on the map. This exemption makes no sense because there are corridors on the map, available for the looking.

The Commission too readily accepts Exemption Requests and in doing so, little by little abdicates its regulatory responsibility. An incomplete application has the effect of shifting the burden of production onto the state agency that approved the exemptions, and on 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 addressing 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 economics of the MISO Tranche 2.1 project have changed dramatically, and the 2024 cost estimates and the cost/benefit analysis on which Tranche 2.1 relies are no longer valid.

The Commission is the regulator, and the applicants have not demonstrated that the line is needed as required by Minnesota law. In short, 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 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. [22]

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 developer filing Notice of Force Majure and the project brought to a screeching halt.[23] Each transmission project before the Commission should be carefully scrutinized and cost increases

[22] See Attachment A, 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.
[23] 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.

identified, and 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 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 Gopher to Badger transmission line does not provide benefits for the proposed transmission corridor.

Whether the project provides benefits to the transmission corridor is a contested issue of fact. The Application does not specify these claimed 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."[24] When it is MISO members, the applicant utilities and others, 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

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

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 does it offset any property tax revenue decrease?[25] 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[26] and in its Intervention[27] in a FERC docket where North Dakota and other Commissions are challenging cost allocation for the MISO Tranche 2.1 projects. [28]

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,[29] stating:

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[25] It is presumed that local governments will receive Utility Personal Property Tax on the project's physical structures, but that amount is unknown.
[26] Attachment B, MISO IMM Comments on LRTP Tranche 2 Benefit Metrics, May 29, 2024.
[27] Attachment C, MISO IMM Motion to Intervene, September 9, 2025.
[28] 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).
[29] Attachment D, 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.[30]

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.

Applicants claim that the line is needed, that there are three drivers:

1) Mitigate system overloads to maintain system reliability to meet existing and future energy needs;
2) Meet growing electrical demand in a cost-effective manner; and
3) Support the energy transition.

Newly permitted transmission lines across southern Minnesota into Wisconsin and Iowa also calls this "need" into question. Some of the transmission build-out applied for and/or permitted in southern Minnesota are:

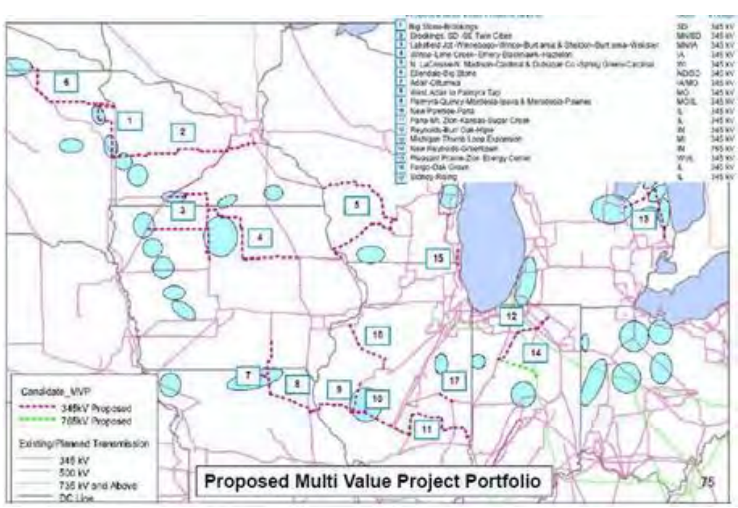
- Wilmarth/North Mankato through North Rochester to Mississippi/Tremval to Columbia
- Big Stone to Brookings …
- 2nd circuit Brookings-Lyon County & Helena -Hampton - PUC CN-23-200; TL-08-1474
- Lyon County to Sherco with 800MW in new gas generation for over 2,000 MVA capacity and 10-12% line loss
- MVP Portfolio – 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 – 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

[30] MISO's Tranche 2.1 analysis and the Gopher to Badger 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.

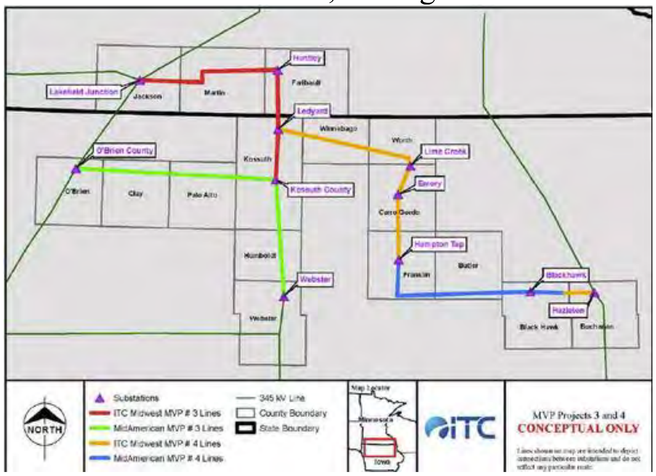
Some of these projects, notably the CapX, MISO MVP Portfolio, and Tranche 1 and Tranche 2.1, are obviously connected, but are segmented, with artificial beginning and end points, most notably for the southern Minnesota projects beginning at the South Dakota Border, extending through Minnesota and also into Iowa (CN-25-117, 118, 119, 120) and Power on Midwest's connection to the Gopher to Badger project at the new "North Rochester" substation.

When these 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.

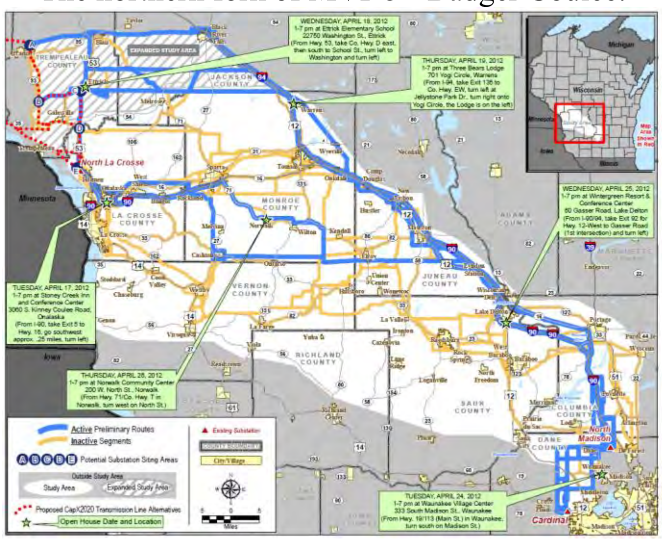
MVP projects 3, 4 through southern Minnesota and into Iowa, and 5, the northern part from La Crosse to Cardinal called Badger Coulee, and from Dubuque to Cardinal, Cardinal-Hickory Creek:



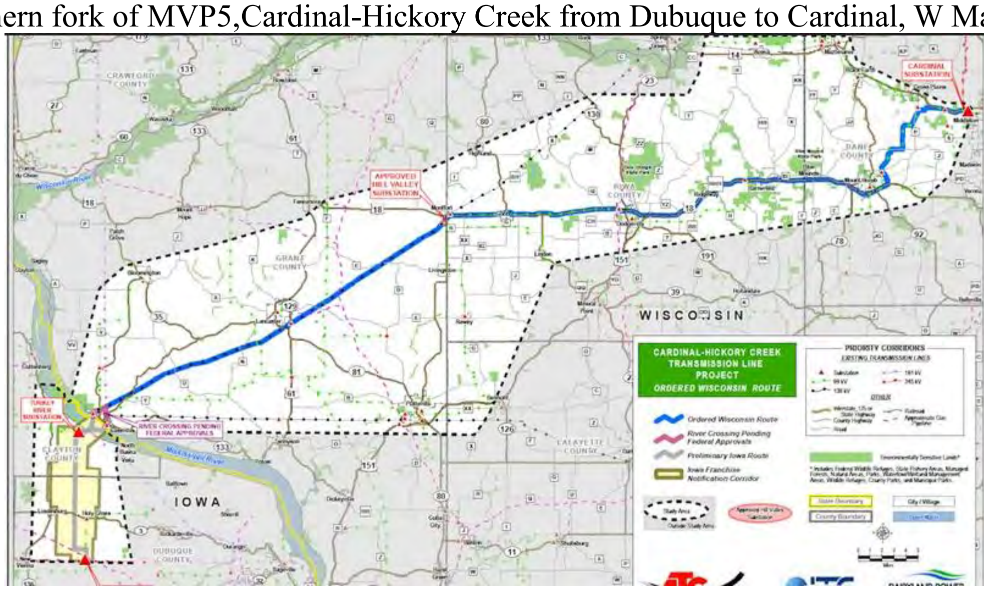
MVP 3 and 4 in southern Minnesota and Iowa; 5 Badger Coulee & Cardinal-Hickory Creek:



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.[31] If these lines were reconductored or rebuilt, much transmission capacity would be gained.

ii. Batteries are an 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 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. Minn. Stat. § 216I.05, Subd. 11(e) and IV. System Alternatives, A (ii) below.

v. Existing and planned transmission projects with the same 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 is claimed in the application to be comparably low. 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,[32] but "consumers" are different from

[31] 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.
[32] Application, §1.4.2, p. 6-7. The section is headed "Local Minnesota Drivers" but the benefit-cost information

ratepayers, and 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.

First, 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, 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, and a cost benefit analysis for each discrete transmission project 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 will accrue – the Commission had best account for the entire cost of MISO Tranche 2.1 and the other "portfolios" in Schedule 26A[33] as a part of this docket, as the dockets in other states that add cost to Minnesotans will not otherwise be addressed.

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

Cost of the project is another issue of fact. As above in paragraph A, economics in the

provided is not local to Minnesota or the project area

[33] 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

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**

[34]

[34] 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."

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.

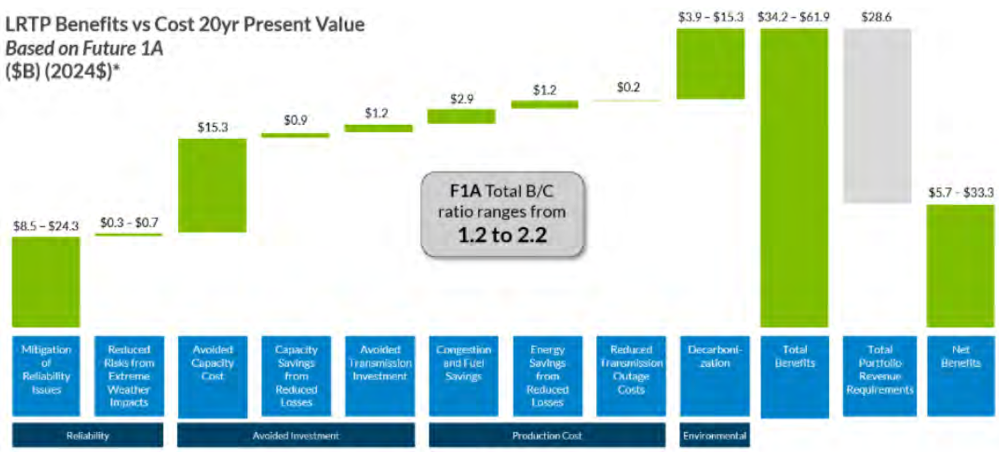


Figure 2.155: Tranche 2.1 Benefits based on Future 1A. [35]

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.

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

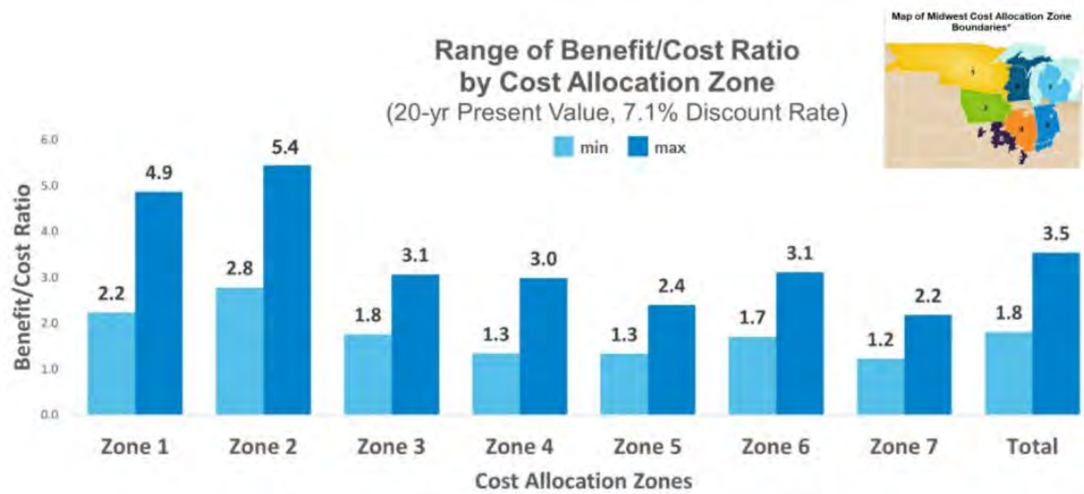


Figure 2.157: Tranche 2.1 Distribution of Benefits – Future 2A [36]

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, and it's impossible to properly evaluate costs. Again, costs of this project and each project in Tranche 2.1 are a contested 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 Gopher to Badger transmission line and runs from North Rochester to Marion to the Mississippi River at a cost ranging from $979 million to $1,273 million.[37]. However, MISO's project 26 is "North Rochester to Columbia," at an estimated cost of $1,924 in 2024 dollars.[38] How can these lines be compared? These cost estimates are a contested issue of fact.

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

At the Maribell open house in Caledonia, this writer was told that the capacity of the

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[36] MTEP24, Benefits, Future 2A, p. 163
[37] Application, §1.1, p. 1.
[38] MTEP24, p. 162, Table 2.35.

project was 5,300 MVA. The application states, “The Studied Projects help enable approximately 24,000 MW of new generation (10,000 MW in Minnesota) to be reliably connected to the transmission grid,” and “The Applicants and MISO identified the need to transfer upwards of 10,000 MW more electrical capacity to, through, and out of Minnesota to meet customer demands.[39] Additionally, the Applicants claim that “As two 765 kV lines carry the equivalent as twelve 345 kV lines…”[40] logically one circuit would carry the equivalent of six 345kV lines.

For Segment 1, Applicants state:

> On Segment 1, a six-conductor bundle of 1192.5 thousand circular mil (kcmil) 45/7 aluminum conductor steel reinforced (ACSR) Bunting conductor with 15-inch sub-conductor spacing and a total capacity equal or greater than 4,000 amperes (amps) is proposed…

… and without any capacity disclosure:

> On Segment 2, the Project will utilize a six-conductor bundle of 795 kcmil 30/19 ACSR Mallard conductors with 18-inch sub-conductor spacing for the 765 kV circuit and a two-conductor bundle of 795 kcmil 30/19 ACSR Mallard conductors with 18-inch subconductor spacing for the 161 kV circuit. 1037 AECC York conductor will be utilized at the Mississippi River crossing.

The expected and maximum ampacity at 765kV is necessary to determine the capacity numbers for each segment – 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.”[41] This presumes that “approximately” 204 MW line loss, at a rate of 11.33-12.75% for that project.

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[39] Application, §1.5.3, p. 12; 1.6.1, p. 14.
[40] Application, §7.5.1.2, p. 142.
[41] Commission Order Authorizing Joint Proceedings, **20238-198151-01**, August 10, 2023.

This project, adding Segment 1 and Segment 2, total roughly 140 miles, depending what routes are chosen. 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.[42] 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.[43]

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[44], and two HVDC converters at each end of the line. This project is through a relatively congested area near Washington, D.C. The comparative cost of undergrounding near a populated suburban and exurban Washington, D.C. compared with the rural project area for Gopher to Badger 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.

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[42] See also **System Alternatives**, §V A(ii) below.
[43] See Wellstone & Casper's *Powerline: The First Battle of America's Energy War.*
[44] 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

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

Applicants' claim that undergrounding is cost prohibitive is a contested issue of fact. Applicants reject AC undergrounding, which is not an industry standard practice, and do not even consider underground DC lines. As above, PJM has approved a 185 mile underground DC transmission line through a rural, suburban, and exurban area near Washington, D.C. The Soo Green line is designed to be underground utilizing railroad corridor and has been permitted by the Iowa Utilities Commission.[45] The cost of the PJM project in a populated area should be compared with underground cost in the rural project area, and compared with the cost of the AC overhead Gopher to Badger project. The comparative costs of undergrounding DC versus the overhead AC Gopher to Badger project is a contested issue of fact.

M. What are the project's "three delivery points" in Minnesota and three additional delivery points outside of Minnesota?

The application states, in arguing against use of direct current and the high cost of DC converter stations, that "**the Project** has three 765 kV delivery points (i.e., substations) in Minnesota and **three additional delivery points outside of Minnesota**."[46] The Maribel substation near Marion appears to be the only substation with a 765kv connection.[47]

Are the Applicants referring to these substations?

48

45 See below, **System Alternatives**.
46 Application, §7.4.4, High Voltage Direct Current, p. 140 (emphasis added).
47 Application, 1.2.1.3 Substations, p.
48 Application, Figure 6.1.1, p. 87.

If they are, they're referring to "the project" as CN-25-117, 118, 119, 120, and 121, and comparing apples to oranges, conflating the projects, and providing misleading information.

Identification of these 3 in-state substations is an issue of fact. Because "the project" Gopher to Badger as applied for is only in Minnesota, where are these substations and are they the same as on the above map in Figure 6.1.1.1? If so, the Application should be corrected.

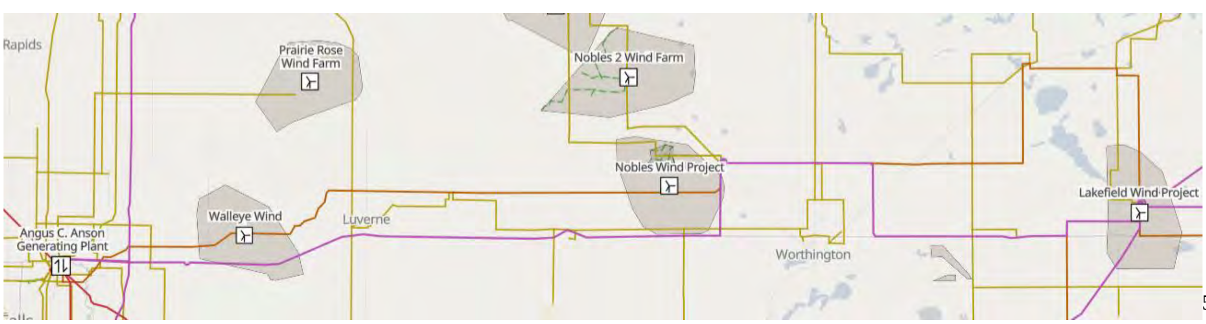
Is Marion/Maribell substation the only 765kV Minnesota substation within this project? Is one substation, one DC converter system, cost prohibitive? What are the specific costs referred to for 765kV substation and DC converters? It appears that the answer to these questions would alter the cost equation in analyzing the use of DC. These are contested issues of fact.

N. Applicants argue excess energy and the need to export that excess energy demonstrates a need for this project.

The Applicants raise the issue of excess energy and the need for **<u>this project</u>** to export that excess:

> Likewise, when southern Minnesota has generation output in excess of what is needed locally, the existing grid is incapable of fully exporting that energy so it can be sold to other areas. The result is this excess energy is currently curtailed (wasted) at times.[162] The inability to fully export excess energy has economic consequences for southern Minnesota through the inability to sell a product and potential reliability consequences for other areas who need power to serve their load.[49]

This footnote 162 states, "The Commission examined generation curtailment and transmission congestion in southern Minnesota (Nobles County). Docket No. E999/CI-24-316."[50] Nobles County and Nobles wind projects are midway between Split Rock and Lakefield Jct. substations.

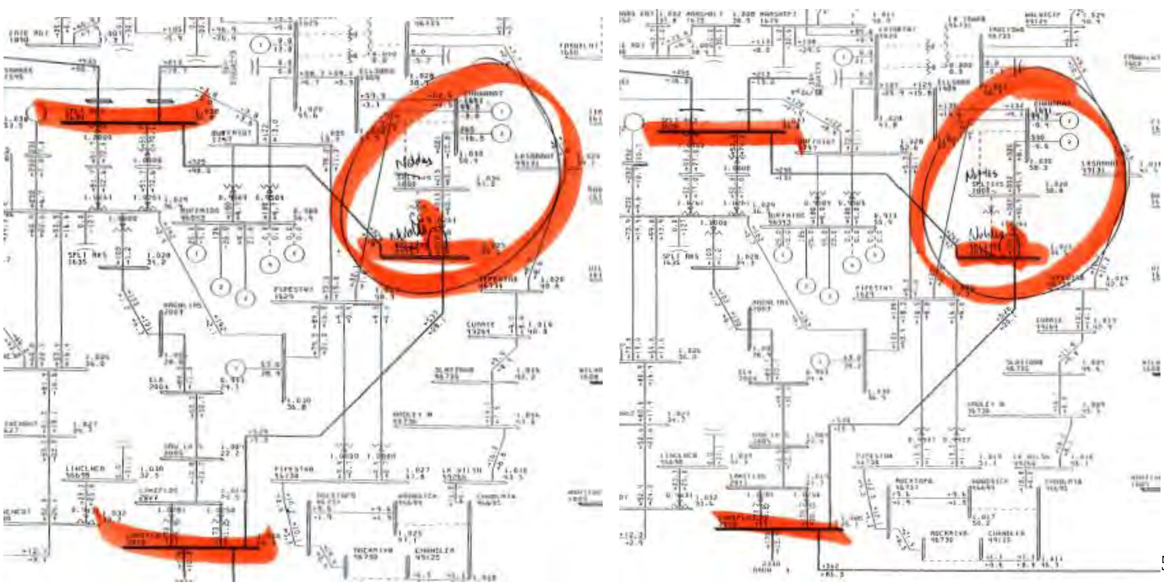


[51]

[49] Application, §6.3.1.1, p. 94.
[50] Id.
[51] https://openinframap.org/#8.78/43.9144/-95.6402

This argument is better suited for the Tranche 2.1 project in that area, MISO 22, Big Stone South- Brookings County- Lakefield Junction, together with consideration of utilization of the SW MN 345kV that was permitted in 2001, the MISO MVP 3 and 4 from a decade ago, and also the Tranche 2.1 Lakefield Jct. to Adair, Iowa.

Coincidentally, it is this same area that as shown in powerflows from the SW MN 345kV Split Rock-Lakefield Jct. transmission line, EQB Docket 01-1958, that was promoted as "transmission for wind," where just 213-302 MW was coming off of Buffalo Ridge into this 2,000+ MVA new transmission line![52]


[53]

The claim that this MISO 26, PUC CN-25-121 from North Rochester to the Mississippi (and onward to Columbia) is needed for export of curtailed energy from Nobles County is an issue of fact and while relevant to the Big Stone II-Brooking-Lakefield Jct 765kV, even if true, it's not a valid argument for need for the Gopher-Badger North Rochester to Columbia line.

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

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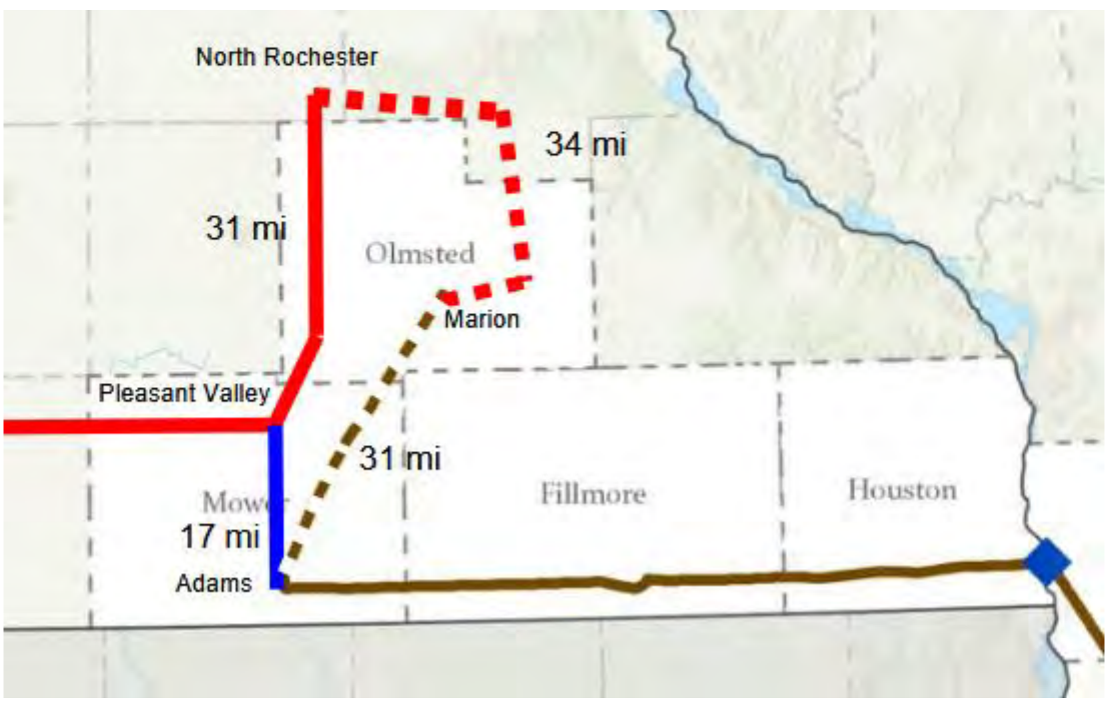
[52] Attachment F, Powerflows, SW MN 345kV Split Rock-Lakefield Jct. 345kV transmission, EQB Docket 01-1958.
[53] Id.

The need for the project becomes an issue of fact when Applicants point to the substations in the map above and 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, and the cost of the project, is to eliminate 65 miles of 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 across southern Minnesota to the Mississippi.



P. 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

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."[54]

Looking at procedure in the Commissions Ch. 7849 and 7829 reveals only one "informal process,"[55] found in Minn. R. 7829.1200, as Ordered in the Iron Range – Arrowhead project:

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[54] 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.
[55] Id.

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 not appropriate 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.

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[56], 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 must follow the letter and spirit of the law.

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

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 and high profile crossings of the protected Zumbro River and Mississippi River.

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 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. Battery storage is a viable and cost recoverable alternative to transmission.

Batteries are now regarded by FERC as a viable alternative to transmission. The value of battery storage has been growing over[57] 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."[58] In his testimony, he notes the directive of FERC Order 890:

[57] See Renewable-Storage Hybrids in a Decarbonized Electricity Supply, https://docs.nrel.gov/docs/fy23osti/84192.pdf

[58] Attachment G, Direct Testimony of Wellinghoff, 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

> *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] [59]

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 Gopher-Badger 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

[59] Id., p. 9.

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. [60]

[60] 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-

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. [61] The Soo Green transmission project is expected to cost $3.2 billion.

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 west of 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:

Feasibility-Study-Minnesota-DOT.pdf

[61] 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-transmission-line/

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.[62]

In Comments in the CapX 2020 Hampton to La Crosse proceeding,[63] the DNR repeatedly discussed undergrounding under the Mississippi River. Routing under the Mississippi was preferred over a new crossing of the river or utilizing an existing corridor above ground. If undergrounding, combining an existing line with the new line underground was recommended.

> The DEIS should include a robust description of possible underground crossings of the Mississippi River. The Mississippi River is one of the primary flyways in North America and, as discussed in the route permit application, a National Wildlife and Fish Refuge in this area. Examples of ways to further analyze an underground option follow: Underground route crossing options discussed in the DEIS should not only include an underground option at the location(s) best suited for considering aerial crossings, but should include an underground route at the location(s) best suited for engineering an underground route, which may or may not be the same location as the Alma crossing. The reasoning for the route(s) chosen for an underground crossing analysis should be included with the description of underground routing. A comparison of impacts and mitigation should be included for aerial and underground crossings of the Mississippi. [64]

> A description is included in the DEIS of an underground configuration to cross the Mississippi River. A thorough assessment of underground routing through this portion of the project is important as the Mississippi River is one of the primary flyways in North America. Underground routing is more expensive and technically challenging and therefore may be considered only practical when a uniquely high risk of natural resource impact exists. Considering that this flyway is one of four primary flyways for all migratory species in North America, that transmission lines pose a risk of avian collision, and that the line is crossing through this narrow flyway corridor, this may be exactly the type of situation warranting the challenging use of underground configuration. A thorough analysis of underground routing, including some assessment of whether this crossing provides the most practical underground engineering out of possible crossings is recommended. This analysis may include locations other than previously described aerial crossings if engineering for underground configuration is more practical at another location.
>
> Analysis of an underground crossing at an existing transmission crossing, such as the Kellogg/Alma location, should include collocation of existing transmission and new transmission so that the possible benefits of underground transmission are not lessened in the analysis.
>
> Whether underground or aerial crossing is planned for this project, further coordination regarding details such as pole placement, pole type and underground line placement should be coordinated with the DNR to address vegetation and wildlife impacts, possible rare species impacts, and for preparation of a License to Cross Public Lands and Waters. [65]

[62] Attachment H, SOO Green Project Overview, October 24, 2018.
[63] CapX 2020 Hampton to La Crosse, PUC Docket TL-09-1448.
[64] Attachment I, DNR Comments, p. 4, CapX 2020 PUC Docket E002/TL-09-1448, May 20, 2010.
[65] Attachment J, CapX 2020 Hampton-La Crosse, E002/TL-09-1448, DNR Comments p. 6-7, April 29, 2011.

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 substation near suburban Washington, D.C. in Aldie, VA[66], and two HVDC converters at each end of the line:

Upgrade ID	Description	Cost Estimate ($M)	Designated Transmission Owner/Entity	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

[67]

[66] 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

[67] 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

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.

Applicants claim a need for export, and 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 through 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.[68] Dale Thomford, New Haven township, has suggested both an overhead Direct Current line and an underground DC line. The Interstate 90 right of way would provide a direct route to Wisconsin for export, a design using direct current which is ideally suited due to elimination of substations on an export line without step down substations for local service and the long length of the line.

vi. Another system alternative available is to utilize existing corridors for higher voltage lines which already have a greater impact than the planned 161kV crossing.

Another system alternative is to utilize existing crossings that already have the higher voltage line. There is the CapX 2020 345kV crossing of the Mississippi at Alma and the Cardinal-Hickory Creek 345kV crossing at Dubuque. The crossing proposed in this application is in tandem with a 161kV, or underbuilt on the 765kV line. The footprint of the project as

[68] MnDOT Utility Accommodation and Coordination Manual, https://dot.state.mn.us/policy/operations/oe002.html

presented is much larger, more impactful, than joining with an existing high voltage line.

vii. A crossing of the Zumbro River should also utilize the existing CapX 2020 transmission corridor.

As a system alternative, the Gopher to Badger transmission line should utilize the existing corridor to cross the Zumbro River. The DNR also recommended that the Zumbro River crossing utilize a corridor with existing infrastructure, the White Bridge Road, and not the North Route nor the Dam Route:

> As stated in previous comment letters, the DNR recommends crossings of public waters to generally be located where there is existing infrastructure. For example, the Zumbro River should be crossed where existing infrastructure exists and there is the least impact to resources from clearing or construction activities. The Zumbro River crossing at the white bridge in Segment 3 appears to result in the least impact from clearing, and utilizes an existing river crossing.
>
> Specifically, there are three Zumbro River crossings included in the project record: the north crossing, which is a greenfield crossing, a middle crossing at a dam, and the southernmost crossing at the white bridge. As stated above a crossing with no existing infrastructure such as the northernmost crossing is not encouraged. The northernmost crossing also has Natural Heritage Information System (NHIS) records of a state-listed threatened turtle in the vicinity of the crossing. There is also a Minnesota County Biological Survey (MCBS) Site of Biodiversity Significance ranked as Moderate near the crossing. The Zumbro River crossing near the dam is located next to an MCBS Site of Biodiversity Significance ranked as High. Rare species in the area include state-listed special concern American ginseng (plant), and state-listed special concern moschatel (plant). The southernmost white bridge crossing would affect an MCBS site of Biodiversity Significance ranked as Moderate and one ranked as Below. To avoid a greenfield crossing, the northernmost route is not recommended. Considering a comparison of rare species, MCBS site presence and ranking, and a general goal of reducing deforestation between the two crossings with existing infrastructure, the DNR recommends utilizing the white bridge crossing in this area rather than the crossing at the dam. [69]

The crossing of the Mississippi River, and traversing the driftless area leading to and from the river is "challenging," and undergrounding makes the most ecological and economic sense.

vi. The King-Eau-Claire-Arpin and Prairie Island-Byron 345kV transmission lines have not been updated in over 50 years.

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."[70] Half are not in Minnesota:

[69] Attachment K, DNR Comment, CapX 2020 Hampton-La Crosse, E002/TL-09-1448, June 29, 2011.
[70] Figure 6.3-1, p. 93.

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

Two of the problem lines originate near the Metro, and are near and affect the project area. Heading directly 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 years ago, and it has not been upgraded. The King-Eau Claire-Arpin[71] was placed in service on January1, 1960, sixty-five years ago,, and it has not been upgraded. Neither of these two lines have been upgraded since they were built.[72] The other lines shown in Minnesota as "Top Steady-State Reliability Issues" were also built decades ago. The Wilmarth line in southern Minnesota was reconductored to address a decades long sag problem, but more information is needed as to impact of upgrading efforts as it is identified as a "Top Steady-State Reliability Issues" line.

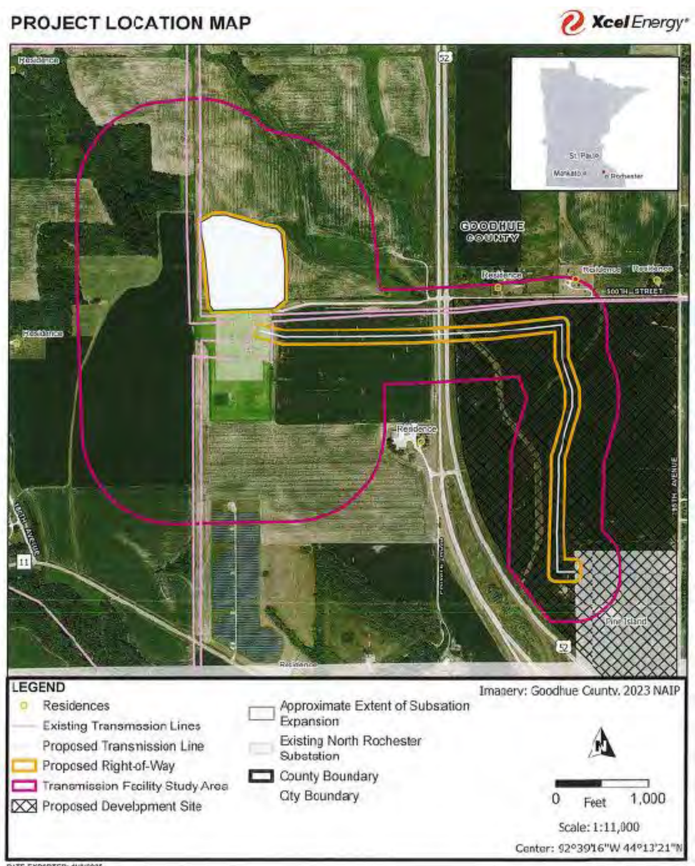
The upgrade, reconductor, rebuild states of these lines is another issue of fact. If these lines are a steady-state reliability issue, why hasn't the problem been fixed? These lines appear to

[71] 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 entire Eastern Interconnect. legalectric.org/f/2020/01/Northern-MAPP-Northwestern-Ontario-Disturbance-June-25-1988-FINAL-REPORT-1.pdf
[72] 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.

have been neglected for decades, and are now used as justification for this project. As a system alternative, these lines are identified as problem lines now and yet are relied on to provide support for the 345kV system and would be expected to support the 765kV system. Without upgrades, this is foolhardy. These "Top Steady-State Reliability Issues" should be rectified, upgraded, reconductored, whatever is necessary to provide steady-state reliability. If upgraded and no longer the "Top Steady-State Reliability Issues," what is the impact on need for the Gopher to Badger transmission project? This is a contested issue of fact.

vii. The space at North Rochester and the short transmission line should be converted to 765kV and used for the Pine Island Google data center and extended for the Gopher to Badger transmission project.

There is a plan to run a 345kV transmission line from the North Rochester substation across Highway 52 to the data center on the other side of Highway 52:



[73]

[73] Attachment L, Data Center Line

As s system alternative, doubling up on projects would be less impactful and may lessen the space conundrum in the North Rochester substation.

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

A primary "other issue" is environmental review. Environmental review for a project 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 alternative impacts that need to be identified and considered in the Certificate of Need 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.

In Minnesota, there are no 765kV transmission lines – this project is queued up to be the first. The environmental consequences of 765kV lattice towers through southeast Minnesota's Driftless and across the protected Mississippi cannot be overstated.

VI. CONCLUSION

This Certificate of Need application is essentially complete – information missing can be obtained through Information Requests. Several contested issues of fact focused on need, cost, and cost benefit have been raised, sufficient to justify a contested case proceeding. An informal process of any sort is not appropriate. Thorough environmental review is necessary, particularly where there are reasonable and available system alternatives.

Procedurally, there are significant notice problems, both where many landowners were not sent notice under the Notice Plan, and in publication, where at least two newspapers were not on Applicant's newspaper list and did not publish notice. The Commission approved the Notice Plan, and Applicants presumably have a list of potentially affected landowners. In addition, landowners known to the Applicants did not receive notice of the Certificate of Need Completeness and Process Comment Period from the Commission. Was the Commission provided with the landowner list? The Commission must correct this failure of notice. Because failure of notice of the Comment Period 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, it is also a systemic failure of Commission process and procedure, which must also be corrected. How can these multiple failures of notice be corrected but for a do over and extension of the Comment Period?

Based on the above Comments and Exhibits, the North Route Group and NO765MN request that Applicants be Ordered to provide Notice Plan notice to all potentially affected landowners and that the Commission provide Comment Period notice to those landowners. North Route Group and NO765MN also request a joint Contested Case process for the Certificate of Need and Route Applications, with multiple public hearings in the counties along the route, an evidentiary hearing, and thorough environmental review as provided by an Environmental

Impact Statement.

Thank you for the opportunity to file these comments in the Gopher to Badger transmission line docket.

Dated: February 25, 2026

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Attachments to Comment of North Route Group and NO765MN

Attachment A - 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.

Attachment B - MISO IMM Comments on LRTP Tranche 2 Benefit Metrics, May 29, 2024.

Attachment C - MISO IMM Motion to Intervene, September 9, 2025.

Attachment D - Correspondence to PJM, from Melanie Joy El Atich, Deputy Consumer Advocate, Counsel to Pennsylvania Consumer Advocate, Darryl Lawrence.

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.

Attachment F - Powerflows, SW MN 345kV Split Rock-Lakefield Jct. 345kV transmission, EQB Docket 01-1958.

Attachment G - Direct Testimony of Wellinghoff, Transmission Project, ERF 370609 Ex.-DALC/WWF-Wellinghoff-9, Wisconsin PSC 5-CE-136.

Attachment H SOO Green Project Overview, October 24, 2018.

Attachment I - DNR Comments, p. 4, CapX 2020 PUC Docket E002/TL-09-1448, May 20, 2010.

Attachment J - CapX 2020 Hampton-La Crosse, E002/TL-09-1448, DNR Comments p. 6-7, April 29, 2011.

Attachment K - DNR Comment, CapX 2020 Hampton-La Crosse, E002/TL-09-1448, June 29, 2011.

Attachment - Data Center Line

Northland Reliability Project

December 16, 2025

VIA E-FILING

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

Re: Variance Analysis Notification (Order Point 4 and Route Permit Section 6.10)
In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line
MPUC Docket Nos. E015,ET2/CN-22-416 and E015,ET2/TL-22-415

Dear Ms. Bergman:

On February 28, 2025, the Minnesota Public Utilities Commission ("Commission") issued an order ("Order") granting Great River Energy and Minnesota Power ("Permittees") a Certificate of Need and issuing a Route Permit for the Northland Reliability Project ("Project").

In compliance with Order Point 4 and Section 6.10 of the Route Permit, the Permittees herby notify the Commission that on December 15, 2025,[1] the Midcontinent Independent System Operator, Inc. ("MISO") initiated a Variance Analysis under Attachment FF of the MISO Tariff for the Project.[2] A copy of MISO's notice of Commencement of Variance Analysis for the Project is included as **Attachment A**.

If you have any questions or need additional information, please contact Christian Winter at CWinter@mnpower.com or Matthew Ellis at MEllis@GREnergy.com.

/s/ Christian Winter
Christian Winter
Minnesota Power
Manager – Regional Transmission Planning

/s/ Matthew Ellis
Matthew Ellis
Great River Energy
Director – Transmission Planning & Compliance

cc: Service Lists

[1] While a variance analysis was discussed by the MISO Board of Directors on December 10, 2025, the variance analysis commenced on December 15, 2025.
[2] Both the Order Point and the Route Permit require notice within five business days of initiation.

LRTP Tranche 1 - Iron Range-Benton County-Big Oaks Transmission Project Commencement of Variance Analysis

Pursuant to Attachment FF, Section IX of the MISO Tariff, MISO has initiated Variance Analysis for the Iron Range-Benton County-Big Oaks Long Range Transmission Planning (LRTP) Tranche 1 project (Project) upon MISO's initial determination that the estimated costs of the facilities within the Project have exceeded, or are projected to exceed, the MISO Tariff's permitted cost increase threshold (defined herein) for a transmission project.[1] The purpose of Variance Analysis is for MISO to review the reasons and potential impacts of such increased costs and determine an outcome to resolve and conclude the Variance Analysis process for this Project. This communication constitutes MISO's public notice that it has initiated the Variance Analysis procedures contained in Attachment FF, Section IX of the MISO Tariff.

BACKGROUND

On July 25, 2022, MISO's Board of Directors approved the LRTP Tranche 1 portfolio for inclusion in the MTEP21. Tranche 1 was made up of 18 discrete Eligible Projects, including the Project.[2] In accordance with the Tariff, following Board approval, MISO determined the facilities included in the Project were not eligible for the MISO Competitive Transmission Process and were therefore designated to the relevant incumbent Transmission Owners, Great River Energy (GRE) and Minnesota Power (MP). GRE was designated to construct five facilities of the Project, and MP was designated to construct six facilities of the Project.

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.

---

[1] *See* MISO Tariff, Attachment FF, § IX.C.I.

[2] The Project includes eleven facilities identified in MTEP21 as Facility ID Nos. 27051–27061. GRE was assigned five facilities of the Project: 27051, 27052, 27053, 27054, and 27055. MP was assigned six facilities of the Project: 27056, 27057, 27058, 27059, 27060, and 27061.

INITIATION OF VARIANCE ANALYSIS

In accordance with Attachment FF, Section IX.C.I of the Tariff, if MISO determines that the estimated costs of the facilities in an MTEP project have exceeded, or are projected to exceed, the project's Baseline Cost Estimate by 25% or more, MISO shall initiate Variance Analysis. In light of the forecasted project cost increases submitted by both GRE and MP for the Project, MISO is initiating the Variance Analysis process.

This public notice shall denote the commencement of Variance Analysis for the Project. MISO will adhere to the applicable Tariff processes, including the Variance Analysis procedures set forth within Attachment FF, Section IX, as well as the confidentiality restrictions contained within the Tariff. MISO will publish on its website a description of, and rationale for, its Variance Analysis determination in due course.

MISO IMM Comments on LRTP Tranche 2 Benefit Metrics

MISO Independent Market Monitor

David Patton, Ph.D.
Potomac Economics

May 29, 2024

Comments on Analysis of Transmission Benefits

- Transmission investment will be a critical component of MISO's evolution over the next 20 years.
- It is important that this investment be economic –
  - ✓ Uneconomic investment will raise costs and undermine investment in resources, storage and other alternatives to transmission.
  - ✓ We have previously expressed concerns about the unrealistic nature of Future 2A growth assumptions.
  - ✓ MISO has chosen not to attempt manual optimization (evaluating alternative siting impacts on individual projects or to resolve overloads).
  - ✓ The benefits methodologies are likely to lead to substantially over-estimated benefits, which we describe in this presentation.
- One of our primary concerns is related to the fact that the effects of MISO's markets are not properly recognized as illustrated below.

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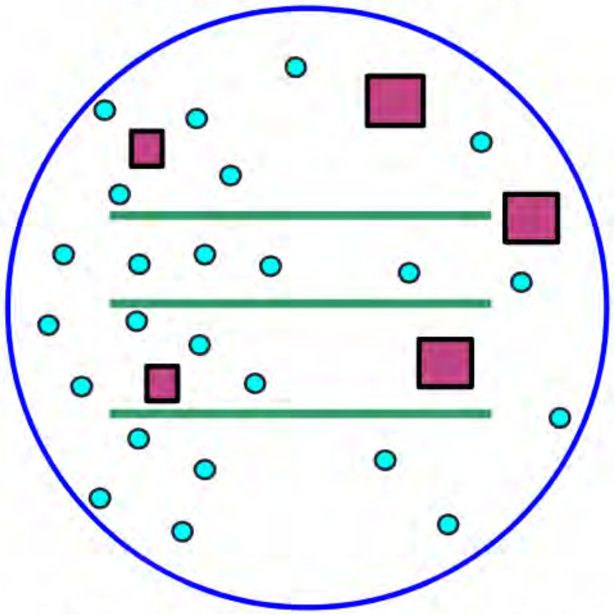
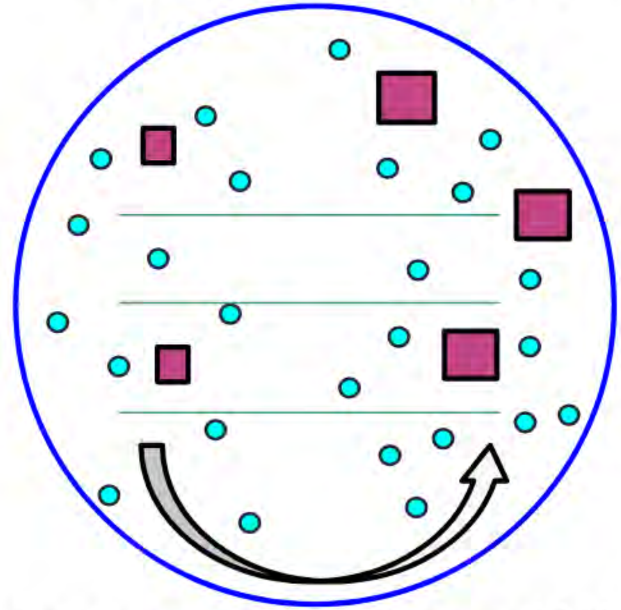
Recognizing the Market Effects in the Benefit Analyses

With Tranche 2



Without Tranche 2



- One of MISO's main responsibilities is to operate markets that provide key economic signals to guide generation investment and retirement decisions.
- Benefit analyses must recognize that new transmission will change energy and capacity market signals – less transmission will shift resources closer to load.
- This will reduce or eliminate many of the benefits (e.g., capacity savings and reduced losses).

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POTOMAC ECONOMICS

Classes of Transmission Benefits

- MISO has proposed 9 classes of transmission benefits.
- Classes that are likely to be valid and reasonable, depending on the details:
  - ✓ Congestion and fuel costs savings
  - ✓ Reduced transmission outage costs
- Classes for which we have significant or fundamental concerns:
  - ✓ Avoided capacity costs
  - ✓ Decarbonization
  - ✓ Mitigation of reliability issues
- Classes that are may be overestimated depending on the methodology
  - ✓ Capacity savings from reduced losses
  - ✓ Energy savings from reduced losses
  - ✓ Avoided transmission investments
  - ✓ Reduced risks from extreme weather events
- This presentation discusses our comments on each class of benefits.

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Congestion and Fuel Costs Savings

- This class of benefits is the most valid and represents the truest measure of the economic benefits of transmission
- **Concerns**: Although it is the most valid, it depends heavily on the input used to ensure the savings are accurate. Some factors that would tend to reduce these benefits may not be included in MISO's methodology.
- **Recommendations**:
  - ✓ Develop a reference case that modifies siting assumptions to simulate market responses without Tranche 2.   Siting would locate new additions inside of congested areas (closer to load, in capacity import limited areas, at raise help locations).
  - ✓ Include the effects of AARs on the existing network facilities.
  - ✓ Model the contribution of storage in reducing peak transmission flows and congestion since mitigating congestion is a significant component of the business case for storage.

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Reduced Transmission Outage Costs

- **Comment**:
  - ✓ This benefit is a potentially valid class of benefits since the base production costs savings would not tend to include transmission outages that are experienced regularly.
  - ✓ However, the magnitude of this estimated benefit is highly uncertain.
- **Recommendation**:
  - ✓ MISO should adopt a conservative approach to estimating this benefit that reflects the historical effects of outages.

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Avoided Capacity Cost

- **Concern**: There is little basis to assume that transmission will affect MISO's capacity requirements.
- The extent to which resources are deliverable *will* affect the amount of capacity needed, but the markets provide incentives to be deliverable.
- However, the MISO methodology:
  a. Creates a base case with sufficient generation to meet 1-in-10 on a copper sheet, but the generation is not deliverable.
  b. Adding in the network makes it appear that more capacity is needed to meet 1-in-10 since the assumed generation is not fully deliverable.
  c. Tranche 2 makes the generation much more deliverable so capacity needs are lower than in (b).
- This is not a valid benefit because, absent the transmission, markets will motivate/require generation in deliverable locations closer to load.
- **Recommendation**: i. Eliminate this benefit or ii. Develop alternative case with modified siting assumptions and calculate cost of *moving* resources.

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Decarbonization

- **Concern**: The congestion and fuel savings include the PTC values, which fully reflects the value of decarbonization, so calculating an additional benefit is double counting.
  - ✓ The PTC is the most reasonable benchmark for the value of carbon since it is law and represents what the government will actually pay.
  - ✓ The PTC corresponds to a carbon value of ~$50/ton. The Biden administration's value of carbon is $51/ton, which is being litigated.
  - ✓ EPA has proposed almost a 4-fold increase, almost all of which is based on lowering the discount rate from 3% to 2% percent based on falling interest rates up to 2021. Rates have been rising since then to > 4%.
  - ✓ MISO has no basis to impose a cost higher than the PTC on its customers when there is no consensus that the PTC undervalues carbon.
- **Recommendation**: Eliminate this benefit class as it is already captured in the production cost savings.

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Mitigation of Reliability Issues

- **Concerns**:
  - ✓ Quantifying this benefit by assuming MISO will shed load to address voltage or other issues (without Tranche 2) is not realistic.
  - ✓ In reality, these issues are addressed by thermal proxies, reconfigurations, or by investments in other equipment that would be much less expensive than load shedding.
- **Recommendation**:
  - ✓ Eliminate this class of benefits; or
  - ✓ Quantify cost based on the next operating action to address the issues if transmission is not built (not load shedding):
    - – Congestion from modeling a thermal proxy; or
    - – The costs of equipment to address the issues (e.g., voltage support).

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Capacity and Energy Savings from Reduced Losses

- **Concern**:
  - ✓ In principle we agree that new higher voltage transmission will reduce losses;
  - ✓ BUT, the loss reductions should reflect the fact that resources will relocate closer to load without the Tranche 2 projects.
- **Recommendations**:
  - ✓ Develop alternative reference case that modifies siting assumptions to reflect market responses without the portfolio.
  - ✓ Siting would locate new additions closer to load, in capacity import limited areas, and at raise help locations.

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Avoided Transmission Investment

- **Concerns**:
  - ✓ Avoided transmission maintenance/replacement could be a valid benefit.
  - ✓ Avoided transmission investment that is hypothetically needed to address congestion would be inappropriate unless:
    - Avoided benefits are quantified and deducted from the avoided capital costs.
- **Recommendation**:
  - ✓ Include only maintenance/replacement projects (age and condition) that would be avoided.

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Reduced Risks from Extreme Weather Events

- **Concern**:
  - ✓ This is one of the most uncertain and speculative benefits.
  - ✓ Each of the extreme weather events have resulted in extremely different patterns of flows so it is difficult to predict how transmission would help.
  - ✓ The benefits should be small because the probability of extreme weather events are low.
- **Recommendation**:
  - ✓ MISO should ensure that it does not implicitly increase the probability of extreme weather events in calculating the benefits.
  - ✓ Benefit = Potential Savings during Event * Probability of Event.

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Other Comments on Benefit Estimates

- We have additional recommendations to improve the benefit estimates.
- Divide the portfolio into groupings of projects that address separate issues to validate that each grouping passes a benefit-cost test.
  - ✓ Assessing the entire portfolio together would not allow MISO to pair it down so that it only includes the economic groupings.
- Adopt a sensitivity case similar to IMM-2A, which has more dispatchable/storage/hybrid resources than MISO's Future 1A.
  - ✓ Although Future 1A has substantially less intermittent renewables, it also understates the likely quantity of dispatchable resources that are key for managing congestion.
- Consider improving a) the siting of resources based on the location of congestion, and b) the modeling of battery storage to resolve congestion.
  - ✓ MISO should examine whether the congestion identified in reference case can be more economically be managed with storage to verify the robustness of the business case.

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North Dakota Public Service Commission	)	
Montana Public Service Commission	)	
Arkansas Public Service Commission	)	
Mississippi Public Service Commission	)	
Louisiana Public Service Commission	)	
Complainants,	)	**Docket No. EL25-109-000**
	)	
v.	)	
	)	
Midcontinent Independent System Operator, Inc.,	)	
Respondent	)	

MOTION TO INTERVENE AND COMMENTS OF THE MISO INDEPENDENT MARKET MONITOR

Pursuant to Rules 212 and 214 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or "Commission"), 18 C.F.R. §§ 385.212 and 214 (2018), Potomac Economics, Ltd. respectfully moves to intervene in the above-captioned proceedings concerning the July 30, 2025 complaint by the Public Service Commissions of North Dakota, Montana, Arkansas, Mississippi, and Louisiana ("the Concerned Commissions") against the Midcontinent Independent System Operator, Inc. ("MISO") in which they assert that MISO violated the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff).[1] They argue that MISO miscalculated the benefits and inappropriately approved $22 billion in transmission projects ("Tranche 2.1") as Multi-Value Projects.

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1 *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) ("Complaint").

Potomac Economics is the Independent Market Monitor ("IMM") for MISO and respectfully submits this Motion to Intervene to address issues raised by the Concerned Commissions in their Complaint.

I. NOTICE AND COMMUNICATIONS

All correspondence and communications in this matter should be addressed to:

Dr. David B. Patton
Potomac Economics, Ltd.
10560 Arrowhead Drive, Ste 400
Fairfax, VA 22030
(703) 383-0720

II. MOTION TO INTERVENE

Potomac Economics is the Independent Market Monitor for MISO. In this role, we are responsible for monitoring and evaluating the performance of MISO's energy and ancillary services markets. We also are responsible for recommending market design changes to improve the performance of the markets and evaluating design changes proposed by MISO or market participants. Potomac Economics has a direct interest in this proceeding that cannot be adequately represented by any other party. Good cause also exists to permit Potomac Economics' motion to intervene as it has a significant interest in this proceeding.

III. BACKGROUND

Transmission investment will be a critical component of MISO's evolution over the next 20 years. It is, therefore, vitally important that this investment be economic. Uneconomic investment will raise costs – we estimate that Tranche 2.1 will cost each family in the Midwest more than $2500 in present value terms. More importantly, uneconomic transmission investment is likely to undermine efficient investment in generation and storage resources that can address some of MISO's transmission congestion needs at a much lower cost to MISO's customers. It is this adverse effect on the markets' ability to facilitate efficient investment in generating resources that caused Potomac Economics, as the IMM for MISO, to evaluate MISO transmission planning processes and results. The Commission validated that this monitoring and evaluation is an important component of the IMM's scope as market monitor in July 2025.[2]

The IMM's evaluation of MISO's Tranche 2.1 benefit cost analysis revealed flaws in MISO's processes and supporting analyses and ultimately demonstrated that the likely benefits of Tranche 2.1 are far below the costs as argued by Dr. Hogan and the Concerned Commissions.[3] The Complaint is supported by Dr. Hogan independent assessment of MISO's benefit analyses, which is consistent with the IMM's evaluation. As Dr. Hogan's assessment is the basis for the Complaint, we find the arguments made in the Complaint to generally be sound and accurate. In these comments, we describe our evaluation of MISO's transmission planning results and the extent to which they support the arguments made in the Complaint.

MISO's transmission planning process includes the following steps:

1. MISO develops its forecasted "Futures" scenarios for future load growth and resource development used to estimate the transmission needs MISO may encounter in the future.
2. It then develops assumptions regarding where resources in the future will be located.
3. MISO uses these assumptions to identify where transmission congestion and reliability issues may arise
4. It develops a portfolio of transmission projects that address its identified transmission needs and quantifies its costs
5. MISO then develops a "business case" by calculating an array of benefits the transmission projects may generate. Since the benefits are inherently uncertain and

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[2] *Midcontinent Independent System Operator, Inc.*, Order on Petition for Declaratory Order, 192 F.E.R.C. ¶ 61,055, (2025).

[3] See Testimony of William Hogan at p. 39.

the costs more certain (and tend to rise before completions), the benefit-cost ratio of long-range transmission should be well above 1.0.

Our evaluation of MISO's Futures that were the basis of Tranche 2.1 began in 2023 and continued through the analysis of the benefits of Tranche 2.1 in late 2024. This evaluation supports the concerns raised in this Complaint. In summary, we found that:

- MISO's Future 2A that is the basis for the Tranche 2.1 transmission proposal does not accurately reflect its members plans and likely significantly overstates MISO's future transmission needs;
- Reasonably calculated, the benefits of the Tranche 2.1 projects are likely well below its costs even if one accepts the Future 2A scenario.
- Because reasonably calculated results do not indicate that Tranche 2.1 is economic, its implementation will undermine the market incentives for participants to invest in lower-cost resources and transmission upgrades that would be more efficient and lower MISO's long-term costs.

While these findings support the requested relief in the Complaint to reclassify Tranche 2.1 to no longer be deemed Multi-Value Projects (MVPs), this may not address our concerns regarding the adverse market effects of Tranche 2.1. Therefore, we respectfully recommend that the Commission Order MISO to revise Tranche 2.1 based on an updated Futures scenario and improved benefits assessment. To address future LRTP tranches, we support the request in the Complaint for the Commission order a modification to the MISO tariff to require that future business cases be filed and approved by the Commission.

Our comments below provide a detailed discussion of these issues and comment on the relief requested by the Concerned Commissions in this Complaint.

IV. SUMMARY OF THE IMM EVALUATION OF MISO LRTP RESULTS

A. MISO's Future 2A is Not Realistic and Does Not Reflect its Members' Plans

We generally agree with the concerns raised in the Complaint regarding MISO's benefit analyses. These concerns are heightened when one considers that the benefits are calculated based on Future 2A, which is not a realistic forecast of future resource development in MISO. Dr. Hogan discusses significant flaws in the Future 2A scenario.[4] These flaws likely increased the perceived long-term transmission needs in MISO, causing MISO to propose projects to address needs that may never materialize.

As an initial step in the transmission planning process, MISO establishes the long-term future forecast of generating resources and loads. Scenarios with different types of resources, even if they are located in the same locations, can substantially affect transmission flows and the perceived transmission needs of the system. In particular, intermittent renewable resources create different and generally larger transmission needs than dispatchable resources for at least three reasons:

- The output of these resources tend to be highly correlated;
- The resources have been developed in geographically concentrated areas, particularly the wind resources;
- Intermittent resources can only reduce output when needed manage congestion and they are generally very costly to curtail.

For these reasons, developing a Future with an excessive amount of intermittent renewables and underestimating the quantity of dispatchable storage and conventional resources will generally inflate the transmission needs of the system. The figure below illustrates the difference in transmission needs and congestion that can arise in different futures. The first

[4] Id. at p. 16.

illustration depicts a system with a large quantity of remotely cited intermittent renewable resources. When the output of these resources peaks, it loads the transmission paths between location A and B in this illustration, resulting in transmission overloads. This illustration is consistent with MISO's Future 2A that is the basis for Tranche 2.1.

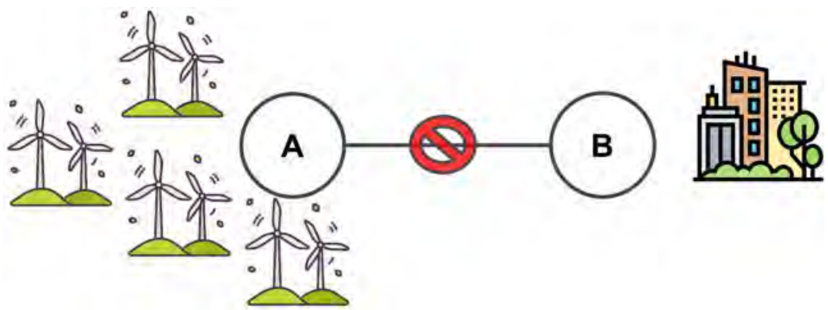


Illustration B depicts a more realistic view of MISO's future system, which is likely to include a much heavier reliance on storage resources and dispatchable generation than is included in Future 2A.

This illustration shows a scenario that would produce substantially lower transmission flows and associated congestion between A and B because of: (i) lower quantities of intermittent renewable resources, (ii) greater quantities of storage resources that can charge when the renewable resource output peaks to take the loading off of the transmission system, and (iii) the presence of dispatchable resources whose output can be adjusted up and down by MISO to reduce the transmission flows and manage congestion.

This difference between these types of Future scenarios is significant because our evaluation found that the latter scenario is more consistent with the plans of MISO's members.

Additionally, such a scenario will satisfy all of MISO's reliability needs at a much lower cost than Future 2A while still allowing the states to achieve their carbon goals.

We established this finding when we evaluated MISO's Future 2A in detail and the capacity expansion model MISO used to produce it. MISO started with the member utilities' plans regarding the resources they plan to build in the coming years. MISO then used a capacity expansion model, EGEAS, to determine additional resources that will be built over the long term. Unfortunately, EGEAS (i) predicted an excessive amount of intermittent renewable resources will be built and (ii) understated investment in dispatchable and storage resources. This occurred because of the following flaws in the model and the input assumptions MISO used:

- EGEAS simply minimizes the costs of meeting MISO's carbon and reliability objectives rather than building the most economic and profitable resources as one would expect to be built in a market. After MISO included the production and investment tax credits included in the Inflation Reduction Act as cost-reducers, the model forecasted that virtually all new resources would be intermittent renewables. In the real world, the energy, ancillary services, and capacity revenues for energy storage and dispatchable resources will likely make them extremely profitable to build in the future, which is not perceived by the cost-minimization objective of the EGEAS model.
- MISO assumed capacity accreditation values for intermittent renewables that were inflated and that do not fall as more resources are assumed to be built, which was inconsistent with the marginal capacity accreditation framework that MISO had proposed and that has now been approved by the Commission.
- MISO modeled a system-wide carbon constraint that was inconsistent with the carbon policies and targets of its states and members. Modeling this constraint restricted the model's ability to properly forecast that generators will invest in dispatchable conventional resources in states with no carbon legislation or targets. MISO's capacity and energy markets will provide strong incentives to invest in such resources, which we see reflected in MISO's interconnection queue.

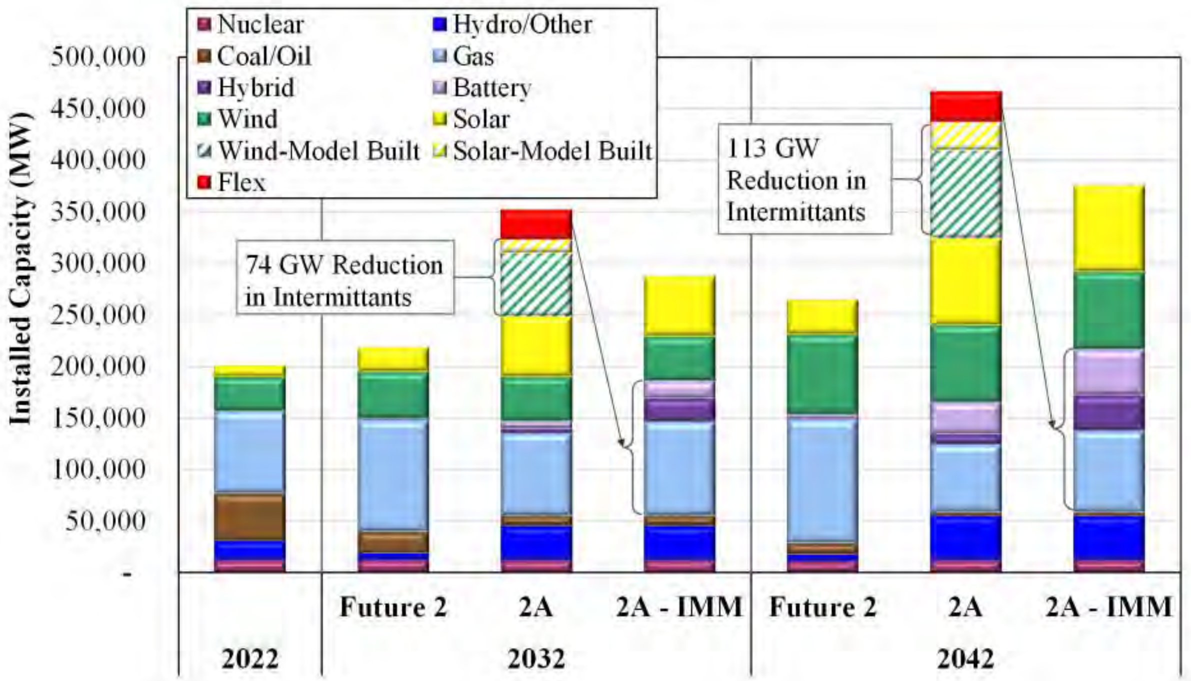
These issues caused EGEAS to forecast that nearly all new model-built resources will be intermittent renewable resources and virtually no new conventional dispatchable resources. The fact that the EGEAS model did not recognize the attributes and reliability value of different types of resources caused it to forecast a portfolio that would not satisfy MISO's energy adequacy needs. Therefore, after MISO developed the capacity expansion plan, it added 30 GW of "Flex" resources that are non-emitting dispatchable resources.

The fact that the Flex resources were added *after* the capacity expansion model ran and attempted to optimize the investment in new resource invalidates the results of the model. A valid analysis would require that MISO iterate to add the Flex resources as an input to the model and then re-run EGEAS to determine a new quantity of model built resources. We believe this would have reduced the forecasted intermittent resources by a quantity much larger than the quantity of Flex resources since the capacity availability and reliability value of dispatchable Flex resources would be much higher than the intermittent resources.

B. A More Realistic Future 2A Would Be More Consistent with the Members' Plans

To estimate the corrections in Future 2A that would address these issue, we estimated the quantity of intermittent resources that would be displaced by the addition of the dispatchable flexible resources that will be needed to meet MISO's energy adequacy needs. The difference in our case is that we assume the "flex resources" will be a blend of storage, hybrid renewables, and new natural gas resources. This is consistent with MISO members' Integrated Resource Plan's (IRPs) and the resources that already exist in MISO's interconnection queue. Our replacement methodology determined the quantity of dispatchable "flex" resources necessary to provide the same amount of accredited capacity as MISO assumed would be provided by the intermittent resources and sufficient to eliminate MISO's need for its assumed Flex Resources.

As shown in the figure below, we estimate that building dispatchable resources to meet MISO's reliability and energy adequacy needs would displace 113 GW of intermittent renewable resources and reduce the costs of Future 2A by $92 billion.



Importantly, the IMM's modification of Future 2A would satisfy all of the States' and member utilities carbon goals by 2042, as well as the energy adequacy needs of the MISO system. The IMM Future 2A portfolio is also much better aligned with the generation in MISO's interconnection queue and the IRPs of MISO's members.

For example, MISO recently implemented an Expedited Resource Addition Study (ERAS) process intended to accelerate the interconnection of resources needed for reliability. The initial proposals were accepted in August 2025 and total more than 26 GW of new resources. Of this total, 89 percent of the proposals are the types of dispatchable we predict in the IMM Future 2A alterative – 74 percent gas resources and 15 percent battery storage resources. On an accredited capacity basis (rather than installed capacity), this share would exceed 95 percent. Importantly, many of the natural gas-fired resources are proposed by member utilities that have carbon goals and/or in states that have carbon mandates. These ERAS proposals are summarized by state and generating technology in the table below.

Summary of Projects Proposed for Expedited Study

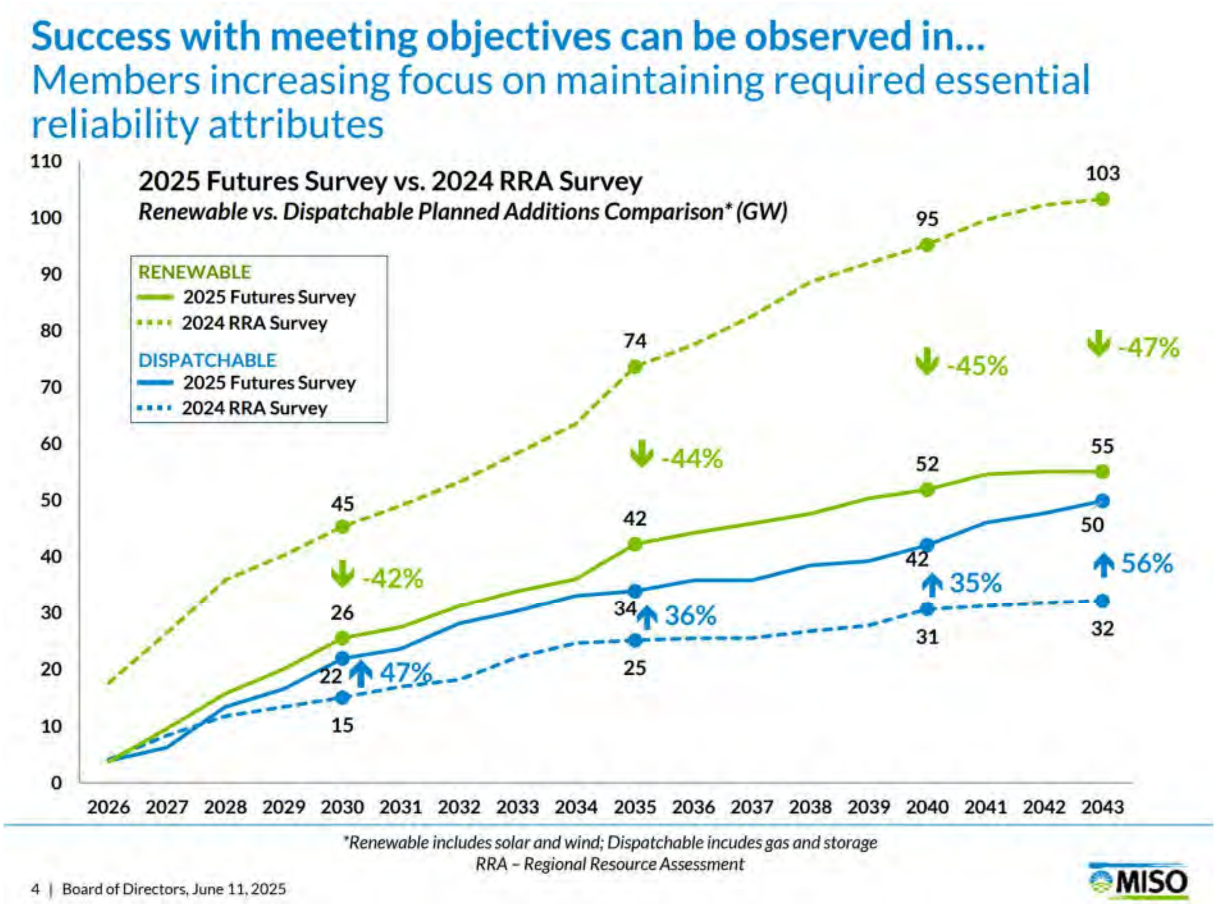
State	ERAS Projects (MW)	Share of Total (%)	State Shares by Technology			
			Gas	Nuclear	Renewable	Storage
Iowa	3084	12%	66%	22%	12%	0%
Illinois	128	0%	0%	0%	100%	0%
Indiana	5564	21%	74%	0%	0%	26%
Louisiana	6376	24%	97%	0%	0%	3%
Michigan	1177	4%	0%	0%	33%	67%
Minnesota	2468	9%	33%	0%	16%	50%
Missouri	568	2%	0%	0%	55%	45%
Mississippi	1640	6%	100%	0%	0%	0%
North Dakota	659	2%	0%	0%	100%	0%
South Dakota	265	1%	100%	0%	0%	0%
Texas	1298	5%	100%	0%	0%	0%
Wisconsin	3323	13%	100%	0%	0%	0%
Total	**26550**		**74%**	**3%**	**8%**	**15%**

The substantial quantities of natural gas and storage resources proposed through the ERAS process is very important because their flexible, dispatchable characteristics make them valuable for managing transmission flows and congestion. Hence, MISO's transmission needs are likely to be substantially affected by the recognition of these resources.

In addition to this evidence from the ERAS process, the changes in members' IRPs over the past year after the approval of MISO's marginal accreditation framework by the Commission also validate our concerns with Future 2A. As the members have recognized that intermittent renewable resources will not satisfy MISO's reliability requirements over time, the IRPs have been revised substantially. These revisions were summarized in a figure produced by MISO to show the changes in the survey results of its members from 2024 to 2025 that reflects the changes in the members' IRPs.[5] This figure shows that the amount of planned renewable resources has

5 Board of Directors: MISO Strategy Update, June 11, 2025.

fallen by 47 percent by 2043 and the amount of planned new gas resources has increased by 56 percent in the same timeframe.



Maybe even more compelling than the changes in the IRPs is the vast difference between these values and the quantities MISO projects in its Future 2A. MISO's Future 2A shows 235 GW of new renewable resources by 2042 compared to just 55 GW currently in the members' plans. Likewise, MISO's Future 2A shows 23 GW of new gas resources compared to its members' 50 GW by 2043.

C. The Flaws with MISO's Future 2A are Critical Because Future 2A Determines MISO's Transmission Needs and the Benefits of Tranche 2.1

The stark differences outlined above between MISO's Future 2A and a more realistic alternative to Future 2A would likely substantially affect MISO's transmission needs and the projects needed to address those needs. Although the Complaint did not focus on the shortcomings of Future 2A, using Future 2A to evaluate the benefits of Tranche 2.1 would likely greatly increase the perceived benefits of the proposed transmission projects. With considerably less intermittent renewables loading the transmission system during hours of high output and many more dispatchable resources available to manage the system flows, the need for and benefits of new transmission investment would likely be far lower. Therefore, we have always advocated that reforming Tranche 2.1 based on an improved version of Future 2A is necessary to ultimately correct the shortcomings in Tranche 2.1.

V. COMMENTS ON THE BENEFIT ANALYSIS SUPPORTING TRANCHE 2.1

A. Fundamental Problem with MISO's Benefit Analyses

As Dr. Hogan describes in his testimony, one of the most pervasive issues with MISO's cost-benefit analyses is that it fails to adopt the fundamental approach that should be used in all cost benefit analyses: to quantify the costs and benefits of the outcomes *with* and *without* the actions being studied.[6] MISO departs from this fundamental approach by not developing a base case future scenario without Tranche 2.1. Specifically, MISO does not recognize that the transmission investments in Tranche 2.1 will affect the resources that enter in the Midwest and where they are located. MISO has developed a single Reference Case, including siting assumptions that are based on an exogenous methodology (existing sites and sites identified by stakeholders). In reality, resource entry and siting decisions will be substantially affected by the transmission investments because it will affect congestion pricing and local capacity requirements in the PRA.

To ignore these effects is a key oversight, particularly since one of MISO's fundamental roles is to operate markets designed to facilitate resource investments by MISO suppliers. Therefore, it is essential for MISO to have two generation siting cases:

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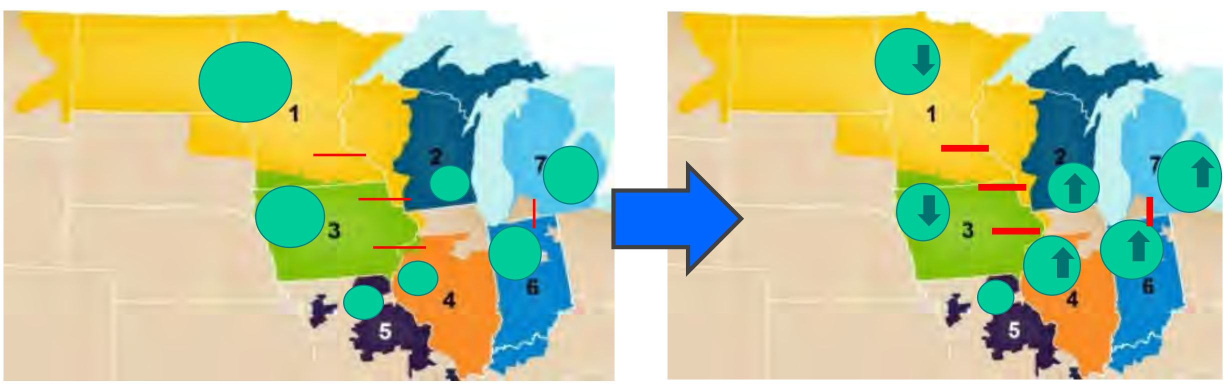
6 Id. at p. 6.

- A case *with* the Tranche 2.1 investments; and
- A case *without* the Tranche 2.1 investments.

The differences in resource entry and siting in these two cases must be estimated because they will affect MISO's transmission needs and congestion patterns. Therefore, the benefit estimates will not be accurate if MISO does not estimate the effects of the transmission investments on participants' resource investment and siting decisions. This is illustrated in the figure below where the green circles represent the quantity of new resources and the red lines represent the constraints (with the thickness indicating the severity of the constraints).

Transmission Case – With Tranche 2.1 **Base Case – Without Tranche 2.1**



This illustration shows why the benefit analyses must recognize that new transmission will change energy and capacity market signals – *because less transmission will shift resources closer to load*. The left illustration depicts the distribution of new resources under Future 2A, showing a larger share of resources located farther from load and utilizing the reinforced transmission network to deliver its energy output to the larger load centers. Assuming this fixed distribution of new resources under Future 2A leads to relatively large transmission benefits from Tranche 2.1 associated with reducing congestion, reducing transmission losses, reducing the need to build additional generation to replace capacity that is not deliverable, and mitigating reliability issues associated with transmission violations.

However, the distribution of new resources is not fixed and will be substantially affected by the change in market signals if Tranche 2.1 is not built as Dr. Hogan indicates in his testimony.

The right illustration shows how the location of resources is likely to change, as indicated by the green arrows and the changing size of the green circles. This illustration shows that the new resources will generally shift closer to load if less transmission is built. This will occur because both investment and retirement decisions will be affected by the change in market signals and capacity requirements. Importantly, this shift in resources will reduce or eliminate many of the benefits MISO estimated because it will reduce:

- The congestion and fuel cost savings by reducing congestion and renewable curtailments as resources shift from constrained locations to locations the relieve constraints;
- The two categories of transmission loss benefits as resources shift closer to load;
- The mitigation of reliability issues as resources shift to locations that will likely mitigate the transmission violations; and
- The avoided capacity costs as new resources shift to deliverable locations. This shift will reduce or eliminate the need to build additional resources.

The overstatement of benefits in the last two areas listed above are the largest by far so we describe the concerns in these two areas in the following subsections.

B. Avoided Capacity Benefits

MISO's avoided capacity cost benefit is based on an assertion that decreasing the levels of congestion will decrease the planning reserve margin requirements (PRMR) of the system to achieve the 1-in-10 LOLE level. Dr. Hogan discusses the issues with MISO's calculation of this class of benefits at length, which are consistent with the concerns we have raised previously and discuss in this subsection.[7]

[7] Id. at p. 14.

The reason it may appear that additional capacity is required by MISO's planning model is because new generation that is sited behind transmission constraints (i.e., resources that are not deliverable) will not be deployable when contingencies occur. Therefore, one could conclude that additional generation would be needed to meet the 1-in-10 reliability standard in the absence of Tranche 2.1. The cost of this additional generation is the avoided capacity benefit quantified by MISO. However, Dr. Hogan explains why this method of calculating benefits in this area will be substantially overstated.[8]

One critical issue cited by Dr. Hogan is that MISO implicitly assumes that the new generation would be sited in the same locations regardless of whether the Tranche 2.1 transmission projects are made. This is an unreasonable assumption because MISO's market incentives and resource adequacy requirements will compel resource investments to shift away from undeliverable locations toward deliverable locations. These incentives and requirements include:

- Energy and ancillary service prices that would include congestion, causing prices and market revenues to rise in deliverable locations and fall in undeliverable locations; and
- Local clearing requirements in the capacity market zones that would: increase capacity prices and revenues in deliverable zones that are tight and reduce capacity prices and revenues in undeliverable zones that are over-supplied.

Additionally, most members develop their integrated resource plans with the intention of meeting their resource adequacy requirements. Therefore, the effect of the differences in LCRs with and without Tranche 2.1 on members' IRPs must be estimated and considered. Ultimately, if MISO were to estimate the changing locational patterns of resource development in a reasonable manner, it would likely find that little or no additional resources are needed if Tranche 2.1 is not

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[8] Id. at p. 14-27.

built. Although there may be costs associated with resources moving to more deliverable locations in the absence of Tranche 2.1, the costs of moving resources are likely to be an order of magnitude lower than the costs of building additional resources.

Importantly, these changes in resource investment and retirement will ensure that the resources needed to satisfy MISO's capacity needs remain deliverable and will prevent the PRMR from rising as MISO assumes. While some renewable resources would undoubtably be less deliverable without the transmission investments, these resources over time will supply a very small portion of MISO's capacity given that their capacity accreditation will be extremely low. Hence, we find no basis to believe that transmission investment will change the PRMR appreciably.

Even if one were to believe new resources may be needed, MISO's methodology substantially overstates the costs of any new resources by the same capacity expansion model (EGEAS) as it used to create Future 2A. The EGEAS model strongly prefers intermittent renewables because it does not accurately perceive the relative market and reliability value of renewables versus other technologies. After MISO estimates the additional MWs needed for reliability, its model chooses to meet 75 percent of this need with intermittent renewables (16.8 GW). This is problematic because these resources are being built to satisfy a reliability need but will provide almost no marginal reliability in the out years, which will be recognized by MISO's new capacity accreditation framework. The same reliability value can be provided by a combination of battery storage, hybrid renewables, and dispatchable resources totaling 5 to 6 GW and costing $13 billion less than MISO's assumed 23 GW of new resources.

C. Mitigation of Reliability Issues

MISO asserts that building the Tranche 2.1 transmission projects will address or mitigate local reliability issues. While this may be true, MISO proposes to quantify this benefit by assuming that these local reliability issues would result in load shedding absent the Tranche 2.1 projects and then estimating the costs of the load shedding as avoided costs. Because the value of lost load is very high, this methodology massively overvalues these issues because RTOs never manage such reliability issues by relying on frequent load shedding. Therefore, MISO is not quantifying a valid benefit since load-shedding would not happen without Tranche 2.1.

Dr. Hogan correctly asserts that in reality RTOs manage these types of voltage and local reliability issues by taking other short and long-term actions *to avoid* load shedding.[9] In particular, they are managed operationally through out-of-market commitments, modeling thermal proxy transmission constraints, or transmission reconfigurations. In the longer-term, RTOs manage such issues by investing in other transmission facilities and establishing locational capacity requirements to facilitate resource development that will address these types of reliability issues.

An example may help illustrate the flaw in MISO's analysis. Imagine that a person drives a car and his mechanic identifies a faulty component that could cause an accident resulting in serious injury to himself and others. Assume that the expected value of these injuries is $2 million and that the component would cost $700 to replace. Now, imagine that person is now considering buying a new car that costs $100,000 and doing a benefit-cost analysis of the new car, which would eliminate this risk. Is the benefit of buying the new car:

- $2 million because it eliminates this risk; OR
- $700 because it eliminates the need to make the repair?

The answer to this question depends on what the person would rationally do if he does not buy the new car. Clearly, a rational person would spend the $700 to repair the car so this avoided repair cost is the benefit of buying the new car. MISO's methodology would quantify this benefit

9 Id. at p. 35.

at $2 million because it does not consider the alternative costs that it would incur to avoid the load shedding, i.e., the $700 repair in this example. Importantly, if this person deems the $2 million expected value of the risk to be the proper benefit, he could justify purchasing virtually any new car in the world regardless of its cost.

Hence, a proper benefit analysis would identify the actions that would be necessary in the base case (without Tranche 2.1) to address any potential reliability issues. The benefit could then be quantified based on the avoided cost of these actions. In this case, however, the avoided cost of these actions is already captured in other categories of benefits. For example, the shift in locational capacity requirements and resulting shift in new resource siting would already be captured in the avoided capacity cost category if it were calculated correctly. Likewise, the avoided transmission investment category would capture any necessary transmission upgrades that can be avoided by building Tranche 2.1. Therefore, we find that there are no benefits to quantify in these area.

Even if one were to accept MISO's assertion that 23 GW of new resources will be needed in deliverable locations without Tranche 2.1 under its avoided capacity cost methodology, Dr. Hogan points out that MISO failed to consider that these additional resources would likely address the identified reliability issues.[10] If these resources enter in high-value locations related to MISO's perceived reliability issues, they would be more than sufficient to eliminate the load shedding MISO estimates. Therefore, this category of benefits is double counted, which can most reasonably be addressed by simply eliminating it.

[10] Id. at p. 32-33.

D. Comments on the Decarbonization Benefits

Dr. Hogan makes a number of key points on the decarbonization benefits MISO estimates.[11] First, he correctly notes that the current Federal Production Tax Credit (PTC), which implies a social cost of carbon (SCC) of roughly $50 per metric ton, already internalizes the value of decarbonization. In other words, incurring costs to build transmission to produce more renewables at a cost of $50 per ton and then paying the PTC at $50 per ton would only be justified if the social cost of carbon equaled $100 per ton. If one accepts that the PTC establishes an implied value of environmental benefits of renewable output, as argued by Dr. Hogan, then the low-end decarbonization benefit would be zero. Likewise, the high-end decarbonization benefit based on the Minnesota PUC SCC of $249 per metric ton would have to be reduced by 20 percent to appropriately net the PTC subsidy.

Dr. Hogan also notes that that the wide disparity in views on the SCC within the MISO footprint is not appropriately reflected in MISO's analysis. While MISO includes the Minnesota PUC view to quantify the high end of the range, MISO ignores that other states like North Dakota currently assume a $0 per metric ton value of carbon. While we do not personally believe that $0 is a reasonable SCC, we find it inappropriate for the IMM or MISO to impose its views regarding the SCC on its members in the absence of a consensus. This may explain why FERC did not endorse a decarbonization benefit to be included in long-range transmission planning more broadly.

Given that the current PTC internalizes a $50 per metric ton SCC. Additional valuation of decarbonization is embedded in the implied subsides for renewable resource investment that is embedded in Future 2A. As the marginal capacity accreditation falls and shortages in the energy

---

11 Id. beginning at p. 37.

market occur only when renewable energy output is low, the subsidies necessary to support the net costs in renewable resources in excess of $200 billion will rise substantially. Since these subsidies are only justified on the basis of decarbonization benefits, it is unlikely than any additional decarbonization benefits can be attributed to Tranche 2.1 without double counting the decarbonization benefit. In other words, if the states will be required to pay $200 per metric ton in subsidies to achieve Future 2A (through renewable energy credits and other programs) and the SCC is less than $200 per metric ton, then there is no residual decarbonization benefit to be claimed associated with incurring the costs to build Tranche 2.1.

For all of these reasons, we agree with Dr. Hogan that the most reasonable approach for estimating the benefits of LRTP tranches is not to include decarbonization benefits.[12] This would be consistent with FERC policy issued in Order 1920.

E. Estimate of Corrected Benefit-Cost Ratios

It is important to estimate a corrected benefit cost ratio because this a key result indicating whether Tranche 2.1 is economic and whether it qualifies for MVP cost allocation. We are not able to correct all of MISO's classes of benefits to address the failure to establishing a base case without Tranche 2.1. As discussed above in Section V.A., establishing a proper base case would reduce most of the categories of benefits. For the analysis presented in this section, however, we focus only on the three specific categories of benefits discussed in detail above.

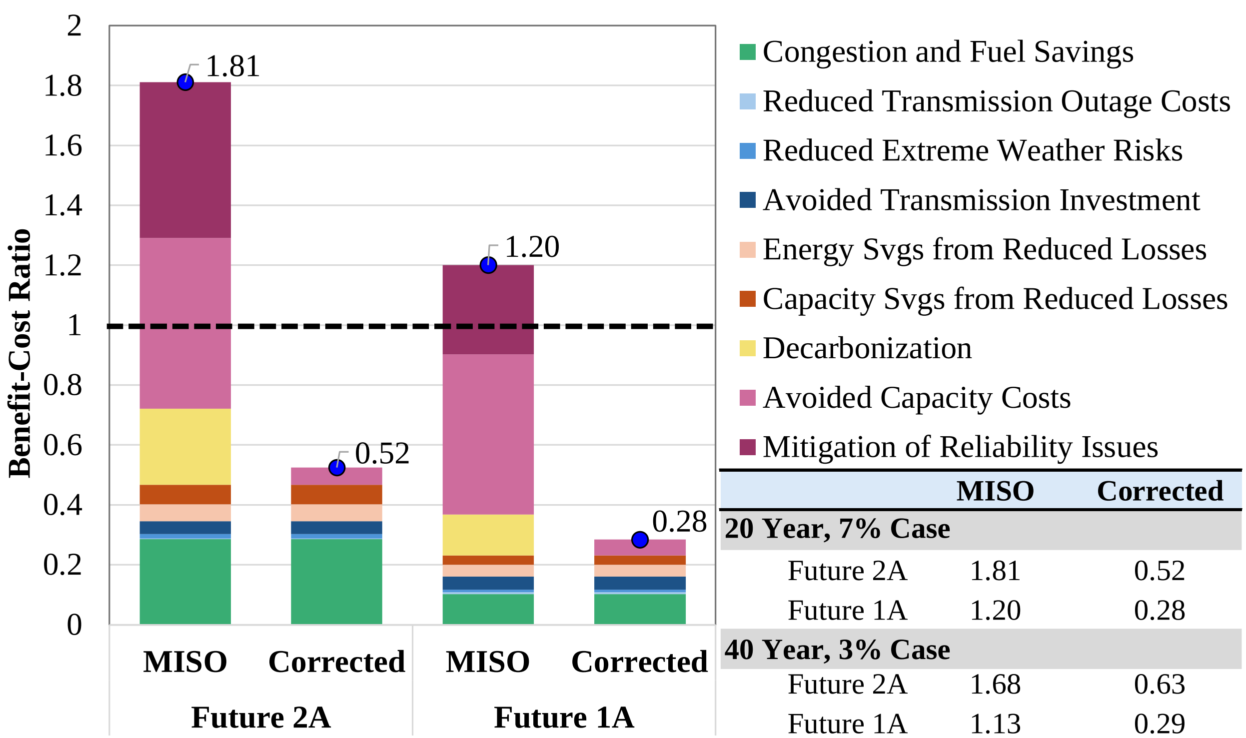
To correct MISO's benefits, we make the following adjustments:

- To account for the fact that resources will enter in deliverable locations closer to load if Tranche 2.1 is not built, we assume that the cost of the 23 GW MISO finds that it needs will entering at locations that are 10 percent higher than assumed originally. This 10 percent assumption is generally consistent with the differences in overnight capital costs on the western MISO states and eastern MISO states in the Midwest.

12 Id. at p. 39.

- We eliminate the mitigation of reliability issues for the reasons described in Section V.C.
- We eliminate the decarbonization benefits for the reasons discussed in Section V.D.

These three adjustments, although they do not completely correct the results of MISO's business case for the flaws discussed in these comments and in the Complaint, produce very different benefit-cost ratios for Tranche 2.1. The figure below summarizes and compares the benefit-cost results produced by MISO compared to our corrected results. MISO's results are produced over two timeframes – 20 and 40 years, and with two discount rates – 3 percent and 7 percent. The stacked bars on the left side of the figure show the contribution of each category of benefits to the benefit cost ratio in the 20-year 7% discount rate cases. MISO measured its benefits against the Future 2A scenario and the Future 1A scenario, which assumes lower levels of renewable resources and loads. We show the benefits for both scenarios. The inset table in the lower right also summarizes the benefit-cost ratio results in the 40 year 3% case.



	MISO	Corrected
20 Year, 7% Case		
Future 2A	1.81	0.52
Future 1A	1.20	0.28
40 Year, 3% Case		
Future 2A	1.68	0.63
Future 1A	1.13	0.29

* MISO cases show the minimum value, affecting only 2 benefits by excluding the high-end carbon value and VOLL.

This figure shows that even if one only corrects the three categories of benefits discussed in our comments above and specifically identified by Dr. Hogan and the Concerned Commissions, the 20-year benefit-cost ratio falls to 0.5 for Future 2A and 0.3 in Future 1A. These ratios rise only marginally in the 40-year 3% case.

These results demonstrate that it would be reasonable to grant the Concerned Commission's request to reclassify the Tranche 2.1 projects to not be MVPs. More broadly, it raises concerns that this Tranche is not economic and should be reformed to ensure that the costs MISO's customers will be asked to bear are reasonable.

VI. CONCLUSION

While the IMM findings support the requested relief in the Complaint to reclassify Tranche 2.1 to no longer be MVPs, this may not address our concerns regarding the excess costs and adverse market effects of Tranche 2.1. Therefore, we respectfully recommend that the Commission Order MISO to revise Tranche 2.1 based on an updated Futures scenario and improved benefits assessment.

To address future LRTP tranches, we support the request in the Complaint for the Commission order a modification to the MISO tariff to require that future business cases be filed and approved by the Commission. This will provide extremely valuable independent regulatory oversight of this process, which we believe is necessary to ensure that FERC-sanctioned transmission rates are just and reasonable.

Respectfully submitted,

/s/ David B. Patton

David Patton
President
Potomac Economics, Ltd.

CERTIFICATE OF SERVICE

I hereby certify that I have this day e-served a copy of this document upon all parties listed on the official service list compiled by the Secretary in the above-captioned proceeding, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated this 9th day of September 2025 in Fairfax, VA.

/s/ David B. Patton

COMMONWEALTH OF PENNSYLVANIA

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January 21, 2026

<u>Via Electronic Mail</u>
The PJM Board of Managers
PJM Planning Department
PJM Interconnection, LLC
2750 Monroe Boulevard
Audubon, Pennsylvania 19408
custsvc@pjm.com

To the PJM Board of Managers and Planning Department:

The Pennsylvania Office of Consumer (PA OCA) submits these comments requesting the PJM Board of Managers (Board) to not approve Project 237 for the Mid-Atlantic Area Cluster (MAAC), as contained within PJM's 2025 Regional Transmission Expansion Plan (RTEP). The 2025 RTEP, including Project 237, was submitted by PJM staff to the PJM Board for consideration and approval following the conclusion of the Transmission Expansion Advisory Committee (TEAC) meeting held on January 6, 2026.

The 2025 RTEP contains a record $11.6 billion of planned new bulk grid projects. PJM staff selected projects to solve reliability needs. The costs of these projects, of course, will be paid for by electricity consumers, with the residential customer allocation being approx. $9 billion.

Project 237

Of paramount concern is Project 237 submitted by NextEra and Exelon and selected by PJM staff. This solution is a 221-mile long, 765 kV single-circuit line from the Kammer Station in Marshal County, West Virginia, crossing 9 Pennsylvania counties, and terminating at the Juniata substation in Perry County, Pennsylvania. Project 237 requires 200-foot-wide, mostly greenfield right-of-way (ROW). Estimated at nearly $2 billion in costs, Project 237 was selected in large part to accommodate PPL's **new** projected data center demand (beyond the 2025 load forecast) and the **recent** removal of NJ offshore wind development.

However, selection of Project 237 for final PJM Board approval, in the PA OCA's view, is premature given rapidly evolving circumstances around data center AI load, incomplete assumptions, and process concerns.

As for rapidly evolving circumstances and incomplete assumptions:

- 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.

- it is not clear, at this time, whether or how the recent leadership direction 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.

- selection of Project 237 ignores the 8.4 GW of announced Pennsylvania natural gas projects expected to enter PJM's four-year paused queue in 2026, which could obviate the need for all or part of the project.[1]

- Finally, from the PA OCA's experience over the last 20 years of litigating high-voltage transmission line cases, PJM staff severely underestimates the costs and risks of building a 221-mile, high-voltage greenfield right-of-way line in Pennsylvania.

As for process concerns:

- Project 237, especially the portion from Kammer to Buttermilk Falls which facilitates transfers from the PJM West cluster to the MAAC cluster, is a long lead-time solution. However, the 2025 RTEP Proposal Window #1 Problem Statement and Requirements RFP document clearly stated that in 2032 for the MAAC 500 kV system overloaded facilities from terminal equipment constraints could be mitigated without long-lead time solutions.

- Furthermore, the load deliverability analysis was conducted on regional cluster-groupings that did not seem to follow the Zonal LDA or Global LDA capacity emergency transfer limit (CETL) Study Areas in Manual 14B. This approach was not discussed in the initial January 2025 assumptions presentation6 at TEAC or subsequent updates in March7 or April.8

[1] Referring to the 4.5 GW of natural gas in Homer City, the 2.7 GW in Shippingport/Bruce Mansfield, 944 MW in Hummingbird, and the 269 MW in Armstrong. PJM's generation queue has been on hold since 2022. The 8 GW of western PA gas generation will benefit from the 500 kV line upgrade from Keystone or Conemaugh to Juniata and may have the potential to eliminate the need for transfers into the large MAAC study region.

- PJM identified load deliverability issues in one scenario where NJ offshore wind did not materialize as planned. However, PJM stated in its reliability analysis slide 11 that it intends to defer decisions on other upgrades related to NJ offshore wind.

- PJM identified load deliverability issues in one additional scenario that used 3.5 GW of additional PPL load from the 2026 Load Forecast, whereas the rest of RTEP is all developed with the 2025 Load Forecast. This approach was not discussed in the assumptions presentations.

- There was a 60-day competitive window rather than a 120-day competitive window recommended to be used for long-lead time projects in Manual 14F.

Other Potential Solutions and Alternative Paths Forward

We believe that likely in-state generation buildouts or faster-to-deploy alternatives utilizing existing ROWs could solve the problems this line intends to address while imposing lower costs and providing higher benefits to Pennsylvania ratepayers

PJM does a very good job of defining needs that exist on the regional high-voltage grid. However, Project 237 has the potential to become the “poster child” for overbuilding new transmission infrastructure and failure to solve reliability needs with potentially less expensive generation options, storage, demand response and other innovative proposals.

The PA OCA urges the re-starting or re-bidding of the project need with more clear, complete, and consistent assumptions, with a new long lead time window in RTEP 2026 to allow for additional proposed solutions that are more cost-effective and capable of being built faster. Alternatively, PJM could reopen and extend the project bidding window in a second competitive round to allow for more cost-effective proposals that account for likely build time and generation buildout.

Final Thoughts and Closing

To be clear, PJM has a very important mandate – to keep the lights on. The PA OCA has great respect for the work that PJM does in this regard, and these comments should not be interpreted as denigrating the important work that PJM does.

In closing, utility consumers in Pennsylvania are paying higher energy prices, due, in large part, to increased costs for bulk power grid services. A primary reason for higher bulk power grid costs is the current imbalance in supply and demand for electricity, driven by data center and artificial intelligence demand that is outstripping existing and forecasted supply, resulting in higher wholesale supply costs and expensive transmission grid expansion. While this letter addresses specifically the expensive expansion to electric transmission facilities to support data center AI demand contained within Project 237, the PA OCA is concerned about rising

PJM costs generally and will continue to stay engaged in matters concerning Pennsylvania ratepayers.

Respectfully,

/s/ Melanie Joy El Atieh
Melanie Joy El Atieh
Deputy Consumer Advocate
Counsel to Pennsylvania Consumer Advocate, Darryl Lawrence
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☐ **Public Document – Not-Public Data Has Been Excised**
☒ **Public Document**

Xcel Energy		Information Request No.	3
Docket No.:	E002/CN-22-532 & E002/TL-23-157		
Response To:	Prehn Family and NoCapX 2020		
Requestor:	Carol A. Overland		
Date Received:	March 28, 2025		

Question:
When was the Prairie Island-Byron-Adams line first built and capacity at that time, expressed in MVA? When was it last updated and/or uprated, and what updates and/or uprates were made? What is the current capacity of that line, expressed in MVA?

Response:
Please see Table 1 below.

Table 1

	Prairie Island-Byron-Adams 345 kV			
First In Service Date	January 2, 1970			
Original rating (MVA)	SN (MVA)	SE(MVA)	WN(MVA)	WE(MVA)
	956.1	1192.1	1195.1	1195.1
Date of last uprate	N/A			
Description of upgrade	N/A			
Current rating (MVA)	SN (MVA)	SE(MVA)	WN(MVA)	WE(MVA)
	956.1	1192.1	1195.1	1195.1

Preparer:	Max McFee
Title:	Sr, Transmission Product
Department:	Integrated Transmission
Telephone:	612-330-6417
Date:	April 7, 2025

☐ **Not-Public Document – Not For Public Disclosure**
☐ **Public Document – Not-Public Data Has Been Excised**
☒ **Public Document**

Xcel Energy		Information Request No.	2
Docket No.:	E002/CN-22-532 & E002/TL-23-157		
Response To:	Prehn Family and NoCapX 2020		
Requestor:	Carol A. Overland		
Date Received:	March 28, 2025		

Question:
When was the King-Eau Claire-Arpin first built and capacity at that time, expressed in MVA? When was it last updated and/or uprated, and what updates and/or uprates were made? What is the current capacity of that line, expressed in MVA?

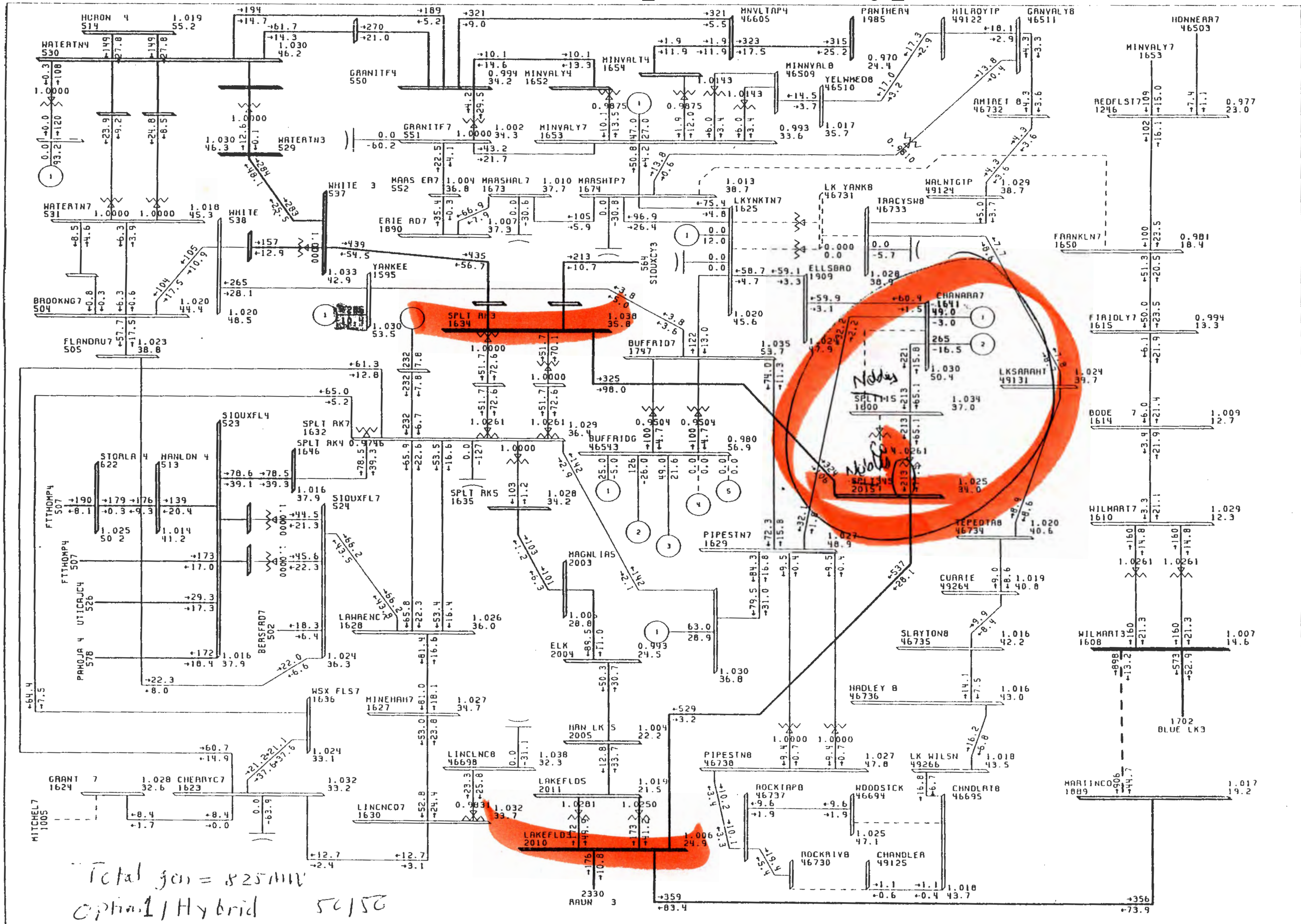
Response:
Please see Table 1 below.

Table 1

	King-Eau Claire-Arpin 345kV			
First In Service Date	January 1, 1960			
Original rating (MVA)	SN (MVA)	SE(MVA)	WN(MVA)	WE(MVA)
	1188.5	1188.5	1195.1	1195.1
Date of last uprate	N/A			
Description of upgrade	N/A			
Current rating (MVA)	SN (MVA)	SE(MVA)	WN(MVA)	WE(MVA)
	1191.5	1191.5	1195.1	1195.1

Preparer:	Max McFee
Title:	Sr, Transmission Product Modeling
Department:	Integrated Transmission Planning
Telephone:	612-330-6417
Date:	April 7, 2025

Attachment F_Powerflows off Buff Ridge_SW MN 345kV EQB Docket 01-1958



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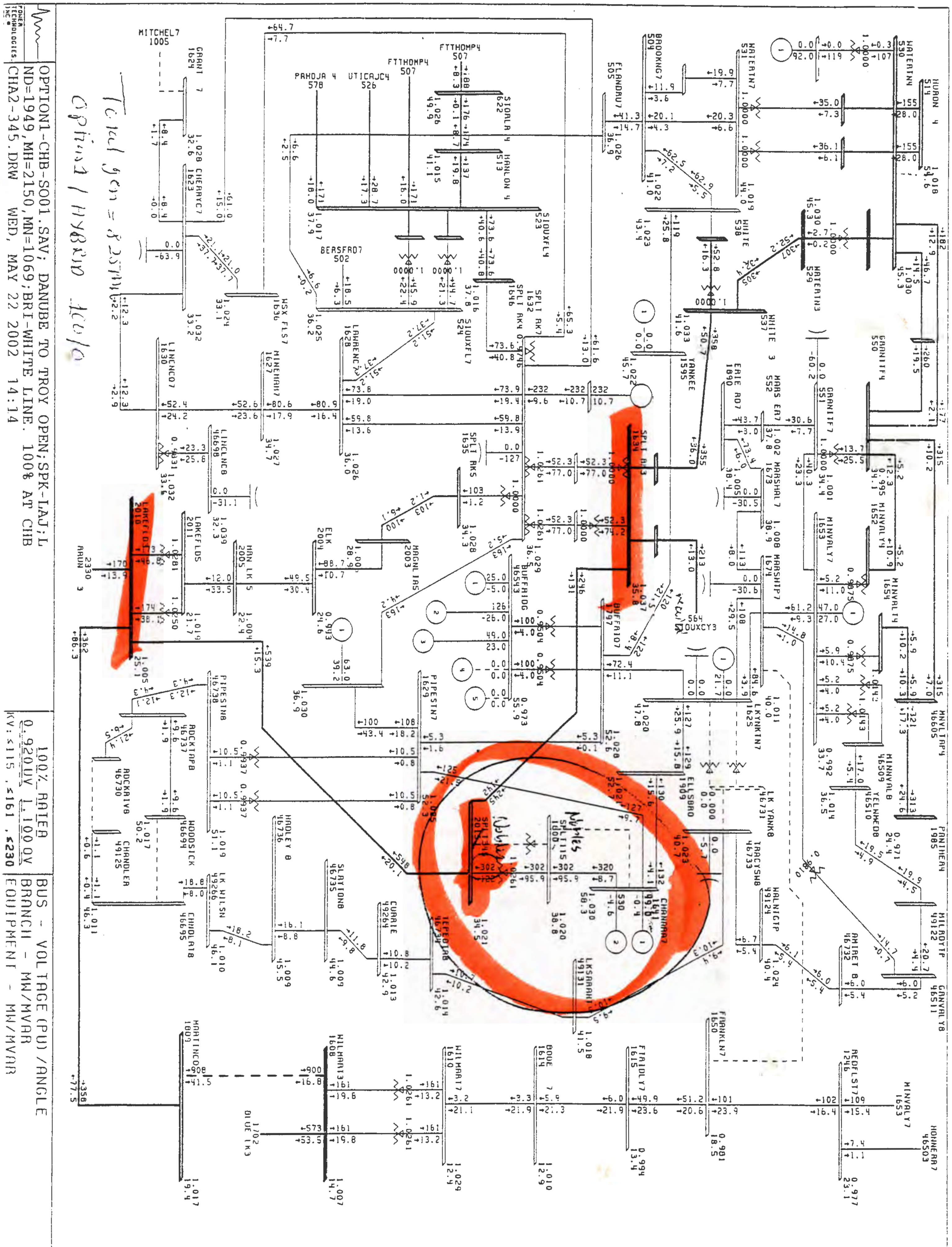
POWER TECHNOLOGIES, INC.

100% RATEA
0.920UV 1.100OV
KV: ≤115 ,≤161 ,≤230

BUS - VOLTAGE (PU)/ANGLE
BRANCH - MW/MVAR
EQUIPMENT - MW/MVAR


POWER TECHNOLOGIES INC.
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CHA2-345.DRW WED, MAY 22 2002 14:14
100% RATEA
0.920UV 1.100OV
KV: ≤115 , ≤161 , ≤230
BUS - VOLTAGE (PU)/ANGLE
BRANCH - MW/MVAR
EQUIPMENT - MW/MVAR
Total gen = 825 MW
Option 1 / hybrid 100%

 PSC REF#:364939

Public Service Commission of Wisconsin
RECEIVED: 04/26/2019 11:29:37 AM

BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Joint Application of American Transmission Company, ITC Midwest LLC, and Dairyland Power Cooperative, for Authority to Construct And Operate a New 345 kV Transmission Line From the Existing Hickory Creek Substation in Dubuque County, Iowa, to the Existing Cardinal Substation in Dane County, Wisconsin, to be Known as the Cardinal-Hickory Creek Project	)	5-CE-146

DIRECT TESTIMONY OF JON WELLINGHOFF
ON BEHALF OF THE DRIFTLESS AREA LAND CONSERVANCY
AND WISCONSIN WILDLIFE FEDERATION

TESTIMONY SUMMARY

There is not sufficient evidence of record for this Commission to definitively conclude that the Cardinal-Hickory Creek (CHC) transmission line project is the highest priority energy option that is also cost effective and technically feasible as required by Wisconsin law. My conclusion is based on the Application in this proceeding, the direct testimony and exhibits submitted by the Applicants, the responses to data requests from the parties, and the testimony and exhibits submitted by witnesses for the Driftless Area Land Conservancy and Wisconsin Wildlife Federation (DALC-WWF).

In order to determine the highest priority energy option that is cost effective and technically feasible, this Commission should direct the Applicants to develop technically feasible least cost Alternative Transmission Solutions (ATS) that are properly and fully formulated and optimized. Once the ATSs are formulated, their total estimated costs should be compared to the updated total projected costs of the CHC transmission line project rather than simply the allocated Wisconsin share in order to achieve a true apples-to-apples comparison of cost effectiveness of alternative project options. Upon completing this analysis, Applicants should submit the analysis to the Commission for a determination of which alternative is the highest priority energy option to be selected for Wisconsin, and other parties should be allowed a full and fair opportunity to respond.

The Commission is likely to find that a properly analyzed ATS is the most cost effective alternative for the Cardinal-Hickory Creek project because: there are a number of significant high priority energy options that could be included in that analysis that Applicants have failed to consider, the price of solar energy generation is rapidly declining as solar panels become more efficient, energy storage costs are rapidly declining, and there are many untapped low cost energy efficiency and demand response opportunities that can be realized. Solar energy is an especially valuable peak resource as the Commission recently recognized in approving 500 megawatts of new solar projects in Wisconsin. ATS involving robust combinations of these resources are more flexible, more in-state, more available at peak when most needed and can be more cost effective compared to approving a Certificate of Public Convenience and Necessity (CPCN) which locks in for 40 years a potentially less flexible high voltage transmission line alternative carrying an unspecified mix of out of state electricity generation to Wisconsin and potentially displacing development of more renewable energy resource projects in Wisconsin.

The Commission should adopt this "no regrets" approach. Approving this Application now without having a proper comparable analysis of the alternatives would potentially result in adopting a suboptimal alternative. Such action by this Commission may fail to deliver the benefits that an optimal portfolio of cost effective high priority resources could deliver to the state. Furthermore, there is no near term reliability need that would require proceeding with the proposed CHC transmission line project now without conducting the full and fair ATS analysis that I have explained in my testimony.

Moreover, based on my experience as Chair of the Federal Energy Regulatory Commission (FERC) and my overall utility regulatory and market experience, the costs of Alternative Transmission Solutions, including ones that incorporate high priority energy options as I discuss below, should be eligible for regional cost-sharing by the Midcontinent Independent

System Operator (MISO). This is certainly true if the ATS provides comparable services and is more cost effective than the proposed Cardinal-Hickory Creek transmission line.

Q: Please state your name, employer, title, and business address.

A: My name is Jon Wellinghoff. I am Chief Executive Officer for GridPolicy, Inc. My business address is 2120 University Ave, Berkeley, CA 94704.

Q: Please describe your current position and provide your education and professional experience as it relates to this direct testimony.

A: I have been an energy regulatory attorney and consultant for the past forty-three (43) years holding various positions at the local, state and federal government level as well as industry. I have served as the Chair and as a Commissioner of the Federal Energy Regulatory Commission (FERC), in senior-level federal and state utility and energy regulatory positions, and in senior-level private sector business positions as more fully explained below.

I have testified in a number of proceedings including before the regulatory commissions of Nevada, Texas, Washington and the District of Columbia, the U.S. Congress and the Federal Trade Commission (FTC). I have been offered to testify as an expert on Integrated Resource Planning (Nevada), energy efficient lighting systems (Texas and D.C.), solar energy industry (FTC), transmission planning procedures and policies (U.S. Congress, House of Representatives) and demand response (private lawsuit).

I am currently the CEO of GridPolicy, Inc., an international consulting firm. We provide energy policy and strategic consulting services to our client base on a range of topics including wholesale and retail electric energy services and markets, transmission and distribution grid issues, distributed energy resources (DER), renewable energy, storage and other issues related to electric energy systems and markets.

Previously, I was the Chief Policy Officer for SolarCity/Tesla, which, at that time, was the largest developer of both residential and commercial solar systems in the U.S. While I worked at SolarCity, we were responsible for the development and installation of over one gigawatt of rooftop, community and large scale solar, and solar plus storage systems.

I served as a Commissioner at the Federal Energy Regulatory Commission (FERC) from 2006 through 2013, and was designated Chairman by the President for the last five of those years. At FERC, I initiated and/or assisted in the development of rulemaking proceedings on demand response (Order 755, Order 745 and Order 719), transmission planning (Order 890 and Order 1000), renewable system integration into the transmission grid (Order 764) and accounting for new electric storage systems (Order 784) among other issues and Orders. While serving as Chair of FERC, I also initiated a reporting system for demand response that provides data on the historical installed capacity of and future potential for demand response within the transmission grid.

I also served as a regulatory attorney at the Federal Trade Commission in the Bureau of Consumer Protection, Division of Energy Product Information. I was responsible for oversight of the solar industry from the perspective of industry product information being provided to consumers.

I served as Nevada's first Advocate for Consumers of Public Utilities, heading a division of the Nevada Attorney General's Office working to protect the interests of utility ratepayers. While serving in that position, I participated in numerous certificate proceedings for transmission lines as well as Integrated Resource Planning (IRP) proceedings analyzing alternatives to transmission projects. In 1983, I wrote the IRP statute for Nevada, which was later adopted in whole or in part by seventeen (17) other state jurisdictions.

I served as General Counsel to the Nevada Public Utilities Commission. Again, in that position, I participated in transmission certificate proceedings and in IRP proceedings analyzing transmission and transmission alternatives.

I was the regional director of NORESCO, one of the nation's largest energy service companies, providing comprehensive energy efficiency, demand response and renewable energy project development services to commercial and industrial customers in the Southwestern U.S.

I was also one of two principals in the energy efficiency-consulting firm, Efficiency Energy Systems, Inc. (EEIS). As an EESI principal, I oversaw the specification and installation of over ten megawatts of energy efficient lighting upgrades in the facilities of multiple clients such as Nellis Air Force Base, Southern California Edison, Pasadena City College, Hawaiian Electric, Orange County School District and others. Also, as an EESI principal, I designed the curriculum and taught energy efficient lighting system technology and auditing to over 300 of Southern California Edison's Energy Service Representatives.

I received a BS in mathematics from the University of Nevada, Reno, a MAT in mathematics from Howard University, and a JD from Antioch School of Law. Although my BS is in mathematics, I started my academic career as physics major. Thus, before changing my major I took all the physics courses required of an engineering major.

I have been a member of the Nevada State Bar since 1975. My complete résumé is attached as Ex.-DALC-WWF-Wellinghoff-1**.**

Q: On whose behalf are you testifying in this proceeding?

A: I am testifying on behalf of the Driftless Area Land Conservancy and the Wisconsin Wildlife Federation (DALC-WWF), which are intervenor parties in this proceeding.

Q: What is the purpose of your direct testimony?

A: The purpose of my testimony is to review the Application in this proceeding for the proposed Cardinal-Hickory Creek (CHC) transmission line and specifically the "Non Transmission Alternative" (NTA) analysis conducted by the Applicants. I will relate that NTA analysis to both Wisconsin statutory requirements and the requirements for transmission planning under applicable FERC standards.

Q: Do you have any exhibits to offer in support of your direct testimony?

A: Yes.

- Ex.-DALC-WWF-Wellinghoff-1
- Ex.-DALC-WWF-Wellinghoff-2
- Ex.-DALC-WWF-Wellinghoff-3
- Ex.-DALC-WWF-Wellinghoff-4
- Ex.-DALC-WWF-Wellinghoff-5

Q: What are the Wisconsin requirements regarding evaluation of alternatives to transmission projects in a proceeding such as this one?

A: The Public Service Commission of Wisconsin (PSCW or Commission) stated in its Final Decision in the Badger Coulee transmission line case: "The Commission has the responsibility to ensure that Wisconsin receives adequate, reliable, and economical electric service now and in the future."[1]

In that context, the Commission is required by statute, to the extent cost effective and technically feasible, to consider options to meet energy demands by prioritizing energy conservation and efficiency and noncombustible renewable energy resources before other energy resources.[2] Regarding those priorities, the Wisconsin Supreme Court stated that in a case such as this one for a Certificate of Public Convenience and Necessity (CPCN):

> *The EPL itself states that the priorities are to be applied '[i]n meeting energy demands." Wis. Stat. § 1.12. Wisconsin Stat. § 196.025(1) states the priorities of § 1.12(4) are to be applied "in making all energy-related decisions and orders.' When the PSC makes a determination on a CPCN under the Plant Siting Law, it applies the EPL in the context of determining whether to approve the requested plant siting.* ***The question the PSC should ask is thus: Given the requirements of the Plant Siting Law, what is the***

[1] PSCW Docket No. 5-CE-142, *Final Decision* (April 23, 2015) (PSC REF#: 236151).

[2] **Wis. Stat. § 1.12(4)**

> ***highest priority energy option that is also cost effective and technically feasible?*** [3]

With that framing by the Wisconsin Supreme Court, the PSCW should then ask: "Is the Cardinal Hickory Creek transmission line project the highest priority energy option that is also cost effective and technically feasible?"

Q: Did Applicants provide sufficient evidence for the Commission to answer this question?

A: No, they did not.

Q: Please explain why.

A: As I explain more fully below, and as explained in more detail in the testimony of DALC-WWF witness Kerinia Cusick, the Applicants failed to conduct a legally sufficient project options analysis that would allow a comparison of the CHC Project to Alternative Transmission Solutions (ATS) composed of feasible high priority energy resources that are optimized for cost effectiveness as required by Wisconsin law and FERC regulations.

Q: Why are you using the terminology Alternative Transmission Solutions or ATS instead of the terminology used by Applicants of Non Transmission Alternatives or NTA?

A: Although some use ATS and NTA as equivalent terms, they actually have distinct and significant legal meanings. An Alternative Transmission Solution or ATS is a term used by FERC in its Order 890 on transmission planning to designate potential alternative solutions to transmission problems that have been identified by a utility transmission provider, a third party project developer or a planning authority. Those solutions could encompass traditional transmission infrastructure such as wires and towers and substations. The FERC made clear in Order 890,

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[3] <u>*Clean Wisconsin, Inc. v. Public Service Commission of Wisconsin*</u>, 282 Wis.2d 250 (2005) at ¶ 122. Emphasis added.

however, that Alternative Transmission Solutions also encompass another category of transmission assets, Advanced Transmission Technologies (ATT). Specifically, Order 890 states:

> *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]

Q: What are Advanced Transmission Technologies?

A: The term Advanced Transmission Technologies (ATT) identifies a distinct class of potentially FERC jurisdictional transmission assets defined by Congress in the Energy Policy Act of 2005. They are broadly defined as:

> …the term 'advanced transmission technology' means a technology that increases the capacity, efficiency, or reliability of an existing or new transmission facility,…[5]

The statute then provides a list of 18 examples of ATTs that include battery storage, solar photovoltaic systems, load control and numerous other technologies.

[4] *Preventing Undue Discrimination and Preference in Transmission Service*, FERC Order 890, p. 436-437 (2007). Emphasis added.

[5] Pub. L. 109–58, title XII, § 1223, Aug. 8, 2005, 119 Stat. 953.

Q: How are battery storage and solar PV systems considered as potential Alternative Transmission Solutions under the FERC Order 890 and Order 1000 transmission planning process?

A: For such resources to be considered as an Alternative Transmission Solution by FERC, two criteria must be met. First, they must fit within the Congressionally determined categories of an Advance Transmission Technology. Second, they must be assessed in the transmission planning process to provide transmission services for the transmission problem identified. FERC indicated a requirement for comparable treatment in the planning process for Advanced Transmission Technologies if they are found to provide transmission services in Order 890:

> *We therefore find that, where demand resources are capable of providing the functions assessed in a transmission planning process, and can be relied upon on a long-term basis, they should be permitted to participate in that process on a comparable basis. This is consistent with EPAct 2005 section 1223.*[6]

Q: What does "comparable basis" and treatment mean in this context?

A: To consider Alternative Transmission Solutions comparably, each separate proposed solution should be formulated independently to provide the transmission services required to solve the transmission planning problem at issue. That formulation should be structured to use the most cost effective assets possible. Once a set of Alternative Transmission Solutions have been formulated and tested for both feasibility of resolving the planning problem and cost effectiveness they should be compared to each other to determine the most cost effective among the alternatives.

Q: What is the significance of an ATT being designated as a potential FERC jurisdictional Alternative Transmission Solution?

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[6] *Preventing Undue Discrimination and Preference in Transmission Service*, FERC Order 890, p. 479 (2007). Note the reference to EPAct 2005 section 1223 refers to Advanced Transmission Technologies.

A: Designating an Alternative Transmission Solution as an aggregation of Advanced Transmission Technologies capable of providing a transmission services solution means that the solution, as an ATS, is eligible for regional cost recovery under FERC transmission planning Orders 890 and 1000. That is a significant benefit. FERC specifically stated in Order 890:

> *Through the regional transmission planning process, public utility transmission providers will be required to evaluate, in consultation with stakeholders, alternative transmission solutions that might meet the needs of the transmission planning region more efficiently or cost-effectively than solutions identified by individual public utility transmission providers in their local transmission planning process. …* ***When evaluating the merits of such alternative transmission solutions, public utility transmission providers in the transmission planning region also must consider proposed*** *…* ***alternatives on a comparable basis****. If the public utility transmission providers in the transmission planning region, in consultation with stakeholders, determine that an alternative transmission solution is more efficient or cost-effective than transmission facilities in one or more local transmission plans, then* ***the transmission facilities associated with that more efficient or cost-effective transmission solution can be selected in the regional transmission plan for purposes of cost allocation.***[7]

Q: Did FERC also use the term "Non-Transmission Alternative" (NTA) in its transmission planning orders, and what is your understanding of the meaning and use of that term?

A: Yes, FERC referenced the term "Non-Transmission Alternative" in both Orders 890 and Order 1000. In the Introduction to Order 890, the FERC stated:

> *Transmission planning is a critical function under the pro forma OATT because it is* ***the means by which customers consider and access new sources of energy and have an opportunity to explore the feasibility of non-transmission alternatives****. Despite this, the existing pro forma OATT provides limited guidance regarding how transmission customers are treated in the planning process and provides them very little information on how transmission plans*

[7] *Preventing Undue Discrimination and Preference in Transmission Service*, FERC Order 890, P 148 (2007). Emphasis added.

> *are developed.* ***These deficiencies are serious, given the substantial need for new infrastructure in this Nation.***[8]

Q: Did FERC link the term Advanced Transmission Technology with how a Non-Transmission Alternative becomes a transmission asset as an Alternative Transmission Solution and thus eligible for cost recovery?

A: Yes. In referring to the ***"…need for new infrastructure…"*** in the above Introduction, FERC then sites the Advanced Transmission Technologies text in a section of the 2005 Energy Policy Act. This section taken together with paragraphs 436 and 437 of FERC Order 890, quoted above, makes it clear that a Non-Transmission Alternative does not become a FERC jurisdictional Alternative Transmission Solution until it meets the two criteria stated above: (1) It is classified as an Advanced Transmission Technology, and (2) It has been assessed in the planning process to be capable of providing transmission services. Then, it can be considered for regional rate base cost recovery.[9]

FERC brought home this point in Order 1000 in discussing Non-Transmission Alternatives and the mechanism for cost recovery for such alternatives in the Order, stating:

> *As we make clear above in the section on Regional Transmission Planning, we are maintaining the approach taken in Order No. 890 and will require that generation, demand resources, and transmission be treated comparably in the regional transmission planning process. However,* ***while the consideration of non-transmission alternatives to transmission facilities may affect whether certain transmission facilities are in a regional transmission plan, we conclude that the issue of cost recovery for non- transmission alternatives is beyond the scope of the transmission cost allocation reforms we are adopting here, which are limited to allocating the costs of new transmission facilities****.*[10]

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[8] *Preventing Undue Discrimination and Preference in Transmission Service*, FERC Order 890, P 3 (2007). Emphasis added.

[9] There may be other non-discriminatory criteria established by the regional planning authority and approved by FERC to qualify for regional cost recovery.

[10] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 at P 779 (2011). Emphasis added.

Q: Did FERC then specify under what circumstances a Non-Transmission Alternative that meets the criteria of an Alternative Transmission Solution will be eligible for cost recovery?

A: Yes. FERC indicated in a footnote to the above-quoted paragraph how Non-Transmission Alternatives could become eligible for rate base cost recovery as a transmission asset:

> *As we stated in the Proposed Rule,* ***the Commission has recognized that, in appropriate circumstances, alternative technologies may be eligible for treatment as transmission for ratemaking purposes****. See Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at n.58 (citing Western Grid Development, LLC, 130 FERC ¶ 61,056 (2010)).*[11]

The "appropriate circumstances" cited by the FERC are those explained above. The ATS must be an ATT (as in the case of *Western Grid Development*- battery storage) and be found by the regional planning authority (CAISO in *Western Grid's* case) to be capable of providing the transmission services needed to meet the identified regional transmission problem. FERC stated in *Western Grid* that for the ATT asset to be considered transmission infrastructure for the purposes of rate base FERC jurisdictional cost recovery, the ATT asset should "mimic" the transmission services necessary to solve the transmission need posed.[12]

Q: What are the implications of these FERC determinations regarding ATS and NTA for this case?

A: The most significant is that Applicants approached their analysis of their constricted NTA option in a manner that will potentially deny and deprive Wisconsin ratepayers of the opportunities for regional cost recovery through rate base treatment of that option at the FERC jurisdictional level.

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[11] Ibid, Fn 563. Emphasis added.

[12] *Western Grid Development, LLC*, 130 F.E.R.C. ¶ 61,056 at P 43 (2010.)

Q: Overall, how did Applicants conduct their NTA analysis?

A: In his deposition, excerpts included in Ex.-DALC-WWF-Wellinghoff-5, Applicant witness Thomas Dagenais describes the general process that he and his colleague, Erik Winsand, used to develop the NTA portfolio for this case:

> *For the non-transmission alternative we looked at the cost of the proposed project to Wisconsin rate payers, and we assumed that that same amount of dollars would be spent on non-transmission alternative developments.*
> *So as I discussed earlier, we had approximately $90 million in 2023 dollars to spend, and we attempted to maximize the benefits of the non-transmission alternative while hitting the four different types of non-transmission components that we included.*[13]

Q: Is this approach legally defensible under the requirements of FERC Orders 890 and 1000?

A: No. FERC requires comparability when analyzing separate transmission options. The requirement is stated repeatedly in FERC Orders 890 and 1000.

Q: How and why was the Applicants' approach not consistent with comparability?

A: Applicants started with a $90 million limit and worked from there. The Cardinal-Hickory Creek transmission line was not planned that way, so neither should comparable options such as the NTA option. Instead, the PSCW should require the Applicants to consider the NTA option on a comparable basis to other options including the CHC transmission line project as required by FERC Orders 890 and 1000.

Q: What does this mean as to how NTA options should be approached?

A: That means that NTA options should first be designed to meet the transmission needs identified in the planning process in the most cost effective manner possible and then their total costs and capabilities should

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[13] Ex.-DALC-ATC-Wellinghoff-5, page 3 of 4.

be compared to all other options. There should not be such an upfront cost limit placed on the NTA options design. ATT resources should instead be cost effectively chosen and aggregated as necessary in order to best mimic the transmission services required to meet the desired transmission solution. In order to comply with Wisconsin law, Applicants should select ATT resources that optimize the portfolio for the most cost effective high priority energy resources available. Applicants clearly did not do that. They started with a basket of suboptimal resources, they also started with a cost limiting resource assumption that they should not have used.

Q: So does Applicant's analysis of its NTA option fail to meet FERC's criteria for cost recovery?

A: Yes. Applicants fail to meet the FERC criteria. First, they failed to test each of their NTA technologies against the criteria for ATT in the 2005 EPAct. They did not determine if the resource set that they chose would "…increase the capacity, efficiency, or reliability of an existing or new transmission facility…". Second, they entirely failed to design their NTA solution in a manner that would "mimic" the transmission services of the Cardinal-Hickory Creek line as required by the *Western Grid* order cited by FERC.[14] In performing their analysis in a less than rigorous and proper manner by ignoring these two critical requirements, the Applicants' NTA solution cannot be considered an ATS by FERC. Therefore, this constricted approach by the Applicants limits consideration for regional cost recovery.

Q: If a properly conducted NTA analysis had determined that the components of the NTA were ATTs and those technologies provided transmission services making the NTA an ATS, could the full cost of the ATS then be considered by FERC for rate base cost recovery?

[14] *Western Grid Development, LLC*, 130 F.E.R.C. ¶ 61,056 at P 43 (2010.)

A: Yes. The *Western Grid* case makes that clear, and FERC reiterated that point in Order 1000 as set forth above.

Q: Did MISO evaluate an NTA option as an ATS for the proposed Cardinal-Hickory Creek transmission line as part of the MVP portfolio analysis?

A: No. A review of MTEP 2011 indicates that MISO apparently did not consider an NTA as an ATS in the MVP planning process.[15]

Q: If MISO did not fully and comparably evaluate an NTA option against the CHC line as an ATS for this MVP Project, why should Applicants be required now to do so in this proceeding?

A: Because they are required to do so by Wisconsin law. As stated above, Applicants must provide sufficient evidence of record for this Commission to conclude that the proposed CHC transmission line is the highest priority energy option that is cost effective and technically feasible.

Q: Did the Applicants do that?

A: No, they did not. Instead of solving for the transmission problems and needs by optimizing a set of high priority technologies, which could comply with both Wisconsin and federal transmission planning law and regulations, they chose a seemingly random set of technologies and applied a constricted dollar cap to the total package to comprise their limited NTA. Ex.-DALC-WWF-Wellinghoff-2 sets out the technology categories, the proposed investment in 2018 and 2023 dollars, and the maximum peak megawatts saved for the Applicants' NTA technologies. These numbers are taken directly from the Applicants' work papers. From these numbers I calculated the dollars per kilowatt (kW) for each kilowatt

[15] This seems to be further confirmed from a review of the Direct Filed Testimony of MISO Witness Rauch in PSCW Docket 5-CE-142 in the Badger-Coulee proceeding where she indicated for that project that MISO only considered traditional transmission alternatives. Direct-MISO-Rauch-1, PSCW Docket 5-CE-142, September 15, 2014, p. 29, l. 3-11, DALC-ATC-00002492.

of maximum peak saved from the 2023 dollars invested (column 3/column 4/1000).

Q: What observations do you have from the numbers that you calculated?

A: It appears that Applicants propose to spend an average of $1,400/kW for each kW of maximum peak load saved in 2023 dollars. Ex.-DALC-WWF-Wellinghoff-2. This ranges from a high of $3,265/kW for the proposed residential solar component of the NTA package to $645/kW for the demand response component. From my knowledge, experience and understanding of potential NTA technologies that could be classified as Advanced Transmission Technologies and thus qualify for FERC rate recovery, the costs of the Applicants' NTA energy options are 4 to 10 times higher than would be expected if one selected an optimized bundle of Advanced Transmission Technologies to provide a comprehensive transmission services solution for Southwestern Wisconsin. Applicants appear to have chosen NTA energy options that are clearly not the most cost effective available as required by statute.

Q: Did the Applicants optimize the NTA technology bundle?

A: No, the Applicants did not. First, they improperly capped the total expenditures for the NTA bundle at $92.5 million and should have considered the full cost of the CHC transmission line project as an upper boundary.

Moreover, the PSCW Staff now states in the Draft Environmental Impact Statement:

> After considering all of the costs (including the capital cost, project financing, and operation and maintenance) that would be associated with the proposed project, the projected MVP allocated present value (discounted to year 2018) cost to the MISO footprint of the proposed Cardinal-Hickory Creek project is $629.2 million. By contrast, the "Applicants' estimate that the capital cost of the

proposed Cardinal-Hickory Creek project would be between $492 million and $543 million in year-of-occurrence dollars."[16]

Second, the Applicants also made numerous errors and improper assumptions in technology choices and the costs of technologies. Those errors resulted in the Applicants producing a suboptimum bundle of technologies.

Q: Please explain those errors?

A: The Applicants first error is that they did not review or consider some of the most cost effective transmission specific technology available. There currently exist commercially proven, technically feasible and cost effective power line technologies that the Applicants appear to have completely ignored.

Q: What are some of these technologies and how do they fit into the FERC/Congressional definitions of ATT?

A: They are all included in the EPAct 2005, Section 1223 definitions of Advanced Transmission Technology. They all increase the capacity and/or efficiency of existing transmission facilities and improve system reliability, and they are specifically called out in Section 1223. They include: "…(14) enhanced power device monitoring…" and "…(17) power electronics and related software…".[17]

Q: What can these technologies do, and how do they work?

A: There are two types of technologies that are currently in use which meet the above ATT definitions. Both of these technologies are used in conjunction with existing transmission lines such as the 161 kV lines found in Southwest Wisconsin. When used with those lines, these technologies can improve reliability, reduce congestion and increase flows at peak periods. These are all transmission services of the type that the CHC transmission line is intended to provide. For example, one technology is an enhanced power line monitoring device that places sensors

[16] Staff Draft Environmental Impact Statement, p.77. PSC REF#: 360500
[17] Pub. L. 109–58, title XII, § 1223, Aug. 8, 2005, 119 Stat. 953.

adjacent to the line taking measurements of line flow, ambient temperature and wind speeds. From these readings the grid operator can determine the appropriate line rating in real-time and potentially increase flows as appropriate. Using machine learning algorithms, the technology can then reliably increase the capacity on congested lines with forecasted line ratings and real-time dynamic line ratings (DLR).

The second technology is a power electronics package that can provide in essence an intelligent "valve" for transmission lines by dynamically increasing or decreasing line reactance.[18] By increasing or decreasing flows on the transmission line in real time in the flow gate, the grid operator can direct flows as needs, improving reliability and increasing throughput of the system. Minnesota is now successfully using this technology in its transmission system to improve system efficiency.[19]

Q: How cost effective are these technologies?

A: In general, they are certainly less expensive than the least expensive technology that Applicants examined, demand response at $645/kW. In certain use cases, these technologies could be as inexpensive as $100/kW.

Q: Should the Applicant have reviewed more use cases for the CHC transmission line with such technologies?

A: Yes. Ignoring these clearly cost effective and technically feasible technologies is, in part, evidence that Applicants failed to attempt to optimize an NTA solution and thus failed to meet their burden in this case.

[18] Reactance is the non-resistive component of impedance in an AC circuit. It can also be thought of as the opposition of a circuit element to a change in current or voltage due to that element's inductance or capacitance.

[19] Available at: https://www.duluthnewstribune.com/business/4124502-minnesota-power-partners-smart-wires

Q: What other concerns do you have with the Applicants' analysis of the NTA option?

A: A second error is apparent from reviewing their estimates for both utility scale solar and residential solar technologies. As shown in Ex.-DALC-WWF-Wellinghoff-4, readily available public source data demonstrates that their cost estimates for both of these technologies are much higher than is reasonable. Moreover, they apparently failed to consider in their NTA analysis over 300 MW of utility scale solar that is approved to be built in Montfort, Wisconsin close to the proposed CHC transmission line location, as well as an additional 50 MW of utility scale solar that is approved to be built in neighboring Richland County, Wisconsin. DALC-WWF witness Kerinia Cusick discusses in more detail the Applicants' failures in the area of solar technology.

Q: Do you have comments on other components of Applicants' NTA option package?

A: Yes, let me turn to a third set of errors. I have comments on both the demand response program and the energy efficiency program. First, with respect to demand response, it appears from the deposition of Applicant witness Dagenais that neither he nor his colleague, Mr. Winsand, fully considered the multiple types of demand response potentially available to provide transmission services. I conclude this from the explanation that Mr. Dagenais gave in his deposition on how he approached the NTA demand response component. He stated in his deposition at pages 47 and 48:

> *The most effective summer peak reducer is demand response where you're simple[y] having large industrial loads shut down during high usage times and they're compensated through that – to do that through more favorable rates.*
> *Looking at the load projections for the study area and evaluating where we knew industrial loads were located, we came up with – I did jot down some notes if I can refer to them. 31.5 megawatts of demand response, which we thought was a reasonable amount to*

> *assume based on the loads in the area, and then based on MISO's MTEP 18 futures workshop…they had published a dollar per kilowatt cost of the initial implementation of demand response. And we put $20 million on the $90 million towards demand response to get us the 31.5 megawatt peak savings, which is the most bang for our buck, but we didn't feel it was appropriate to go larger than that because we didn't feel based on other studies we have reviewed that it was feasible to ask industrial customers to have a larger share of demand response than that.*[20]

Q: What did Applicants overlook in this approach?

A: They appear to have focused entirely on demand response resources from industrial customers. Applicants seem to have entirely ignored the commercial and residential customer class as sources of achieving demand response.

Q: Is it technically feasible and cost effective to derive demand response resources from the commercial and residential customer classes?

A: Yes, it is technically feasible and cost effective to derive demand response resources from residential and commercial customer classes. The most recent FERC staff report on demand response indicates that in 2016, nationwide, there is a potential for over 10,000 MW of residential demand response, and over 11,000 MW of commercial sector demand response.[21] By overlooking these two large sectors, the Applicants excluded a significant transmission services resource in this case.

Q: Do you also have concerns regarding the price that Applicants used for demand response?

A: Yes, and that is a fourth error. The aggregation of demand response resources can be done by third-party aggregators or by load-serving entities. As such, the provision of demand response services can be very competitive. Certain resource assets like residential controllable thermostats may already be in place and paid

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[20] Ex.-DALC-WWF-Wellinghoff-5, p. 1-2 of 4.

[21] Available at: https://www.ferc.gov/legal/staff-reports/2018/DR-AM-Report2018.pdf

for by the customer. The cost to activate those resources and provide a demand response resource to reduce transmission congestion or assure reliability at peak times can be extremely low depending on the customers' perceived cost to participate. For example, Portland General is offering residential customer $1/kWh for peak demand reductions.[22] This is considerably less than the Applicants proposed cost of $645/kW.

Q: What concerns do you have regarding the Applicants energy efficiency NTA option?

A: It appears that Applicants spent their entire energy efficiency budget on LED light bulbs. That is a fifth error. Mr. Dagenais states in his deposition:

> *Q: So in your cost analysis, is it true that you assumed the entire cost of the EE measures would be charged against the NTA budget? I can rephrase that if it would be helpful.*
> *A: Yes, please.*
> *Q: How much did you assume your energy efficiency measures would cost?*
> *A: $2.4million in 2023 dollars.*
> *Q: And did you assume those costs reflected the entire cost of the energy efficiency measure or only part of the cost of that measure?*
> *A: The $2.4 million in 2023 dollars was implemented to achieve 2.6 megawatts of max peak savings in terms of energy efficiency, so, yes, the entire cost of the 2.6 megawatt max peak savings came from the pool of dollars available to the NTA.*
> *Q: And you used—you modeled those measures as LED light bulbs?*
> *A: Correct.*[23]

Q: Why is that a concern?

A: There are several significant problems with this approach. First, for LED light bulbs to be cost effective energy efficiency measures, they need to replace higher wattage incandescent and halogen bulbs. Under current United States Department of Energy regulations, however, most of the higher wattage incandescent and

[22] Available at: https://www.utilitydive.com/news/portland-general-pilot-proposes-reward-to-customers-for-reducing-energy-use/546095/
[23] Ex.-DALC-WWF-Wellinghoff-5, p. 4 of 4.

halogen bulbs that Applicants' LED bulbs are intended to replace will no longer be manufactured or available to consumers after 2020.[24] Second, LED lighting is not the most cost effective measure that Applicants could have selected for providing maximum peak savings.

Q: Why do you believe that LED bulbs are not the most cost effective high priority energy resource that Applicants could have selected for the energy efficiency portion of their NTA option?

A: On Ex.-DALC-WWF-Wellinghoff-3, I have reproduced pages from the Wisconsin Focus on Energy Evaluation Report, Volume I, for calendar year 2016. That report sets forth data for the incentive dollars spent for all Wisconsin energy efficiency programs and the verified kilowatts saved for each program. This data indicates the residential LED program spent approximately $8.3 million and achieved kW savings of 15,639 kW for a cost of $533/kW.[25] However, the residential HVAC controls program spent $508,726 and achieved kW savings of 3,642 kW for a cost of $140/kW. Further, in the commercial sector, the commercial rooftop unit/split system AC program spent $420,400 and achieved kW savings of 1,095 kW for a cost of $384/kW. And the commercial variable speed drive program spent $1.3 million and achieved kW savings of 5,771 kW for a cost of $234/kW. Apparently Applicants failed to select the most cost effective high priority energy efficiency resources for their limited NTA option analysis.

Q: What conclusions do you reach from your analysis of the demand response and energy efficiency programs that the Applicants included in their NTA option analysis?

[24] Available at: https://www.epa.gov/cfl/how-energy-independence-and-security-act-2007-affects-light-bulbs
[25] It is interesting to note that even this figure is considerably lower than the $800/kW number of Applicants for energy efficiency programs shown on Ex.-DALC-WWF-Wellinghoff-2.

A: I conclude that Applicants failed to consider and incorporate into that analysis demand response and/or energy efficiency resources that were very cost effective and available. The Applicants' failure to do so is a critical flaw in their NTA option analysis.

Q: Please summarize your review of the Applicants' NTA option?

A: From my review, I have concluded that the NTA option presented by Applicants in this proceeding does not optimize an aggregation of the highest priority energy resources to meet the transmission service needs. By failing to do so, Applicants have not set forth a comparable Alternative Transmission Solution composed of Advanced Transmission Technologies as defined by FERC, which could then be reviewed against the CHC transmission line project and considered for cost recovery.

Q: Based on your review, what do you recommend that the Public Service Commission of Wisconsin do in this proceeding?

A: There is not sufficient evidence of record for this Commission to definitively conclude that the Cardinal-Hickory Creek transmission line project is the highest priority energy option that is also cost effective and technically feasible as required by Wisconsin law. In order to determine the highest priority energy option that is cost effective and technically feasible, this Commission should direct the Applicants to develop technically feasible least cost Alternative Transmission Solutions that are properly and fully formulated and optimized. Once the Alternative Transmission Solutions are formulated, their total estimated costs should be compared to the updated total projected costs of the CHC transmission line project rather than simply the allocated Wisconsin share in order to achieve a true apples-to-apples comparison of cost effectiveness of alternative project options.

Upon completing this analysis, Applicants should submit the analysis to the Commission for a determination of which alternative is the highest priority energy option to be selected for Wisconsin, and other parties should be allowed a full and fair opportunity to respond.

Q: Do you believe that the Commission should adopt this "no regrets" approach?

A: Yes, I do. The Commission should adopt this "no regrets" approach. Approving this Application now without having a proper comparable analysis of the alternatives would potentially result in adopting a suboptimal alternative. Such action by this Commission may fail to deliver for Wisconsin the benefits that an optimal portfolio of cost effective high priority resources could deliver to the state. Furthermore, as I understand from the testimony of DALC-WWF witness Rao Konidena, there is no near term reliability need that would require proceeding with the proposed CHC transmission line project now without conducting the full and fair ATS analysis that I have explained in my testimony.

Q: Does this conclude your testimony?

A: Yes, it does.

MRO Fall Reliability Conference

Attachment H_Soo Green HVDC Overview

SOO Green Project Overview

October 24, 2018

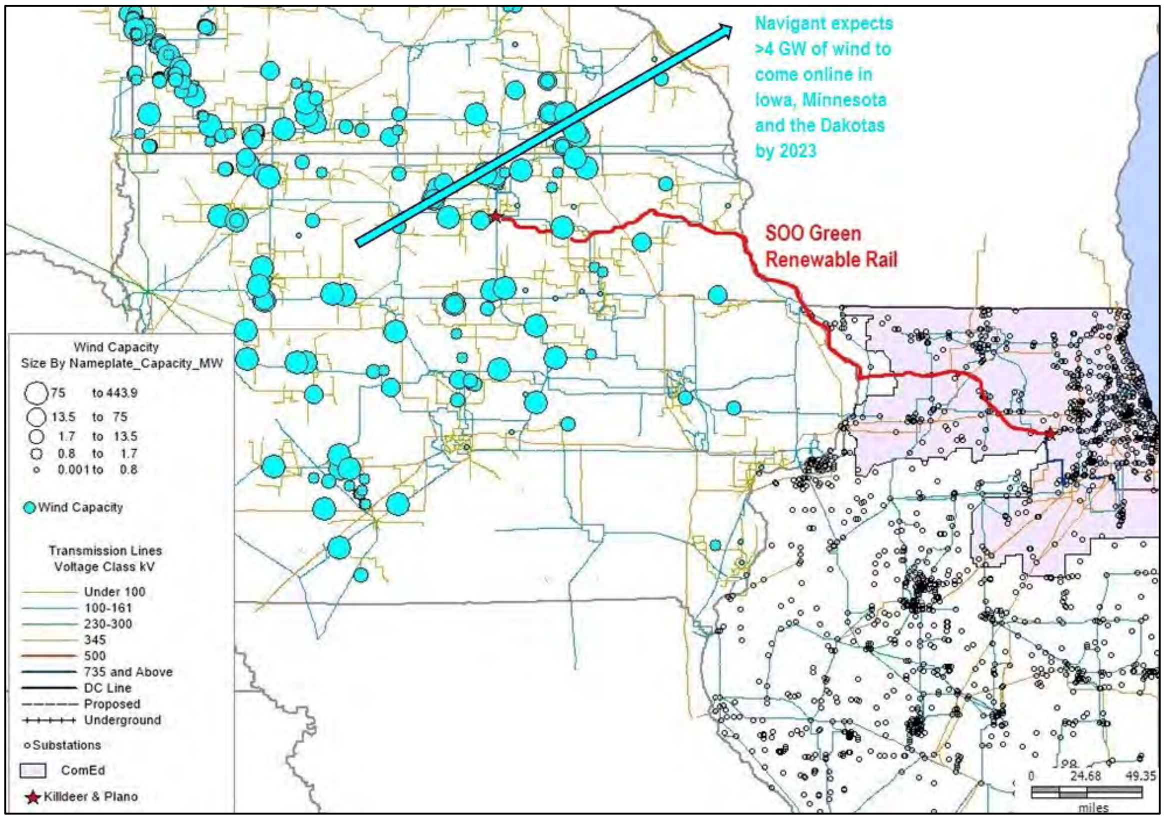
DIRECT CONNECT
DEVELOPMENT COMPANY

and

SOO Green HVDC Link Project Company

Project Overview

The *SOO Green* HVDC Link is a 349 mile, 525KV HVDC underground transmission line that seeks to replicate the model used to build America's fiber optic network by burying a high voltage direct current electric transmission line along an existing railroad to transport renewable energy.

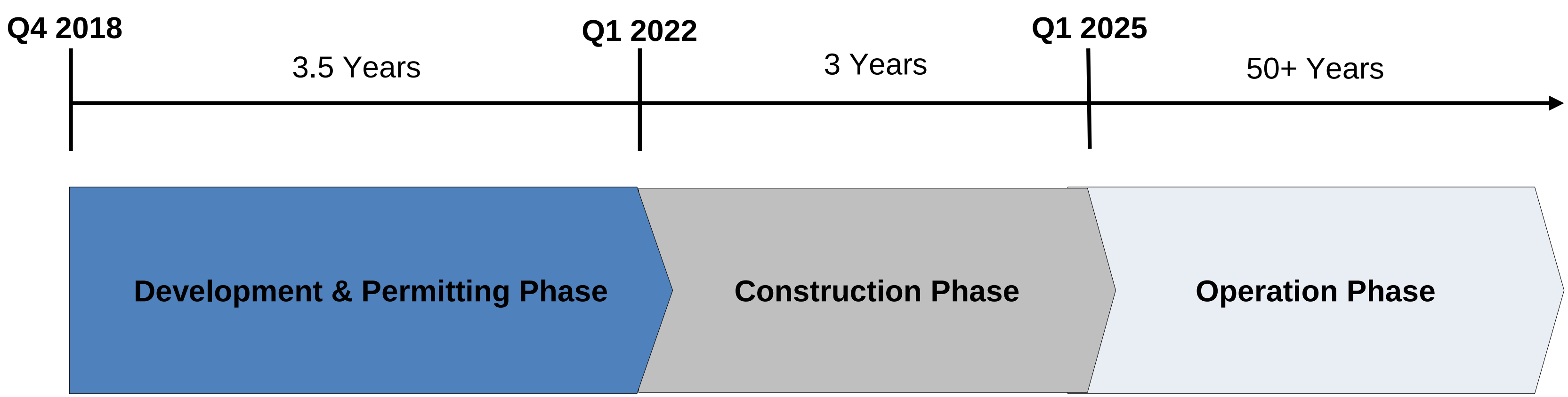


Crossing the MISO/PJM market seam creates significant economic value by allowing SGRR shippers to arbitrage the prices differences between the two markets (Energy, Capacity and RECs). .

Project Overview

Maximum Transmitted Power	2,100 MW
Peak Delivered Power	2,022 MW
End to End Peak Loss of Transmitted Power	3.7%
Projected Line Utilization	69%
MISO Interconnection/ Line Start	345kV Killdeer Substation
PJM Interconnection/ Line End	765kV PJM System via ComEd's Plano Substation
Development Financial Close	Q4 2018
Construction Financial Close	Q4 2021

Target NTP	Q1 2022
Target COD	Q1 2025
HVDC Technology	Siemens 525kV VSC
Cable Technology	525kV XLPE
Maximum (Minimum) Project Length	349 miles (334 miles)
Route Buried Underground	>99%
Route Secured to Date	~85%



Project Differentiators

- SGRR is an innovative project that seeks to replicate the model used to build America's fiber optic network by co-locating transmission line along existing rail.

- Avoiding the use of Eminent Domain and locating underground along an existing railroad helps SGRR avoid the contentious land owner issues plaguing other transmission projects.

- Some of the best wind resources in the world can be found in the upper Midwest US, and SGRR brings that cheap renewable energy to eastern markets.

- Building SGRR underground limits impacts to the environment, streamlines the permitting process, and will allow the project to be permitted and constructed in record time.

- Crossing the MISO/PJM market seam creates significant economic value by allowing SGRR shippers to arbitrage the prices differences between the two markets (Energy, Capacity and RECs).

- SGRR will directly create more than 600 jobs during its construction, and indirectly create more than 200 permanent jobs during operation. These numbers do not include the jobs created to construct the winds farms enabled by the HVDC line.

- No Cost Allocation - Those who use the line will pay for the line

Grid Benefits

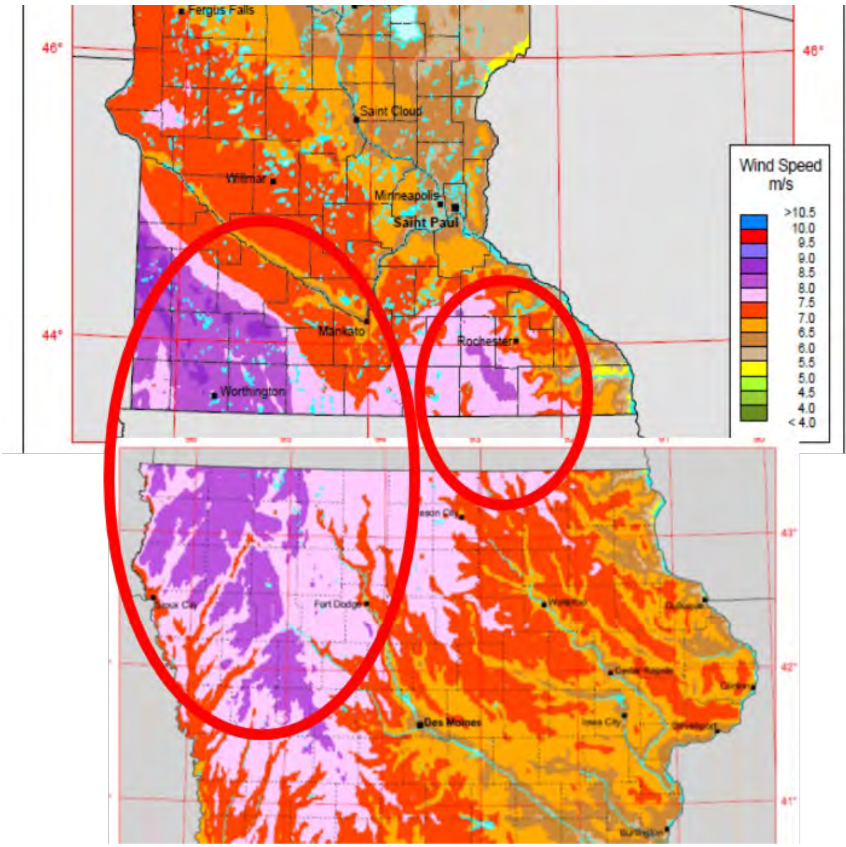
- Heightened MISO risk to resource adequacy due to unit retirements – Range of Resource possibilities
  - SOO Green allows MISO to import or export capacity as needed
- 90GW in MISO Queue mostly wind and solar & 12 GW of Demand Response
  - SOO Green’s rapid response can help MISO mitigate renewable intermittency and increasingly unpredictable loads
  - SOO Green will facilitate new generation entry
  - SOO Green will become a renewable energy hub, making a market to overcome $0 marginal cost generation
  - SOO Green is considering installing batteries on either end of line
- As resources become smaller, more distributed, and more intermittent, the value of large, highly networked systems to manage diversity increases
- SOO Green can aggregate renewable energy production over a wide geographic footprint

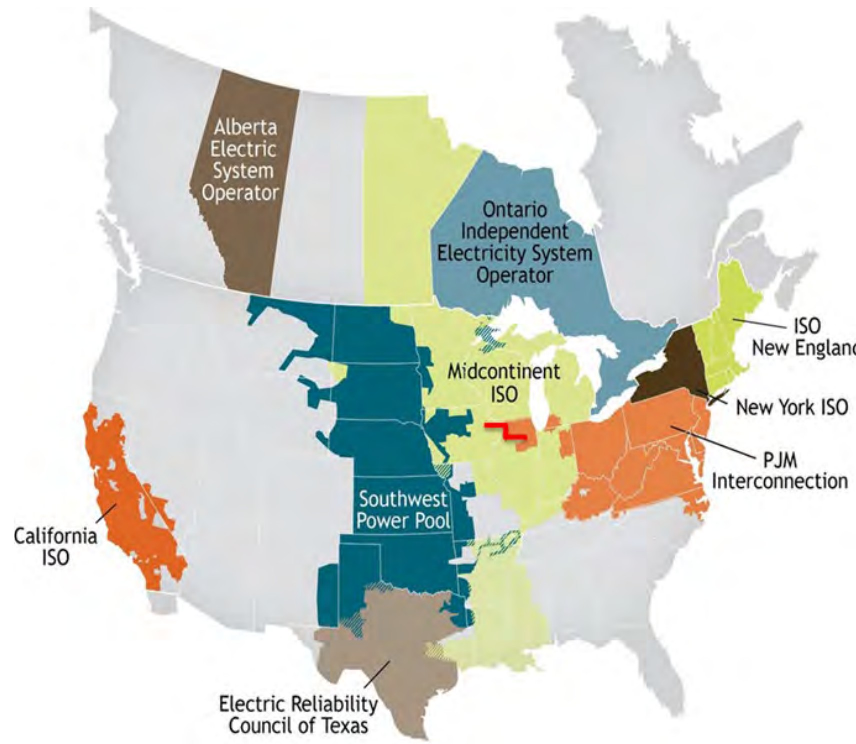
Grid Benefits

- Grid Benefits - HVDC vs AC transmission
  - HVDC can supply services like a generator
  - HVDC systems can act as generation, transmission or load
  - HVDC Voltage Source Converters can provide power scheduling, reactive power regulation (voltage regulation), black start capabilities and power ramping controls superior to generation performing the same function
- HVDC lines do not overload unless scheduled to do so
- HVDC Overlay Networks can be designed so not to impact the AC system at all during contingencies on the AC system
- HVDC can provide contingency support for the AC system
- Loop flows are mitigated
  - The impact on intervening systems is nearly eliminated for HVDC terminals buried several buses deep in the HVDC participants transmission systems.
  - Shift factors of the HVDC transaction are small to neighboring systems.
  - HVDC systems change the power angles on the participant systems to offset the power angle increases of increasing generation for an export and decreasing generation for an import

Value Proposition

Some of the best wind resources in the world can be found in the upper Midwest U.S., and the Project brings that cheap renewable energy to eastern markets. Crossing the PJM/MISO seam allows the owners of the Project's firm transportation capacity to arbitrage the energy, REC and capacity differences between the two markets, creating substantial value

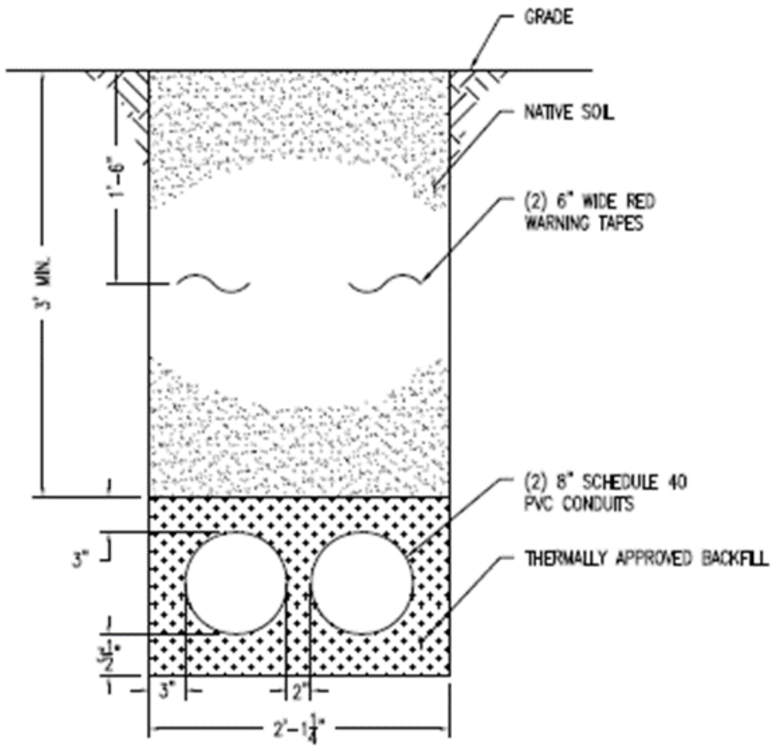




Real Estate

The limited viewshed and environmental impact of underground transmission lines limits landowner concerns

Underground	Overhead



The Project utilizes two slender buried cables approximately five inches in diameter. The compact layout occupies two-and-a-half feet of railroad ROW at a five foot depth.

Construction

The Project will bore under the Mississippi River and other sensitive environmental habitats

Construction

- SOO Green intends to complete civil work and install conduit along a given stretch of rail prior to installing the electrical cable
- Trenches can be closed after conduit installation to limit safety issues and allow for better coordination with rail operations
- The electrical cable will be pulled at a later date, and then spliced
- Civil and electrical work will be staggered along the length of line to keep crews fully utilized

Construction

SOO Green ROW

Source: SOO Green

Permitting

Boring under sensitive environmental habitat along an existing railroad row simplifies the Project's permitting and has garnered support at the local, state and federal level

Agency Meetings

- In June 2016, SOO Green met with the following relevant federal and state environmental and regulatory permitting agencies to introduce the Project, solicit inputs and refine SOO Green's strategy and budget:
  - USFWS
  - USACE
  - U.S. Coast Guard ("USCG")
  - IUB
  - ICC
  - State governors
- Meetings with USFWS, USACE and USCG went exceedingly well, with the federal agencies concluding this is "precisely the kind of project that [the United States] needs to build out its infrastructure" and that they would like to be viewed as a "partner" with SOO Green. The Project was also well received by the ICC, IUB, Iowa Governors Branstad and Reynolds, representatives of Illinois Governor Bruce Rauner and the Director of the Illinois Environmental Protection Agency (EPA)

Permitting Overview

- E&E conducted a critical issues analysis in November 2015 and found no critical issues or constraints that would prevent construction of any of the route options for the Project
- The Project's underground railroad co-location model within an existing pre-disturbed ROW avoids or minimizes the typical impacts of overhead transmission line construction on sensitive areas, including wetlands and forested areas
  - E&E believes that the anticipated reduced impacts of the Project should translate into a shorter construction period

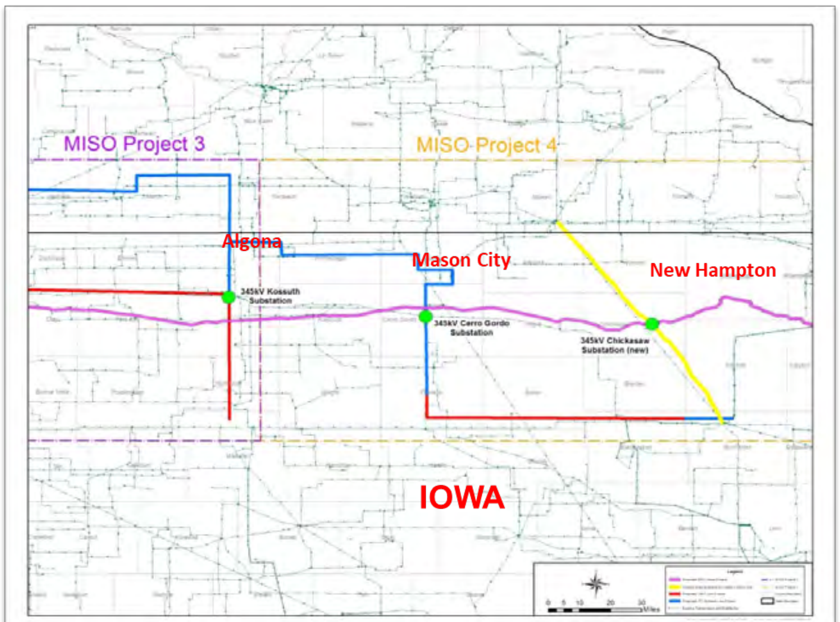
Key Permits

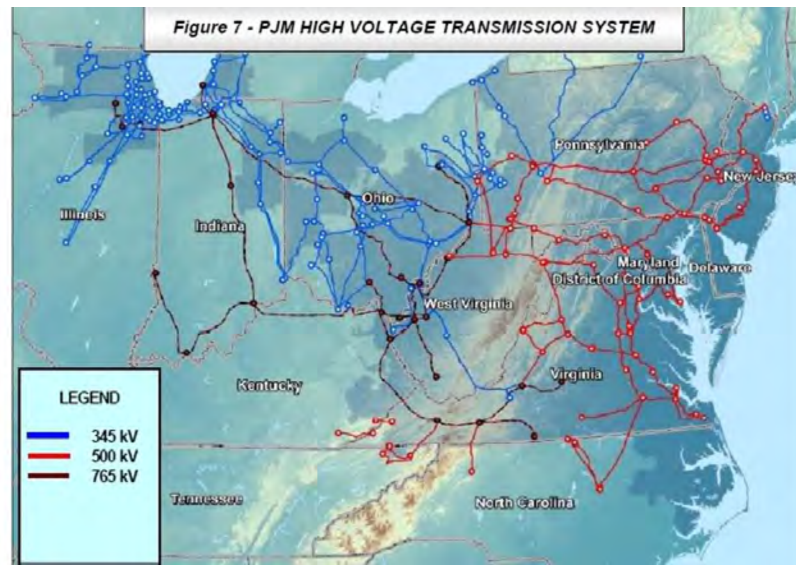
- The USACE concluded that it would be the lead federal agency and that only a USACE Nationwide Permit 12 would be needed and that permit process would cover both Section 10 of the Rivers and Harbors Act and Section 404 of the Clean Water Act
- While unclear, a permit under Section 408 may also be required due to the levies near the Project's river crossing. USACE also stated that it would only need to prepare an Environmental Assessment
- A September 2017 Illinois Supreme Court decision obviates the need for SOO Green to obtain ICC approvals to construct the Project, including a CPCN. SOO Green will instead be required to obtain various routine county and local-level approvals along its route

Interconnection

The Project connects to a strong point on the MISO system, as opposed to acting as a generator tie. This strong system interconnection allows the Project to draw wind energy from across the entire region. The geographic diversity increases the hours in which wind energy can utilize the line, thus increasing the RECs, energy and capacity payments that can be sold into PJM

MISO	PJM



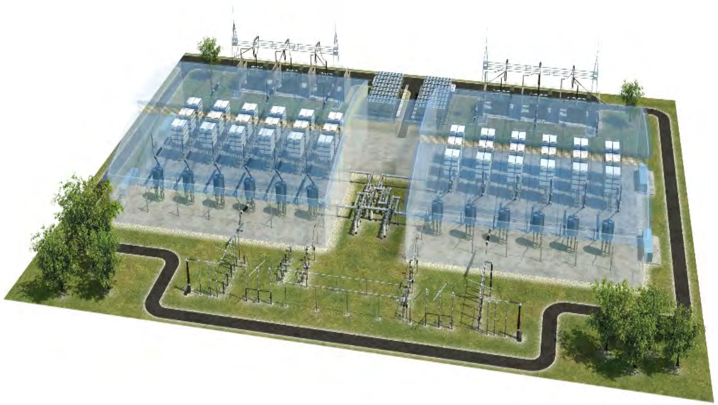


The Project's PJM POI is located on one of the most robust points on the North American grid, ComEd's 765kV extra high voltage transmission system

Technology – Converter Stations

The Project's two Converter Stations will be built by Siemens with state-of-the-art, self-commutated VSC power conversion technology

Siemens Converter Station Technology



Source: Siemens

INELFE (Spain) – 2,000 MW Siemens VSC Converter Station

Source: Siemens

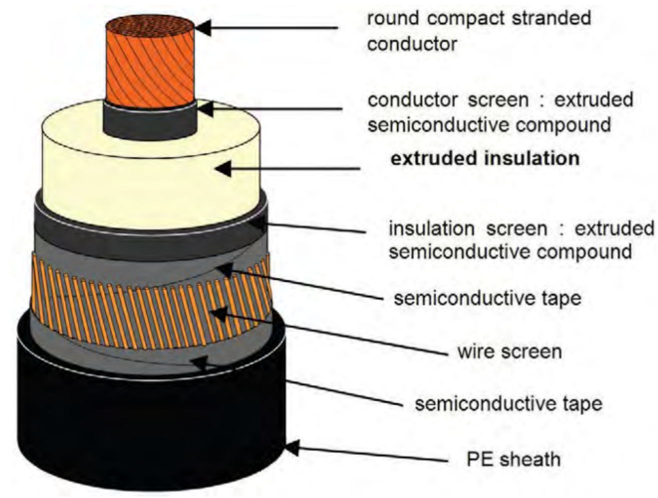
Technology – Transmission Line

SOO Green is currently conducting an RFP process to identify a qualified cross-linked polyethylene (“XLPE”) cable vendor for the Project

XLPE Cable

- Several cable manufacturers are qualified to supply SOO Green’s 525kV cables: NKT Group GmbH (“NKT”), Prysmian S.p.A. (“Prysmian”), Sumitomo Electric Inc. (“Sumitomo Electric”), Nexans S.A. (“Nexans”), ZTT International Ltd. (“ZTT Cable) and LS Cable & System Ltd. (“LS Cable”)
- NKT and Prysmian also offer cables over 525kV that could potentially be selected by the construction equity investor prior to construction
- In general HVDC cable technology experiences lower line losses than AC transmission lines, and as line voltage increases, line losses decrease further. SOO Green expects that the Transmission Line’s loss will be under 4%
- HVDC technology is more economical than AC for transporting large amounts of power point-to-point over long distance routes

525kV XLPE Cable

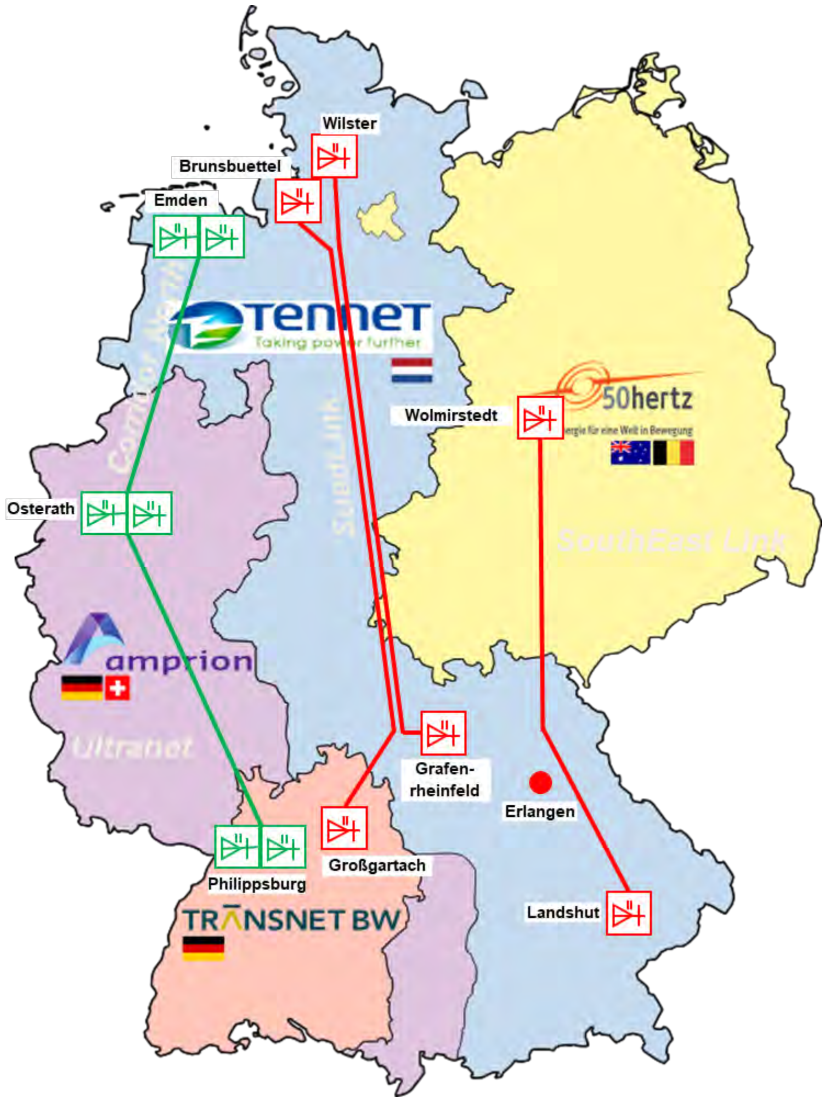


Source: NKT Cables

Potential Cable Providers

- NKT, Prysmian, Sumitomo Electric Inc., Nexans and ZTT Cable are qualifying for a similar 525kV cable tender in Germany. LS Cable is also a qualified vendor
- These cable OEMs have each provided HVDC technology for projects across the world and manufacture a range of cables and cable accessories
- Each manufacturer offers 525kV cables, with NKT and Prysmian also offering several other models over 525kV that could potentially be selected by the construction equity investor prior to construction

Underground HVDC in Germany



Source: German HVDC Grid Extension Plans

- Due to public opposition, the German government decided its national HVDC grid will similarly use 525kV XLPE underground cables so as to not further delay the permitting process for the required HVDC Links to power the country's southern industrial base
- As part of its 525kV XLPE cable tender, Germany is currently completing supplier qualification testing with five leading cable OEMs

Corridor	Sending Station	Receiving Station
Corridor North	Amprion	Amprion
Ultranet	Amprion	TransnetBW
SuedLink Track 1	Tennet	TransnetBW
SuedLink Track 2	Tennet	Tennet
SouthEast Link	50 Hertz	Tennet

400kV VSC DC

525kV VSC DC

Total Transfer Capacity (2025): 8 GW

Development Team

SOO Green has partnered with CP, Siemens and the very best experts in the industry to support the successful development and operation of the Project

JINGOLI POWER

SIEMENS

LE
LONDON ECONOMICS

LS2group

ecology and environment, inc.
Global Environmental Specialists

POWER ENGINEERS

PRW COMMUNICATIONS

PowerGEM
POWER GRID ENGINEERING & MARKETS

PSE Power System Engineering, Inc.

STINSON LEONARD STREET

Fredrikson & BYRON, P.A.

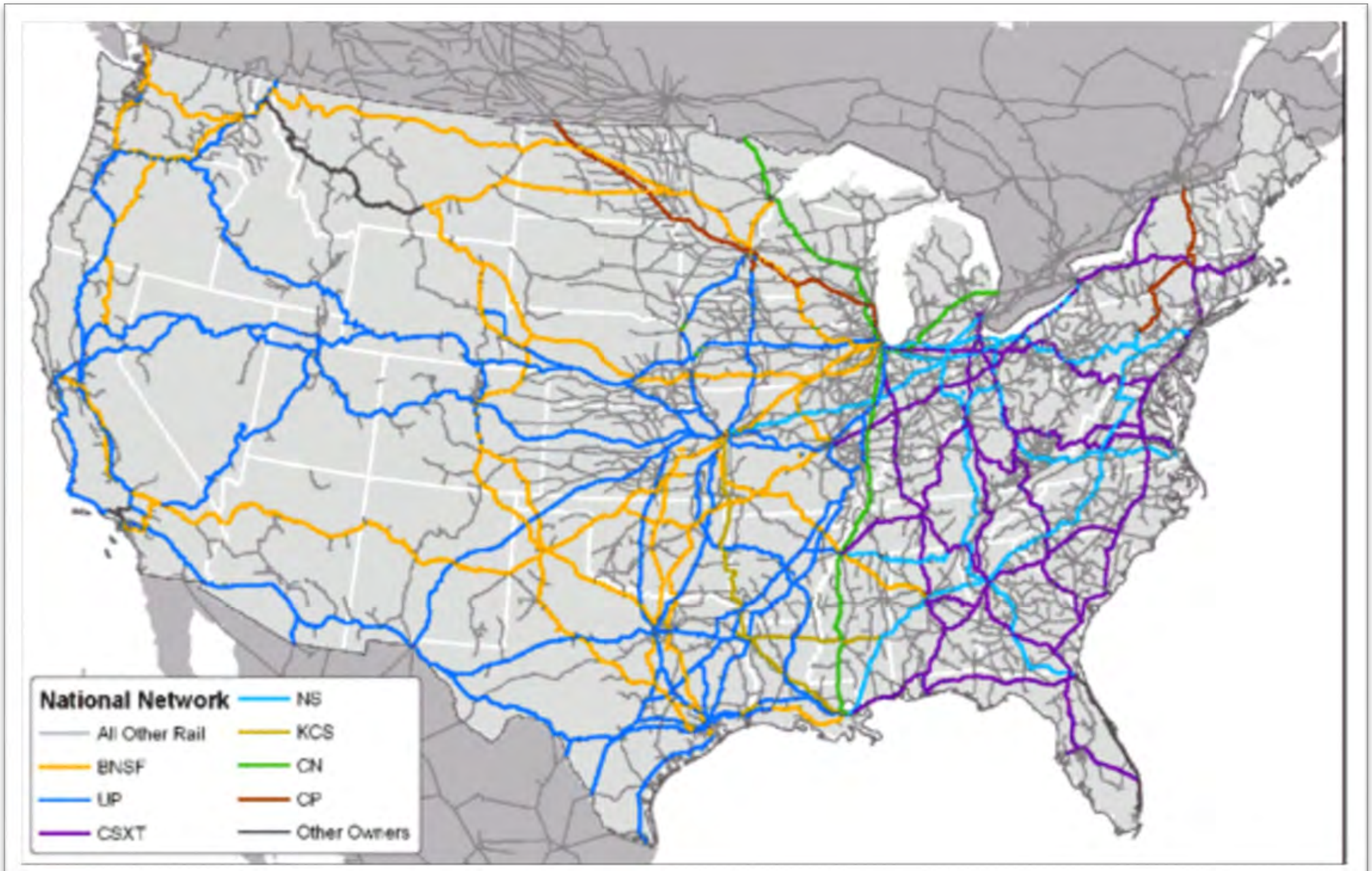
NEIL F. FLYNN & ASSOCIATES
ATTORNEYS AT LAW

whittsturtevant

NAVIGANT

Conclusion

***"Logic will get you from A to B. Imagination will take you everywhere."* – Albert Einstein**



Direct Connect Development Co, LLC

Contacts

All communications or inquiries relating to the project should be addressed to project developer Direct Connect Development Company ("DC DevCo"). Please direct all inquiries to the following professionals:

Joseph DeVito
President
Direct Connect Development Co LLC
(512) 608-8448
jdevito@soogreenrr.com

Minnesota Department of Natural Resources
500 Lafayette Road • St. Paul, MN • 55155-40

Minnesota
DEPARTMENT OF NATURAL RESOURCES

May 20, 2010

Matthew Langan
State Permit Manager
Minnesota Office of Energy Security
85 7th Place East, Suite 500
St. Paul, Minnesota, 55101-2198

Re: Route Permit Application and Draft Environmental Impact Statement (DEIS) Scoping for the Hampton-Rochester-La Crosse 345 kV Transmission Line Project [PUC Docket Number: E002/TL-09-1448]

Dear Mr. Langan:

The Minnesota Department of Natural Resources (DNR) has reviewed the route permit application for the Hampton-Rochester-La Crosse 345 kV Transmission Line Project and offers the following comments regarding the application and scoping for the DEIS. General DEIS Scoping Comments and Preferred, Alternative, and Route Option Comments are included. Most comments are suggested topics for analysis in the DEIS. Some comments are also provided as a review of the route permit application and are intended for early coordination of permit related topics.

General DEIS Scoping Comments

The DEIS should include a comparative environmental analysis of the Preferred, Alternate, and Route Options to determine which route would minimize negative environmental effects from the project. The DNR has several sources of information that should be included as part of the comparative analysis. The Natural Heritage Information System (NHIS) provides information on rare resources such as state threatened and endangered plant and animal species that should be included in the comparative analysis as well as an impact assessment and potential mitigation for the various alternatives carried forward for analysis in the EIS. The Minnesota County Biological Survey (MCBS) identifies and maps native plant communities and sites of outstanding, high and moderate biodiversity that should also be used. The MDNR has also prepared a comprehensive wildlife conservation strategy (*Tomorrow's Habitat for the Wild and Rare, An Action Plan for Minnesota Wildlife*, Jan. 2006) that identifies key habitats for Species of Greatest Conservation Need within each Ecological Classification System (ECS) subsection. The degree to which key habitats are affected by an alternative should also be included in the comparative analysis as well as an impact assessment and potential mitigation for the various alternatives carried forward in the EIS.

It should be noted that rare species surveys will be required if any native prairie remnants, other potential habitat of state-listed threatened, or endangered species will be impacted by the proposed project. In addition, habitat surveys may be required if more information is needed to assess areas with limited data.

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The DEIS should include detailed information concerning any possible state-listed threatened or endangered species takings.

Tables 5.1-5 and 5.2-2 of the Route Permit Application, dated January 20, 2010, provide a format for communicating the rational for choosing the Preferred over the Alternate Route selections. The DEIS should include details of where these features are located within the segments of the identified routes would be helpful in determining which route would have the least environmental impact to natural resources. An example of some of the features that warrant further discussion include conservation areas, grasslands, native communities, bluff habitats, and state-owned lands.

The application discusses further coordination between the project proposer and the DNR regarding rare species and habitats. The DNR encourages this further coordination. GIS shapefiles are needed from the project proposer for DNR review of rare species and habitats in the project area.

The DEIS should identify the locations, associated natural resource impacts, and mitigation planned for temporary laydown areas and staging areas for each route described.

The DEIS should describe maintenance activities, possible associated natural resource impacts, and mitigation that will take place associated with this project for each route. For example, maintenance activities within public lands may be detrimental to natural resources if herbicide spraying were included.

The DEIS should identify distances to nearby State Parks. If a route is proposed near a State Park, the DEIS should include a viewshed analysis and a description of the effects the transmission line would have to park visitors.

Preferred, Alternative, and Route Options

There are two routes identified for crossing the Cannon River. Portions of the Cannon River in this area are designated as a State Recreation River per Minnesota Rules 6106.1600. State wild, scenic and recreational rivers are defined as rivers, along with their adjacent lands, that possess outstanding scenic, scientific, historical, and recreational resources (MN Statutes 86A.05, Subd.10). A greenfield crossing of the Cannon River would have substantial negative effects to the natural characteristics which underlie the Wild and Scenic River designation. In addition, Dakota County's Master Plan for Lake Byllesby Regional Park references the area as having high potential for intact pre-contact archaeological resources due the relatively undisturbed nature of the area (*Lake Byllesby Regional Park Master Plan,* July 2005). Routes to crossing this river should be limited to existing disturbed corridors such as highways or existing transmission lines.

The Preferred, Alternate, and Route Options would adversely affect the McCarthy Lake Wildlife Management Area (WMA). This area has many important natural resources that could be impacted by the proposed project. McCarthy Lake WMA has one of the largest concentrations of the Blanding's turtle, a state-listed threatened species, in the United States and is also considered a significant habitat area for six other species of native turtles. The WMA also receives substantial numbers of waterfowl during spring and fall migrations and provides nesting habitat for sandhill cranes, one of the few in the state for Greater sandhills, and many migratory waterbirds. In addition, there are recorded breeding Henslow's sparrows, state-listed as endangered, and other rare grassland bird species on the WMA, which require open grassland habitats. Studies have shown towers and poles to be considered "hostile" as an environmental component of grassland songbirds. Power line corridors are typically chemically treated to keep brush and trees down, and this would put many native plants at risk. Although there is a route option to avoid the WMA, the proposed bypass would follow the west property line on the WMA for over a mile and would cross a wetland mitigation bank currently being constructed. The DNR cannot support this route option. The DEIS should analyze another route option in the area to avoid the above listed natural resources.

One of the proposed alignments is adjacent to the Woodbury WMA in Goodhue County near Zumbrota. There is a 69kV line less than a mile to the north. The DNR would recommend that the new line follow the existing alignment to the north for this route.

Page 3-3 of Section 3.0 of the route permit application discusses coordinating structure design with the USFWS. The DNR is interested in structure design related to public land and water crossings, particularly if a route crosses an area such as a state forest or WMA. Please coordinate with the DNR regarding the Mississippi River Crossing and other public land or water crossings.

Generally, crossings of public waters should be located where there is existing infrastructure. For example, the Zumbro River should be crossed where existing infrastructure exists and there is the least impact to resources from clearing or construction activities. The Preferred Route crossing of the Zumbro appears to result in the least impact from clearing, and utilizes an existing river crossing.

The Douglas State Trail corridor is a 100-foot ROW owned by the DNR. The corridor was purchased using federal Land and Water Conservation Fund Act (LAWCON) funds, which stipulate that the use of the corridor remains recreational. In Rochester, transmission lines run parallel the Douglas State Trail between 60th Ave NW and CSAH 22 (West Circle Dr.). The DEIS should give more detail about whether the trail ROW and the transmission line ROW overlap. If they do, there may be conflicts with LAWCON funding.

The purpose of the Land and Water Conservation Fund Act (LAWCON) is to help preserve, develop and provide accessibility to outdoor recreation resources. LAWCON stipulates that any land planned, developed or improved with LAWCON funds cannot be converted to other than outdoor recreational use unless replacement land of at least equal fair market value and reasonable equivalent useful is provided. (Title 16 of U.S. Code, Chapter 45, Section 2509). The process related to determining whether a crossing of public lands with LAWCON funding is possible may be time consuming. If any routes are proposed to cross public land, the applicant should coordinate with the DNR to determine whether the public lands have LAWCON funding and determine further steps regarding the license to cross public lands and waters. If any conflicts exist with the purpose of LAWCON funding, the DEIS should explain this topic.

The DEIS should include a robust description of possible underground crossings of the Mississippi River. The Mississippi River is one of the primary flyways in North America and, as discussed in the route permit application, a National Wildlife and Fish Refuge in this area. Examples of ways to further analyze an underground option follow: Underground route crossing options discussed in the DEIS should not only include an underground option at the location(s) best suited for considering aerial crossings, but should include an underground route at the location(s) best suited for engineering an underground route, which may or may not be the same location as the Alma crossing. The reasoning for the route(s) chosen for an underground crossing analysis should be included with the description of underground routing. A comparison of impacts and mitigation should be included for aerial and underground crossings of the Mississippi.

It would be informative if the DEIS contained a brief discussion of the possible extent of impacts in Wisconsin, particularly related to how the choice of a Mississippi River crossing location affects routing in Wisconsin and Minnesota. Providing information in the DEIS regarding the impacts in both Minnesota and Wisconsin would help the reader better assess the overall environmental impacts of an interstate project.

Thank you for consideration of these comments. If you have any questions, please contact me.

Sincerely,

Jamie Schrenzel

Jamie Schrenzel
Principal Planner
Environmental Review Unit
(651) 259-5115

Minnesota Department of Natural Resources
500 Lafayette Road • St. Paul, MN • 55155-40_

April 29, 2011

Matthew Langan, State Permit Manager
Minnesota Office of Energy Security
Energy Facility Permitting
85 7th Place East, Suite 500
St. Paul, Minnesota 55101

Re: Hampton-Rochester-La Crosse 345 kV and 161 kV Transmission Line Project DEIS [PUC Docket Number: E002/TL-09-1448]

Dear Mr. Langan:

The Minnesota Department of Natural Resources (DNR) has reviewed the Draft Environmental Impact Statement (DEIS) for the Hampton – Rochester – La Crosse 345 kV and 161 kV Transmission Line Project. The DNR appreciates the explanation of impacts and attention to detail included in the DEIS and provides the following comments regarding environmentally sensitive areas and state lands located in each segment, rare species, and information regarding construction, design and the DNR License to Cross Public Lands and Waters. Please also see the attached comments regarding the application for a route permit for the Hampton – Rochester – La Crosse Project dated May 20, 2011 for additional context and DNR input.

Segment 1: Hampton Substation to North Rochester Substation

The Cannon River in the project area is designated as a State Recreation River per Minnesota Rules 6105.1600. State wild, scenic, and recreational rivers are defined as rivers, along with their adjacent lands, that possess outstanding scenic, scientific, historical, and recreational resources (MN Statutes 86A.05, Subd. 10). Minnesota Rules 6105.0170 state that in reviewing License to Cross or Work in Public Waters permit applications for such crossings, primary consideration shall be given to crossings that are proposed to be located with or adjacent to existing public facilities, such as roads and utilities. Routes crossing the Cannon River should be limited to existing disturbed corridors such as an existing highway or transmission line.

Considering overall avoidance of natural resources as described in the DEIS, suggested use of an existing corridor to cross the Cannon River, and avoiding impacts to resources such as Byllesby Lake and the Warsaw WMA, the Preferred Route (1P) appears to generally impact the least natural resources for Segment 1. It is recommended that variations of the Preferred Route that may be necessary during project development be used to avoid public water crossings and associated natural resource impacts to the extent practicable.

Segment 2: North Rochester Substation to Northern Hills Substation

It appears that the proposed crossing of Shady Lake occurs at a location where there is no existing infrastructure. Flood damage to the dam at Shady Lake recently caused this waterbody to change from a reservoir to a river. Regional DNR staff have reported possible plans for a restoration project in this area. Avoiding a greenfield crossing in this area is preferred and would likely correspond well with future restoration plans.

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Section 7. 7. 2.1 of the DEIS describes the risk of spreading Chronic Wasting Disease (CWD) in the Segment 2 area by moving soil containing prions, the disease agent for CWD. The DNR appreciates inclusion of this analysis and adds that avoiding construction work within the fence of the Elk Run Development, which was formerly an elk farm, would help avoid the movement of prions. Also, best management practices used to avoid the spread of invasive species, which should be used for all construction areas, should be particularly emphasized in areas identified in Section 7.7.2.1 for risk of CWD spread. Removing soil from equipment would help avoid the spread of invasive species as well as prions.

The Draft EIS indicates that for Segment 2, North Rochester Substation to Northern Hills Substation, all route alternatives provided will have some impact to the Douglas State Trail. The Douglas State Trail ROW is 100-feet wide and was purchased by the DNR using LAWCON (Land and Water Conservation Fund Act) funds. As provided in previous comments (January, 2009), LAWCON funding includes stipulations that any land planned, developed or improved with LAWCON funds cannot be converted to uses other than outdoor recreational uses unless replacement of land of at least fair market value and reasonable equivalent usefulness is provided (Title 16 of U.S. Code, Chapter 45, Section 2509). It is preferred that the proposed project avoid the Douglas State Trail to the greatest extent possible.

The Draft EIS, Section 8.2, is not clear about proposed route locations and whether or not the power lines will be physically located on state land <u>within</u> the Douglas State Trail Right-of-Way (ROW), or, if the transmission lines will run adjacent the trail ROW and <u>not</u> be located on state lands. Additionally, it is not clear as to whether or not the trail and transmission line ROWs will overlap in some way with potential visual impacts from the trail. Transmission lines currently run parallel to the trail between 60th Ave NW and CSAH 22 (West Circle Drive), however the transmission lines are located outside of the trail ROW.

The Draft EIS is also not clear as to whether the 80-foot ROW width must be clear of all woody vegetation along the Douglas State Trail. The removal of woody vegetation along the Douglas State Trail ROW along with the placement of the transmission lines and support structures would have a negative impact on trail users. The existing narrow strip of vegetation along the trail provides a wind break and shade, as well as scenic value, to trail users along the fairly open trail corridor.

The Mitigation section, on page 138, does not fully discuss mitigation measures other than minimizing impacts by choosing a route alternative other than the most intrusive alternative offered. As none of proposed alternatives completely avoid the Douglas State Trail, it appears that there will be some impact to the trail. The Draft EIS does not currently offer any mitigation strategies for the unavoidable impacts to the recreational resources of this segment.

The DNR Parks and Trails Division requests further explanation of the potential impacts to the Douglas State Trail ROW and requests additional information about mitigation strategies related to the recreational resources for this segment. Parks and Trails staff will need to work with proposer on appropriate mitigation measures to comply with the requirements associated with LAWCON funding and to mitigate for the recreational and resource impacts to the trail.

8.2.4.5 Land Based Economies describes aggregate resources within Segment 2. Overall, sand and gravel deposits are scarce within this region. Generally, the original Preferred Route encumbers less undeveloped sand and gravel resources. The portion of original Alternative Route in the northwest corner of New Haven Township (Sections 5, 6, 7, and 8) dissects an important undeveloped, deposit of sand and gravel resources. This deposit is important because it is within a regional scarcity area for

Class C aggregates. Avoidance of this resource is recommended.

It is difficult to determine from the scale of the Land Use Compatibility Map whether there is more than one sand and gravel mine near the proposed line for Segment 2.

Please note that the Aggregate Source Information System (ASIS) is an additional source of information available from the DNR Division of Lands and Minerals regarding aggregate mining and is an inventory of pits used for state projects. However, please note that there are many additional gravel mines that are not in the ASIS database.

Segment 3: North Rochester Substation to Mississippi River

As stated in the attached May 20, 2010 letter, crossings of public waters should generally be located where there is existing infrastructure. For example, the Zumbro River should be crossed where existing infrastructure exists and there is the least impact to resources from clearing or construction activities. The Zumbro River crossing at the white bridge in Segment 3 appears to result in the least impact from clearing, and utilizes an existing river crossing.

Map 8.3.40 shows the statutory boundary of state forest in Segment 3, but does not show the actual state ownership boundary, which would show considerably less acreage. This should be corrected to avoid any confusion about the amount of forested land and state ownership. If needed, the DNR Division of Forestry would be able to assist with more accurate mapping for this area.

If final routing does cross state forest, single pole construction is preferred to reduce the acreage of forest clearing.

The McCarthy Lake Wildlife Management Area (WMA) has many important natural resources that could be impacted by the proposed project. McCarthy Lake WMA has one of the largest concentrations of the Blanding's turtle, a state-listed threatened species, in the United States and is also considered a significant habitat area for six other species of native turtles. The WMA also receives substantial numbers of waterfowl during spring and fall migrations and provides nesting habitat for sandhill cranes, one of the few in the state for Greater sandhills, and many migratory waterbirds. In addition, there are recorded breeding Henslow's sparrows, state-listed as endangered, and other rare grassland bird species on the WMA, which require open grassland habitats. Studies have shown towers and poles to be considered "hostile" as an environmental component of grassland songbirds. Power line corridors are typically chemically treated to keep brush and trees down, and this may put many native plants at risk. Though there is an existing transmission corridor in this area, expansion of the ROW and construction and maintenance activities would increase impacts in this area. Also a proposed bypass to follow the west property line on the WMA for over a mile (3A-Kellogg or 3P-Kellogg) would cross a wetland mitigation bank currently being constructed. Considering these possible natural resource impacts, and to avoid forest impacts within DNR managed state forest along the Preferred Route, the DNR encourages utilization of Highway 42 (Route 3B-003) in this area.

In Section 8.4, it is unclear if the existing line near the Kellogg Crossing and the proposed line would be collocated on the same poles.

A description is included in the DEIS of an underground configuration to cross the Mississippi River. A thorough assessment of underground routing through this portion of the project is important as the Mississippi River is one of the primary flyways in North America. Underground routing is more expensive and technically challenging and therefore may be considered only practical when a uniquely high risk of natural resource impact exists. Considering that this flyway is one of four primary flyways for all migratory species in North America, that transmission lines pose a risk of avian collision, and that the line is crossing through this narrow flyway corridor, this may be exactly the type of situation warranting the challenging use of underground configuration. A thorough analysis of underground routing, including some assessment of whether this crossing provides the most practical underground engineering out of possible crossings is recommended. This analysis may include locations other than previously described aerial crossings if engineering for underground configuration is more practical at another location.

Analysis of an underground crossing at an existing transmission crossing, such as the Kellogg/Alma location, should include collocation of existing transmission and new transmission so that the possible benefits of underground transmission are not lessened in the analysis.

Whether underground or aerial crossing is planned for this project, further coordination regarding details such as pole placement, pole type and underground line placement should be coordinated with the DNR to address vegetation and wildlife impacts, possible rare species impacts, and for preparation of a License to Cross Public Lands and Waters.

Rare Species

The DNR recommends that the FEIS include an assessment of state-listed species of special concern as these are rare resources that may be impacted by project activities. Also, the list of legally protected species (state-listed threatened and endangered) may change within the time periods described for project construction. Some state-listed species of special concern may be included as threatened or endangered at the time of final project construction. These species could also become listed during ongoing maintenance activities. Therefore, inclusion in the EIS will assist project developers and the DNR with an understanding of potential impacts at the time of construction.

Key Habitats and Species of Greatest Conservation Need (SGCN) as described in Minnesota's Comprehensive Wildlife Conservation Strategy are mentioned in the beginning of the DEIS, but potential impacts to Key Habitats do not seem to be further discussed. Further analysis of Key Habitats would strengthen an environmental assessment of this project and would be an appropriate way to utilize Minnesota's wildlife planning, considering the possible impact footprint of a large project such as the Hampton – Rochester – La Crosse Transmission Line.

It appears that an incorrect table was included in Appendix F under the title Segment 1 – Rare Communities. A Rare Species table appears to be included instead of a Rare Communities table. A Rare Communities table should be inserted here.

Once a route is chosen through the Public Utilities Commission (PUC) permitting process, or earlier if possible, suitable habitat for threatened and endangered species will need to be identified along routes and may need to be surveyed. The applicant should coordinate with the DNR regarding any required surveys for threatened or endangered species. It is important to note that surveys may be required during a specific time period and may affect project planning and scheduling.

Project Overview

The DEIS indicated that three substations will be expanded or constructed. Brief descriptions of adjacent ROWs, graded areas and grade access roads are provided. The DEIS should include discussion on other existing utility lines within or near the proposed ROW and expand the description on transmission line proximity to ROWs. While section 8.14.11 provides discussion on shared ROW with highways, this discussion should include shared ROWs with trails, transmission lines, and pipelines as shown on map 8.1-26.

Additional information should be provided on the effects to existing Farmland Natural Areas Program easements adjacent to the Applicant's Preferred Route.

Engineering and Operation Design

Figure 4.3-1 indicates heights that are inconsistent with the heights shown in the handout "345kV Transmission Pole Design Alternatives" which was provided at the meeting with the DNR on March 14, 2011. A consistent design should be included in the FEIS.

The DEIS indicates widths that are inconsistent with the widths shown in the handout "345kV Transmission Pole Design Alternatives" which was provided at the meeting with the DNR on March 14, 2011. A consistent width should be provided in the FEIS.

Construction

The DEIS should evaluate storm water management. Specific practices should be implemented for the protection of water quality from storm water runoff including contaminated runoff from construction, operation and maintenance activities.

It is recommended that the DEIS discuss and assess differences between winter and summer construction.

The DEIS should evaluate the location of storage piles and source of materials used in construction. The DEIS should discuss disposal or wasting of the excavated material from the construction of the tower footings and include consideration of Chronic Wasting Disease precautions.

The DEIS should discuss permanent and temporary access roads/points to the proposed ROW routes, whether they are asphalt, concrete, gravel, and the season and duration of use. These should be identified and impacts assessed.

The DEIS should identify all hazardous materials that will be used at project sites, the amount that is to be used and stored, and how they are to be transported. The likelihood and/or frequency of hazardous material spills and response plans should be discussed, particularly near sensitive areas such as water crossings.

The DEIS should evaluate clearing practices.

The DEIS should discuss possible preventive measures and management techniques for invasive species. DNR invasive species standards will apply to state-administered lands and water and will include cleaning of equipment. Native species mixes for re-vegetation and use of clean weed-free straw for mulch will be required on state land and public water crossings. Best Management Practices to avoid the spread of invasive species are also important for the containment of soil contaminated with prions associated with Chronic Wasting Disease.

Required Permits and Approvals

The review and issuance of DNR lands and water crossing licenses are coordinated by the DNR Division of Lands and Minerals. The Lands and Minerals Regional Supervisor for Dakota Goodhue and Wabasha counties is Trina Zieman (651/259-5792). The applicant should contact Trina Zieman to schedule a pre-application meeting to discuss administrative procedures for submitting the land and water crossing applications. Several licenses may be required depending on the timing and scope of the project. DNR monitoring will be required in the DNR licenses. Independent monitors may also be required during construction. Additional work areas on state land that are adjacent to the ROW may be considered under the land crossing license application. Temporary access to the ROW across state land is not part of the license application process and is considered a separate transaction. Such temporary access could not be granted through a lease. Requests for temporary access require review and approval and may not be granted. Adequate time for processing these requests should be allowed. Please also consider Executive Order 11-04, which sets a goal for the DNR of completing environmental permits within 30 days of final approval of the Final Environmental Impact Statement. Coordination may be necessary regarding this project and meeting the goal included in Executive Order 11-04.

Please note that the DEIS page numbering and some map numbering appears to be different on two different versions of the document available during the comment period. The DNR appreciates receipt of the notice related to these changes. However, it is possible there may be some references in DNR comments that unintentionally do not match the most updated DEIS version. Please feel free to contact me with any needed clarifications if any confusion exists.

DNR staff appreciate the opportunity to review the DEIS for the Hampton – Rochester – La Crosse Transmission Line Project.

Sincerely,

Jamie Schrenzel

Jamie Schrenzel
Principal Planner
Environmental Review Unit
(651) 259-5115

Enclosures: 1

C: Richard Davis, USFWS
Tom Hillstrom, Xcel Energy
Melissa Doperalski, DNR

Minnesota Department of Natural Resources
500 Lafayette Road • St. Paul, MN • 55155-40

June 29, 2011

Minnesota
DEPARTMENT OF NATURAL RESOURCES

Judge Kathleen D. Sheehy
Office of Administrative Hearings
P.O. Box 64620
600 North Robert Street
St. Paul, Minnesota 55164-0620

Re: Hampton-Rochester-La Crosse 345 kV and 161 kV Transmission Line Project
[PUC Docket Number: E002/TL-09-1448; OAH Docket No. 3-2500-21181-2]

Dear Judge Sheehy:

The Minnesota Department of Natural Resources (DNR) has reviewed the Route Permit Application and Draft Environmental Impact Statement (DEIS) for the Hampton-Rochester-La Crosse Transmission Line Project and has provided testimony during the Office of Administrative Hearings (OAH) evidentiary hearing. The attached comments regarding the DEIS, dated April 29, 2011, are included for analysis and consideration in the administrative record and findings of fact. In addition to these comments, further clarification is provided, as requested by parties in the evidentiary hearing, regarding DNR comments about possible Zumbro River crossings in Segment 3 of the project.

As stated in previous comment letters, the DNR recommends crossings of public waters to generally be located where there is existing infrastructure. For example, the Zumbro River should be crossed where existing infrastructure exists and there is the least impact to resources from clearing or construction activities. The Zumbro River crossing at the white bridge in Segment 3 appears to result in the least impact from clearing, and utilizes an existing river crossing.

Specifically, there are three Zumbro River crossings included in the project record: the north crossing, which is a greenfield crossing, a middle crossing at a dam, and the southernmost crossing at the white bridge. As stated above a crossing with no existing infrastructure such as the northernmost crossing is not encouraged. The northernmost crossing also has Natural Heritage Information System (NHIS) records of a state-listed threatened turtle in the vicinity of the crossing. There is also a Minnesota County Biological Survey (MCBS) Site of Biodiversity Significance ranked as Moderate near the crossing. The Zumbro River crossing near the dam is located next to an MCBS Site of Biodiversity Significance ranked as High. Rare species in the area include state-listed special concern American ginseng (plant), and state-listed special concern moschatel (plant). The southernmost white bridge crossing would affect an MCBS site of Biodiversity Significance ranked as Moderate and one ranked as Below. To avoid a greenfield crossing, the northernmost route is not recommended. Considering a comparison of rare species, MCBS site presence and ranking, and a general goal of reducing deforestation between the two crossings with existing infrastructure, the DNR recommends utilizing the white bridge crossing in this area rather than the crossing at the dam.

Thank you for the opportunity to provide input regarding the Hampton-Rochester-La Crosse Transmission Line Project. Please contact me with any questions regarding the attached comments, evidentiary hearing testimony, or additional information provided in this letter.

Sincerely,

Jamie Schrenzel

Jamie Schrenzel
Principal Planner
Environmental Review Unit
(651) 259-5115

Enclosures: 1

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Minneapolis, MN 55401

November 5, 2025

Scott O. Arneson, Secretary
Goodhue County Economic Development Authority
509 West 5th Street
Goodhue County Government Center
Red Wing, MN 55066

Re: Stakeholder Outreach - Proposed 345 kV Transmission Line Project Goodhue County, Minnesota

Dear Mr. Arneson:

Xcel Energy is proposing to permit, construct, and operate a new, approximately 1.3 mile long, double-circuit, 345-kilovolt (kV) high voltage transmission line (Project) that will connect Xcel Energy's existing North Rochester Substation to new substation facilities located at a proposed technology center/mixed use industrial development site (development site) near the City of Pine Island in Goodhue County, Minnesota. The development site (known as the Skyway Project[4]) is undergoing permitting and approval processes with the City of Pine Island separate from this 345 kV transmission line project.

To accommodate the proposed 345/345-kV high voltage transmission line, Xcel Energy's existing North Rochester Substation will be expanded to the north by approximately 17.9 acres and additional substation facilities will be constructed within the development site. The transmission line is proposed to have a 150-foot-wide right-of-way. The enclosed map shows the location of the proposed Project facilities. The proposed transmission line and substation expansion would be constructed primarily on land currently being farmed for corn and soybeans.

Xcel Energy plans to submit a Route Permit Application (RPA) with the Minnesota Public Utilities Commission (PUC) in the first quarter of 2026. We intend to file the RPA in accordance with Minnesota Statutes (Minn. Stat.) 216I.07 under the standard review process.

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[4] The Skyway Project is being proposed by Ryan Companies US, Inc. An Alternative Urban Areawide Review (AUAR) has been completed for the development site project and the City of Pine Island is currently reviewing that project for applicable permits and approvals. See the City of Pine Island website (Project Skyway - Pine Island, MN) for more information.

Xcel Energy requests your feedback to assist in identifying potential impacts. If you would like to meet to discuss the Project, or if you have questions or would like additional information, please contact me at Ellen.L.Heine@xcelenergy.com or (612) 330-6073.

We look forward to hearing from you about this Project and respectfully request comments by or before December 19, 2025.

Sincerely,

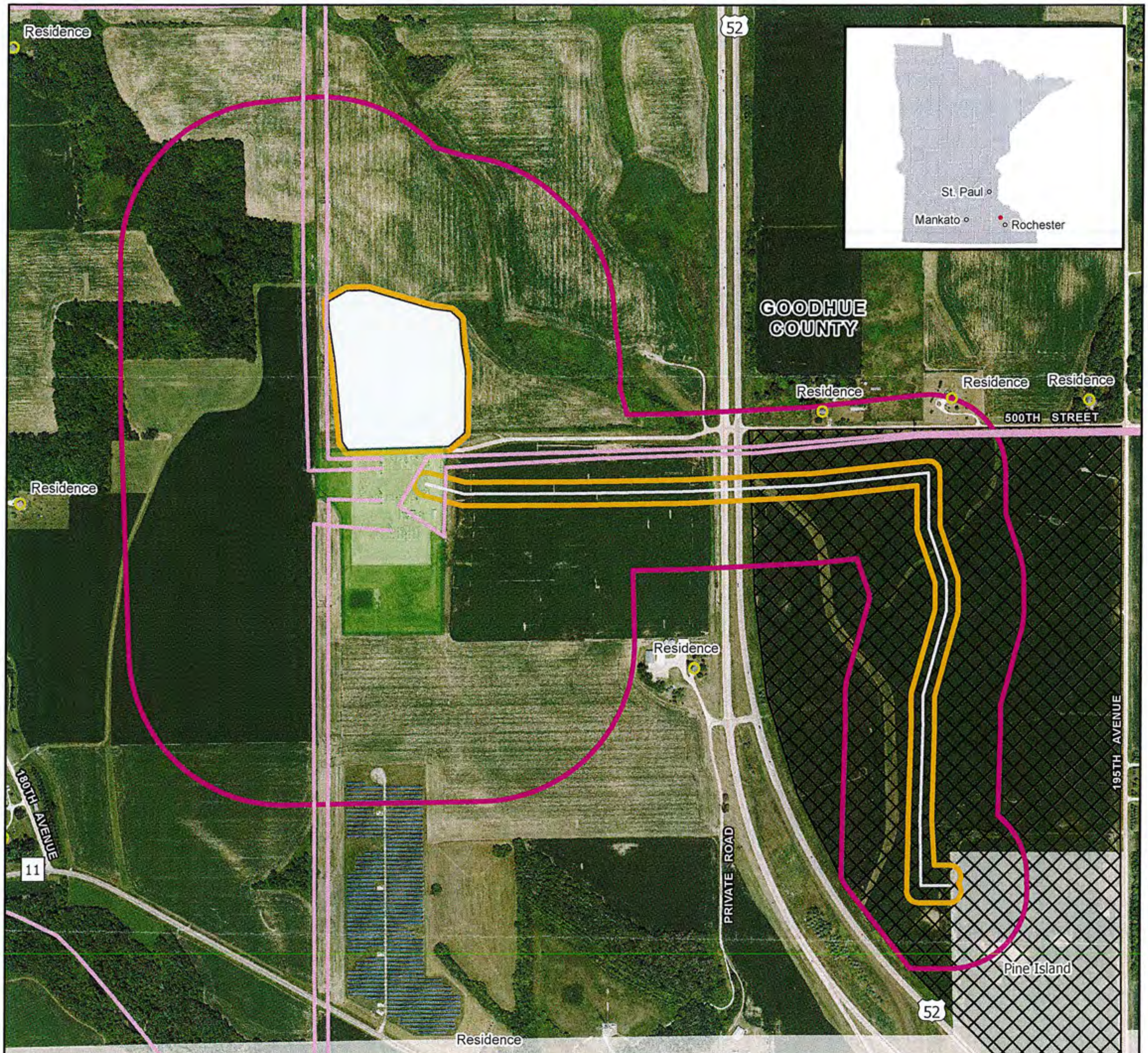
Ellen Heine

Ellen Heine
Xcel Energy
Principal Siting and Permitting Agent

Enc. Project Location Map

PROJECT LOCATION MAP

Xcel Energy®



LEGEND

- Residences
- Existing Transmission Lines
- Proposed Transmission Line
- Proposed Right-of-Way
- Transmission Facility Study Area
- Proposed Development Site
- Approximate Extent of Substation Expansion
- Existing North Rochester Substation
- County Boundary
- City Boundary

Imagery: Goodhue County, 2023 NAIP

0 Feet 1,000

Scale: 1:11,000

Center: 92°39'16"W 44°13'21"N

DATE EXPORTED: 11/3/2025