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April 11, 2025

VIA E-FILING
Mr. William Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
Saint Paul, MN 55101-2147

Re: In the Matter of the 2025 Biennial Transmission Projects Report
Docket No. E999/M-25-99

Dear Mr. Seuffert:

Minnesota Transmission Owners ("MTO") respectfully submits these initial comments.

These initial comments have been e-filed through www.edocket.state.mn.us. A copy of this filing is also being served upon the persons on the Official Service List of record.

Please let me know if you have any questions regarding this filing.

Sincerely,

FREDRIKSON & BYRON, P.A.

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STATE OF MINNESOTA
BEFORE THE
PUBLIC UTILITIES COMMISSION

Katie Sieben	Chair
Hwikwon Ham	Commissioner
Audrey Partridge	Commissioner
Joseph Sullivan	Commissioner
John Tuma	Commissioner

In the Matter of the 2025 Biennial Transmission Projects Report

Docket Number: E999/M-25-99
INITIAL COMMENTS

INTRODUCTION

Minnesota Transmission Owners (MTO) respectfully submit these comments in response to the Minnesota Public Utilities Commission's (Commission) February 14, 2025 Notice (Notice) seeking comments on the appropriate methodology for calculating the payback period of grid enhancing technologies (GETs), as directed by Minnesota Session Laws, 2024, Chapter 127, Article 42, Section 52 (2024 Session Law). The MTO appreciates the Commission initiating this process well in advance of the November 1, 2025 Biennial Transmission Projects Report (2025 BTPR) to provide regulatory certainty on how the Commission will consider implementation plans and cost recovery for GETs. The MTO provides initial comments on each of the six topics in the Commission's Notice.

As discussed at the Commission's March 6, 2025 agenda meeting, the MTO is analyzing which GETs may be helpful on a short-term basis to address congestion and curtailment around the Nobles County Substation and across the state. Updated GETs study work has begun for the upcoming 2025 BTPR as directed by the 2024 Session Law. While the results of this study work are not yet available, the process for establishing the study informs the MTO's comments.

Furthermore, MTO proposes that national study work by the U.S. Department of Energy's

Idaho National Laboratory[1] can serve as a framework for the Commission's review of GETs projects and guide its determination of a cost/benefit methodology. Idaho National Laboratory provides a succinct overview of GETs costs and other benefits:

> *Since the GETs industry is relatively new, potential device users do not always know how much an investment in GETs will cost. Similarly, there is no valuation framework to estimate the benefit provided by GETs. One challenge with valuation is that many benefits may come from avoiding additional costs, such as using higher priced generators or even avoiding an outage caused by congestion. INL has identified multiple factors to consider in a cost/benefit analysis:*
>
> - *Cost of devices*
> - *Cost of design work (impact analysis, device placement, sizing needs, siting analysis)*
> - *Cost of installation (extra materials, labor, etc.)*
> - *Cost of maintenance (monitoring device health)*
> - *Cost of licensing (continuing to receive support and/or connection to devices from vendors)*
> - *Avoided costs of energy (e.g., using more wind energy instead of a peaker plant generator)*
> - *Avoided costs of outages (e.g., can safely push more power over a line or can redirect power to reduce congestion)*
> - *Ability to serve more load*
> - *Ability to perform maintenance in opportune windows*

DISCUSSION

I. IN ADDITION TO THE FREQUENCY OF CONGESTION AND INCREASED COSTS TO RATEPAYERS (AS REQUIRED BY SUBD 2, CLAUSE 2), WHAT, IF ANY, ISSUES, COSTS, AND BENEFITS ARE RELEVANT TO CALCULATING THE PAYBACK PERIOD OF GETS INSTALLED TO REDUCE TRANSMISSION SYSTEM CONGESTION?

The capital and O&M costs of the GETs should be included in any calculation of payback periods, including any physical security and cybersecurity protections needed to ensure that the GET is not tampered with or compromised. Capital costs include hardware and software costs necessary to implement the GET.

[1] https://inl.gov/national-security/grid-enhancing-technologies/

Reduced benefits associated with GETs, like dynamic line ratings, also need to be considered. As the Organization of MISO States noted in their October 15, 2024 comments to the Federal Energy Regulatory Commission's (FERC) Dynamic Line Ratings (DLR) Advance Notice of Proposed Rulemaking:[2] "DLRs can also result in line ratings that have a rating lower than a transmission line's static rating. For instance, a study in Massachusetts found that DLRs can result in line ratings below ambient adjusted ratings (AAR) approximately 22-27 percent of the time throughout the year." When projecting GETs benefits, we also need to include instances where their use may reduce, rather than increase, the rating on a transmission line.

The February 2022 report from ILB U.S. Department of Energy titled "Grid-Enhancing Technologies: A Case Study on Ratepayer Impact" provides some cautionary notes when trying to project the benefits of dynamic line ratings:

> *Because of the interconnected nature of the electric power system, implementing GETs to alleviate congestion on a line or group of lines may move congestion downstream to other connected lines, limiting the effectiveness of the GETs solution. Ambient conditions could also vary along different spans of a long transmission line. If the DLR system does not cover the limiting span of the transmission line, values calculated using DLR could overstate the safe ampacity rating of the line and downstream equipment ratings could become the most limiting element. In addition, the assessment of DLRs may need to factor in the incremental value of DLR over AAR. The addressable market for GETs is often framed with respect to the total congestion costs in a system, but GETs can only offset a fraction of those costs.*

Any calculation of the benefits and costs of a GET solution needs to consider the full costs required to solve the problem at issue, not a single fix that merely pushes the problem to the next limiting element. If we develop a solution for just one segment in a series of lines that shows congestion, we may soon find that the next span needs improvement, and this cycle could continue.

[2] Implementation of Dynamic Line Ratings, Docket No. RM24-6-000.

Furthermore, because many of the substations in Minnesota are shared facilities, the next span may have different ownership creating additional regulatory and cost recovery challenges.

When calculating the benefits to ratepayers of a particular GET, the Commission should also consider other solutions being implemented by Minnesota utilities to reduce congestion. This will help avoid implementing a GET solution that provides little to no benefit when viewed in a broader context. For example, in 2023, Great River Energy (GRE) participated with the other GNP members to develop a series of transmission solutions intended to reduce near-term transmission congestion in the Upper Midwest, with implementation dates from 2023 through 2026.[3] These projects, many of which are low-cost solutions, are expected to provide economic savings for customers in excess of the $130 million investment, helping ensure continued access to low-cost electricity for utility ratepayers.

The costs of implementing GETs technologies should consider outages on existing transmission lines and substations that may temporarily exacerbate congestion and curtailment issues. With construction of the MISO LRTP Tranche 1 projects beginning, all Minnesota transmission owners and developers will need to closely coordinate scheduling to mitigate these issues. However, outages and other scheduling impacts are a direct cost that should be considered when determining the GETs cost/benefit.

[3] The 2023 BTPR addressed the GNP's work at that time on page 17: "GNP Technical Effort: GNP Members have been actively coordinating as MISO develops their LRTP Tranche 2 study. Coordination around system modeling, study assumptions and solution alternatives will help develop provide feedback as the LRTP Tranche 2 effort continues into 2024. A transmission congestion study was also completed by the GNP Technical Team. The study reviewed historical and projected transmission system congestion in the MISO market with an effort to identify potential system upgrades that could potentially reduce congestion in the GNP footprint. The congestion effort was wrapped up in 2023 and at least 21 projects from several GNP member companies are underway to increase transmission capacity and reduce market congestion in the GNP footprint."

Finally, the Commission should consider which electric utility ratepayers would receive the benefits of the implementation of the GETs and which ratepayers would bear the associated costs of the implementation of the GETs. Ratepayers who receive the benefits of GETs should be responsible for bearing the costs, to ensure that no particular group of ratepayers is unfairly burdened by the costs of GETs without receiving the corresponding benefits.

II. WHAT METHODOLOGY SHOULD THE COMMISSION DIRECT AFFECTED TRANSMISSION OWNERS TO USE IN CALCULATING THE PAYBACK PERIOD OF GETS IN REDUCING CONGESTION?

There are two potential values that could be used for the benefit portion of a benefit/cost ratio.

The first is the shadow price ($/MW), which is the incremental cost savings associated with relieving a binding constraint by 1 MW. Essentially, if a constraint binds at 100 MW, what would be the congestion benefit if the rating was increased to 101 MW? This metric is reported by PROMOD simulations, and MISO historic congestion data reports the hourly shadow price for each constraint. When we run PROMOD simulations, we commonly sum up the hourly shadow prices per constraint to get an annual total, then compare shadow prices of different constraints to assess the severity of each constraint. We do not use the shadow price as a measure of savings for fixing a constraint because it would severely underestimate the savings, given that it only accounts for a 1 MW increment. Instead, we would compare MISO's Adjusted Production Cost or a utility's load costs and generation revenues before and after fixing the constraint in a PROMOD simulation. Of course, reviewing historic congestion using these methods may not be reliable, as we cannot always accurately recreate historic congestion in a PROMOD model—a difficulty that MISO and Minnesota utilities have consistently expressed.

This leads to the second value, which is called "Congestion Charge" (or Congestion Rent in CAISO). Based on discussions with the GNP Tech Team, MTO prefers this method. This value takes the shadow price of a constraint and multiplies it by full rating of the constraint, resulting in a dollar value for the constraint's cost to the market. The MTO believes this value has the potential to overstate congestion costs, because instead of just using 1 MW of relief for shadow price, it is using the entire line's rating for relief. While there are still issues with this methodology, it is preferrable given the challenges in replicating all the historical constraints in PROMOD.

III. WHAT PAYBACK PERIOD VALUE SHOULD THE COMMISSION SET AS THE THRESHOLD AT WHICH A GETS PROJECT MUST BE INCLUDED IN THE IMPLEMENTATION PLAN PORTION OF A GETS REPORT?

The payback period value threshold should be on a gradient scale to reflect the specific technology and application of each GET. For some technologies, such as dynamic line rating implementation, the payback period may be very short and almost immediate. Other GETs may have a longer payback period, and the threshold for those should be set at or near the expected life of the technology. This could include new batteries or other capital-intensive projects.

The MTO notes there are studies that provide specific payback periods. For example, the Brattle Group conducted a generic modeling study in 2021 that estimated implementing $90 million of GETs in the Southwest Power Pool (SPP) would provide a payback of $175 million of wind energy savings, or a payback period of about 0.5 years.[4] Studies like these demonstrate the value of GETs in heavily congested areas. However, study results that are not based on a specific GET in a specific market provide only limited guidance for the Commission.

[4] https://watt-transmission.org/wp-content/uploads/2021/02/Brattle__Unlocking-the-Queue-with-Grid-Enhancing-Technologies__Final-Report_Public-Version.pdf90.pdf

IV. SHOULD THE COMMISSION REQUEST OR REQUIRE TRANSMISSION OWNERS TO EVALUATE THE COST EFFECTIVENESS OR PAYBACK PERIODS OF GETS PROJECTS ADDRESSING LOCATIONS LIKELY TO EXPERIENCE HIGH LEVELS OF CONGESTION DURING THE NEXT FIVE YEARS (SUBD. 2, CLAUSE 3), IN ADDITION TO THOSE WITH EXISTING CONGESTION (SUBD. 2, CLAUSE 1)?

No. When evaluating potential use of GETs in relation to historical congestion costs, utilities are projecting only GETs O&M costs, as the capital costs and historical congestion costs are known. Attempting to evaluate the cost effectiveness or payback periods of GETs against potential future congestion runs the risk of implementing GETs for facilities that do not ultimately experience high levels of congestion over the next five years. This could lead to increased costs for ratepayers with little to no benefit. Currently, there are simply too many unknowns to extend the evaluation to potential future congestion areas, and the modeling tools cannot accurately predict which areas will experience congestion.

Ambient adjusted ratings will also be required on transmission lines under MISO's functional control when FERC Order No. 881 goes into effect. Using ambient adjusted ratings can mitigate future congestion costs at a much lower cost than a typical GET solution, greatly reducing the impact of stranded costs for GET solutions applied to combat future projected congestion that ends up not occurring.

V. ARE THERE EQUITY, WORKFORCE, OR ENVIRONMENTAL JUSTICE FACTORS THE COMMISSION SHOULD CONSIDER WHEN DEVELOPING A GETS PAYBACK PERIOD METHODOLOGY?

The MTO recognizes that the Commission considers additional factors when evaluating projects and new resources.[5] While challenging to directly quantify, the MTO agrees that equity,

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[5] *In the Matter of an Inquiry into Utility Investments that May Assist in Minnesota's Economic Recovery from the COVID-19 Pandemic*, Docket No. E,G999/CI-20-492, Order Accepting Economic Recovery Investment Reports, Requiring Filings and Encouraging Advancement of Diversity Goals (Order dated March 16, 2021): "The Commission will encourage utilities to advance the work of the Energy Utility

workforce, and environmental justice factors should be included in evaluating GETs. This evaluation could involve maximizing the value of GETs based on the location of the projects and considering impacts on local communities experiencing tax revenue adjustments due to congestion or other factors that GETs may partially alleviate. Additionally, it ensures a local workforce is available to install and operate GETs technologies, providing the best value for customers and communities. Local workforce factors should consider that many GETs providers self-install their technologies. Overall, the MTO is committed to working with the Commission and stakeholders in considering these factors and suggests first utilizing existing tools and best practices the Commission has established in other proceedings. For example, in the COVID-19 Pandemic Docket, the Commission ordered a number of directives including encouraging utilities to share best practices on diverse suppliers and explore partnerships with key stakeholders in industry, labor and local communities to develop career pipelines and training opportunities for underrepresented populations.[6] For the environmental justice factor, the Commission can rely upon the definition of "environmental justice area" recently enacted in Minn. Stat. § 216B.1691, subd. 1(e) and clarified in a Commission Order.[7] These and other items already identified by the Commission provide a framework for developing a GETs payback period methodology that takes into account equity, workforce and environmental justice factors.

Diversity Group in designing and implementing economic-recovery investment proposals, as outlined in the ordering paragraphs below. The recommendations of the Energy Utility Diversity Group are the result of an extensive Commission-led stakeholder process and reflects a range of perspectives and strategies to promote diversity in the utility industry."

[6] *In the Matter of an Inquiry into Utility Investments that May Assist in Minnesota's Economic Recovery from the COVID-19 Pandemic*, Docket No. E,G999/CI-20-492, Order Accepting Economic Recovery Investment Reports, Requiring Filings and Encouraging Advancement of Diversity Goals (Order dated March 16, 2021).

[7] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-Free Standard under Minn. Stat. § 216B.1691*, Docket No. E999/CI-23-151 (Order Initiating New Docket and Clarifying "Environmental Justice Area" dated November 7, 2024).

VI. ARE THERE OTHER ISSUES OR CONCERNS RELATED TO THIS MATTER?

Yes. When setting GETs requirements for Minnesota utilities, it will be important for the Commission to recognize the pending Advance Notice of Proposed Rulemaking (ANOPR) proceeding at FERC (Docket No. RM24-6-000) related to dynamic line ratings implementation. In 2021, FERC adopted FERC Order No. 881 FERC to more efficiently utilize the nation's transmission grid and help lower costs for consumers by improving both the accuracy and transparency of transmission line ratings. If FERC finalizes this ANOPR, MTO believes it will be important for the Commission to consider how to reconcile these requirements to avoid Minnesota utilities potentially having to comply with two separate sets of requirements on dynamic line ratings.

CONCLUSION

The MTO appreciates the Commission initiating this process well in advance of the 2025 BTPR and the MTO looks forward to continuing to engage on issues related to GETs.

Dated: April 11, 2025

Respectfully submitted,

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In the Matter of the 2025 Biennial Transmission Projects Report	**Docket No. E999/M-25-99**

CERTIFICATE OF SERVICE

Abby Goshgarian certifies that on the 11th day of April, 2025, she e-filed a true and correct copy of the initial comments on behalf of Minnesota Transmission Owners via eDockets (www.edockets.state.mn.us):

Said documents were also served as designated on the Official Service Lists on file with the Minnesota Public Utilities Commission and as attached hereto.

Executed on: April 11, 2025

Signed: /s/ Abby Goshgarian
Fredrikson & Byron, P.A.
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1	Christina	Brusven	cbrusven@fredlaw.com	Fredrikson Byron		60 S 6th St Ste 1500 Minneapolis MN, 55402-4400 United States	Electronic Service		No	M-25-99
2	Generic	Commerce Attorneys	commerce.attorneys@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street Suite 1400 St. Paul MN, 55101 United States	Electronic Service		Yes	M-25-99
3	Ian M.	Dobson	ian.m.dobson@xcelenergy.com	Xcel Energy		414 Nicollet Mall, 401-8 Minneapolis MN, 55401 United States	Electronic Service		No	M-25-99
4	Sharon	Ferguson	sharon.ferguson@state.mn.us		Department of Commerce	85 7th Place E Ste 280 Saint Paul MN, 55101-2198 United States	Electronic Service		No	M-25-99
5	Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	1400 BRM Tower 445 Minnesota St St. Paul MN, 55101-2131 United States	Electronic Service		Yes	M-25-99
6	Christine	Schwartz	regulatory.records@xcelenergy.com	Xcel Energy		414 Nicollet Mall FL 7 Minneapolis MN, 55401-1993 United States	Electronic Service		No	M-25-99
7	Will	Seuffert	will.seuffert@state.mn.us		Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul MN, 55101 United States	Electronic Service		Yes	M-25-99