Minnesota's Electric Transmission System Annual Adequacy Report

Minnesota Statutes, section 216C.054

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Report Prepared By

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Contents

List of Acronyms

APFC	Advanced Power Flow Control	**LSE**	Load Serving Entity
BESS	Battery Energy Storage Systems	**MWh**	Megawatt-Hour
BTPR	Biennial Transmission Projects Report	**MISO**	Midcontinent Independent System Operator
CFS	Carbon-Free Standard	**MTO**	Minnesota Transmission Owners
CN	Certificate of Need	**MTEP**	MISO Transmission Expansion Plan
DLR	Dynamic Line Rating	**NERC**	North American Electric Reliability Corporation
DOE	U.S. Department of Energy	**NTP**	National Transmission Planning
EIPA	Energy Infrastructure Permitting Act	**OMS**	Organization of MISO States
EPIC	Environmental Policy Innovation Center	**PNAS**	Proceedings of the National Academy of Sciences
EPR	Expedited Project Review	**PRM**	Planning Reserve Margin
ERAS	Expedited Resource Addition Study	**PRMR**	Planning Reserve Margin Requirement
ERCOT	Electric Reliability Council of Texas	**PUC**	Minnesota Public Utilities Commission (Commission)
FERC	Federal Energy Regulatory Commission	**RMI**	Rocky Mountain Institute
GETs	Grid Enhancing Technologies	**ROE**	Return on Equity
GIA	Generator Interconnection Agreement	**ROW**	Right(s) of Way
GNP	Grid North Partners	**RSC**	Regional State Committee
IIJA	Infrastructure Investment and Jobs Act	**RTO**	Regional Transmission Organization
IPSAC	Inter-Regional Planning Stakeholder Advisory Committee	**PJM**	Pennsylvania-New Jersey-Maryland Interconnection
ISO	Independent System Operator (or regional grid operator)	**SPP**	Southwest Power Pool
		TL	Transmission Line
LOLP	Loss of Load Probability	**TO**	Topology Optimization
LRTP	MISO's Long Range Transmission Planning	**WECS**	Wind Energy Conversion Systems
LRZ	Local Resource Zone		

Executive Summary

Minnesota Statutes § 216C.054 requires that the Commissioner of Commerce, in consultation with the Minnesota Public Utilities Commission (PUC or Commission), submit an Annual Transmission Adequacy Report (Report) to the Legislature. The report must contain 1) a narrative describing what electric transmission infrastructure is needed within the state over the next 15 years, 2) the specific progress that is being made to meet that need, 3) a description of specific transmission needs and the current status of proposals to address that need, and 4) identify any barriers to meeting transmission infrastructure needs and make recommendations, including any legislation, necessary to overcome those barriers.

The Department of Commerce (Commerce) and PUC find that both new transmission and supplementary measures are necessary to meet the medium- and long-term needs of the system. Within the state, there are several plans for new regional transmission line projects. In addition to building new lines, the state is exploring alternatives to attenuate continued transmission build-out. Methods to address the near-term need for new transmission include energy savings initiatives, programs to manage electric demand, the build-out of distributed energy generation near sources of electricity demand, the build-out of strategically located short- and long-duration energy storage, and the implementation of a wide variety of grid-enhancing technologies (GETs). Minnesota has adopted new policies related to all those possible options over the last few legislative sessions.

The regional high-voltage transmission system plays a critical role in providing reliable and affordable electricity to Minnesotans. Looking forward, upgrades to the high-voltage transmission system in Minnesota and across the region will be needed to: maintain reliable service, allow better access to low-cost sources of electricity, meet anticipated growing electrical demand driven by manufacturing, data centers, and beneficial electrification and, achieve Minnesota's Carbon-Free Standard (CFS).

The high-voltage transmission system in Minnesota and much of the United States is planned and operated by regional transmission organizations (RTOs). Since high-voltage electricity transmission crosses state boundaries and operates as large, interconnected networks, it also operates under federal oversight. Depending on location, Minnesota's utilities operate in either the Midcontinent Independent System Operator (MISO) or Southwest Power Pool (SPP), with the vast majority of Minnesota falling inside MISO.

As detailed in the 2025 Report to the Legislature, Tranche 2.1 of the MISO Long-Range Transmission Plan (LRTP) is underway. LRTP projects are meant to serve as backbone reliability projects to move bulk power and interconnect more generation projects. Tranche 2.1 includes eight transmission lines in Minnesota; four are 345 kV lines, and four are 765 kV transmission lines. In 2025, the Commission approved six transmission line projects, totaling nearly 380 miles in length, which are discussed further below. In 2026, Commerce and the Commission are expecting to begin processing projects approved in MISO's LRTP Tranche 2.1.

In addition to the large projects discussed above, the 2025 Minnesota Transmission Owner's Biennial Report identified approximately 158 separate transmission inadequacies across the state, including 79 new inadequacies from the last report. The report describes the planned projects to address these lower voltage inadequacies. Many of these are considered "low-hanging fruit" to upgrade Minnesota's transmission network and do not require a certificate of need or route permit.

Findings

Key findings from the 2025 Minnesota Electric Transmission System Annual Adequacy Report include:

- The Minnesota Department of Commerce (Commerce) and Minnesota Public Utilities Commission (PUC, or Commission) continue to monitor progress on the development and deployment of grid-enhancing technologies (GETs), particularly in response to the inaugural GETs Report, published on October 31st, 2025, by the Minnesota Transmission Owners (MTOs). The proposed report is currently under review by interested stakeholders and will be considered by the Commission for approval by June 1st, 2026.

- MISO continues to move forward with its Long-Range Transmission Planning (LRTP) analyses, including the modeling forecasts on future transmission needs. The 2025 MISO Transmission Expansion Plan (MTEP25) includes 11.6 GW of expected load growth and $12.3 billion in planned investments.

- Minnesota has been a leader in approving regional and interregional transmission projects with broad benefits. In 2025, Commerce and the PUC engaged with the regional transmission organizations (RTOs) and the relevant state agency stakeholder groups in MISO and SPP, the Organization of MISO States (OMS), and the Regional State Committee (RSC), respectively, to provide valuable feedback and input into planning, scenario modeling, and grid interconnection issues.

- Both new generation and new transmission will be needed to reach state policy goals and enable more generation in this era of demand load growth.[1]

- Minnesota recognizes the value of both regional and interregional transmission planning. Coordinated action amongst state regulators will be necessary to ensure interregional transmission planning aligns with state policy goals, enables necessary, additional generation in a period of new load growth, and continues to adequately protect the state's jurisdictional claims over transmission and generation projects in Minnesota.

- A 2022 FERC Order, Order 881, requires all transmission owners to provide transmission line ratings—adjusted by temperature and by season—by June 12th, 2025. This Order and compliance in the relevant RTOs specify that transmission owners implement ambient-adjusted ratings (AARs) for transmission lines, controlling for voltage stability in normal and emergency conditions. This Order serves to increase transmission capacity on lines rated for different times of year.

- Future regional transmission planning is likely to be impacted by FERC Order 1920, which requires a greater emphasis on long-term transmission planning by regional transmission organizations. Initial compliance filings for the two RTOs that Minnesota is a part of, MISO and SPP, are both due on June 12th, 2026.

- The PUC only has the power to protect state-regulated utility ratepayers from high FERC-approved transmission Return on Equity (ROE), so customers of utilities not subject to PUC ratemaking are not protected and may bear the full impact of high ROEs. High transmission ROEs continue to influence capital-intensive transmission projects, and many Minnesota ratepayers are unprotected.

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[1] Barbose, Galen. U.S. State Electricity Resource Standards: 2025 Data Update. Lawrence Berkeley National Laboratory. (August 2025) At 23. https://emp.lbl.gov/sites/default/files/2025-08/State%20Electricity%20Resource%20Standards-2025%20Data%20Update.pdf

Recommendations

To overcome transmission infrastructure barriers and meet the current and future needs of the system, the following actions are recommended by the Department of Commerce:

- Expand the analysis of the GETs Report to include pairing of multiple GETs, with additional system improvements such as substation upgrades, battery storage, or advanced reconductoring, to address any potential downstream impact of singular GETs technologies. Identifying ways to maximize the existing transmission system may improve reliability more than any single technology alone.
- Reconsider whether a payback period is the proper methodology for evaluating GETs technologies identified by the state's transmission-owning utilities. The GETs law requires analysis of the payback period for cost-effectiveness of different grid enhancing technologies for inclusion in the GETs Report.[2] Using payback period evaluations may exclude possible beneficial technologies that are nascent or have high capital cost.
- Require more investigation into battery energy storage technologies as a grid-enhancing technology that support grid stability and enhance the transmission system. This could include, but is not limited to, investigation of energy systems modeling with and without battery storage at strategic locations of the grid, investigation of the value of Battery Energy Storage Systems (BESS)relative to the costs of congestion and nodal price differences, and procurement mandates for energy storage technologies.
- Commission a study addressing the value of wind production tax revenue to counties, and the missed revenue to counties from the non-production of wind assets due to curtailment.
- Commission a study of reconductoring with necessary sectionalization and stability support to compare the speed and cost-effectiveness (including avoided need for new rights of way) to the existing transmission expansion plan. Study traditional utility incentives for building new transmission relative to avoided costs of reconductoring. Investigate further the cost recovery capabilities of utilities seeking to deploy advanced reconductoring technologies.
- Commission a study that identifies the costs that non-regulated utilities must bear for high transmission ROEs. Identify legal precedent for a rule or statute that protects non-regulated utility ratepayers from high transmission ROEs.

[2] Laws of Minn. 2024, ch. 127, art.42, sec 52.

Introduction: The transmission system and how it impacts Minnesota

Electricity is generally delivered to consumers via three main steps: 1) electricity is produced at various generation facilities, 2) it is then transmitted on an integrated system of high voltage transmission lines, and 3) is delivered to consumers through a distribution system of lower voltage power lines. The combined electrical infrastructure necessary for electricity generation and delivery makes up the bulk electric system but is known colloquially as the electric grid ("grid").[3]

Determining the amount of transmission infrastructure needed to provide economic and reliable electric service in Minnesota requires careful balancing of the amount of transmission capacity built to deliver electric service from available generation resources with the cost of that transmission and other factors, such as state policy goals relating to carbon-free electricity resources.

If more transmission capacity is built than is needed, the system will be relatively free of transmission constraints but will have a higher cost than is necessary to provide adequate service. If too little transmission capacity is built for the delivery of electric service from existing and new generation resources, the transmission cost component of providing electricity service may be lower, but there could be a cost to Minnesotans and the Minnesota economy in terms of reliability, access to affordable generation, and higher curtailment of generation resources.

As the link between the mass production (generation) of electricity and delivery (distribution) to consumers, transmission plays a vital role in helping to ensure that consumers have low-cost, reliable electricity. The transmission system can be impacted by changes in either supply or demand for energy. As smaller generation or storage facilities are added to the distribution system (also known as distributed energy resources (DERs)), which include technologies such as solar panels and battery storage), the dynamic and interconnected nature of the electricity system requires transmission to adapt to resulting changes in the flow of electricity.

When the original transmission facilities in Minnesota were built in the 1960s, they were designed primarily to interconnect an individual utility's generation and distribution facilities and secondarily to interconnect neighboring utilities to each other to provide additional backup power and reliability. However, as the generation mix has changed over time, utilities now draw from multiple sources located in disparate locations, which necessitates a more connected grid.

Over time, the focus on transmission planning and reliability has grown to include interconnecting broader regions, even as the need to connect a utility's generation and distribution systems remains. This evolving design enables utilities to access other generation or transmission systems if something goes wrong on an individual utility's system. Interconnection with other electric systems provides a more reliable system overall compared to isolated systems and allows utilities to access lower-cost power from other suppliers, or purchase power on a temporary basis rather than building a generation facility that may be used only occasionally.

[3] North American Electric Reliability Corporation. *Frequently Asked Questions (March 2023).* NERC (Mar. 2023). Available at: https://www.nerc.com/globalassets/who-we-are/news/2023/march-2023-nerc-frequently-asked-questions-faq.pdf

The nation's transmission grid is split into three sections: The Eastern Interconnection, the Western Interconnection, and the Electric Reliability Council of Texas (ERCOT). The North American Electric Reliability Corporation (NERC) is responsible for reducing risks to the reliability and security of the electric grid, including establishing standards. The PUC participates in NERC as a state regulatory representative. Reliability standards for the transmission grid in the part of the Eastern Interconnection, in which Minnesota is located, are overseen by the Midwest Reliability Organization (MRO). Commerce is an adjunct member of MRO.

Utilities in Minnesota are members of either the Midcontinent Independent System Operator (MISO) or the Southwest Power Pool (SPP) regional transmission organization, with the vast majority in the MISO system. Regional transmission organizations work to ensure that there is an adequate supply of electricity, even at times of peak demand. They also work to plan future expansion of regional transmission infrastructure and operate energy markets. Being a part of a broader regional grid allows Minnesota utilities to benefit from efficiencies that come with regional coordination and to avoid unnecessary costs.

MISO is divided into 10 geographical regions, called Local Resource Zones (LRZ), while most of Minnesota is part of MISO's Local Resource Zone 1. Each zone is defined by the physical resources in its territory, such that the LRZ can deliver all the physical capacity to meet the seasonal Planning Reserve Margin Requirement (PRMR). The PRMR and LRZ framework works to ensure that there are adequate electric generation resources to meet the needs in each zone (having sufficient resources is also known as "resource adequacy").

Recent Developments

Grid-Enhancing Technologies Report

For the first time, following changes in Minnesota legislation, the Minnesota Transmission Owners (MTO) reported on their efforts to address grid-enhancing technologies (GETs) in the 2025 Biennial Transmission Report. This work builds upon other investigations into lower-cost transmission improvements that can be done to more quickly address congestion and curtailment issues on the Minnesota grid. In previous years, a group of ten utilities that own or operate high voltage transmission lines in Minnesota worked together as Grid North Partners (GNP) to identify 19 near-term solutions to address pervasive congestion in Minnesota, alongside traditional grid upgrades. As an outcome of 2024 Minnesota legislative changes, the GNP merged this work with the GETs report.

In 2024, the Minnesota Legislature passed H.F. 5247, which required the state's public utilities, by November 1, 2025, to file a report identifying the most congested areas on the transmission grid, based on a three-year lookback, and to forecast which areas would be expected to experience transmission congestion for the next five years. Following a stakeholder process, the PUC ordered the utilities to provide the locations of areas experiencing a high level of congestion, whether the congestion was recurring, and cost estimates to install a feasible grid-enhancing technology at each congestion point. This report is referred to as the "GETs Report."

Commerce and the PUC continue to monitor progress, consult with stakeholders, and encourage transmission planning and addressing congestion with innovative solutions to benefit Minnesotans. The MTOs have reported their first annual inclusion of the GETs Report in their 2025 Biennial Transmission Projects Report (BTPR) on

October 31, 2025.[4] The GETs Report, newly required by legislation, acts as a successor to the aforementioned Grid North Partners' report on near-term congestion.[5] The resulting report identified congested areas and identified the least-cost, quickest solutions for those points of congestion. The past report found 19 transmission solutions that are worth $130 million, which are completed or pending completion. These projects implemented by the MTOs are "expected to provide economic savings for customers in excess of the $130 million investment."[6] Many of these fixes would not fall into GETs categories, which refer in the legislation to specific types of technologies that are relatively new, rather than more traditional transmission upgrades identified in the GNP report. Updates to the congested transmission components, which created the limiting factor (such as conductors, substation equipment, sag, etc.), were the focus of GNP in the 2023 report.

In contrast, the 2025 GETs Report identifies areas on the grid that could be candidates for implementing grid-enhancing technologies cost-effectively and likewise identifies a few different types of GETs. In Appendix B of the BTPR, the GETs Report maps out historic congestion for the past three years from the Day-Ahead energy market, finding 66 locations of congestion ("constraints") that met the requirement of 168 hours or more of congestion (which equates to approximately 2% of annual hours).[7] Any GET solutions identified would also be subject to certain requirements on payback periods relative to the proposed solutions' costs, necessitating a payback period of five years or less to be implemented. Of the 66 constraints identified by the MTOs, the GETs Report addresses 30 feasible solutions that the MTOs are undertaking to address congestion in the near-term. MTOs have already completed 18 of 30 congestion solutions over the past three years. An additional 12 of 30 have met the payback thresholds (five-year payback or less) as required in the September 10, 2025, PUC Order.[8]

Initial comments for the final GETs Report and recommendations on whether the Commission should approve the implementation plans proposed in the report are due on February 2, 2026, and Commerce plans to file comments in the associated proceeding at the Minnesota PUC in Docket No. E-999/M-25-99.

The September 10, 2025 Order also directed the Minnesota Transmission Owners (MTOs) to consult with GETs vendors to ensure that modeling best practices were incorporated into the MTOs' modeling of GETs proposed costs versus proposed benefits (as measured by production cost savings). The MTOs met with three vendors for three main grid-enhancing technology types. The findings are listed below.

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[4] *In the Matter of the 2025 Biennial Transmission Projects Report*. Minnesota Transmission Owners. 2025 Biennial Transmission Projects Report (Report). October 31st, 2025. Docket No. E999/M-25-99. (eDockets) 202510-224474-02 at 245.

[5] Laws of Minn. 2024, ch. 127, art.42, sec 52.

[6] *In the Matter of the 2025 Biennial Transmission Projects Report*. Minnesota Transmission Owners (MTOs). Initial Comments, April 11th, 2025, Docket No. E999/M-25-99. (eDockets) 20254-217521-01. At 4.

[7] *In the Matter of the 2025 Biennial Transmission Projects Report*. Minnesota Transmission Owners. 2025 Biennial Transmission Projects Report, Appendix B Grid Enhancing Technologies Report (GETs Report). October 31st, 2025. Docket No. E999/M-25-99. (eDockets) 202510-224474-05. At 4.

[8] *In the Matter of the 2025 Biennial Transmission Projects Report. Order Establishing Requirements.* Docket No. E-999/M-25-99. September 10th, 2025. 20259-222888-01, (hereinafter "September 10th, 2025 Order"). At 6, Order Point 4b.

Table 1: Grid Enhancing Technologies Explored by MTOs

Grid-Enhancing Technology Type	Summary
Dynamic Line Ratings (DLR)	• The consulted vendor had existing experience in Minnesota from DLR deployment with Great River Energy (GRE) in 2024. • An estimate of a 10-20% increase in conductor rating of transmission line for all seasons with DLR deployment.
Advanced Power Flow Control (APFC)	• By controlling grid impedance, APFC can push or pull power around congested areas. • Uses production cost modeling to ensure that congestion is not moved downstream. • Costs range from $10M to $40M, with implementation timelines of 12 – 18 months. • Scalable for the full range of HVTL (69 kV to 500 kV) and can be relocated if system conditions change.
Topology Optimization (TO)	• Once constraints are identified, the TO software works to identify power reconfigurations to reroute power, thereby relieving the congestion. • Typically used for planned outages, where reconfigurations have time to develop a solution to forecasted congestion. • Costs of implementation are not conclusive, due to software, rather than physical, assets. However, the cost to implement is low relative to congestion savings.

GETs vary in their relative purpose and costs, as well as their benefits. This makes comparison between the different types of technology challenging. As documented in the Department's initial comments in the BTPR Docket, the Department recommended a benefit-cost ratio (BCR) for determining the relative benefits and costs of different GETs projects, due to the different expected payback periods between different GETs, and the difficulty in comparing savings from implementing different types of GETs. Ultimately, following significant stakeholder engagement and deliberation, the Commission ordered that a five-year payback period, as the threshold for GETs deployment by the MTOs. This links back to the statutory language, requiring the implementation plan to include projects "at which the *payback period* is less than or equal to a value determined by the commission."[9] Review of the GETs Report is still being performed by various stakeholders, including the Department of Commerce.

As highlighted in Table 1 above and in the MTOs initial comments, GETs have different costs of implementation, which determines the payback period. DLRs are inexpensive and therefore have an almost immediate payback

[9] Laws of Minn. 2024, ch. 127, art. 42, sec. 52, subd. 2 (6)

period, whereas TO has a higher upfront cost and therefore a longer payback period.[10] Thus, comparing any two GETs based solely on payback period may result in GETs that could still deliver ratepayer savings and reduce congestion, but do not meet a five-year payback threshold.

The MTOs also highlighted a study in which the deployment of a DLR software in Massachusetts resulted in a decrease in transmission line rating. The MTOs offered this as evidence that DLR, by virtue of constantly monitoring the line's temperature, sag, and ambient conditions, can lower transmission capacity as well as increase it.[11] However, there is also likely a commensurate benefit to the transmission owner from a decrease in transmission line rating, given that transmission lines that are operated within the preferred range experience less depreciation and damage to equipment, allowing for longevity of the transmission line.
More examination of the full impact of GETs is still needed. The MTOs also highlighted in their initial comments that some GETs implementations can move congestion to another area on the grid, which proves the need to consider GETs as one part of transmission planning, and to consider the whole interrelatedness of the grid.

While GETs offer quickly deployable solutions to increase transmission capacity and maximize the ratepayer value of existing transmission, these solutions cannot fully substitute for the large-scale transmission needs of the future. The state and the region continue to need more transmission, due to load growth, aging utility infrastructure, state policy goals, extreme weather, and diversification of generation resources. Although GETs can serve to increase the capacity of existing lines, a variety of factors to drive the need for longer-term, concerted transmission buildout. Policies like the state's Carbon-Free Standard (CFS) (requiring the state's investor-owned utilities to procure 100% of their retail electric sales from carbon-free resources by 2040) drive the need for more wind, solar, and 4-hour battery storage, alongside new, emerging technologies, like long-duration storage. All these new resources require interconnection to the regional wholesale markets, necessitating more transmission capacity and more transmission buildout to deliver electricity as a retail product. In this context, GETs can be seen as a valuable opportunity to unlock transmission capacity without the capital costs of a full new transmission line.

Other technologies beyond GETs can also increase transmission capacity. One such example is advanced reconductoring, which refers to repairing or replacing existing steel-core transmission wires with new technologies, such as advanced composite core conductors, which have a stronger and stiffer composite core. A recent Energy Innovation report documents how clean energy transitions are being slowed due to grid interconnection issues ("gridlock"), and proposes many solutions, including GETs and other advanced technologies, for increasing the transmission capacity of our existing system.[12] They find that reconductoring with advanced conductors can result in real-world examples of doubling existing transmission capacity, all while also siting transmission within existing rights of way (ROW).[13]

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[10] Id. At 6.

[11] *In the Matter of the 2025 Biennial Transmission Projects Report.* Minnesota Transmission Owners (MTO). Initial Comments. April 11th, 2025. Docket No. E999/M-25-99. (eDockets) 20254-217521-01. At 3.

[12] Chojkiewicz, Emilia, Paliwal, Umed, Abhyankar, Nikit, Baker, Casey, et. Al, *Reconductoring with Advanced Conductors Can Accelerate the Rapid Transmission Expansion Required for a Clean Grid,* Energy Innovation Policy and Technology, LLC, April 2024, At 18, Available at GridLab_2035-Reconductoring-Technical-Report.pdf.

[13] Ibid. At 24.

While traditional reconductoring regularly takes place, advanced conductors, which utilize materials that can increase transmission capacity by up to two-fold, open new opportunities to maximize capacity using existing transmission rights-of-way. Depending on the project, a certificate of need (CN) and route permit may not be required, which could accelerate deployment times. In addition, maximizing the use of existing transmission rights-of-way allows Minnesota to better utilize state energy resources and requires less-contentious local transmission projects to permit increased renewable energy interconnections.

Despite the potential benefits of advanced reconductoring, to date, there has been no comprehensive analysis performed on the potential to reconduct Minnesota's existing transmission assets as a supplement or alternative to newly constructed lines. Minnesota law does not name advanced conductors or require such analysis.

In addition to optimizing transmission line capacity and stability with GETs and other technologies, energy storage holds the potential to increase transmission line utilization by effectively shifting power flows from low-cost renewable resources to battery energy storage systems (BESS), which helps control for the intermittency of renewable resources. Energy storage can move power during times of high renewable generation, when grid congestion/curtailment is high, to times when congestion is lower, which may be coincident with peak hours and high energy costs.

The Minnesota PUC directed Xcel Energy and the MTOs to investigate battery storage as a possible option for addressing curtailment in a recent investigation into curtailment.[14] Commerce recommended deploying GETs and BESS to address the steep, ongoing congestion and curtailment of wind energy conversion systems (WECS) in Nobles County, Minnesota.[15] The PUC concurred with the Department's analysis in their Order and directed the MTOs to include a cost-benefit analysis for battery storage solutions, compared to any status quo transmission buildout or transmission upgrades.[16]

Per Commerce's analysis in Docket No. 24-316, battery storage can help to address transmission and congestion by capturing the value of low-cost wind electricity that would otherwise be curtailed due to adverse price signals from a lack of transmission capacity.[17] The stored electricity can then be discharged later, when price signals and available transmission capacity signal need. The MTOs included a report on a proposed BESS deployment in Appendix C and D on BESS in the BTPR.

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[14] *In the Matter of the Investigation into Transmission-Curtailment Matters, Drivers, and Potential Solutions to Limitations Resulting from the Nobles County Substation, Order Establishing Filing Requirements,* March 24th, 2025, Docket No. E-999/CI-24-316, (eDockets) 20253-216722-01. (Hereinafter "March 24, 2025, Curtailment Matters Order").

[15] *In the Matter of the Investigation into Transmission-Curtailment Matters, Drivers, and Potential Solutions to Limitations Resulting from the Nobles County Substation,* December 3rd, 2024, Docket No. E999/CI-24-316. Minnesota Department of Commerce, Division of Energy Resources (DOC DER), Reply Comments at 27.

[16] March 24, 2025, Curtailment Matters Order at 4.

[17] *In the Matter of the Investigation into Transmission-Curtailment Matters, Drivers, and Potential Solutions to Limitations Resulting from the Nobles County Substation,* DOC DER, December 3rd, 2024, Docket No. E999/CI-24-316, (eDockets) 202412-212623-02 At 26.

Xcel Energy also completed the Economic Screening Study of a proposed Nobles County BESS project, featuring a 300 MW/1,200 MWh BESS, and studied the battery for charging only when curtailment was available.[18] The study found that, if the BESS were charged at times when the wind energy was curtailed (thus relieving some economic constraints leading to curtailment), the BESS would save an estimated 240,257 megawatt-hours (MWh) of curtailed electricity, representing approximately 25% reduced curtailment in the Nobles County region.[19] Xcel Energy also stated that the BESS, as a grid-forming (GFM) inverter resource, would also help contribute to dynamic voltage stability to the region on the grid, both when the battery is dispatching power to the grid and when not actively exporting power to the grid.[20] Deploying a BESS as a GFM resource would enhance transmission system stability by mitigating voltage fluctuations, as occurs with more renewable resources exported onto the grid, thus raising the threshold at which congestion and curtailment occur.

Xcel Energy also recently filed a request for expedited interconnection for the above 300 MW Nobles County BESS project in the expedited generator-interconnection queue process at MISO, known as the Expedited Resource Addition Study (ERAS) process.[21] MISO completed study of the first round of projects evaluated through the ERAS process, a short-term study process that grants eligible projects expedited review for an generator interconnection agreement (GIA). Each ERAS cycle lasts for 90 days, and the first projects were submitted on September 2, 2025. As of early January, Nobles County BESS project has an active submission status for ERAS evaluation and was 35th to apply for participation in the ERAS study, which is evaluated on a first-come-first served basis. Based on its place in the list of projects that applied for study, it will likely be evaluated as part of the third cycle, which will begin on March 2, 2026, after which the PUC and Commerce expect to see more filings from Xcel Energy.[22]

Identifying innovative "non-wires" solutions to transmission congestion can also provide localized benefits to counties, in addition to ratepayers. Reducing curtailment of existing wind energy sources helps contribute to stable tax revenues to counties, as counties and municipalities receive tax revenue from the Wind Energy Production Tax.[23] Thus, deploying a BESS could help to alleviate congestion and generate more tax revenue for counties, while also helping ratepayers save money by using the low-cost resources when they are available and by avoiding any payments for curtailed energy. Commerce will continue to monitor and provide comments on any further BESS System Impact or Economic Screening Studies, in addition to any planned or proposed BESS deployments for reducing curtailed energy.

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[18] *In the Matter of the 2025 Biennial Transmission Projects Report.* Minnesota Transmission Owners. Appendix C, Xcel Energy Nobles Battery Study 2025 and Appendix D, System Impact Study Project Nobles BESS. October 31, 2025, Docket No E999/M-25-99, (eDockets) 202510-224474-06, at 10.

[19] Id.

[20] Ibid. at 3, Appendix D.

[21] MISO, ERAS Informational Guide, https://cdn.misoenergy.org/ERAS%20Informational%20Guide707493.pdf

[22] MISO, ERAS Interconnection Requests (2025), https://www.misoenergy.org/planning/resource-utilization/generator-interconnection/

[23] Minnesota Department of Revenue, *Wind Energy Production Tax,* (Feb. 20, 2025). Wind Energy Production Tax | Minnesota Department of Revenue

Minnesota's Transmission System: Planning for the Future

Transmission Projects Approved in 2025

The PUC issued two route permits, four generation tie permits, approved six minor route alterations, and two transmission line certificates of need (CN) in 2025. If a CN is required for a project, the CN must be approved before a project can receive a route permit. However, not all projects that require a route permit also require a CN. In all cases, the PUC is responsible for approving the CN/route permit. Below is a table detailing projects, which plan they are a part of, and whether they received approval for a CN or route permit.

Project	Docket Number (CN/TL)	Regional Plan	CN Status	Status
Northern Reliability 345 kV	22-416/22-415	Tranche 1	Approved	Approved
Sherburne County to Lyon County 345 kV Gen-Tie 1 (Xcel Energy Minnesota Energy Connection)	22-131/22-132	N/A	Approved	Approved
Dairyland Wabasha 161 kV	23-388 (TL)	N/A	N/A	Approved
Beaver Creek 161 kV	24-95 (TL)	N/A	N/A	Approved
Forks-Rost 161 kV	24-232 (TL)	N/A	N/A	Approved
Iron Pine Solar Gen-Tie 230 kV	23-415 (TL)	N/A	N/A	Approved
115kV - Red Rock and Battle Creek Substations	25-169 (TL)	N/A	N/A	Minor Alteration Approved
Sherco Solar West 345kV	21-189 (TL)	N/A	N/A	Minor Alteration Approved
Magnolia Substation	25-101 (TL)	N/A	N/A	Minor Alteration Approved
Allen S. King Plant Gen Tie Project	25-255 (TL)	N/A	N/A	Minor Alteration Approved
Lines 0984 and 0992 – 345kV	25-257 (TL)	N/A	N/A	Minor Alteration Approved
LR-PC 115-KV	25-268 (TL)	N/A	N/A	Minor Alteration Approved

Transmission Projects Under Review in 2025 and Onward

There are dozens of transmission line projects currently undergoing certificate of need or route permit review in the state. Below are some of those projects, notably from MISO's LRTP Tranche 1 and Tranche 2.1:

Project	**Docket Number (CN/TL)**	**Regional Plan**	**CN Status**	**Route Permit Status**
Mankato to Mississippi 345 kV	22-532/23-157	Tranche 1	In Process	In Process
Maple River to Cuyuna 345 kV	25-109/25-110	Tranche 2.1	Anticipated Filing 1Q 2026	Anticipated Filing 3Q 2026
Iron Range to St. Louis County to Arrowhead 345 kV	25-111/25-112	Tranche 2.1	Anticipated Filing Dec 2025	In Process
Bison to Alexandria second circuit 345 kV	25-116 (CN)	Tranche 2.1	Anticipated Filing Feb. 2026	Anticipated Filing in Q2 of 2026[24]
SD/MN Border to Lakefield Junction 765 kV*	25-117 (CN)	Tranche 2.1 and PowerOn Midwest	Anticipated Filing Feb. 2026	Anticipated Filing Q1 of 2027[25]
Lakefield Junction to MN/IA Border 765 kV*	25-118 (CN)	Tranche 2.1 and PowerOn Midwest	Anticipated Filing Feb. 2026	Anticipated Filing Q1 of 2027[26]
Lakefield Junction to Pleasant Valley to North Rochester 765 kV*	25-119 (CN)	Tranche 2.1 and PowerOn Midwest	Anticipated Filing Feb. 2026	Anticipated Filing Q1 of 2027[27]

[24] *In the matter of the Application for a Certificate of Need for the Bison to Alexandria Second Circuit 245 kV Transmission Line Project*, Northern States Power Company, d.b.a. Xcel Energy, Great River Energy, Minnesota Power, Otter Tail Power Company, and Western Minnesota Municipal Power Agency, Seventh Status Update to the Commission, December 23, 2025, Docket No. E002, ET2, E015, E017, ET6135/CN-25-116, (edockets) 202512-226168-01, at 2.

[25] *In the matter of the Application for a Certificate of Need for the PowerOn Midwest 765 kV and 345 kV High Voltage Transmission Line Project*, Great River Energy, Xcel Energy, and ITC Midwest LLC, LRTP 2.1 765 kV Status Update Letter, December 23, 2025, Docket No. E002, ET2, ET6675/CN-25-117, (eDockets) 20259-223346-01, at 2.

[26] *Ibid.*

[27] *Ibid.*

Pleasant Valley to North Rochester to Hampton 345 kV*	25-120 (CN)	Tranche 2.1 and PowerOn Midwest	Anticipated Filing Feb. 2026	Anticipated Filing Q1 of 2027[28]
North Rochester to MN/WI Border 765 kV	25-121 (CN)	Tranche 2.1	Anticipated Filing Feb. 2026	Anticipated Filing late 2026[29]
**Projects were combined into docket 25-117*				

The projects that will be under review in 2026 represent a significant increase in transmission development in Minnesota. The projects under review are similar in scale to the large CapX2020-era 345kV build out, but with the addition of a historic development of 765 kV transmission lines. Most of these projects are part of MISO's LRTP Tranche 2.1, which seeks to develop a 765 kV transmission "backbone" across the upper Midwest. Tranche 2.1 is further discussed in the next section.

Regional and Interregional Planning

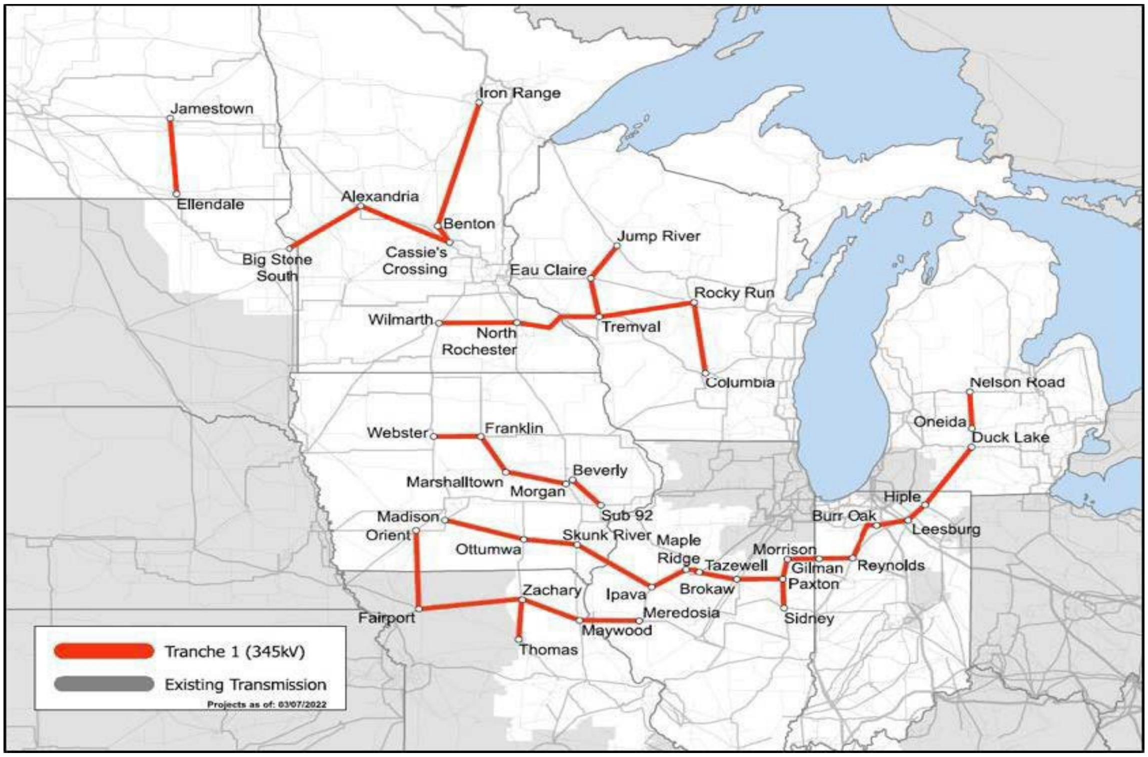
MISO Long Range Transmission Planning: Tranche 1 and Tranche 2.1

Due to the evolving generation mix, load growth, emerging transmission constraint problems, and the long lead time required for large new transmission projects, Commerce and the PUC continue to advocate for MISO to engage in long-range planning.

MISO initiated its most recent long-range transmission planning (LRTP) effort in August 2020 to better assess, from the top down, what upgrades over the next 20 years may be needed. In July 2022, MISO approved an initial group of 18 new regional transmission line projects to ensure the reliable and efficient operation of the transmission grid in the Upper Midwest (Tranche 1 portfolio). Three of these projects are in the state of Minnesota. Total construction costs are expected to be approximately $10 billion for all 18 projects located across the Midwest. A map of the Tranche 1 portfolio is shown below in Map 1.

[28] *Ibid.*

[29] *In the Matter of the Application for a Certificate of Need for the North Rochester-Columbia 765 kV High Voltage Transmission Line Project (LRTP 26)*, Xcel Energy and Dairyland Power Cooperative, Gopher to Badger Link-Project Status Update, December 31, 2025, Docket No. ET3, E002/CN-25-121, (eDockets) 202512-226315-01, at 1.



Map 1. MISO LRTP Tranche 1

On December 11th, 2025, the MISO Board met to discuss the merits of MISO's 2025 Transmission Expansion Plan (MTEP25). Complementary to the long-range transmission planning process, the MTEP process helps to identify transmission from the bottom up, becoming one of the first steps in building the Futures scenarios for Long Range Transmission Plans (LRTPs). MISO released its updated planning assumptions for MTEP25 in June 2025. Based on the findings in the MTEP25 Report, MISO estimates approximately $12.3 billion in capital will be invested in 432 proposed projects to support load growth forecasts of 11.6 GW in new spot load across the MISO footprint (Map 2).[30] Of the 432 total projects, 49 projects totaling 9.7 GW of the total sought to use the "Expedited Project Review" (EPR) pathway, whereby transmission owners would be able to advance certain transmission projects outside of the standard MTEP review due to "immediate need."[31] The larger proportional use of the EPR process, and its associated need, was driven by large loads seeking to interconnect to the grid, and the reliability concerns stemming from the large load additions.

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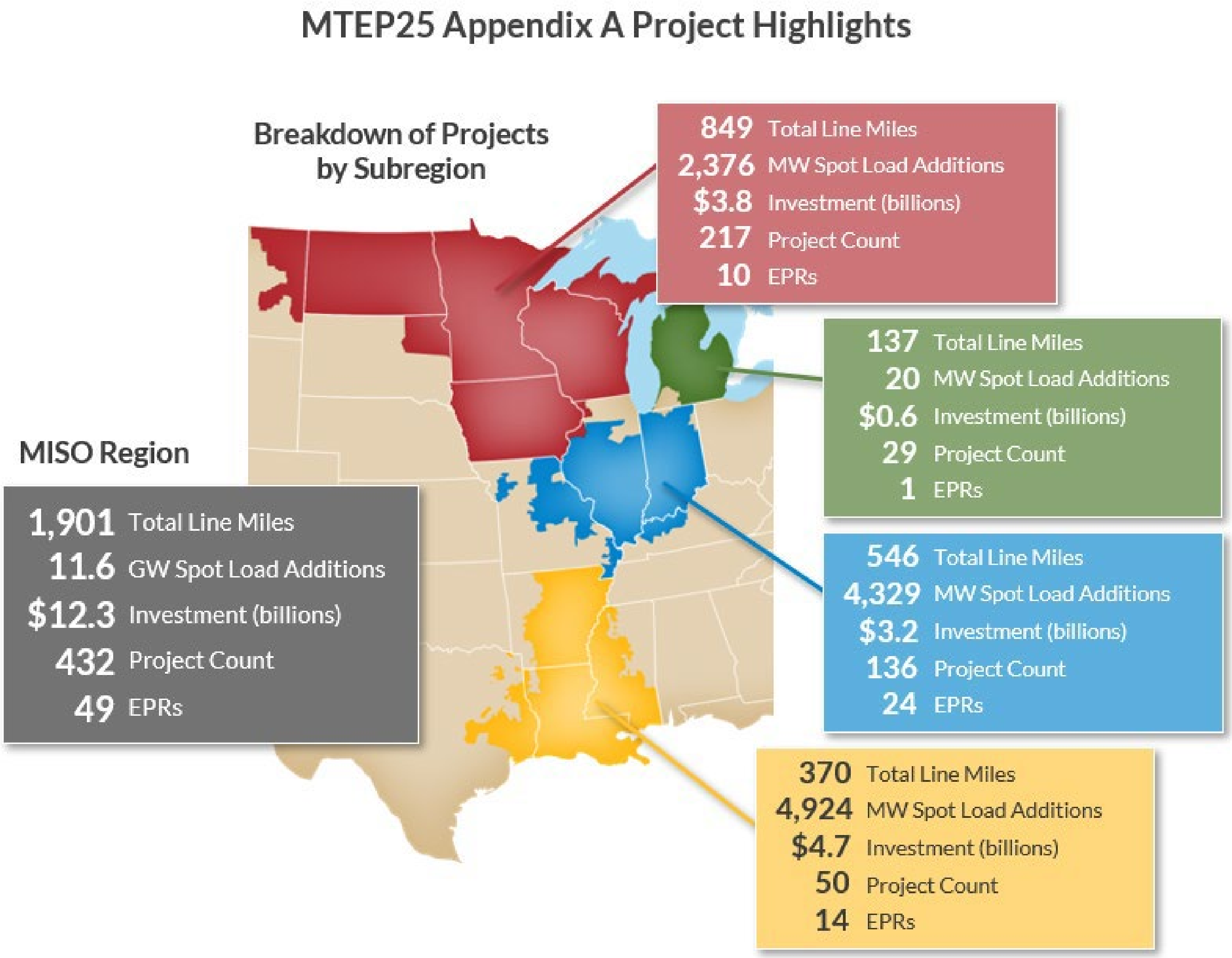
[30] MISO Transmission Expansion Plan (MTEP). MISO Energy, (accessed 12.30.2025). Available at https://extranet.misoenergy.org/planning/transmission-planning/mtep/#t=10&p=0&s=&sd=

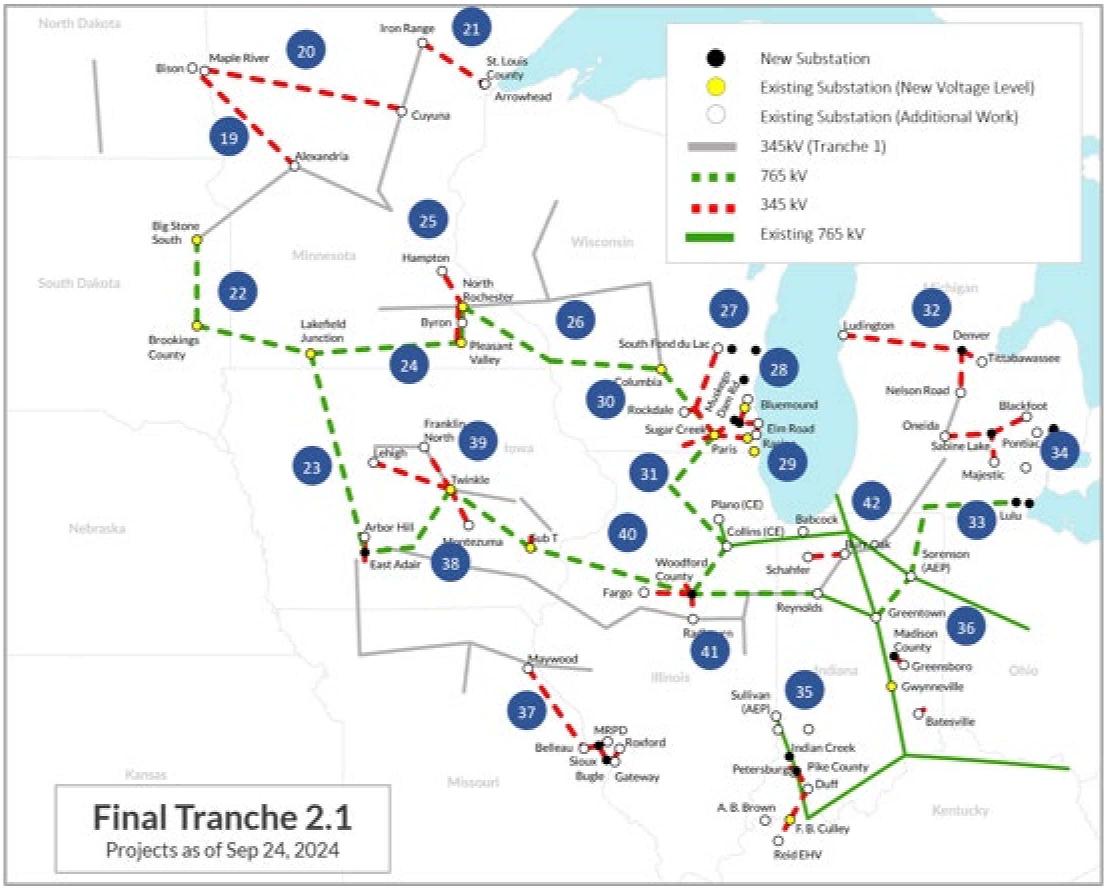
[31] Id., at Chapter 1: Transmission Planning Overview at 15.



Map 2. MTEP25 Projects by MISO subregion

In December 2024, the MISO Board of Directors approved the Tranche 2.1 portfolio as part of MTEP24. The Tranche 2.1 portfolio included over $22 billion in new transmission projects and is primarily located in the MISO north region (map below, Map 2: MISO LRTP Tranche 2.1). The upper Midwest portion of Tranche 2.1 includes eight projects in Minnesota and is expected to begin in 2026. Subsequent phases of the LRTP will focus on the South (2027) and Midwest (2028).[32]

[32] Midcontinent Independent System Operator, Inc. *Long Range Transmission Planning* MISO (last visited January 2, 2026). Available at: https://www.misoenergy.org/planning/long-range-transmission-planning/



Map 3. MISO LRTP Tranche 2.1

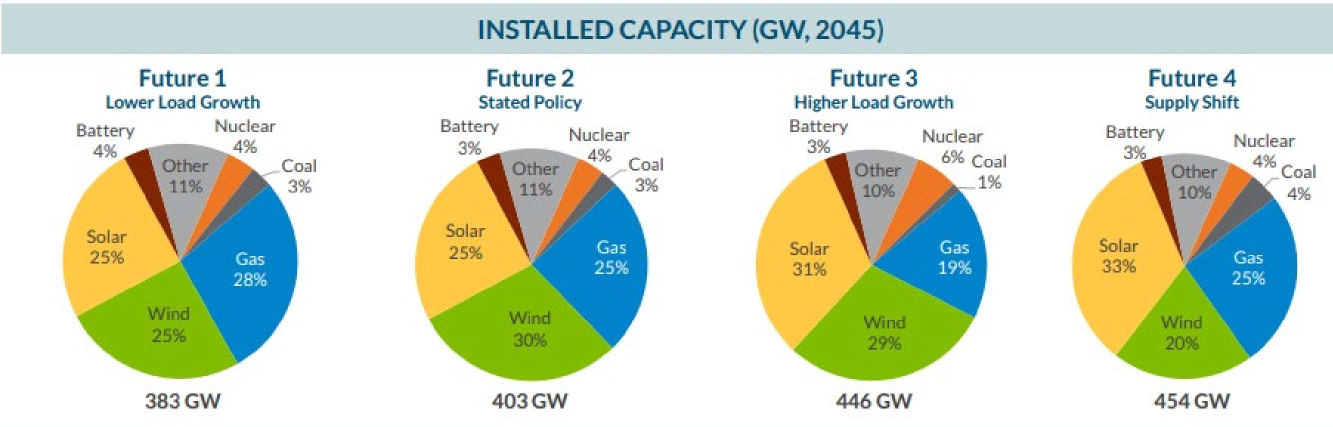
MISO Future Planning Scenarios

MISO and relevant stakeholders are also currently in the process of developing the Series 2 Futures, started in 2025, which are an educated projection about what the electric system will look like in the future years. Series 1 Futures from 2021, and Series 1A Futures from 2023, supported Tranche 1 and Tranche 2.1, respectively.[33]

Futures capture a range of potential system conditions over a 20-year planning forecast. The different scenarios capture economic, policy, and technological developments that impact MISO's regional planning. These forecasts are made to reduce uncertainty by utilizing stakeholder information, policy direction, industry trends, and capacity expansion modeling.

Series 2 Futures builds on the two prior models and focuses on policy, increased load growth from data centers and manufacturing, supply chain limitations. This series includes four capacity scenarios shown below:

[33] Midcontinent Independent System Operator, Inc. *Futures* MISO (last visited January 2, 2026). Available at: https://www.misoenergy.org/engage/committees/futures/



The Series 2 Futures includes four future scenarios: Lower Load Growth, Stated Policy, Higher Load Growth, and Supply Shift.

- Future 1: "Low-end demand growth bookend. Change in key macroeconomic drivers reduces the trajectory of load growth from anticipated values, leading to a decreased requirement for new supply."
- Future 2: "Current projections of load growth are applied to define the forward-looking system needs, reflecting reindustrialization, data center growth, electrification, and other key factors. Generation investment, based on current member policy plans and goals, increases to match based on economics and incentives."
- Future 3: "High-end demand growth bookend. Changes in key macroeconomic drivers increase the trajectory of load growth from anticipated values, leading to an increased need for new supply."
- Future 4: "Supply frictions limit the pace of generation additions, and load growth must be managed with existing generation and demand-side resources. These frictions are due to a range of potential drivers, including supply chain constraints, construction delays, labor shortages, interconnection delays, the policy environment, and changes in economics. Input will be sought on the appropriate generation and demand-side levers to ensure sufficient supply is available to meet capacity and energy needs."

Commerce works closely with the Organization of MISO States (OMS) to participate in MISO's stakeholder process for the Futures, ensuring the process addresses the challenges and hurdles in Minnesota. The Series 2 Report will be finalized in March of 2026.

Federal and State Actions Related to Minnesota's Transmission Grid in 2025

Additions to transmission are needed not only due to factors in Minnesota but also due to federal and regional governmental actions directly affecting the use of Minnesota's transmission grid (as well as other states' grids). Issues that developed recently with potential effects in Minnesota are described in this section of the report.

Energy Infrastructure Permitting Act (2024)

In 2024, the State Legislature passed the Energy Infrastructure Permitting (EIPA), a law designed to modernize and consolidate how Minnesota reviews and permits energy infrastructure projects, including transmission lines. The EIP Act also led to the creation of new units at the Minnesota Department of Commerce and the PUC. The Energy, Environmental Review and Analysis (EERA) unit moved to the PUC and is now known as the Energy

Infrastructure Permitting (EIP) unit, while the Department created a new Energy Infrastructure and Reliability (EIRA) unit focused on transmission, grid reliability, and other planning activities.

Following the legislative changes of the EIPA, the Commission adopted two methods for reviewing route permit applications for transmission lines: the Standard Review Process and the Major Review Process, which vary by the length and voltage of the proposed project. The Certificate of Need (CN) process was also reformed and is only required for transmission projects that exceed certain length and voltage thresholds. The EIP Act went into effect on July 1st, 2025, meaning all applications and permits after this date follow the new rules and state laws. Several projects that had applied in 2025 withdrew their CN applications since the project no longer required one under the new law, which will have the longer-term impact of delivering a faster overall regulatory process that will continue as new applications are filed.

The Environmental Policy Innovation Center (EPIC) praised the Act as a major win for clean energy deployment by streamlining approvals for renewable generation and high-voltage transmission lines.[34] EPIC also commended Minnesota lawmakers for achieving faster timelines for agency decisions while preserving public engagement and environmental protections in the permitting process.

FERC Order 1920

Numerous federal changes are occurring with respect to regional and interregional transmission planning. On May 13th, 2024, the Federal Energy Regulatory Commission (FERC) acted on coordinated, long-range transmission planning with Order 1920, requiring the nation's regional transmission organizations (RTOs) to conduct long-term regional transmission planning on the order of 20 years, requiring robust state entity stakeholder participation on cost allocation for transmission proposals. Order 1920 is largely based on MISO's current LRTP process. MISO and SPP's first compliance filing under Order 1920 is due on June 12th, 2026, with the second compliance filing due December 12th, 2026.[35]

In May of 2024, FERC issued Order 1920, which requires regional transmission organizations to engage in long-term transmission planning. The order requires that planning occur at least every 5 years, look 20 years into the future, and consider at least three plausible scenarios. The order lays out the following seven factors that must be considered when assessing transmission scenarios:

- Federal, state, Tribal, and local laws and regulations affecting the resource mix and demand.
- Federal, state, Tribal, and local laws and regulations affecting decarbonization and electrification.
- State-approved Integrated Resource Plans (IRPs) and expected supply obligations for Load-Serving Entities (LSEs)

[34] Environmental Policy Innovation Center. "Minnesota's Energy Infrastructure Permitting Act delivers a major win for clean energy deployment…" LinkedIn. (November 2025). Available at: https://www.linkedin.com/posts/environmental-policy-innovation-center_energy-infrastructure-permitting-activity-7400537776305364992-kqqD?utm_source=share&utm_medium=member_desktop&rcm=ACoAADA2wN0B07_QjO9yOzcbD5OxSAuurWl7NUQ

[35] Federal Energy Regulatory Commission. *Order No. 1920 Compliance Filings Schedule*. FERC. June 16, 2025. https://www.ferc.gov/news-events/news/order-no-1920-compliance-filings-schedule

- Trends in fuel costs and the cost, performance, and availability of generation, electric storage resources, and building and transportation electrification technologies.
- Resource retirements such as legislatively mandated closures or economic retirements driven by regulations.
- Generator interconnection requests and withdrawals
- Utility and corporate commitments and federal, state, Tribal, and local policy goals

The Order identifies seven specific benefits that must be quantified when transmission projects are being assessed:

- Avoided or deferred reliability transmission facilities and aging infrastructure replacement
- Either reduced loss of load probability (LOLP) or reduced planning reserve margin (PRM)
- Production cost savings
- Reduced transmission energy losses
- Reduced congestion due to transmission outages
- Mitigation of extreme weather events and unexpected system conditions
- Capacity cost benefits from reduced peak energy losses

The order also requires consideration of Alternative Transmission Technologies when assessing the need for transmission lines, mandates interregional coordination, and lays out more structured processes for local meetings on proposed transmission processes.

The transmission providers are allowed to identify how their current long-term transmission planning processes may already meet the Final Rule. Within existing planning processes, states will have the opportunity to engage in analysis and planning inputs, transmission needs assessments, and cost allocation for transmission modeling. The Final Rule in Order 1920 also requires transmission providers to consider selecting transmission facilities that incorporate grid-enhancing technologies, such as dynamic line ratings and advanced power flow control, similar to Minnesota's requirements for GETs evaluation.

In November 2024, FERC updated Order 1920, Order 1920-A, allowing states more input in the transmission planning and cost allocation process.[36] It also extended the compliance window for transmission owners from one year to two years.

In April 2025, FERC again updated Order 1920 with Order 1920-B, affirming that state regulators will be key decision makers as the electric industry looks to build out the nation's electric transmission system.[37] Order 1920-B emphasizes the critical consumer-protection role of state utility regulators in transmission planning by giving states more power to influence the regional cost allocation of transmission projects.

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[36] *FERC Strengthens Order No. 1920 with Expanded State Provisions*. Federal Energy Regulatory Commission, (November 21st, 2024). https://www.ferc.gov/news-events/news/ferc-strengthens-order-no-1920-expanded-state-provisions

[37] *What State Regulators Need to Know About Order No. 1920-B*. Federal Energy Regulatory Commission (April 22, 2025). https://www.ferc.gov/what-state-regulators-need-know-about-order-no-1920-b

FERC Order 1920 is likely to have less of an immediate impact on MISO than other regional transmission organizations because MISO is already engaged in the long-term planning process for expanding its transmission portfolio contemplated by FERC. To the extent that the Order encourages joint evaluation of interregional facilities, MISO and SPP may identify projects that are more efficient and cost-effective in meeting long-term transmission needs.

U.S. Department of Energy National Transmission Planning Study

The previous iteration of this report detailed the findings of the DOE's National Transmission Planning (NTP) Study, published in October of 2024.[38] The NTP concluded that the largest benefits to consumers are realized when interregional transmission is built across the RTO/ISO seams, and the report advocated for more coordination between planning processes.

In January of 2025, the National Laboratory of the Rockies (formerly the National Renewable Energy Laboratory) and Pacific Northwest National Laboratory published the Planning and Development Pathways to Interregional Transmission report to serve as a high-level assessment of obstacles to deploying interregional transmission, along with potential solutions.[39] At the state level, this report advocates for collaboration between state agencies and more active stakeholder participation in interregional planning, which is consistent with the PUC's and Commerce's mission.

Additionally, Commerce has an active role in the MISO-PJM and MISO-SPP Interregional Planning Stakeholder Advisory Committees (IPSAC).

This perspective, on the value of regional and interregional transmission, persists throughout transmission planning and modeling. In one 2025 analysis on transmission cost-benefit analyses, a Rocky Mountain Institute (RMI) white paper highlighted how regional and interregional transmission planning can drive considerable benefits for ratepayers, resulting in annual savings that outweigh costs of new transmission, and which can deliver more benefits to ratepayers than local transmission projects.[40] Despite this, trends show that, according to FERC, the "vast majority of investment in transmission facilities" has been in local facilities over the last decade.[41] Additionally, the RMI report highlights how the most effective transmission projects are regional or interregional projects (which tend to be higher voltage lines 345 kV – 765 kV), whereas local transmission projects provide fewer benefits (tend to be smaller and lower voltage lines 61 kV – 230 kV, but which may have less oversight and jurisdictional constraints. This "regulatory gap," RMI argues, between the pace at which regional transmission versus local transmission are undertaken, can be lessened at the state level by expanding

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[38] *National Transmission Planning Study*. U.S. Department of Energy Grid Deployment Office, (2024). Available at: https://www.energy.gov/gdo/national-transmission-planning-study.

[39] Juliet Homer, Christina Simeone, David Hurlbut, Brie Van Cleve, and Faith Martinez Smith. *Planning and Development Pathways to Interregional Transmission*. Pacific Northwest National Laboratory, National Renewable Energy Laboratory, (January 2025). Available at: https://doi.org/10.2172/2500353.

[40] Wayner, Claire, Rebane Kaja, Teplin, Chaz. *Mind the Regulatory Gap: How to Enhance Local Transmission Oversight.* Rocky Mountain Institute, (November 2024). At 9. https://rmi.org/wp-content/uploads/dlm_uploads/2024/11/mind_the_regulatory_gap_report.pdf

[41] Id. At 11.

certificate of public convenience and necessity (CPCN) authority, offering expedited cost recovery for local projects that have undergone a robust regional review, update IRPs to incorporate transmission planning, and grow regulatory staff capacity and expertise on topics of regional transmission planning.

Other states, like Kansas, have taken steps towards prioritizing cost prudency in transmission rate setting, including a legislative amendment to their approach around transmission delivery charges. This legislation allows the Kansas PSC to distinguish between RTO-directed projects versus local projects, and to make sure that the return on equity (ROE) for transmission projects follows state (rather than FERC) approval, in cases where the utility seeks to recover the rider on local transmission projects.[42]

MISO Transmission Owners' Return on Equity

As discussed in prior reports to the Legislature, a group of industrial end-users filed a complaint at FERC seeking to reduce the allowed return on equity (ROE) of MISO Transmission Owners and limit capital structure ratios and incentive equity adders. At that time, MISO transmission owners had a base ROE of 12.38%. The complaint sought to decrease the transmission owners' base ROE by over 300 basis points below the then-current base ROE, to 9.15%. MISO's Public Consumer Group, including Commerce, identified bases for decreasing the ROE to a reasonable level. FERC's Trial Staff filed briefs that were supportive of consumer advocates' positions. On October 17, 2024, FERC ordered MISO transmission owners to change their return on equity (ROE) calculation, eliminating the risk premium model from the methodology, resulting in a base ROE of 9.98%.[43]

Following FERC's October 17, 2024, order, the MISO Transmission Owners sought judicial review at the United States Court of Appeals for the D.C. Circuit, challenging the revised ROE methodology. On December 12, a joint intervenor brief was filed by the Louisiana Public Service Commission and other intervenors.[44] The Organization of MISO States (OMS) joined consumer advocates, utilities, municipalities, cooperatives, and industrial consumers in the Joint Intervenors' Brief. Both the PUC and Commerce endorsed OMS's decision to join as an intervenor. Oral argument has not been scheduled, but a ruling can be expected by the end of 2026.

Under its rate-making authority, the PUC requires utilities to account for transmission revenues when setting retail rates, so ratepayers are not required to pay the full cost of FERC-approved transmission ROEs without recognizing the associated transmission revenues. This ratemaking practice reduces the impact of high ROEs on Minnesota retail ratepayers, but the benefits are only realized when utilities are required to pass those revenues or voluntarily provide credits. Even when the offsets lower retail rates, high ROEs continue to influence utility investment decisions by encouraging capital-intensive transmission projects, creating ongoing distortions in planning and resource selection.

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[42] Id. At 45.

[43] FERC Order on Remand in Docket numbers EL14-12-016, EL15-45-015, https://www.ferc.gov/media/e-4-el14-12-016.

[44] Intervenor Brief of the Louisiana Public Service Commission & Other Aligned Intervenors, *MISO Transmission Owners & Louisiana Public Service Commission v. FERC*, No. 25-1045 (D.C. Cir. Dec. 12, 2025) (intervenor brief), FINAL Intervenor Brief MISO ROE- Case No.25-1045.pdf

Incentive Return on Equity for Transmission

In another long-running issue, on March 20, 2020, in Docket No. RM20-10, FERC issued a Notice of Inquiry, seeking comments on the scope and implementation of its electric transmission incentives regulations and policy. The OMS (with Commerce supporting) filed comments with FERC recommending the evaluation of granting ROE incentive adders on a case-by-case basis[45]. The comments recommended keeping benefits to consumers at the forefront of any analysis to determine whether to grant or eliminate ROE transmission incentives and support non-ROE incentives first for mitigation of transmission project risks. A response from FERC on the issue is still pending.

Impacts to Future Transmission Planning in Minnesota

Ongoing Transmission Constraint Issues

Transmission constraints continue to slow the interconnection of large-scale wind and solar generation in Minnesota. New high-voltage transmission lines are needed to help reduce these interconnection constraints. However, even after MISO approves plans with large transmission upgrades, such as Tranche 1, Tranche 2.1, and future long-range transmission plans, it often takes at least five to ten years to plan, permit, and construct them before they are energized. Given these long timespans, more immediate solutions are needed to address transmission capacity issues. While long-term transmission regional capacity issues are addressed, there is increased industry interest in improving the operating capacity and efficient use of the existing system in the short term. Efforts to improve the capacity of the existing high-voltage system are ongoing in the MISO region, including using ambient-adjusted line ratings and system reconfigurations.

On December 16, 2021, FERC issued a final rule (Order No. 881) on the use of ambient-adjusted ratings, requiring all transmission providers, both inside and outside of organized markets, to use ambient-adjusted ratings on a seasonal basis to evaluate the accuracy of near-term line ratings. Both the Biennial Transmission Plan and Grid-Enhancing Technologies report, which are currently before the PUC and receiving comments from Commerce, detail the adoption of ambient-adjusted ratings and dynamic line ratings to reduce congestion and constraints on the grid. Transmission owners in their relevant regional transmission organizations (RTOs) were directed by FERC to file their updated ambient-adjusted ratings for their transmission lines by June 12th, 2025.

Cost Responsibility

With many new large-scale transmission improvements planned, utilities will be constructing significant infrastructure in the near future. To afford Minnesotans' fair and affordable rates, state regulators will need to stay vigilant to the costs incurred by these new projects. Fundamental to the vertical integration of utilities is the need to ensure cost transparency and cost prudency when utilities recover the costs of their investments. To

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[45] Organization of MISO States, Organization of PJM States, New England States Committee on Electricity, and Southwest Power Pool Regional State Committee. Comments Requesting FERC Eliminate the RTO Participation Adder in Perpetuity. (June 27, 2025). Available at: https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250627-5115&optimized=false

encourage cost discipline and prevent ratepayers from paying more than is reasonable for new utility infrastructure, at a minimum, a utility must justify any cost recovery above the amount the utility originally indicated that the project would cost. Cost discipline conclusions should consider alternatives to new transmission discussed in this report, including energy savings initiatives, programs to manage electric demand, the build-out of distributed energy generation near sources of electricity demand, the build-out of strategically located short and long-duration energy storage, and the implementation of a wide variety of grid-enhancing technologies (GETs).

At the same time, these higher value regional transmission investments can help actualize cost savings for Minnesota ratepayers; a more efficient, interconnected system can offer easier access to low-cost energy. Ensuring, however, that the benefits of these efficiencies are clear will be important, particularly because load forecasts have remained steady for so long that many ratepayers are experiencing a period of utility investment like this for the first time. This focus on broader benefits and the alternative projects that could be considered is important, particularly since decisions to approve or deny a project are based in part on the cost-effectiveness of the proposed facility. Consequently, it is important to minimize errors in estimation to avoid ill-informed decisions from being made that would result in higher system costs than necessary.

When utilities install infrastructure in an area, mitigation measures must reasonably consider the cost implications noted above. Further, the costs of any significant upgrades must be equitably allocated to ratepayers, based on rate-making principles such as cost-causation, cost-minimization, and administrative feasibility.

Conclusion

The high-voltage transmission system that Minnesota is a part of is in a period of rapid change, alongside commensurate changes on the generation and power demand side. The regional transmission organizations (RTOs) of which Minnesota belongs to have already begun sweeping changes to their planning and forecasting of future energy scenarios. This includes the historic Long-Range Transmission Planning (LRTP) process in MISO, which includes many-year phases of considerable investment in the Upper Midwest’s transmission expansion, including MISO’s Tranches 1 and 2.1. MISO transmission processes will continue to drive further investments to interconnect low-cost energy resources and will continue to deliver more benefits than costs and be subject to considerable review through the MISO stakeholder process.

Minnesota’s utilities and state agencies have focused on the nearer-term transmission solutions like grid enhancing technologies (GETs) to utilize the existing transmission capacity in the state to its best and highest capability in the short term. Further study on improving and upgrading the existing transmission system could extend to investigations into reconductoring with advanced conductors, or to other transmission solutions which can be more cost-effective than new transmission buildout, while also mitigating any land use and environmental impact of new transmission buildout. Continuing to advance GETs and innovative solutions to managing congestion will remain an important part of the future of grid and resource planning.

Minnesota remains a leader in the clean energy transition, and ensuring adequate transmission capacity—alongside strategic investments in making the highest and best use of the state’s transmission owner’s existing transmission system—will remain an important part of delivering on the state’s landmark climate and environmental goals.