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

Executive Summary

Minnesota Statutes § 216C.054 requires that the Commissioner of Commerce , in consultation with the Minnesota Public Utilities Commission (PUC), 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 assert that both new transmission and supplementary measures are necessary to meet medium and long-term needs of the system. The state has plans for several new regional transmission line projects. In addition to building new lines, the state is exploring alternatives to 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 of those possible options over the last few legislative sessions.

Commerce and the PUC continue to monitor progress, consult with stakeholders, and encourage these efforts to benefit Minnesotans. The Minnesota Transmission Owners (MTO) will report its first analysis of GETs in its 2025 Biennial Transmission Report. Commerce argued in Docket No. E9999/ CI-24-316 that rapid deployment of GETs and the other supplements/alternatives to new transmission can help alleviate ongoing congestion and curtailment in southwestern Minnesota and suggested an accelerated timeline to study GETs and propose pilots in the 2025 Biennial Transmission Report.

The regional high-voltage transmission system plays a critical role in providing reliable electricity to Minnesotans. Looking forward, upgrades to the high-voltage transmission system in Minnesota and across the region are will be needed to maintain reliable service; to allow better access to low-cost sources of electricity; to meet anticipated growing electrical demand driven by manufacturing, data centers, and beneficial electrification; and to meet Minnesota's carbon-free electricity by 2040 law as well as the energy policy goals of other states in the region.

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

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. In December of 2024, the MISO board—encouraged by the Walz Administration-- approved the Tranche 2.1 portfolio that represented over $22 billion in transmission investments.

In 2024, Minnesota was the first state to approve regional transmission projects from MISO's Tranche 1 portfolio with the Big Stone South—Alexandria—Big Oaks project's Eastern Segment (TL-23-159). The Commission also issued three route permits for local high-voltage transmission projects: (1) the Dodge County Wind 161 kV Transmission Line (TL-20-867), (2) the Cedar Lake 115 kV HVTL Reroute Project (TL-23-170), and (3) the Minnesota Power HVDC Modernization Project (TL-22-611). There are ten additional transmission lines currently in the permitting process at the Public Utilities Commission.

One key to improved reliability and affordability for electricity in our region going forward is improving the links that allow electricity to move between MISO, SPP, and other regional grids. In 2023 Commerce, along with MISO, SPP, the Great Plains Institute, and the transmission-owner utilities applied for and were awarded a $464 million grant from the U.S. Department of Energy's Grid Resilience and Innovation Partnership Program. The award will help offset the cost of five transmission projects that are part of the Joint Targeted Interconnection Queue (JTIQ) portfolio that MISO and SPP had developed, and which aim to address issues that are understood to be the primary hurdles for generator interconnection requests along the MISO-SPP seam. On November 14, 2024, FERC approved the cost-allocation approach that will be used to fund the projects and in December of 2024, the MISO and SPP boards approved the JTIQ portfolios.

In addition to the large projects discussed above, the 2023 Minnesota Transmission Owner's Biennial Report identifies 164 smaller transmission plan inadequacies across the state and describes the projects planned to address these lower voltage inadequacies. While several of these projects will be large enough to require a certificate of need and route permit from the Commission—most of them are small upgrades or replacement projects and they should move forward.

The 18 high-voltage 345-kV LRTP projects that MISO approved in the Tranche 1 portfolio are not expected to be in service until sometime between 2028 and 2030, and the newly approved Tranche 2.1 portfolio will follow behind. Although these new, large transmission projects will be planned, permitted, and constructed during the rest of this decade, new generation projects, primarily wind and solar, could continue to face interconnection delays and costly transmission network upgrade requirements. Not only are new generation projects facing transmission interconnection delays, but existing wind generation facilities in southwest Minnesota, are experiencing increasing curtailment due to transmission constraints. These challenges illustrate why GETs and other faster solutions are going to be necessary while we wait for the buildout of new transmission lines.

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.

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.

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 and access to affordable generation.

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 more smaller generation or storage facilities are added to the distribution system (also known as distributed energy resources), 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.

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.

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 at NERC as a state regulatory representative. Reliability standards for the transmission grid in the part of the Eastern Interconnection, in which Minnesota is located, is 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 ensuring that there are adequate electric generation resources to meet the needs in each zone (also known as "resource adequacy"). Most of Minnesota is part of MISO's Planning Reserve Zone 1.

Recent Developments

The Minnesota Transmission Owners (MTO) will first report on their efforts to address GETs in the 2025 Biennial Transmission Report. With a legislative mandate to study GETs, during a PUC investigation Commerce recommended the 2025 Biennial Transmission Report be enhanced by a thorough case study of GETs and new pilot projects in the most congested region of Minnesota around the Nobles County Substation area. One large wind facility reported ongoing curtailment of up to 50% annually due to grid congestion, which ultimately ratepayers subsidize through curtailment payments. This case study offers a cautionary tale that the status quo may produce suboptimal outcomes. While there is consensus among stakeholders that new grid infrastructure upgrades are necessary to fully alleviate the congestion, these solutions may be a decade away, which makes short-term grid optimization with GETs ideal.

The PUC's decision regarding Commerce's recommendation is pending. Therefore, it is important to let the regulatory process play out as GETs begin formal study by the MTO. However, early results indicate that single GETs in isolation may not offer comprehensive congestion relief in the Nobles County Substation area because grid congestion can be caused by a range of grid constraints, with thermal (capacity), voltage (stability) and substation limits all interacting in unison. In the future, Commerce may seek a PUC requirement to expand the scope of analysis of GETs to include the study of multiple GETs paired with substation upgrades to fully maximize the transmission capacity of existing grid infrastructure.

While GETs offer quickly deployable solutions to increase transmission capacity and maximize ratepayer value, these solutions cannot fully substitute for the large-scale transmission needs of the future. Traditionally, new transmission projects are proposed to meet increased transmission needs. While reconductoring, which involves the replacement of old transmission lines with new lines, regularly takes place, new transmission projects are still proposed. Advanced conductors, which utilize newer technology transmission wires that can increase transmission capacity by up to two-fold, open new opportunities to maximize transmission 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.

In one analysis recently published in the Proceedings of the National Academy of Sciences (PNAS), advanced reconductoring coupled with 50-mile sectionalization and voltage support, was found to be able to double the United States' transmission capacity and could save ratepayers half of the cost compared to new transmission lines. Despite the potential benefits of reconductoring, to date, there has been no comprehensive analysis performed on the potential to reconductor Minnesota's existing transmission assets as an alternative to newly constructed lines. Minnesota law does not name advanced conductors or require such analysis. Future legislative or PUC action could require such a study to compare the speed and cost-effectiveness of advanced reconductoring with necessary sectionalization and stability support to the existing transmission expansion plan.

In addition to optimizing transmission line capacity and stability, energy storage holds the potential to increase transmission line utilization by effectively shifting power flows 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. Xcel Energy is currently conducting an energy storage study to determine potential locations for battery energy storage and will include the results in the 2025 Biennial Transmission Report. Commerce recommended the PUC expand the scope of Xcel's study to include a cost-benefit analysis of battery storage compared to the status quo, in order to ensure that any proposed storage projects are beneficial.

Minnesota’s Transmission System: Planning for the Future

Transmission Projects Approved in 2024

In 2024, the PUC approved a proposal by Minnesota Power to modernize and expand its existing Square Butte high-voltage transmission line that connects North Dakota and northern Minnesota. The upgrades aim to increase the capacity of the line and reduce line failures. The PUC issued four route permits for high-voltage transmission projects in 2024: (1) the Dodge County Wind 161 kV Transmission Line (TL-20-867), (2) the Cedar Lake 115 kV HVTL Reroute Project (TL-23-170), (3) the Minnesota Power HVDC Modernization Project (TL-22-611) discussed above and (4) the Alexandria to Big Oaks 345 kV Transmission Line Project (TL-23-159). The Alexandria to Big Oaks Line is approximately 106 miles long and is the first MISO LRTP Tranche 1 portfolio project to receive state approval.

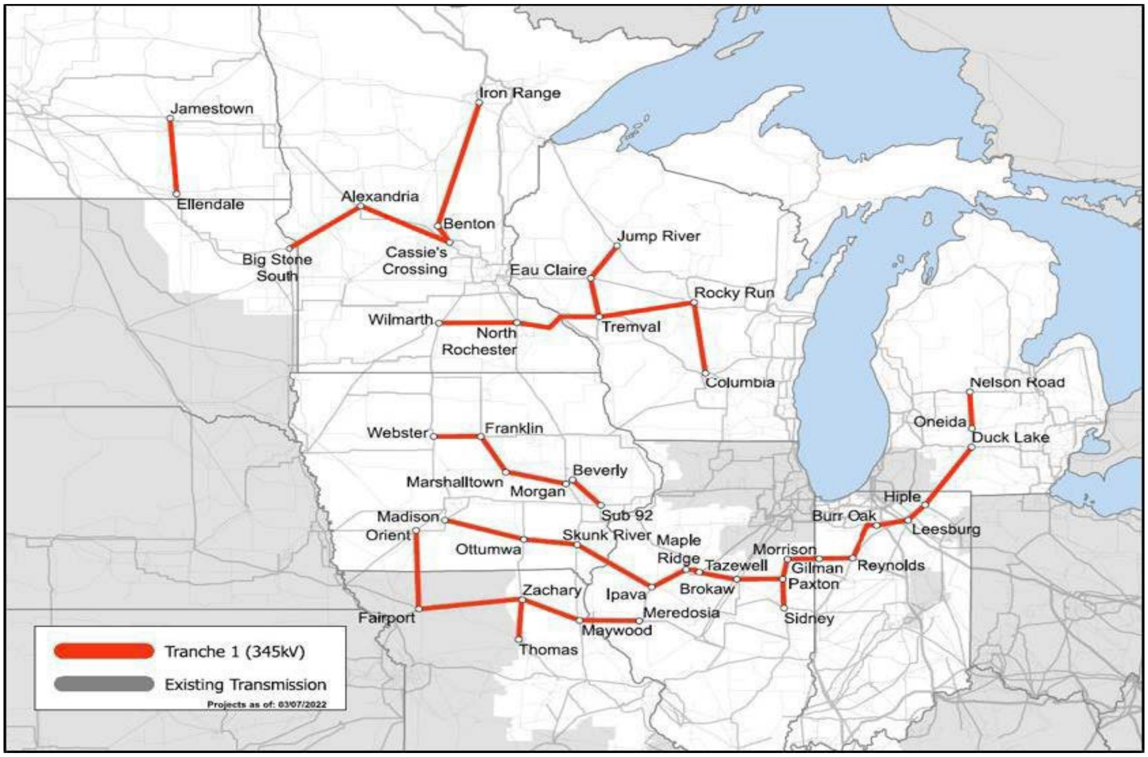
Notably, however, there are 10 transmission line projects currently undergoing certificate of need or route permit review in the state:

- Big Stone South to Alexandria, 90 miles, 345 kV (TL-23-160)
- Northland Reliability Project, 140 miles, 345 kV (TL-22-415)
- Minnesota Energy Connection (Sherco to Lyon County Project), 180 miles, 345 kV (TL-22-132)
- Mankato to Mississippi River Project, 130 miles 345 kV, 20 miles 161 kV (TL-23-157)
- Dairyland Wabasha Relocation, 13.3 miles, 161 kV (TL-23-388)
- Forks-Rost 161 kV Transmission Line Project, 8.5 miles, 161 kV (TL-24-232)
- Beaver Creek Transmission Line Project, 3.5 miles, 161 kV (TL-24-95)
- Midwater Energy Storage Interconnection Project, 0.5-mile, 161 kV (TL-24-295)
- Benton Solar Interconnection Project, 0.4-mile, 115 kV (TL-23-423)
- Laketown Project, 4.3 miles 115 kV (24-132)

MISO Long-Range Transmission Planning

Because of the evolving generation mix, 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 planning effort in August 2020 to better assess 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 proposed Tranche 1 portfolio is shown below in Map 1.



Map 1. MISO 2022 Long-Range Transmission Project

In December 2024, the MISO board approved the Tranche 2.1 portfolio. The Tranche 2.1. portfolio included over $22 billion in new transmission projects, primarily located in the MISO north region. The Tranche 2.1 approval occurred at the same time as the approval for the JTIQ portfolio. Planning for the Tranche 2.2 portfolio is set to begin in 2026.

In addition, MISO and SPP completed a related but separate planning process in 2022, the JTIQ study, to evaluate potential joint transmission projects that would reduce transmission upgrade costs when proposed new generation projects affect the other's transmission network. The planning for this joint MISO/SPP effort started in December 2020.

Minnesota Transmission Owner's Biennial Transmission Report

Minnesota Statutes § 216B.2425 requires utilities that own or operate electric transmission facilities in the state to report by November 1st of each odd-numbered year on the status of the transmission system, including present and foreseeable inadequacies and proposed solutions. The transmission owners filed [the 2023 report](#) on November 1st, 2023. The next report is due in November 2025.

The 2023 Minnesota Transmission Owner's Biennial Report identifies 164 transmission inadequacies across the state and the associated projects to address these inadequacies. While several of these projects will be large enough to require a certificate of need and route permit from the Commission—including the 345-kV LRTP projects described above—most of them are smaller upgrades or replacement projects. The report also indicates that Minnesota electric utilities have enough capacity to meet renewable energy standards through 2035. The report does not evaluate compliance with the new 2040 carbon-free energy standards since some compliance details were still pending at the time of the report. The most recent report also contains an appendix describing the potential impact of transmission construction outages on congestion costs.

The 16 participating utilities also jointly maintain the following website that provides information about transmission planning and projects: http://www.minnelectrans.com.

The report was approved by the PUC in May 2024 with a requirement that future versions of the report include a discussion of reliability and grid congestion challenges.

Federal and State Actions Related to Minnesota's Transmission Grid in 2024

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.

Impacts of Federal Funding on Transmission Infrastructure

The federal Infrastructure Investment and Jobs Act (IIJA), passed in 2021, includes approximately $27 billion in new spending over 5 years on the nation's energy grid. Most of the funding targets updating and improving the existing grid, with some targeted towards new transmission lines.

Commerce, along with MISO, SPP, the Great Plains Institute, and the transmission owner utilities applied to the U.S. Department of Energy's Grid Resilience and Innovation Partnership (GRIP) Program for a grant to help offset the cost of these JTIQ projects. In October 2023, the U.S. Department of Energy (DOE) notified Commerce that it had been selected to negotiate a $464 million cooperative agreement for this project. In October 2024, the Minnesota Department of Commerce entered into a cooperative agreement with DOE for the JTIQ grant agreement. In November 2024, FERC approved revisions to the joint operating agreement between SPP and MISO that include the cost allocation for the JTIQ portfolio. In December 2024, the boards of MISO and SPP voted to approve the JTIQ portfolio.

Federal funding has also been dedicated to several other transmission projects that impact Minnesota. This includes a $700 million award to the Montana Department of Commerce to fund an HVDC line from Montana to North Dakota that Duluth-based ALETTE is a partner on.

FERC Order 1920

In May 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)

- 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 also 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.

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

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

On October 3, 2024, DOE released the final National Transmission Planning (NTP) Study using a national approach to optimize transmission planning. The study compares different transmission frameworks and concludes that the largest benefits to consumers are realized when interregional transmission is built across the seams. The highest benefits were calculated using high-voltage direct current (HVDC) transmission technologies but would still require additional strengthening of AC networks. Overall, the study identifies robust benefits across a variety of scenarios by merging siloed planning processes and increasing coordination between regional transmission operators A companion report identifies ways to reduce barriers to interregional planning. The recommendations included within the report are closely aligned with the Joint Transmission Interconnection Queue (JTIQ) portfolio of projects that Commerce is closely engaged in and highlights the importance of this effort.

MISO Transmission Owners' Return on Equity

As discussed in prior reports, 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 percent. The complaint sought to decrease the transmission owners' base ROE over 300 basis points below the then-current base ROE, to 9.15 percent. 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%.[1]

Because the PUC requires utilities under its rate-making authority to offset high ROE transmission costs with high ROE transmission revenues, Minnesotans taking service from such utilities have been spared from paying high ROEs without the revenue offset. While these ratemaking decisions have reduced the harm of paying for high ROEs for such ratepayers in Minnesota, such benefits will be returned to Minnesota retail ratepayers only if utilities choose to provide a credit to Minnesota retail ratepayers for higher revenues or—as with utilities subject to the PUC's rate-making—are required to do so. Even if Minnesota retail ratepayers receive the benefit of revenue offsets to reduce the high rates they pay for electric service, the distortion of utility decision-making remains an issue.

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 and the PUC supporting) filed comments with FERC recommending the evaluation of granting ROE incentive adders on a case-by-case basis. 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 FERC decision on the issue is still pending.

Impacts to future planning of Transmission 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. In recent years, MISO has approved two large transmission portfolios in our region.

Even after MISO approves plans with large transmission upgrades, it takes time—five to ten years—to plan, permit, and construct them. To help address this issue in Minnesota, in 2023 the PUC convened a series of stakeholder meetings to discuss improvements to their wind, solar, and transmission permitting and

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

environmental review process. A summary report on the results of this process was issued on December 31, 2023.

Over the short term, while long-range transmission regional capacity issues are addressed, there is increased industry interest in improving the operating capacity and efficient use of the existing system. Efforts to improve the transfer capability of the existing high-voltage system are ongoing in the MISO region, including using ambient-adjusted line ratings and system reconfigurations. Ambient-adjusted rating changes are based on temperature alone. More complicated and more expensive, but potentially more valuable, Dynamic Line Ratings are based not only on forecasted ambient air temperature but also on other weather conditions such as wind, cloud cover, solar irradiance intensity, precipitation, and/or on transmission line conditions such as tension or sag.

On December 16, 2021, FERC issued a final rule on the use of ambient-adjusted ratings requiring all transmission providers, both inside and outside of organized markets, to use ambient-adjusted ratings as the basis for evaluating near-term transmission service to increase the accuracy of near-term line ratings. While the final rule does not mandate the adoption of dynamic line ratings, the rule does require that organized market operators establish and maintain systems and procedures necessary to allow transmission owners who would like to use dynamic line ratings the ability to do so.

In 2024, new Minnesota law required entities that own more than 750 miles of transmission lines in Minnesota to submit a report (as part of the 2025 biennial transmission plan) to the PUC that identifies areas of congestion and evaluates their impact on the electric grid. It also requires transmission owners to assess the potential benefits of various grid-enhancing technologies, including dynamic line ratings.

Grid North Partners Transmission Upgrades

In October 2023, Grid North Partners, a collaboration of utilities located in Minnesota, North Dakota, South Dakota, and Wisconsin, announced a plan to implement 19 transmission upgrade projects in the region. The goal of these projects is to reduce grid congestion while increasing access to renewable energy generation. When announced, Grid Partners estimated the projects to cost $130 million and aimed to complete the projects within three years. Unlike some of the larger proposed transmission projects discussed in this report, such as the JTIQ portfolio and the MISO Tranche 2.1 projects, which are more focused on longer-term solutions to grid congestion, these projects are much smaller in size with the longest project being 67 miles in length and are focused on short-term solutions.

Cost Responsibility for Mitigation

As utilities build more infrastructure, state regulators must ensure that utilities use cost discipline. To 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). This focus is important 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.

Conclusions

- New laws passed in 2024 directly relate to the transmission system and are aimed at making it simpler to site and permit transmission projects and increase the adoption of grid-enhancing technologies on existing transmission lines.
- The Minnesota Department of Commerce and Minnesota Public Utilities Commission continue to monitor progress on the development and deployment of grid-enhancing technologies.
- MISO and SPP work with their member utilities and member states to plan and operate the electric transmission system in Minnesota and surrounding states to achieve reliability, regional coordination and efficiency.
- Minnesota has been a leader in approving transmission projects with regional benefits. In 2024, Minnesota was the first state to approve a project that was part of the MISO Tranche 1 Portfolio, the Big Stone South—Alexandria—Big Oaks project's Eastern Segment (TL-23-159). Additionally, three smaller local transmission projects were also approved in 2024.
- For the short term, some utilities will be able to interconnect new wind and solar projects using interconnection capacity at their existing or retiring coal or natural- gas plants. Other shorter-term projects and reconfigurations to reduce transmission constraints are being put into operation while the larger projects are undergoing permitting and construction.
- Commerce, along with MISO and SPP, was selected in 2023 for a $464 million U.S. Department of Energy Infrastructure Act grant that will pay for about one-quarter (1/4) of the costs of JTIQ projects. In 2024, Commerce staff worked with its grant partners to complete the necessary steps to enter into a cooperative agreement with DOE for the grant. In late 2024, FERC approved the cost allocation for the portfolio, and MISO and SPP's boards approved the portfolio. The grant is expected to cover a period of up to 8 years.
- Going forward, 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.
- Expanding the scope of analysis of GETs to include the study of multiple GETs paired with substation upgrades to fully maximize the transmission capacity of existing grid infrastructure may be helpful.
- Future legislative or PUC action could require a study of reconductoring with necessary sectionalization and stability support to compare the speed and cost-effectiveness to the existing transmission expansion plan.