Order No. 202-25-7

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. §7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

Order No. 202-25-3

J.H. Campbell Generating Plant (Campbell Plant) is a 1,420 MW coal-fired plant primarily owned by Consumers Energy Company (Consumers) and located in West Olive, MI. In 2021, Consumers announced that it planned to implement a "speed closure" of the Campbell Plant fifteen years before the end of its scheduled design life..[1] Instead of retiring the Campbell Plant at the end of its design life, Consumers planned to accelerate the Campbell Plant's retirement and discontinue its operations on May 31, 2025.

Order No. 202-25-3, issued pursuant to FPA section 202(c), required that the Campbell Plant remain in operation for 90 days, until August 21, 2025. That order was based on my determination that emergency conditions existed in the region served by the Midcontinent Independent System Operator, Inc. (MISO). Specifically, I determined that MISO likely faced tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output. I determined that the continued operation of the Campbell Plant would provide additional generation capacity during these periods which would help prevent the potential loss of power to homes and local businesses in the areas that might have been affected by curtailments or outages that would otherwise pose a risk to public health and safety. I determined that the continued operation of the Campbell Plant was necessary to alleviate immediate and anticipated threats to reliability. My determination was based on a number of facts.

First, the North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025. In its assessment, NERC indicated that "[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output.".[2] In particular, NERC explained that the retirement of thermal generation capacity increased the likelihood of electricity supply

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[1] *See Consumers Energy Announces Plan to End Coal Use by 2025; Lead Michigan's Clean Energy Transformation*, Consumers Energy (June 23, 2021), https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation. As a coal-fired facility, it would be difficult for the Campbell Plant to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline.

[2] *2025 Summer Reliability Assessment*, North American Electric Reliability Corporation, at 16 (May 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf (NERC 2025 Summer Reliability Assessment).

shortfalls. NERC anticipated that the near-term period of greatest capacity shortfall for MISO would likely occur in August.[3]

Second, multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), "[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned."[4] Additionally, EIA stated, "[t]ypically, Michigan's nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned."[5] The state's Big Rock Point nuclear power plant shut down in 1997, and the Palisades nuclear power plant closed in 2022. While the Palisades nuclear power plant may reopen in 2025, it was not projected to be available during the peak demand period this summer.[6]

Third, the Campbell Plant's retirement would have further decreased available dispatchable generation within MISO's service territory, adding to the loss of the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. Although MISO and Consumers have incorporated the planned retirement of the Campbell Plant into their supply forecasts and Consumers acquired a 1,200 MW natural gas power plant in Covert, MI, the NERC Assessment still anticipates "elevated risk of operating reserve shortfalls."[7]

Fourth, MISO's Planning Resource Auction Results for the 2025-2026 Planning Year, released in April 2025, noted that for the northern and central zones, which includes Michigan, "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources."[8] While the results "demonstrated sufficient capacity," the summer months reflected the "highest risk and a tighter supply-demand balance" and these results "reinforce the need to increase capacity."[9]

Continuing Emergency Conditions

The emergency conditions that led to the issuance of Order No. 202-25-3 continue, both in the near and long term. The summer season has not yet ended, and the production of electricity from the Campbell Plant will continue to be a critical asset to maintain reliability in MISO this summer. That need is evidenced by the fact that the Campbell Plant was called on by MISO to generate large amounts of electricity during the heat wave that hit MISO this past June. According

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[3] *Id.*

[4] *Michigan State Profile and Energy Estimates*, U.S. Energy Info. Admin. (Oct. 17, 2024), https://www.eia.gov/state/print.php?sid=MI.

[5] *Id.*

[6] The start-up of Palisades is scheduled for the fourth quarter of 2025.

[7] NERC 2025 Summer Reliability Assessment at 16.

[8] *Planning Resource Auction—Results for Planning Year 2025–2026,* Midcontinent Independent System Operator, Inc., 13 (May 29, 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf. (MISO Planning Resource Auction – Results for Planning Year 2025-26).

[9] *Id*. at 2,12.

to the U.S. Environmental Protection Agency's data, over the month of June, the Campbell Plant generated approximately 664,000 MWh, running at 61% capacity.[10] In fact, between June 11 and August 18, MISO issued dozens of alerts to manage grid reliability in its Central Region in response to hot weather, severe weather, high customer load, forced generation outages, and transfer capability limits. MISO issued alerts for the Central Region on at least 40 of the 69 days between June 11 and August 18. In June, MISO issued alerts affecting the Central Region on 18 days, including an Energy Emergency Alert (EEA) level 1 ("Max Gen Step 1b") on June 23 to enable MISO to take emergency action to ensure grid stability, including bringing additional resources online.[11] The Central Region had alerts on 21 days in July, including one Max Generation Warning on July 29 and two Max Generation Alerts on July 28 and 29.[12] Two Capacity Advisory Initiate alerts have been issued in August to date.[13] Moreover, the May 2025 NERC Summer Reliability Assessment referenced a Seasonal Outlook issued by the National Oceanic and Atmospheric Administration (NOAA), which estimates that much of the Midwest has a 33%-40% chance to experience above-normal temperatures this summer.[14] The Seasonal Outlook released by NOAA on July 17, 2025, increased this estimate for much of the region to a 40%-50% chance.[15]

MISO's resource adequacy problems are not limited to the summer. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[16] MISO justified this revision by explaining that "Reliability risks associated with resource adequacy have shifted from 'Summer only' to a year-round

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[10] *See, Custom Data Download, EPA CAMPD (Clean Air Markets Program Data),* *https://campd.epa.gov/data/custom-data-download (search criteria to produce these results could include Emissions >> Monthly >> Unit (default) >>Apply >>"2025" and "June." The data can then be filtered to only include the Campbell Plant.)*

[11] An Energy Emergency Alert is an alert declared by the Transmission Provider in accordance with the NERC Operating Manual associated with the Transmission Provider's inability to provide for the Energy and Operating Reserve requirements of the MISO Balancing Authority Area. For more information, see MISO, FERC Electric Tariff, Module A, § 1.E (Definitions) (92.0.0). For more information on Energy Emergency Alert levels, see North American Electric Reliability Corporation. (n.d.). *EOP-011-1 Emergency Operations*. https://www.nerc.com/pa/stand/reliability%20standards/eop-011-1.pdf.

[12] A Max Gen Alert occurs when MISO is forecasting a potential capacity shortage. A Max Gen Warning is a warning to prepare for a possible Max Gen Event. *See* MISO Operating Procedures, https://efis.psc.mo.gov/Document/Display/9379 (20180920).

[13] A Capacity Advisory alert is an advisory issued based on the potential for limited operating capacity margins (<5%) in the following 2-3 days. *See* MISO Operating Procedures, https://efis.psc.mo.gov/Document/Display/9379 (20180920).

[14] NERC 2025 Summer Assessment at 9.

[15] *Seasonal Outlook*, NOAA Climate Prediction Ctr., (July 17, 2025), https://www.cpc.ncep.noaa.gov/products/predictions/long_range/seasonal.php?lead=1.

[16] M*idcontinent Independent System Operator, Inc.,* FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. Midcontinent Independent System Operator, Inc., 180 FERC ¶ 61,141 (2022).

concern."[17] MISO noted that over 60 percent of all "MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[18]

In December of 2023, MISO released an "Attributes Roadmap," in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape."[19] Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023/24 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projects that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.[20]

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, "*MISO's Response to the Reliability Imperative.*"[21] In a section of that report entitled "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season.

> Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's highest historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[22]

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season.

The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO. When MISO reported the results of its PRA for the 2025-26 Planning Year, it noted that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Michigan.[23]

On June 6, 2025, subsequent to the issuance of Order No. 202-25-3, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy

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[17] MISO Transmittal Letter at 3, FERC Docket No. ER22-495-000 (Nov. 30, 2021).

[18] *Id.* at 3-4.

[19] *Attributes Roadmap*, MISO (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.

[20] *Id.* at 11.

[21] *MISO's Response to the Reliability Imperative*, MISO (Updated Feb. 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.

[22] *Id.* at 12.

[23] MISO Planning Resource Auction – Results for Planning Year 2025-26 at 13.

planning reserve margin requirements.[24] The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.[25] The survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[26] Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[27]

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large amounts of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[28] Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.[29]

MISO has been taking steps to address these projected deficits. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[30] The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away, and are provided an additional three year grace period to commence commercial operations.[31] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.[32] Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

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[24] *2025 OMS-MISO Survey Results*, OMS and MISO (Updated June 6, 2025) https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf.

[25] *Id.* at 2.

[26] *Id.* at 7.

[27] *Id.* at 9.

[28] *Id.* at 7, 9.

[29] *Id.*

[30] M*idcontinent Independent System Operator, Inc.,* 192 FERC ¶ 61,064 (2025).

[31] 192 FERC ¶ 61,064 at P 84.

[32] *See generally*, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply*, S&P Global (May 2025), US gas-fired turbine wait times as much as seven years; costs up sharply | S&P Global. "With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."

Order 202-25-3 was preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. Specifically, in Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[33] President Trump likewise recognized, in Executive Order 14156, "Declaring a National Energy Emergency," that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[34] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[35]

The Department's July 2025 Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, issued pursuant to the President's directive in Executive Order 14262, details the myriad challenges affecting the Nation's energy outlook. "Absent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[36] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. This growth is illustrated by the fact that there are more than twenty AI companies operating in Michigan alone.[37] In addition, as just one example, Consumers has announced an additional 1 GW of new power to a planned hyperscale data center and "continue[s] to see positive momentum with data centers within the 9 GW pipeline . . . ."[38]

Grid operators—including MISO itself—have likewise acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the House Committee on Energy and Commerce, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, testified that "the MISO region faces resource adequacy and reliability challenges due to the

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[33] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/.

[34] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.

[35] *Id*.

[36] *See also Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, U.S. Department of Energy (July 2025), at 1, https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[37] Ekku Jokinen, *Top 21 Artificial Intelligence Companies in Michigan*, (last accessed Aug. 13, 2025), https://www.inven.ai/company-lists/top-21-artificial-intelligence-companies-in-michigan.

[38] *See Michigan utility Consumers Energy to provide 1GW of power to new hyperscale data center*, Data Center Dynamics (August 05, 2025), https://www.datacenterdynamics.com/en/news/michigan-utility-consumers-energy-to-provide-1gw-of-power-to-new-hyperscale-data-center/ (quoting Consumers Energy CEO Garrick Rochow).

changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[39] Ms. Curran also described "much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence."[40] She added, "[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them."[41]

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[42] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Campbell Plant when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and accelerated retirements of generation facilities supporting the issuance of Order No. 202-25-3 will continue in the near term and are also likely to continue in subsequent years. This could lead to the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Campbell Plant is necessary to best meet the emergency and serve the public interest under FPA section 202(c).

To ensure the Campbell Plant will be available if needed to address emergency conditions, the Campbell Plant shall remain in operation until November 19, 2025.[43]

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[39] Keeping the Lights On: Examining the State of Regional Grid Reliability Before the House Committee on Energy and Commerce, Subcommittee on Energy, 119th Cong. (Mar. 25, 2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Independent System Operator), at 5, https://democrats-energycommerce.house.gov/sites/evo-subsites/democrats-energycommerce.house.gov/files/evo-media-document/witness-testimony_curran_eng_grid-operators_03.25.2025.pdf.

[40] *Id.* at 6.

[41] *Id.* at 7.

[42] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b) (2018).

[43] 16 U.S.C. § 824a(c)(4).

Based on my determination of an emergency set forth above, I hereby order:

A. From August 21, 2025, MISO and Consumer Energy shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers Energy is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Campbell Plant has operated in compliance with the allowances contained in this Order.

C. All operation of the Campbell Plant must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. By September 4, 2025, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Campbell Plant consistent with this Order. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. Consumers is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for the Campbell Plant to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Campbell Plant shall not be considered a capacity resource.

H. This Order shall be effective from 00:00 Eastern Daylight Time (EDT) on August 21, 2025, and shall expire at 00:00 EDT on November 19, 2025, with the exception of applicable compliance obligations in paragraph D.

I. Issued in Norfolk, Virginia at 8:50pm Eastern Daylight Time on this 20th day of August 2025.

Chris Wright

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang

Michigan Public Service Commissioners
Chairman Dan Scripps
Commissioner Katherine Peretick
Commissioner Shaquila Myers

State	Facility Name	Facility ID	Unit ID	Associated Date	Hour	Operating T	Gross Load (MW)
MI	J H Campbell	1710	1	6/23/2025	0	1	235
MI	J H Campbell	1710	1	6/23/2025	1	1	234
MI	J H Campbell	1710	1	6/23/2025	2	1	234
MI	J H Campbell	1710	1	6/23/2025	3	1	233
MI	J H Campbell	1710	1	6/23/2025	4	1	236
MI	J H Campbell	1710	1	6/23/2025	5	1	236
MI	J H Campbell	1710	1	6/23/2025	6	1	236
MI	J H Campbell	1710	1	6/23/2025	7	1	242
MI	J H Campbell	1710	1	6/23/2025	8	1	257
MI	J H Campbell	1710	1	6/23/2025	9	1	257
MI	J H Campbell	1710	1	6/23/2025	10	1	258
MI	J H Campbell	1710	1	6/23/2025	11	1	258
MI	J H Campbell	1710	1	6/23/2025	12	1	257
MI	J H Campbell	1710	1	6/23/2025	13	1	258
MI	J H Campbell	1710	1	6/23/2025	14	0.85	252
MI	J H Campbell	1710	3	6/23/2025	0	1	760
MI	J H Campbell	1710	3	6/23/2025	1	1	759
MI	J H Campbell	1710	3	6/23/2025	2	1	760
MI	J H Campbell	1710	3	6/23/2025	3	1	758
MI	J H Campbell	1710	3	6/23/2025	4	1	712
MI	J H Campbell	1710	3	6/23/2025	5	1	662
MI	J H Campbell	1710	3	6/23/2025	6	1	754
MI	J H Campbell	1710	3	6/23/2025	7	1	760
MI	J H Campbell	1710	3	6/23/2025	8	1	759
MI	J H Campbell	1710	3	6/23/2025	9	1	760
MI	J H Campbell	1710	3	6/23/2025	10	1	760
MI	J H Campbell	1710	3	6/23/2025	11	1	759
MI	J H Campbell	1710	3	6/23/2025	12	1	760
MI	J H Campbell	1710	3	6/23/2025	13	1	761
MI	J H Campbell	1710	3	6/23/2025	14	1	760
MI	J H Campbell	1710	3	6/23/2025	15	1	761
MI	J H Campbell	1710	3	6/23/2025	16	1	760
MI	J H Campbell	1710	3	6/23/2025	17	1	760
MI	J H Campbell	1710	3	6/23/2025	18	1	761
MI	J H Campbell	1710	3	6/23/2025	19	1	761
MI	J H Campbell	1710	3	6/23/2025	20	1	760
MI	J H Campbell	1710	3	6/23/2025	21	1	760
MI	J H Campbell	1710	3	6/23/2025	22	1	761
MI	J H Campbell	1710	3	6/23/2025	23	1	760

Order No. 202-25-3

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

The Midcontinent Independent System Operator (MISO) faces potential tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output. The North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025. In its assessment, NERC indicated that "[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output."[1] In particular, the retirement of thermal generation capacity creates the potential for electricity supply shortfalls. NERC anticipates that the near-term period of highest capacity shortfall for MISO will occur in August.[2]

Multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), "[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned."[3] Additionally EIA stated, "[t]ypically Michigan's nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned."[4] The state's Big Rock Point nuclear power plant shut down in 1997 and the Palisades nuclear power plant closed in 2022. While the Palisades nuclear power plant may reopen in 2025, it will not be available during the peak demand period this summer.

The 1,560 MW J.H. Campbell coal-fired power plant in West Olive, MI, is scheduled to cease operations on May 31, 2025. Its retirement would further decrease available dispatchable generation within MISO's service territory, removing additional such generation along with the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. In 2021, Consumers announced that it planned to "speed closure" of Campbell in 2025, several years before the end of its scheduled design life.[5] Although MISO and Consumers have

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[1] 2025 summer reliability assessment. (May 14, 2025). https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf

[2] *Id.*

[3] U.S. Energy Information Administration, Michigan State Energy Profile, Oct. 17, 2024, *available at*: https://www.eia.gov/state/print.php?sid=mi.

[4] *Id.*

[5] https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation

incorporated the planned retirement into their supply forecasts and acquired a 1,200 MW natural gas power plant in Covert, MI, the NERC Assessment still anticipates "elevated risk of operating reserve shortfalls."

MISO's Planning Resource Auction Results for Planning Year 2025-26, released in April 2025, note that for the northern and central zones, which includes Michigan, "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources." While the results "demonstrated sufficient capacity," the summer months reflected the "highest risk and a tighter supply-demand balance" and the results "reinforce the need to increase capacity."[6]

ORDER

Given the determination that an emergency exists as discussed above, the responsibility of MISO to ensure reliability of its system, and the ability of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, additional dispatch of the Campbell Plant is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on the insufficiency of dispatchable capacity and anticipated demand during the summer months, and the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety.

This Order is limited in duration to align with the emergency circumstances. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts.

Based on my determination of an emergency set forth above, I hereby order:

A. From the time this Order is issued on May 23, 2025, MISO and Consumers Energy shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers. Following conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers Energy is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

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[6] https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250428694160.pdf

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units through the expiration of the Order. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Campbell Plant has operated in compliance with the allowances contained in this Order.

C. All operation of the Campbell Plant must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. By June 15, 2025, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability and economic dispatch of the Campbell Plant consistent with the public interest. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. The extent to which MISO's current Tariff provisions are inapposite to effectuate the dispatch and operation of the units for the reasons specified herein, the relevant governmental authorities are directed to take such action and make accommodations as may be necessary to do so.

F. Consumers is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers necessary to effectuate this order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

G. This Order shall not preclude the need for the Campbell Plant to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

H. This Order shall be effective upon its issuance, and shall expire at 00:00 EDT on August 21, 2025, with the exception of the reporting requirements in paragraph D and applicable compliance obligations in paragraph E.

I. Issued in Washington, D.C. at 3:15:pm Eastern Daylight Time on this 23rd day of May 2025.

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Mark Christie
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang

Michigan Public Service Commissioners
Chairman Dan Cripps
Commissioner Katherine Peretick
Commissioner Alessandra Carreon

UNITED STATES OF AMERICA
Department of Energy
Washington, DC 20585

Midcontinent Independent System Operator, Inc. and Consumers Energy Company Regarding the J.H. Campbell Generation Facility	Order No. 202-25-3A

NOTICE OF DENIAL OF REHEARING BY OPERATION OF LAW AND PROVIDING FOR FURTHER CONSIDERATION

(July 28, 2025)

Rehearing has been timely requested of the Department of Energy's order issued on May 23, 2025, in the above-captioned matter.[1] Thirty (30) days having passed from the date on which rehearing requests were filed, the requests for rehearing are deemed denied by operation of law.[2]

As provided in 16 U.S.C. § 825*l*(a) and 16 U.S.C. § 824a(c), the requests for rehearing of the above-cited order may be addressed in a future order.[3]

Chris Wright

Chris Wright
Secretary of Energy

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[1] *Midcontinent Indep. Sys. Operator, Inc., and Consumers Energy Company*, Order No. 202-25-3 (2025) (regarding the J.H. Campbell generation facility).

[2] 16 U.S.C. § 825*l*(a).

[3] 16 U.S.C. § 825*l*(a) (DOE may modify or set aside its above-cited order, in whole or in part, in such manner as it shall deem proper); 16 U.S.C. § 824a(c) (DOE may issue a supplemental order).

UNITED STATES DEPARTMENT OF ENERGY

Midcontinent Independent System Operator	Order No. 202-25-3

MOTION TO INTERVENE AND PETITION FOR REHEARING OF THE STATES OF MINNESOTA AND ILLINOIS

Pursuant to section 202 (c) of the Federal Power Act, 16 U.S.C. §§ 824a(c), 825l, the States of Minnesota and Illinois ("the States") move to intervene and petition for rehearing of the Department of Energy's ("DOE") May 23, 2025, Order No. 202-25-3 ("Order," Exhibit 1) directing the Midcontinent Independent System Operator ("MISO") to ensure that the coal-burning J.H. Campbell Plant ("Campbell Plant") in West Olive, Michigan, operated by Consumers Energy, remains available to operate through August 20, 2025, expiring at 00:00h on August 21, 2025.

Pursuant to the Federal Power Act ("the Act") and Department procedures applying it to petitions for rehearing, the States hereby file this timely request for rehearing of DOE's Order. The Order proceeds from a faulty conclusion that an emergency exists for the MISO Regional Transmission Organization ("RTO")—specifically for the summer months of 2025. This Order exceeds DOE's legal authority in several respects. And even if an emergency did exist and DOE had the legal authority to issue an Order, this Order is not rationally related to meet the purported need. It should be rescinded.

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MOTION TO INTERVENE

The States[1] move to intervene in this proceeding and thereby to become a party for purposes of Section 313l of the Act, 16 U.S.C. § 825l. The States have an interest in and are aggrieved by the Order in several ways and seek to intervene and petition for rehearing. *FDR v. R.J. Reynolds Vapor Co.*, 606 U. S. ___ (2025) (slip op., at 3–8) (defining an "adversely affected or aggrieved" party within the APA and without as "anyone even 'arguably within the zone of interests to be protected or regulated by the statute . . . in question.'" (quoting *Association of Data Processing Service Organizations, Inc. v. Camp*, 397 U. S. 150, 153 (1970))).

Factual Background

The utilities in the States are members of MISO, the electric grid operator for the central United States. MISO covers the largest geographical range of any independent system operator ("ISO") in the U.S. The 15 states covered by MISO are: Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin. As the ISO of the electric grid in this region, MISO manages the flow of electricity across the high-voltage, long-distance power lines. To do so, MISO develops rules so that the wholesale electricity transmission system operates reliably and safely. MISO has described this as being like the "air traffic controller" for the grid in its territory[2], meaning that MISO seeks to resolve power congestion (traffic) issues in real-time through its control room and has processes in place to anticipate and avoid emergencies that could lead to the loss of power.

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[1] *See* Minn. Stat. § 8.01 ("The attorney general shall appear for the state in all causes in the supreme and federal courts wherein the state is directly interested; also in all civil causes of like nature in all other courts of the state whenever, in the attorney general's opinion, the interests of the state require it.).

[2] "Meet MISO," https://www.misoenergy.org/meet-miso/about-miso/industry-foundations/what-we-do/ (last visited June 23, 2025).

On May 23, 2025, the DOE issued an emergency order pursuant to section 202(c) of the Federal Power Act to MISO. *See* Ex. 1; *see also* 16 U.S.C. § 824(c)(1). The Order directs MISO, in coordination with Consumers Energy, the owner of the plant, to ensure that the Campbell Plant in West Olive, Michigan remains available for operation. *Id.* Consumers Energy announced its plan to retire the coal facility in 2021, and MISO approved that plan three years ago, in March 2022.[3]

Adverse Effects

The States will be adversely affected by the emergency order preventing the planned retirement of the Campbell Plant in two primary ways.

First, households and businesses in the States, and the States as consumers in their own right, all will pay higher electricity bills as a result of the Order's imposition of costs and cost-recovery to the States. By ordering the Campbell Plant to take all steps necessary to be available and ordering MISO to take all steps necessary for the Campbell Plant to provide economic dispatch, costs are already being incurred and more costs will continue to be generated. Notably, the age of the units is concerning for costs, and Consumers Energy projected in 2021 that retiring Campbell in 2025 would avoid $365,008,000 in capital expenditures and major maintenance costs.[4] The Order would likely require at least a portion of capital expenditures and major maintenance costs that were not completed in the last four years, which will potentially drive up

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[3] *See* Consumers Energy, "2021 Clean Energy Plan," https://www.consumersenergy.com/-/media/CE/Documents/company/IRP-2021.pdf (last accessed June 23, 2025).

[4] *In the matter of the application of Consumers Energy Company for approval of its integrated resource plan pursuant to MCL 460.6t and for other relief*, MPSC Case No. U-21090, Revised Direct Testimony of Norman J. Kapala on Behalf of Consumers Energy Company at 3 (Oct. 2021).

costs and impact ratepayer bills. This would be in addition to the cost of rehiring operators and obtaining more coal, among other expenses.

Although the precise amount is not yet known, the Order provides that cost recovery is available to Consumers Energy through Federal Energy Regulatory Commission ("FERC") proceedings, which Consumers Energy has already initiated. Consumers Energy filed a petition FERC[5] asking for a process to allocate costs (net of market revenues) across all of MISO Zones 1 through 7 (which includes Minnesota and Illinois). They ask that costs be apportioned according to load, which would assign costs to the States. MISO has already filed its answer indicating its general support for adjusting its tariff to account for Consumers Energy's cost recovery petition, meaning the costs would be charged to the States according to their respective share of load.

Second, the States will suffer environmental harms as a result of the Order. The Campbell Plant is a significant source of particulate matter, nitrogen oxides, sulfur oxides, and carbon dioxide,[6] among other pollutants. By prolonging the operations of the Campbell Plant beyond its planned retirement date, the Order will increase the amount of pollution emitted in the state of Michigan and other MISO States, causing harm to the public health and welfare.[7] Coal-fired power plants also contribute to regional, national, and global greenhouse gas emissions, which cause global climate change. Climate change directly harms the States, imposes significant additional costs on them for responsive actions and resiliency programs, and threatens state climate goals and comply with federal and state air pollution requirements.

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[5] FERC Docket: EL25-90.

[6] *See In the Matter of the Application of Consumers Energy Co. for Approval of Its Integrated Res. Plan Pursuant to Mcl 460.6t & for Other Relief.*, No. U-21090, 2022 WL 2915368, at *73 (June 23, 2022).

[7] *See* Cross-State Air Pollution Rule (CSAPR) and Clean Air Act § 110.

Minnesota, for example, is experiencing rapid changes including higher winter temperatures and larger, more frequent extreme precipitation events, extreme heat, and drought.[8] Each of Minnesota's top-ten combined warmest and wettest years on record have occurred since 1998, with 2024 standing as the warmest year on record and 2019 the wettest.[9] Minnesota is already suffering from a significant uptick in devastating, large-area extreme rain events, threatening the state with ever greater frequency and intensity.[10] These events damage streets, wastewater facilities, businesses, homes, farms, and natural resources, costing local governments, business owners, and residents millions of dollars in cleanup, repairs, and adaptation expenses.[11] Wildfires are also becoming larger and more frequent, including a rash of devastating fires in the spring of 2025 that consumed more than 32,000 acres and destroyed an estimated 150 structures. The spring of 2024 included heavy precipitation and extreme rainfall events, leading to extensive flooding and federal declarations for large parts of the state.[12] From 1980 to 2024, the annual average for billion-dollar weather and climate disasters in Minnesota is 1.4 events per year, but the annual average from 2020 to 2024 is 4.6 events.[13] The "Lost Winter" of 2023-2024 was the

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[8] Minnesota Climate Trends, *Minnesota Department of Natural Resources* (2023), https://www.dnr.state.mn.us/climate/climate_change_info/climate-trends.html.

[9] *Id.*

[10] *Id.*

[11] *Id.*

[12] "Extreme Rainfall Drenches Northeastern Minnesota," Minnesota Department of Natural Resources, https://www.dnr.state.mn.us/climate/journal/extreme-rainfall-northeast-mn-june-18-2024; "Extreme Rain and Flooding in Southern Minnesota, June 20-22," Minnesota Department of Natural Resources, (August 9, 2024), https://www.dnr.state.mn.us/climate/journal/extreme-rain-flooding-southern-minnesota-june-20-22.html; "Disaster information," Minnesota Department of Public Safety, https://dps.mn.gov/divisions/hsem/em-resources/disaster-information (last visited June 23, 2025).

[13] "Billion Dollar Weather and Climate Disasters, Minnesota Summary, *NOAA National Centers for Environmental Information*, Billion-Dollar Weather and Climate Disasters | Minnesota Summary | National Centers for Environmental Information (NCEI)," https://www.ncei.noaa.gov/access/billions/state-summary/MN.

warmest on record, with temperatures averaging 10.9°F above 1991-2020 averages, greatly harming Minnesota's recreational economy.[14] These impacts will continue, and emissions from the Campbell Plant will contribute to them.

Climate change is affecting Illinois in a number of ways. Illinois' farming industry is vulnerable to cycles of extreme drought and extreme precipitation caused by climate change. In 2023, a severe drought dried up soil throughout the state, with extreme dryness extending down to 20 inches below the surface in some areas.[15] In other years, extreme precipitation has threatened Illinois' agriculture. For instance, January to June of 2013 was the wettest period ever recorded in Illinois, causing widespread flooding in farmland that forced farmers to delay planting and lose revenue.[16] Climate change is also intensifying catastrophic extreme weather events. In 2024, the Illinois State Climatologist recorded strong wind, hail, and tornadoes across all of Illinois' 102 counties and the state logged 142 tornadoes—a new annual record.[17] These storms included a July 15, 2024 "derecho" that produced 100 mile-per-hour winds and 48 separate tornados.[18] In the

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[14] *Id.*

[15] Illinois State Climatologist, Drought Worsens in a Very Dry June (June 30, 2023), https://stateclimatologist.web.illinois.edu/2023/06/30/drought-worsens-in-a-very-dry-june/ (last visited May 23, 2025).

[16] University of Illinois–Institute of Government & Public Affairs, Preparing for Climate Change in Illinois: An Overview of Anticipated Impacts (2015), https://indigo.uic.edu/articles/report/Preparing_for_Climate_Change_in_Illinois_An_Overview_of_Anticipated_Impacts/15078939/1 (last visited May 23, 2025). See also U.S. Dept. of Agriculture Climate Hubs and Great Lakes Research Integrated Science Assessment, Climate Change Impacts on Illinois Agriculture (2022), https://www.climatehubs.usda.gov/sites/default/files/2022_ClimateChangeImpactsOnIllinoisAgriculture.pdf (last visited May 23, 2025).

[17] Tony Briscoe, Lake Michigan Water Levels Rising at Near Record Rate, CHICAGO TRIBUNE (July 12, 2015), https://www.chicagotribune.com/2015/07/12/lake-michigan-water-levels-rising-at-near-record-rate/ (last visited May 23, 2025).

[18] National Weather Service, July 15, 2024 Derecho Produces Widespread Wind Damage and Numerous Tornadoes, available at https://www.weather.gov/lot/2024_07_15_Derecho#:~:text=With%2032%20tornadoes%2C%20t

Chicago area alone, the derecho produced 32 tornados, breaking the previous records set by the July 2014 "double derecho" and March 2023 storm.

PETITION FOR REHEARING

I. Overview and Concise Statement of Error

The challenged Order declares an emergency based on a shortage of electric energy generation when there is no emergency. Even if there were an emergency, the Order imposes several requirements that are inconsistent with and exceed DOE's legal authority. And even if DOE had the authority to impose the requirements, they are not directed to actions that will actually meet the purported emergency.

The Order

The challenged Order is premised on an incomplete recitation of MISO's planned capacity and reserves for the summer of 2025. It notes that MISO "faces potential tight reserve margins during the summer 2025 period." Ex. 1 at 1 (emphasis added). It relies on the North American Electric Reliability Corporation's ("NERC") 2025 Summer Reliability Assessment. Ex. 2. That report does not identify any war, fuel shortage, or natural disaster. *Id*. Rather, it evaluates generation resource and transmission system adequacy as well as energy sufficiency to meet projected summer peak demands and operating reserves. Ex. 2 at 5. Here are NERC's main conclusions regarding MISO:

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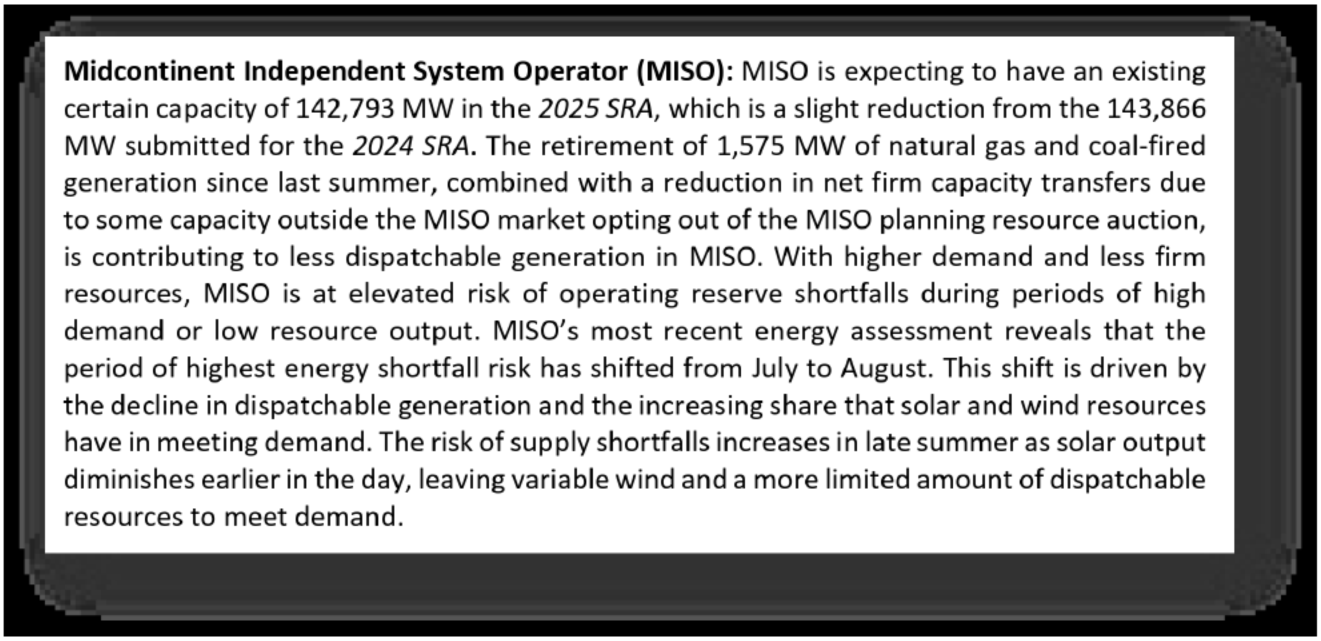
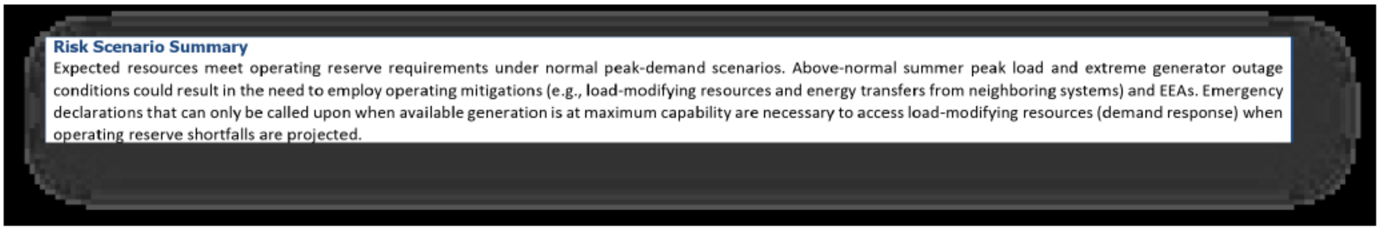
he%20July,March%2031%2C%202023%20tornado%20outbreaks. (last visited May 25, 2025). See also David Struett, Tornado Record Broken with 27 Chicago Area Twisters July 15—Spawned by 'Ring of Fire', WBEZ CHICAGO, available at https://www.wbez.org/weather/2024/07/24/chicago-weather-tornado-record-derecho-july-15 (last accessed May 23, 2025)



Midcontinent Independent System Operator (MISO): MISO is expecting to have an existing certain capacity of 142,793 MW in the *2025 SRA*, which is a slight reduction from the 143,866 MW submitted for the *2024 SRA*. The retirement of 1,575 MW of natural gas and coal-fired generation since last summer, combined with a reduction in net firm capacity transfers due to some capacity outside the MISO market opting out of the MISO planning resource auction, is contributing to less dispatchable generation in MISO. With higher demand and less firm resources, MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output. MISO's most recent energy assessment reveals that the period of highest energy shortfall risk has shifted from July to August. This shift is driven by the decline in dispatchable generation and the increasing share that solar and wind resources have in meeting demand. The risk of supply shortfalls increases in late summer as solar output diminishes earlier in the day, leaving variable wind and a more limited amount of dispatchable resources to meet demand.

Id. at 5. NERC concluded that all areas were projected to have "adequate anticipated resources for normal summer peak load conditions." *Id*. Indeed, the "elevated risk" designation means the probabilistic indices are low but not negligible. *Id*. at 10, Table 1. And further, the MISO-specific "dashboard" concludes that MISO's expected resources meet operating reserve requirements under normal peak-demand scenarios. At worst, operating mitigations "could" be necessary for above-normal summer peak load and extreme generator outage conditions:



Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and extreme generator outage conditions could result in the need to employ operating mitigations (e.g., load-modifying resources and energy transfers from neighboring systems) and EEAs. Emergency declarations that can only be called upon when available generation is at maximum capability are necessary to access load-modifying resources (demand response) when operating reserve shortfalls are projected.

Id. at 16.

The Order then describes how the Campbell Plant was scheduled to cease operations on May 31, 2025, and claims that the Campbell Plant's retirement would further decrease available dispatchable generation within MISO's service territory. Ex. 1 at 1. But NERC's analysis already factored in an assumption that the Campbell Plant would be retired and unavailable for the summer of 2025.

The Campbell Plant's retirement was well known to MISO operators and accounted for in their robust resource planning processes described in further detail below. Indeed, the Order acknowledges that the retirement was already factored into MISO's own supply forecasts. *Id*. at 2. MISO's Planning Resource Auction Results for Planning Year 2025-26 ("PRA," Exhibit 3), cited in the Order, confirm adequate margin for a reliable summer season. *Id*.

Nonetheless, the Order determined than an emergency exists, and that "additional dispatch of the Campbell Plant is necessary," Ex. 1 at 2, even though the Campbell Plant was not included in any of the MISO forecasts finding sufficient capacity. It further based its determination "on the insufficiency of dispatchable capacity and anticipated demand" even though MISO had already determined that there was sufficient capacity to meet anticipated demand (Exs. 3-4) and NERC's Summer Reliability Assessment also does not conclude otherwise. Ex. 2 at *passim*. Nonetheless, the Order concludes with several imperatives:

- That Consumers Energy must take steps to ensure that the Campbell Plant is "available to operate." And that MISO "is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers" Ex. 1 ¶ A.
- That MISO is directed to provide DOE a report "concerning the measures it has taken and is planning to take to ensure the operational availability and economic dispatch of the Campbell Plant consistent with the public interest." Ex. 1 ¶ D.
- That "relevant government authorities" are directed to take such action and make accommodations as may be necessary to effectuate the dispatch and operation of the Campbell Plant if the MISO current tariff provisions "are inapposite." Ex. 1 ¶ E.

- That rate recovery is available pursuant to 16 U.S.C. § 824a(c) (also referred to as section 202(c) of the Federal Power Act). Ex. 1 ¶ G.
- That the Order runs through August 20, 2025. Ex. 1 ¶ H.

DOE's Order issued in error. The Department did not have substantial evidence or engage in reasoned decision-making in declaring the existence of an emergency. It starts from the proposition that there is only a "potential" for insufficient capacity that "could" result in a need for mitigation, which does not present an actual existing or imminent emergency. Plus, section 202(c)'s plain terms limit DOE to actual emergencies—not the potential that emergencies might arise. Section 202(c) is also limited in the type of conduct it allows DOE to order, such as directing the generation, delivery, or transmission of electric energy. This Order, however, requires the Campbell Plant to be available to operate. Ex. 1 ¶ A. Nothing in section 202(c) grants DOE authority to order a plant to remain on standby in case an emergency occurs—especially absent any demonstrated need identified by the utility or grid operator. And even if an emergency did exist and DOE had the legal authority to issue an Order, directing a the Campbell Plant to participate in the bidding market using economic dispatch would not rationally the purported need (because there is no evidence the Campbell Plant can reasonably address any given future emergency need, because emergency responses do not require economic evaluation, and because the Campbell Plant takes so long to ramp up). It should be rescinded.

II. Legal Background

Under section 202(c) of the Federal Power Act, the Commission[19] has authority to issue an order:

> [d]uring the continuance of any war in which the United States is engaged, or whenever the Commission determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes. . . .

16 U.S.C. § 824(c)(1). The same subsection states that the Commission may order "temporary connections of facilities" and "generation, delivery, interchange, or transmission of electric energy" that, in the Commission's "judgment will best meet the emergency and serve the public interest." *Id*. The next subsection, 16 U.S.C. § 824(c)(2), establishes that an emergency order must be limited to only those hours necessary to meet the emergency. It states:

> With respect to an order issued under this subsection that may result in a conflict with a requirement of any Federal, State, or local environmental law or regulation, the Commission shall ensure that such order requires generation, delivery, interchange, or transmission of electric energy only during hours necessary to meet

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[19] The "Commission" refers to the Federal Power Commission (FPC), whose powers were transferred in 1977 to either the Secretary of DOE or the Federal Energy Regulatory Commission (FERC). 16 U.S.C. § 796(14); Department of Energy Organization Act, Pub. L. No. 95-91, 91 Stat. 565, 565-613 (1977). This transfer gave FERC the authority over "the interconnection, under section 202(b), of such Act [16 U.S.C. 824a(b)], of facilities for the generation, transmission, and sale of electric energy (*other than emergency interconnection*)." 42 U.S.C. § 7172(a)(1)(B) (emphasis added). However, this transfer also gave DOE "the function of the Federal Power Commission, or of the members, officers, or components thereof" except as provided in subchapter IV of the act. 42 U.S.C. § 7151(b). Because 42 U.S.C. § 7172(a)(1)(B) explicitly excludes emergency interconnection from FERC's authority, the authority over emergency interconnection has historically been delegated to DOE. However, the delegation of this emergency authority to DOE has not been consistently applied. In *Richmond Power & Light v. FERC*, 574 F.2d 610 (1978), a petitioner objected to FERC's (not DOE's) failure to invoke emergency powers under 16 U.S.C. § 824a(c) and order utilities with excess capacity to supply the petitioner with energy. The court did not address whether FERC had the authority to declare an emergency to begin with. *Id*. Thus, whether FERC or DOE has the power to declare an emergency is inconclusive.

> the emergency and serve the public interest, and, to the maximum extent practicable, is consistent with any applicable Federal, State, or local environmental law or regulation and minimizes any adverse environmental impacts.

Id. at § 824(c)(2).

The applicable regulations define "emergency," as

> an unexpected inadequate supply of electric energy which may result from the unexpected outage or breakdown of facilities for the generation, transmission or distribution of electric power. Such events may be the result of weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected "entity" to prevent. An emergency also can result from a sudden increase in customer demand, an inability to obtain adequate amounts of the necessary fuels to generate electricity, or a regulatory action which prohibits the use of certain electric power supply facilities. Actions under this authority are envisioned *as meeting a specific inadequate power supply situation*.

10 C.F.R. § 205.371[20] (emphasis added).

III. Statement of Issues

Issue A: Did DOE have substantial evidence for its declaration of an emergency, and did it exercise reasoned decision-making in declaring that an actual emergency exists?

No. DOE relied on a NERC assessment that identified an elevated risk for potential capacity exceedance if an extreme weather event were to occur**.** Further, DOE failed to consider substantial countervailing evidence, including the MISO States' Integrated Resource Plans and MISO's PRA for the summer of 2025. The Order fails to identify any reasoned basis for concluding an actual emergency exists or is imminent.

Issue B: Section 202(c)(1) allows DOE to issue temporary emergency orders in times of actual extant or impending emergencies such as war, sudden demand for electric energy, shortage of fuel or water, or other similar conditions creating a specific inadequate power supply

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[20] DOE issued 10 C.F.R. §§ 205.370-379 pursuant to the Department of Energy Organization Act's transfer of emergency responsibilities to the Secretary of Energy.

situation. Did DOE exceed this authority where its Order is based on the nonspecific possibility that such a situation might occur over a period of several months?

Yes. An actual "emergency" is a sudden occurrence requiring immediate response action or a concrete need for energy to be produced; conversely, it is not the mere potential that an emergency might occur. 16 U.S.C. § 824a(c); 10 C.F.R. § 205.371. Emergency orders must respond to "a specific inadequate power supply situation." 10 C.F.R. § 205.371. The Order does not address any sudden occurrence needing imminent response, nor does it identify any actual and specific insufficient supply situation. Thus the Order is contrary to law.

Issue C. Section 202(c)(1) allows DOE to issue emergency orders requiring the "generation, delivery, interchange, or transmission of electric energy." Did DOE exceed this authority where its Order requires the Campbell Plant to take steps to be "available" to generate electricity and requires MISO to employ economic dispatch?

Yes. DOE's emergency powers allow it to order the generation, delivery, interchange, or transmission of electric energy. Section 202(c)(1) does not give the DOE the authority to order that a plant be merely available (absent a showing of why that is needed), nor does it give the DOE authority to order MISO to engage in potential economic dispatch. 42 U.S.C. §16432(b). Because it is not confined to the types of actions allowed under section 202(c)(1), the Order is without authority and contrary to law.

Issue D. If DOE issues an order pursuant to 202(c)(1), then 202(c)(2) requires it to set limits on hours of operation and ensure that environmental impact is minimized. Did DOE exceed its authority by invoking section 202(c) to issue an Order that sets no specific hours of operation, places no limits on hours of operation, and adopts no specific requirements to minimize environmental impact?

Yes. The express statutory language requires an emergency order be limited to only those hours necessary to meet the emergency and minimize adverse environmental impacts. 16 U.S.C. § 824a(c)(2). The Order does not establish any limited hours for operation, and at the same time it allows the Campbell Plant to potentially run at any and all hours for the entire 90 days covered bye the Order. It also does not meaningfully take steps to minimize adverse environmental impacts.

Because the Order does not set any specific hours the Campbell Plant must run, allows for unlimited hours for much of the summer, and doesn't meaningfully minimize adverse environmental impacts, the Order violates the requirements of section 202(c)(2). It is without authority and contrary to law.

Issue E: The Federal Power Act reserves resource adequacy planning to the individual states. Did DOE exceed its authority where its Order directly compels a plant slated for retirement to take steps to be available to operate?

Yes. Section 201(a) of the Federal Power Act explicitly provides that federal regulation over generation and transmission is related to matters of interstate commerce and extends "only to those matters which are not subject to regulation by the States." 16 U. S. C. § 824(a). States retain jurisdiction "over facilities used for the generation of electric energy." 16 U.S.C. § 824(b)(1). Because DOE's Order exceeds its authority by contradicting Michigan's resource plans, it is contrary to law.

Issue F: The states retain primary authority for developing and establishing Integrated Resource Plans or Strategic Energy Plans that get factored into MISO's tariffs. The Order directs "relevant governmental authorities" to accommodate the Order. Does this portion of the Order violate the Tenth Amendment, exceed DOE's authority, and impose arbitrary-and-capricious requirements not based on substantial evidence?

Yes, on all fronts. This section of the Order is incomprehensible and unexplained. It violates the Tenth Amendment to the extent it directs state or local officials to carry out the Order. And Section 202(c) does not include authority to order any unit of government to take any particular action. For all of these reasons, the Order is contrary to law.

Issue G: Even if DOE were correct that an emergency exists and that it had the authority to issue the Order, will the Order's requirements rationally meet the emergency?

No. Section 202(c) contemplates emergency orders that are precisely tailored to meet the specific emergency.16 U.S.C. § 824a(c). Emergency generation is not economic dispatch. Plus, the Campbell Plant is high cost and uneconomical, it requires a long time to ramp up, and there is no reason to think it would be used to meet any shortfall if one were to happen given other considerations such as transmission infrastructure. The Order's specific requirement for MISO to take steps to effectuate "economic dispatch" of the Campbell Plant is not rationally related to the emergency it purports to address, so the Order is without substantial evidence and lacks reasoned decision-making.

IV. Description of MISO

MISO is a regional transmission organization (RTO), an independent, non-profit, membership-based organization responsible for optimizing generation and transmission of electricity and ensuring the reliability of the electric power system within its region, consisting of nearly 3,000 generating units.[21] 18 C.F.R. § 35.34(a), (j)(1). MISO administers bulk or wholesale power markets that centrally commit and dispatch power to facilitate least-cost and reliable power production and delivery throughout the region. The wholesale markets within MISO signal and value power needs and identify the most economically efficient way—the least-cost approach where demand for energy equals the cost supplied—to meet them across the system.[22] MISO also works to coordinate generation and transmission of electricity with other RTOs, exporting power at times and at others allowing electricity to be imported to MISO.[23] MISO uses advanced

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[21] MISO, *Fact Sheet* (July 2024), available at https://www.misoenergy.org/meetmiso/media-center/2024/corporate-fact-sheet.

[22] MISO, *Electric Grid 101*, available at https://www.misoenergy.org/meet-miso/grid-operations-basics.

[23] MISO, *Interregional Coordination*, available at https://www.misoenergy.org/planning/interregional-coodination/; see also MISO, Historical Net Scheduled Interchange (NSI), at https://www.misoenergy.org/markets-and-operations/real-time--marketdata/ market-reports/ (data found under "Summary" Market Reports).

modeling and thorough research to coordinate short and long-term planning for the benefit of generating units and consumers.[24]

MISO planned for adequate capacity during the summer of 2025: "As recognized by the Order, MISO's Planning Resource Auction for the 2025-2026 Planning Year demonstrated sufficient capacity for all zones within the MISO Region." Ex. 3 at 2. It reports: "it is important to recognize existing processes have *cleared sufficient electric generating capacity across MISO for the periods of time covered by the Order*." *Id.* (emphasis added). And it goes on to describe its confidence that it has already ensured "sufficient capacity to meet anticipated demand across the MISO Region for the 2025-2026 Planning Year." *Id.*

The long-planned retirement of the Campbell Plant is not an impediment to summer reliability in the MISO region. Since 2010, MISO has experienced the retirement of 30.8 gigawatts (GW) of generation capacity, a large proportion of which (21.9 GW) was coal-fired generating units.[25] That trend is shown below in the bar graph (from MISO's 2023 Transmission Expansion Plan Report[26]), which displays the retired capacity by generation type over time:

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[24] MISO, *Transmission and Generation Planning 101*, available at https://www.misoenergy.org/meet-miso/grid_planning_basics.

[25] *See also* MISO, *Approved Generator Retirements (Public) as of June 28, 2024* ("*Approved Retirements 2024*"), https://www.oasis.oati.com/woa/docs/MISO/MISOdocs/OASIS_Posting_of_Approved_Generator_Retirements_(Public)_2024-06-28.pdf).

[26] MISO, *2023 Transmission Expansion Plan*, available at https://cdn.misoenergy.org/MTEP23%20Executive%20Summary630586.pdf.

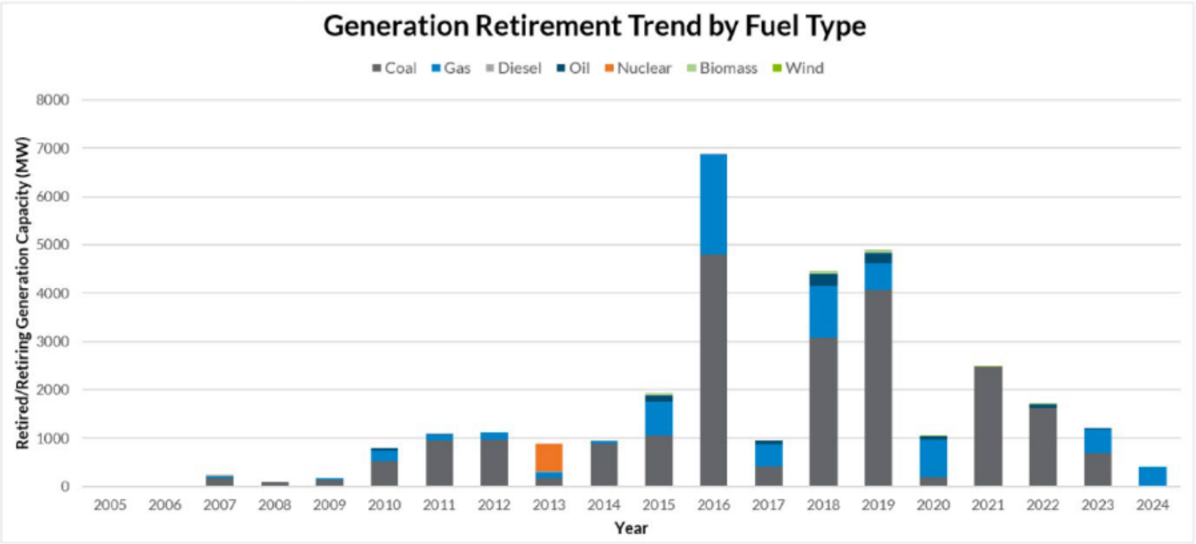

Figure 2.2-1: MW Generation Retirement by Fuel Type

Through use of generation capacity and transmission infrastructure planning, the addition of new capacity—in particular renewables, and the implementation of the other measures discussed above, MISO has been able to absorb these retirements and maintain overall system reliability. *Id*. at 34-35.

V. Argument

A. The Order lacks substantial evidence demonstrating the existence of an actual emergency and DOE failed to engage in reasoned decision-making.

The DOE failed to provide substantial evidence that an unexpected emergency presently exists, as required by 16 U.S.C. § 824a(c)(5). The relevant standard is whether the DOE's determination is supported by substantial evidence. 16 U.S.C. § 824a(c)(5) refers to the possibility of judicial review under 16 U.S.C. § 825l. After an objection has been brought before DOE, the Court may consider it with the understanding that "[t]he finding of the Commission as to the facts, if supported by substantial evidence, shall be conclusive." 16 U.S.C. § 825l. Substantial evidence means "such relevant evidence as a reasonable mind might accept as adequate to support a conclusion." *Duke*

Energy Corp. v. FERC, 892 F.3d 416, 420 (2018). This standard implies deference to an agency's factual determinations. *See, e.g., id*.

While DOE failed to provide substantial evidence of a current and unexpected emergency, the evidence DOE provided, does prove however, that there is currently no energy emergency and will not be an "unexpected emergency" that warrants this Order. MISO is well situated to deliver reliable power throughout its area in the summer of 2025.

In declaring the contrary, DOE relied on a NERC assessment that identified an elevated risk for <u>potential</u> capacity exceedance <u>if</u> an extreme weather event were to occur**.** But the Order makes too much out of too little—the "elevated" category is hardly a call for immediate and unnecessary emergency action. As the NERC assessment points out, MISO expects to have an existing certain capacity of 142,783 MW during the summer—a figure that factored in an assumption that the Campbell Plant would be retired and unavailable for the summer of 2025 and that exceeds both expected demand and the reserve margin[27] anyway. While retirements and fewer suppliers meant that MISO would have fewer firm resources and dispatchable generation, that was no cause for alarm. To the contrary, NERC concluded that all areas were projected to have "adequate anticipated resources for normal summer peak load conditions." *Id*. And nothing in the NERC assessment determined that MISO's interconnection with other RTOs would be insufficient to cover any needs that could arise.

The "elevated risk" category is not tantamount to an emergency. Even though NERC used the term "elevated risk" for the possibility that there could be an operating reserve shortfall, NERC did not apply the "high risk" category to MISO, and did not call for any retired plants to be brought

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[27] MISO PRA, Results for Planning Year 2025-26 at 18 (Corrected May 29, 2025).

back online. Ex. 2. at 5. Moreover, the "elevated risk" designation means the probabilistic indices are low but not negligible. *Id.* at 10, Table 1. And further, the MISO-specific "dashboard" concludes that MISO's expected resources meet operating reserve requirements under normal peak-demand scenarios. At worst, operating mitigations "could" be necessary for above-normal summer peak load and extreme generator outage conditions: *Id.* at 16. The "elevated risk" designation is also far from unusual; it has never required an emergency order before, and the grid has remained stable. MISO has been designated as at "elevated" risk in every NERC Summer Reliability Assessment since NERC initiated the practice of designating regions as "high," elevated," or "normal" risk in 2021.[28] NERC has also designated MISO as "elevated" risk in every Winter Reliability Assessment since 2021. *Id*. Yet no energy shortage has occurred and DOE has never imposed an emergency declaration until now.

Such a declaration is simply unnecessary when considering the bigger picture. DOE clearly erred in its consideration of the evidence, *see Wisconsin Power & Light Co. v. FERC*, 363 F.3d 453, 461 (D.C. Cir. 2004) (an appeals court "must consider . . . 'whether there has been a clear error of judgment.'"), including the contradiction in the Order's citation of MISO's PRA for the summer of 2025 which contrary to the Order actually found sufficient capacity throughout the region. The PRA provides a strong conclusion that supply will be adequate. Ex. 3. The press release announcing the PRA, (Exhibit 4), confirms "adequate resources are available to maintain reliability during the upcoming planning year (June 2025 – May 2026)." Ex. 4. And while "the 2025 auction prices reflect a tightening supply-demand balance during the summer months, there is sufficient capacity throughout the MISO footprint." *Id*. The PRA was based on NERC's standard

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[28] *See* NERC, *Reliability Assessments,* https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx (last visited June 23, 2025).

BAL-502-RF-03 (Exhibit 5), requiring assessment of "one day in ten year" loss of load expectation principles. In short, the NERC standard that MISO applied to conduct the PRA demonstrated that MISO will have sufficient capacity through the summer of 2025. Exs. 3-4. MISO's PRA results show that there will be enough capacity in the summer planning year, and MISO notes that the summer auction price provides a signal to the market to add more capacity for future auction years. DOE appears to have cherry-picked certain phrases from the PRA but does not give it full consideration.

Indeed, in MISO's Answer to the cost-recovery docket dated June 19, 2025, MISO highlights the PRA when it describes its certainty it has planned for adequate capacity: "As recognized by the Order, MISO's Planning Resource Auction for the 2025-2026 Planning Year demonstrated sufficient capacity for all zones within the MISO Region." Ex.10 at 2. It further writes, "it is important to recognize existing processes have cleared sufficient electric generating capacity across MISO for the periods of time covered by the Order." *Id*. (emphasis added). And it goes on to describe its confidence that it has already ensured "sufficient capacity to meet anticipated demand across the MISO Region for the 2025-2026 Planning Year." *Id*. This recent submission undermines DOE's conclusions in the order that MISO faces insufficient capacity.

DOE failed to consider recent comments by MISO's Independent Market Monitor to the Markets Committee of the MISO Board of Directors dispelling NERC's purported concerns. See Exhibit 11. The Independent Market Monitor is charged with ensuring adequate supply markets for the MISO region. He criticized a separate NERC long-term reliability assessment (which has since been revised[29]) that included capacity shortfalls in 2025, noting that NERC's assessment compared the wrong numbers. In doing so, the Independent Market Monitor declared MISO capacity to be "more than adequate," and that he had "no material concerns" over MISO's resource adequacy for the upcoming summer.

DOE also failed to consider MISO's history of strong performance through several extreme weather events including Winter Storms Elliot and Uri, and did not credit MISO's proven track record of engaging in a variety of mechanisms to ensure grid reliability.

DOE further failed to acknowledge that no part of MISO is currently afflicted by any unexpected outage or extreme weather event, and the entire system is running as planned with no outages, unexpected demand, lack of fuel or water, or other such emergencies in place at the time of the order.

Given all of these countervailing considerations, DOE did not have substantial evidence supporting its emergency determination. It did not exercise reasoned decision-making in declaring that an emergency exists. Its Order is arbitrary and capricious.

B. The Order exceeds DOE's authority because it is not limited to a specific inadequate power supply situation as required by Section 202(c) and 10 C.F.R. § 205.371.

An actual "emergency" is a sudden occurrence requiring immediate responsive action; conversely, it is not the mere potential that an emergency might occur. The statute describes the temporary response needed to address a sudden event by its black-letter terms. 16 U.S.C. § 824a(c). And Department regulations define "emergency" to mean an unexpected inadequate supply of

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[29] NERC, *Statement of NERC's Long-term Reliability Assessment*, (June 17, 2025) https://www.nerc.com/news/Pages/Statement-on-NERC%E2%80%99s-2024-Long-Term-Reliability-Assessment.aspx?utm_source=substack&utm_medium=email.

electric energy which may result from the unexpected outage or breakdown of facilities for the generation, transmission or distribution of electric power. "Such events may be the result of weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected 'entity' to prevent." 10 C.F.R. § 205.371. Further, emergency orders must meet "a specific inadequate power supply situation," and although emergencies with extended periods of insufficient supply could qualify, the impacted entity is supposed to firm up commitments for supply "so that a continuing emergency order is not needed." *Id*

These requirements have been demonstrated by DOE's historic use of 202(c) authority to address natural disasters and specific capacity crises. The most common reason to invoke Section 202(c) authority has been to address natural disasters like hurricanes, cold weather events, and extreme heat. *See* DOE Order Nos. 202-05-1 & -2 (Sept. 28, 2005) (Hurricane Rita); DOE Order No. 20208-1 (Sept. 14, 2008) (Hurricane Ike); DOE Order No. 202-20-1 (Aug. 27, 2020) (Hurricane Laura); DOE Order No. 202-24-1 (Oct. 9, 2024) (Hurricane Milton); DOE Order No. 202-21-1 (Feb. 14, 2021) (Winter Storm Uri); DOE Order No. 202-22-3 (Dec. 23, 2022) (Winter Storm Elliot – Texas ERCOT); DOE Order No. 202-22-4 (Dec. 24, 2022) (Winter Storm Elliot – PJM); DOE Order No. 202-20-2 (Sept. 6, 2020) (extreme heat in California); DOE Order No. 202-21-2 (responding to extreme heat, wildfires and drought in California); DOE Order Nos. 20222-1 & 2 and amendments (same). Indeed, during Winter Storm Elliot, MISO exported power to neighboring regions.[30]

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[30] MISO, *Overview of Winter Storm Elliott December 23, Maximum Generation Event* (Jan. 17, 2023) ("*Winter Storm Elliott Overview*") at 7, https://cdn.misoenergy.org/20230117%20RSC%20Item%2005%20Winter%20Storm%20Elliott%20Preliminary%20Report627535.pdf.

While DOE's emergency powers have occasionally been used to address retirements like the Campbell Plant, it has done so only when requested by the operator or local government and there was a specific need demonstrated for the units to operate due to an unexpected emergency. DOE Order No. 202-05-3 (Dec. 20, 2005) (Mirant to supply Washington D.C. when transmission lines were out of service); DOE Order No. 202-17-1 at 2 (Grand River Energy to operate Unit 1 due to lighting strike to Unit 2 and delay in construction for Unit 3); DOE Order No. 202-17-2 (need to operate Yorktown to avoid imminent risk of load-shedding).

A memorandum by the Congressional Research Service, Exhibit 12, confirms that DOE's use of Section 202(c) to order a plant to be generally available is novel. Ex.12 at 3 (Department engaging in "seemingly new interpretations of the emergency authority").

Courts have also likewise recognized Section 202(c)'s limitation to actual or imminent crises. For example, in *Richmond Power and Light v. FERC*, the D.C. Circuit noted that the statute "speaks of 'temporary' emergencies, epitomized by wartime disturbances, and is aimed at situations in which demand for electricity exceeds supply." 574 F.2d 610, 615 (D.C. Cir. 1978). And in *Otter Tail Power Co. v. Fed. Power Comm'n*., the Eighth Circuit noted that 202(c) provides authority to "react to a war or national disaster and order immediate interconnection. . . to maintain electrical service during such emergency." 429 F.2d 232, 234 (8th Cir. 1970). In *Otter Tail*, the Eighth Circuit distinguished between an emergency that is likely to occur and one that is actually occurring, concluding that a separate provision, section 202(b) [31] applies to the former, while section 202(c) applies to the latter:

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[31] Section 202(b) refers to 16 U.S.C. § 824a(b), which states "[w]henever the Commission, upon application of any State commission or of any person engaged in the transmission or sale of electric energy, and after notice to each State commission and public utility affected and after opportunity for hearing, finds such action necessary or appropriate in the public interest it may

> On its face, § 202(c) enables the Commission to react to a war or national disaster and order immediate interconnection of the facilities to maintain electrical service during such emergency. . . On the other hand, § 202(b) applies to a crisis which is likely to develop in the foreseeable future but which does not necessitate immediate action on the part of the Commission.

Otter Tail Power Co., 429 F.2d at 234. In that case, a power company challenged the FPC's order issued under § 202(b) of a temporary connection between the power company and a small municipally owned power producer that was "dangerously close to eroding its firm power supply" due to the proximity between the generator load capacities and the peak load demand. *Id.* It claimed that because the ordered connection was temporary, the order could only be issued under section 202(c), and only in emergency conditions. *Id.* The court disagreed that section 202(c) only applies to temporary orders but agreed that a potential crisis in the foreseeable future was not an emergency, making it "just the type of situation to fit into a § 202(b) hearing rather than § 202(c)." *Id.* The caselaw is therefore clear: for DOE to have any authority under section 202(c) the emergency must be actual and not merely a broadly asserted projected risk.

DOE exceeds its authority because the Order does not address any actual emergency or sudden occurrence needing imminent response, and because it has not identified any actual and specific insufficient supply situation. Thus the Order is without authority and contrary to law.

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by order direct a public utility" if the utility would not face an undue burden. The DOE's authority is much more limited in these situations. Further, 42 U.S.C. § 7172(a)(1)(B) vests this power in FERC, not the Secretary.

C. The Order exceeds DOE's authority because it requires actions not listed in Section 202(c)(1).

DOE's power is limited to orders that require connections or the generation, delivery, interchange, or transmission of electric energy. 16 U.S.C. § 824a(c). This authority does not cover mandating general plant availability untethered to meeting any specific need, nor does it allow for potential economic dispatch (which is not an apt solution for an actual emergency anyway—more on this in Section G below). Section 202(c)(1) does not allow for preemptive measures just in case an emergency might occur, and specifically does not allow for the Department to order availability without a specific need to be available.[32] Plus, "Economic dispatch" is not equivalent to the generation of electric energy. Economic dispatch is constrained by statute to mean only the lowest-cost option under the Energy Policy Act of 2005 Section 1234(c). 42 U.S.C. §16432(b). MISO's determination of lowest-cost sources may not result in the Campbell Plant producing *any* generation whatsoever. Thus the Order is without authority and contrary to law.

D. The Order exceeds DOE's authority because it does not set any hours of operation, limit hours of operation, or minimize environmental impact as required by Section 202(c)(3).

The order must be limited to only those hours necessary to meet the emergency. 16 U.S.C. § 824a(c)(2).

The Order addresses only the potential for an emergency, but does not identify a need for the Campbell Plant to generate electricity to meet it. By the same token, the Order does not establish any limited hours or other parameters for the Campbell Plant to follow to ensure it meets

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[32] Of the 19 times the DOE has issued a 202(c)(1) Order, only once, for Mirant in 2005, did it require a plant to supply as-needed additional capacity—but even then it was based on a specific application demonstrating a concrete and specific need. DOE Order No. 202-05-3 (Dec. 20, 2005). That is not the case here.

the purported emergency, only that it be available at all times. Thus the Order is without authority and contrary to law, and allows the Campbell Plant to generate electricity during times there are not even "elevated risks." Allowing a coal plant to generate electricity and pollute beyond the purported emergency needs would increase the environmental impacts that, by law, the Order must strive to minimize. 16 U.S.C. § 824a(c)(2). Thus the Order is without authority and contrary to law.

E. The Order exceeds DOE's authority because Section 201(b)(1) reserves decisions about plant retirements to the states.

Section 201(a) of the Federal Power Act explicitly provides that federal regulation over generation and transmission is related to matters of interstate commerce and extends "only to those matters which are not subject to regulation by the States." 16 U. S. C. § 824(a). Decisions over what plants should be constructed or retired is traditionally subject to state regulation. States retain jurisdiction "over facilities used for the generation of electric energy." 16 U.S.C. § 824(b)(1). "The states are thus authorized to regulate energy production . . . and facilities used for the generation of electric energy" *Coal. for Competitive Elec., Dynergy Inc. v. Zibelman*, 906 F.3d 41, 50 (2d Cir. 2018). What facilities to build, whether they remain feasible, and utility rates are areas governed by the states. *Pac. Gas & Elec. Co. v. State Energy Res. Conservation and Dev. Comm'n*, 461 U.S. 190, 205 (1983).

The energy market is governed by longstanding principles of cooperative federalism encouraged in Section 209(b) of the Federal Power Act—which explicitly declares that the Federal Energy Regulatory Commission may consult with states "regarding the relationship between rate structures, costs, accounts, charges, practices, classifications, and regulations of public utilities subject to the jurisdiction of such State commission and of the Commission.") 16 U.S. Code § 824h(b). Indeed, FERC has embraced these cooperative federalism principles and developed longstanding consultation practices with the states, including through creation of a Joint Federal-State Task Force. Exhibit 8. And more recently, a Federal-State Current Issues Collaborative. Exhibit 9.

Section 103 of the Department of Energy Organization Act is also applicable; it mandates due consideration to state retirement plans and requires, where practicable, consultation with relevant state officials. 42 U.S.C. § 7113.

States are responsible for developing and approving power generation plans, typically through public commissions like the Public Utilities Commission[33] in Minnesota, the Public Service Commission.[34]. These bodies oversee the development of Integrated Resource Plans ("IRPs"), or Strategic Energy Assessments, which are the blueprints for how a utility plans to generate sufficient electric power to meet its expected demand. *E.g.*, Minn. Stat. § 216B.2422 (Minnesota's IRP statute). An IRP can consider and adopt plans with myriad inputs and considerations and impact overall electricity rates, the specific communities or areas where power plants are located, determinations of which power plants might be built or retired and the fuels that they will use, overall electric system reliability (like the likelihood of power outages and how quickly the lights come back on), and the environment.[35] Such processes can be rigorous and commissions will open a docket to publicly vet a proposed plan, receive comments, and make an informed decision that is in the best interest of the states and its ratepayers.[36]

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[33] Minnesota Public Utilities Commission, *Utility Planning*, https://mn.gov/puc/activities/economic-analysis/planning/ (last visited June 23, 2025).

[34] Wis. Stat. Ann. § 196.491 (West).

[35] *Id*.

[36] Minnesota Public Utilities Commission, *Electric Integrated Resource Planning (EILRP)*, https://mn.gov/puc/activities/economic-analysis/planning/irp/ (last visited June 23, 2025).

MISO, in turn, is one of the country's largest regional transmission organizations (RTOs), which were formed to develop transmission systems, trading markets, and attendant procedures.[37] MISO works collaboratively with its member states to ensure resource adequacy throughout its service area.[38] This means that it ensures there is sufficient generation capacity to meet future electricity demands, including forecasting demand growth, assessing existing generation assets, and planning for new generation resources.[39] MISO works with utilities during their development of submissions to state regulators for the IRPs that that the regulators ultimately approve. And MISO then accounts for the final IRPS in its planning and analyses forecasting the balance between load and capacity. MISO also operates a capacity auction where utilities and other load-serving entities can procure the necessary generation capacity to meet projected demand. This incentivizes the development and maintenance of adequate generation resources.[40] MISO works with utilities, local regulators, and other stakeholders to maintain resource adequacy, including through its annual Planning Resource Auction ("PRA"), which procures sufficient resources and allows market participants to buy and sell capacity via an auction. MISO determines the capacity requirements in its region for each season covering the June 1 to May 31 time period.[41]

The Campbell Plant's planned retirement is subject to precisely such state regulation and MISO integration. The plan to retire the plant received intense scrutiny over years before being approved and worked into MISO's projections—all under the auspices of state law including

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[37] FERC, *Energy Primer*, https://www.ferc.gov/sites/default/files/2024-01/24_Energy-Markets-Primer_0117_DIGITAL_0.pdf

[38] MISO, *System Planning*, https://www.misoenergy.org/meet-miso/about-miso/industry-foundations/grid_planning_basics/ (last visited June 23, 2025).

[39] *Id.*

[40] *Id.*

[41] MISO, *Resource Adequacy*, https://www.misoenergy.org/planning/resource-adequacy2/resource-adequacy/#t=10&p=0&s=FileName&sd=desc (last visited June 23, 2025).

Michigan's IRP processes, state regulatory proceedings, state judicial proceedings, and state participation in MISO. *See In re Application of Consumers Energy Co. for Approval of Its Integrated Res. Plan Pursuant to Mcl 460.6t & for Other Relief.*, No. U-21090, 2022 WL 2915368, at *73 (June 23, 2022). The MPSC approved of Consumers Energy's plan to replace the capacity that the Campbell Plant would have produced with the purchase of a natural gas plant and extension of two units of natural gas peaking plants. *Id*. at *33. The Michigan Court of Appeals affirmed. *Wolverine Power Supply Coop., Inc. v Michigan Public Service Commission (In re Consumers Energy)*; No. 362294, 2023 WL 2620437 (Mich. Ct. App. March 23, 2023).

MISO also reviews planned plant retirements to ensure resource adequacy and grid reliability. Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff requires an operator to provide 26 weeks of advance notice of a planned retirement. MISO then performs a Reliability Study to determine whether the retirement will pose any concern for grid reliability. [42]

Consumers Energy submitted the Attachment Y form to MISO on December 14, 2021, providing notice that it planned to suspend generation at the Campbell Plant by June 1, 2025. MISO approved the Campbell Plant's retirement on March 11, 2022. In making its approval, MISO determined that "the suspension of Campbell Units 1, 2 & 3 would not result in violations of applicable reliability criteria."

DOE did not adequately consult with the state, much less account for or incorporate the findings of MISO in approving Consumer's Energy's Attachment Y submission. Michigan state regulators have primary jurisdiction over IRPs, siting, and cost recovery for utilities operating in

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[42] If MISO does identify a threat to grid reliability if the resource retires, the MISO tariff provides a mechanism to retain that resource until the constraint can be alleviated.

their states including the Campbell Plant. *Zibelman*, 906 F.3d at 50. DOE's failure to consult violates the principles behind FERC and DOT policies to involve the states in light of the statutory reservation of state authority in federal-state regulatory balance, 16 U.S.C. § 824(b)(1). It avoids 209(b) of Federal Power Act regarding federal-state collaboration and upends FERC's historic practice of seeking to develop a robust dialogue between regulators. 16 U.S. Code § 824h(b). And it flouts Section 103 of the Department of Energy Organization Act which requires consultation with relevant state officials—consultation was absolutely "practicable" here given the lack of an imminent emergency and the Order did not give <u>any</u> consideration (much less due consideration) to Michigan's IRP. 42 U.S.C. § 7113.

The Order usurps the State of Michigan's primary rule in resource planning and development; it is contrary to law.

F. The Order impermissibly calls for state governments to assist in its execution.

As discussed in the previous subsection, states retain jurisdiction over facilities used for the generation of electric energy and play a key role in development of MISO's tariff provisions. The Order mandates that to "[t]he extent to which MISO's current Tariff provisions are inapposite to effectuate the dispatch and operation of the units for the reasons specified herein, *the relevant governmental authorities* are directed to take such action and make accommodations as may be necessary to do so." Order ¶ E. As applied to state and local authorities, this mandate is unlawful for several reasons.

First, the Order violates the Tenth Amendment by commandeering state and local officials to implement a federal program. *See, e.g.*, *Printz v. United States*, 521 U.S. 898, 933 (1997). While the Order is not specific as to the object or the nature of its direction to "government authorities," vagueness does not erase the constitutional infirmity; it exacerbates it. *Cf. Murphy v. NCAA*, 584

U.S. 453, 469 (2018). All the more so where the Order lacks specific limited hours for operation and environmental conditions as discussed in Section D above.

Second, the Order violates the plain terms of Section 202(c), which does not grant authority to issue any order directing any governmental authority to do anything. 16 U.S.C. § 824a(c)(1). Third, the Order does not explain why directing state officials to act (or refrain from acting) pursuant to the powers reserved to them by the Constitution would help achieve the Order's purposes, and DOE lacked substantial evidence to support such a conclusion.

G. The Order is unreasoned, arbitrary, and capricious because the actions it mandates will not meet the purported emergency.

Section 202(c) contemplates emergency orders that are tailored to the specific emergency—they must "best meet the emergency and serve the public interest." 16 U.S.C. § 824a(c). Even if an emergency did exist and DOE had the legal authority to issue an Order, this Order is not rationally related to address the emergency that the order identifies.

The Order's specific requirement for MISO to take steps to effectuate "economic dispatch" of the Campbell Plant is noteworthy. Economic dispatch is a term of art for the procedure by which MISO selects generators to add electric energy to the grid. It is designed to ensure that the electricity generated matches the demand in its service area in the most cost-effective way. Beyond must-run units, MISO dispatches additional capacity from generators in increasing order of their respective costs, starting with the cheapest sources and moving up to more expensive ones as demand increases. MISO will also consider longer-term forecasts of generation given constraints such as forced outages and to ensure adequate margin. And then MISO monitors the grid in real time and calls upon available capacity as needed the day-ahead or day-of markets.

"Economic dispatch," by definition, is awarded to the lowest-cost option (all else being equal). Exhibit 6. That is because much of the base load planning takes place years or months ahead of time and is comprised of the must-run units. Additional capacity is then called upon in the day-ahead or day-of markets for which additional generation is required:

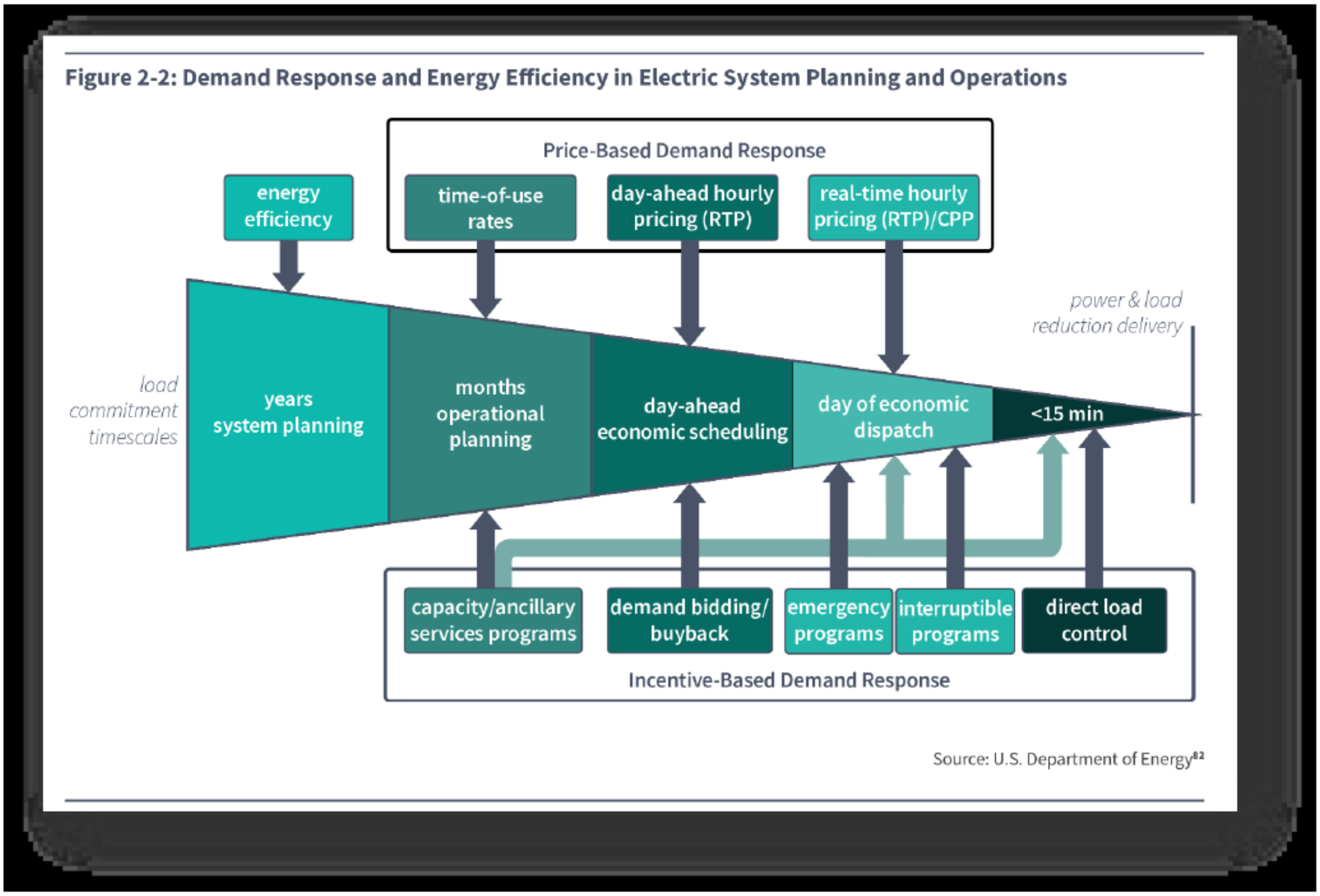

Figure 2-2: Demand Response and Energy Efficiency in Electric System Planning and Operations

Source: U.S. Department of Energy[82]

FERC *Energy Primer*, *supra* n.37 at 43. As explained by DOE's 2007 Report to Congress on economic dispatch, most of the generation available to meet load in real time for economic dispatch is identified and scheduled the day before, based upon the day-ahead load forecast used in the security-constrained unit commitment process. Exhibit 6 at 6. A 2024 report from the Government Accountability Office, Exhibit 13, found that based on 2021 data the vast majority of peaking plants operated on natural gas and oil which can be dispatched in much shorter order; only 3.3 percent of all peakers nationwide burned coal.

Taken together, economic dispatch considers a variety of factors including (1) the cost of generation, (2) the standby condition of the generator, (3) ramp-up time to provide the needed capacity, and (4) whether electric energy can be transmitted to the area of need.

In the context of an emergency, however, plants are generally allowed to run without regard to lowest-cost considerations or bid-submission-and-selection processes. The Order's proposed solution for "economic dispatch" of the Campbell Plant is wholly incompatible with addressing emergency operation (likely because there is no emergency in the first place). In a true emergency, an even uneconomic plants receive cost-of-service payments when they are required to run to alleviate the emergency condition. The RTO does not require the emergency generator to bid into the market and *then* make a determination about whether it will be selected to run as with economic dispatch. Rather, the emergency generator becomes a "price taker" using MISO's "must run" classification. Thus, the order does not use "economic dispatch" in a rational way because an emergency is not addressed with economic dispatch.

Moreover, coal is an expensive fuel type in our current energy mix—indeed the inefficiency of running a coal plant makes it economic in general, and is one of the reasons why this specific Campbell plant was slated for retirement. *See In re Application of Consumers Energy*, No. U-21090, 2022 WL 2915368, at *73.

The Order also does not cite to any evidence that economically dispatching the Campbell Plant will be the appropriate solution for amorphous purported emergency—which is only that a need *might* arise in the future. If, for example, there were a need for additional electricity in North Dakota, it is not likely that there would be sufficient transmission infrastructure across the Great Lakes to deliver electricity from the Campbell Plant to meet that need. And if the need occurs in the day-of or real-time markets, the Campbell Plant will not be able to spool up in time to meet that need, either. That is because it takes over 12 hours to reach peak load. Exhibit 14.[43] And even if there were adequate transmission and lead time, the Campbell Plant still uses an expensive fuel source. If the Campbell Plant's bid is higher than other lower-cost dispatchable alternatives (natural gas, storage, or renewables), then it would not be selected as the most economic resource to meet the need.

Section 202(c)(2) requires the emergency measures to be tailored the actual need; yet here, the Order improperly imposes measures that are not tailored to anything. All the while, the Order imposes costs on the States to maintain an idle plant, adds potentially expensive generation to the mix if it ever were to run, and would generate harmful pollution at the same time. Thus, the Order requiring the Campbell Plant to remain available and for MISO to take steps to use the Campbell Plant for economic dispatch is irrational and arbitrary where the Campbell Plant is unlikely to be a good candidate to serve either economic dispatch or emergency-need functions—especially where it is unclear what need it is supposed to meet in the first place.

Therefore, the Order is not rationally related to meeting the need of the purported emergency that it identifies.

CONCLUSION

For all of the foregoing reasons, the Department should rescind the Order.

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[43] Adapted from U.S. Energy Information Administration submissions according to Forms EIA-860 and EIA923, in which "OVER" indicates ramp-up time exceeding 12 hours. *See* https://www.eia.gov/electricity/data/eia860/; https://www.eia.gov/electricity/data/eia923/.

KEITH ELLISON
ATTORNEY GENERAL
OF MINNESOTA

/s/ Peter Surdo
Peter Surdo
Cat Rios-Keating
Alyssa Bixby-Lawson
Special Assistant Attorneys General
Office of the Minnesota Attorney General
445 Minnesota St., Suite 600
St. Paul, MN 55101

Dated: June 23, 2025

KWAME RAOUL
ATTORNEY GENERAL OF
THE STATE OF ILLINOIS

/s/ *Samuel C. Lukens*
Samuel C. Lukens, Assistant Attorney General
Susan L. Satter, Chief, Public Utilities Bureau
Jason E. James, Assistant Attorney General
Office of the Illinois Attorney General
115 South LaSalle, 25th Floor
Chicago, Illinois 60603

Dated: June 23, 2025

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY

Order No. 202-25-3B
ORDER ADDRESSING ARGUMENTS RAISED ON REHEARING

(Issued September 8, 2025)

1. On May 23, 2025, pursuant to section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy Organization Act,[2] the Secretary of Energy (Secretary) issued an order (Emergency Order) determining that "an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes . . . ."[3] In the Emergency Order, the Secretary determined that "additional dispatch of the Campbell Plant is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c)."[4] Requests for rehearing were filed by Public Interest Organizations (PIOs);[5] Michigan Attorney General Dana Nessel (Michigan AG); the States of Minnesota and Illinois (Minnesota and Illinois); and the Organization of MISO States (OMS).[6] Comments were filed by the Michigan Public Power Agency (MPPA) and the Maryland Office of People's Counsel (Maryland OPC).

2. On July 28, 2025, the Department of Energy (DOE) issued a notice of denial of rehearing by operation of law and providing for further consideration (DOE Notice). However, as provided in sections 202(c) and 313(a) of the FPA,[7] we are modifying the discussion in the Emergency Order and continue to reach the same result in this Order, as discussed below.[8]

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[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b)

[3] Department of Energy Order No. 202-25-3 (May 23, 2025) (Emergency Order).

[4] *Id.* at 2.

[5] Sierra Club, Natural Resources Defense Council, Michigan Environmental Council, Environmental Defense Fund, Environmental Law and Policy Center, Vote Solar, Public Citizen, Union of Concerned Scientists, the Ecology Center, and Urban Core Collective refer to themselves collectively as Public Interest Organizations.

[6] OMS also filed a notice of clarification to identify which of its members voted in support of filing only a petition to intervene and which of its members voted in support of filing a petition to intervene and a request for rehearing.

[7] 16 U.S.C. § 824a(c); 16 U.S.C. § 825*l*(a). In the context of FPA section 202(c) orders, the DOE interprets FPA section 313's references to "the Commission" to mean the DOE.

[8] *See Allegheny Def. Project v. FERC*, 964 F.3d 1, 16-17 (D.C. Cir. 2020). The Department is not

I. Background

3. In the Emergency Order, the Secretary determined that "an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest."[9]

4. The Emergency Order provided substantial support for the Secretary's emergency determination. The Emergency Order explained that, in its 2025 Summer Reliability Assessment, the North American Electric Reliability Corporation (NERC) indicated that "[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output."[10] The Emergency Order observed that multiple generation facilities in Michigan have retired in recent years, specifically identifying the closures of two nuclear plants—Big Rock Point and Palisades. The Emergency Order explained that the retirement of the Campbell Plant would further decrease the amount of available dispatchable generation in the Midcontinent Independent System Operator, Inc. (MISO) service territory, noting that a combined 1,575 MW of natural gas and coal-fired generation had retired since the summer of 2024.[11] The Emergency Order stated that MISO's 2025/2026 Planning Resource Auction results indicated that, for the North/Central sub-regions, "new capacity additions were insufficient to offset the negative impacts of accreditation, suspensions/retirements and external resources" and that, while the results "demonstrated sufficient capacity," the summer months reflected the "highest risk and a tighter supply-demand balance[;]" and the results "reinforce the need to increase capacity."[12]

5. In the Emergency Order, the Secretary determined that continued operation of the Campbell Plant is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination was based on the insufficiency of dispatchable capacity

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changing the outcome of the Emergency Order. *See Smith Lake Improvement & Stakeholders Ass'n v. FERC*, 809 F.3d 55, 56-57 (D.C. Cir. 2015).

[9] Emergency Order at 1.

[10] *Id.* (quoting *2025 Summer Reliability Assessment*, North American Electric Reliability Corporation, at 16 (May 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf (NERC 2025 Summer Reliability Assessment). The Emergency Order stated that NERC anticipates "elevated risk of operating shortfalls" notwithstanding Consumers Energy's acquisition of a 1,200 MW natural gas power plant in Covert, Michigan. *Id.* at 1-2.

[11] *Id.*

[12] *Id.* (citing MISO, *Planning Resource Auction Results for Planning Year 2025-26* (Apr. 2025). After the Emergency Order was issued, on May 29, 2025, MISO posted a corrected version of the presentation, which is available here: https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

and an anticipated increase in demand during the summer months, resulting in a risk to public health and safety caused by the potential loss of power to homes and local businesses in areas that may be affected by curtailments or outages. The Emergency Order was limited in duration to align with the emergency circumstances. In recognition of potential conflict with environmental standards and requirements and consistent with FPA section 202(c), the Secretary placed specific conditions on the operation of this necessary additional generation.[13]

II. Discussion

1. The Secretary's Authority to Require the Campbell Plant to Continue to Operate

6. Michigan AG, PIOs, Minnesota and Illinois, and OMS argue that the Emergency Order impermissibly exceeds the Secretary's statutory authority under FPA section 202(c) in various respects.[14] For instance, Michigan AG and PIOs argue that the Emergency Order, in effect, impermissibly asserts the authority to further its policy decisions by managing issues unrelated to addressing emergencies but rather concerning resource adequacy and electric generation facilities—issues which are reserved for the states and the Federal Energy Regulatory Commission (FERC), pursuant to other provisions in the FPA.[15] Minnesota and Illinois additionally contend that the Emergency Order impermissibly intrudes on the states' authority to make plant retirement decisions.[16]

7. Minnesota and Illinois also assert that section 202(c) has been used sparingly to address retirements like the Campbell Plant, and "only when requested by the operator or local government" in the context of an emergency.[17]

8. In a related argument, OMS asserts that the Emergency Order did not adequately consult with or incorporate the findings of MISO and other relevant state regulatory bodies, which they claim have primary jurisdiction over resource planning, sitting, and cost recovery for utilities operating in their states.[18]

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[13] Emergency Order at 2-3.

[14] Michigan AG Pet. § IV.B; PIO Pet. § IV.C; Minnesota and Illinois Pet. § V.E; OMS Pet. § B.

[15] *See* Michigan AG Pet. § IV.B.i (citing 16 U.S.C. § 824(b)(1) and 16 U.S.C. §§ 824d, 824e); PIO Pet. at 44 (citing 16 U.S.C. § 824(a)); *id.* at 45 (citing *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 281 (2016)).

[16] Minnesota and Illinois Pet. at 27.

[17] *Id.* at 24.

[18] *Id.* at 30-31.

9. Minnesota and Illinois also assert that the Emergency Order, subparagraph E, impermissibly calls for state governments to assist in its execution.[19] In particular, Minnesota and Illinois claim that the Emergency Order's directive that "the relevant governmental authorities are directed to take such action"—*i.e.*, effectuate the dispatch and operation of the Campbell Plant's units—unlawfully violates the Tenth Amendment of the United States Constitution.[20]

The DOE's Determination

10. There is no dispute that the Secretary has the statutory authority under FPA section 202(c) to (1) determine that an emergency exists, and then (2) exercise his judgment to address that emergency. Rather, Petitioners claim that the Secretary exceeded that authority in directing MISO and Consumers Energy to undertake specific actions to keep the Campbell Plant in operation. As explained below, these claims have no merit.

11. Section 201(b)(1) of the FPA specifically reserves authority over "facilities used for the generation of electric energy" for the states "*except as specifically provided* in this subchapter."[21] Section 202(c) constitutes one such carve out. It grants the Secretary the "authority, either upon [the Secretary's] own motion or upon complaint, with or without notice, hearing, or report, to require by order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in [the Secretary's] judgment will best meet the emergency and serve the public interest." Congress thus purposely provided discretion in section 202(c) to require changes to the operation of the U.S. electricity system on a temporary basis, including changes to the operations of electric generation facilities.

12. Michigan AG and PIOs attempt to avoid this clear grant of authority by arguing that the Emergency Order addresses issues unrelated to emergencies but rather concern resource adequacy.[22] But placing a different label on the Secretary's action cannot change the fact that actions taken in the Emergency Order fall squarely within the authority granted by section 202(c). By its terms, that section specifically applies to the potential "shortage of electric energy or of facilities for the generation or transmission of electric energy," which is exactly the situation that led to the issuance of the Emergency Order. And section 202(c) specifically authorizes the Secretary to "require by order . . . such generation . . . of electric energy as in [the Secretary's] judgment will best meet the emergency and serve the public interest," which is exactly the action the Emergency Order requires.

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[19] *Id.* at 31.

[20] *Id.*

[21] 16 U.S.C. § 824(b)(1) (emphasis added).

[22] *See* Michigan AG Pet. § IV.B.i (citing 16 U.S.C. § 824(b)(1) and 16 U.S.C. §§ 824d, 824e); PIO Pet. at 44 (citing 16 U.S.C. § 824(a)); *id*. at 45 (citing *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 281 (2016)).

13. Nor is there any requirement under section 202(c), as Minnesota and Illinois and OMS suggest,[23] for the Secretary to consult with the impacted states prior to issuing a section 202(c) order. Section 103 of the DOE Organization Act requires consultation with states "where practicable."[24] In an emergency situation, it is often not practicable to consult with the states and relevant state agencies prior to taking emergency action. This point is further supported by the plain language of section 202(c), which specifically authorizes DOE to issue an emergency order "with or *without notice*."[25]

14. Finally, the argument that the Emergency Order violates the Tenth Amendment[26] is incorrect. The Emergency Order provides that "[t]he extent to which MISO's current Tariff provisions are inapposite to effectuate the dispatch and operation of the units for the reasons specified herein, the relevant governmental authorities are directed to take such action and make accommodations as may be necessary to do so."[27] Had the Emergency Order directed State governments or their instruments to take such an action, there would, of course, be a constitutional issue, grounded perhaps in regards to the 10th Amendment, but even more directly in the anti-commandeering clause. But that was not the intended endpoint, however, for the avoidance of doubt, we provide clarification that the Order does not direct State governments or their instrumentalities to take such actions.

15. Here, there is no state tariff provision which governs wholesale energy sales. DOE clarifies that the relevant authorities to which the Emergency Order refers are MISO and FERC. DOE is not requiring state governmental authorities to take any action with respect to the Emergency Order.

2. The Secretary's Authority to Determine the Existence of an Emergency

16. Michigan AG, PIOs, Minnesota and Illinois, and OMS each raise similar arguments that the Emergency Order failed to meet the legal definition of an "emergency" within the meaning of FPA section 202(c).[28] For instance, Michigan AG argues that, while section 202(c) "permits some measure of flexibility with respect to what type of events may cause the emergency, allowing for 'other causes' beyond those enumerated," it only authorizes action during extraordinary

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[23] *See, e.g.*, Minnesota and Illinois Pet. § V.E; OMS Pet. at 4.

[24] 42 U.S.C. § 7113.

[25] 16 U.S.C. § 824a(c)(1) (emphasis added).

[26] Minnesota and Illinois Pet. at 31-32.

[27] Emergency Order at 3.

[28] Michigan AG Pet. § IV.A; PIO Pet. § IV.A.1; Minnesota and Illinois Pet. § V.B; OMS Pet. §§ II.A, D.

circumstances.[29] Michigan AG,[30] PIOs,[31] and Minnesota and Illinois[32] cite to the definition of "emergency" in DOE's regulations at 10 C.F.R. § 205.371 and argue that the Emergency Order exceeded the scope of that definition. Michigan AG[33] and PIOs[34] also cite to various dictionary definitions of "emergency" to assert the same point.

17. Further, Michigan AG,[35] PIOs,[36] and Minnesota and Illinois[37] each rely on *Richmond Power and Light v. FERC*, 574 F.2d 610 (D.C. Cir. 1978), and *Otter Tail Power Co. v. Federal Power Commission*, 429 F.2d 232 (8th Cir. 1970), for the proposition that courts have interpreted section 202(c) narrowly to apply only to temporary emergencies requiring an imminent response.

The DOE's Determination

18. In enumerating emergency powers in section 202(c), Congress accorded the Secretary discretion to determine the existence of an emergency. The statute's plain text grants the Secretary authority to respond, in certain circumstances, to emergencies posing dire threats to the Nation's electric infrastructure. Specifically, the Secretary "*shall* have authority" to act "*whenever* the [Secretary] determines that an emergency exists."[38] Next, the statute sets forth three different categories of emergencies where section 202(c) action is permissible. An emergency may exist "by reason of [1] a sudden increase in the demand for electric energy, or [2] a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or [3] other causes."[39]

19. Section 202(c)(1) delegates a wide degree of latitude for the Secretary to determine the existence of an emergency, "either upon its own motion or upon complaint, with or without notice,

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[29] Michigan AG Pet. at 24.

[30] Michigan AG Pet. at 26.

[31] PIO Pet. at 28-29.

[32] Minnesota and Illinois Pet. at 22-23.

[33] Michigan AG Pet. at 25.

[34] PIO Pet. at 26.

[35] Michigan AG Pet. at 25-26.

[36] PIO Pet. 26-27.

[37] Minnesota and Illinois Pet. at 24.

[38] 16 U.S.C. § 824a(c)(1) (emphases added).

[39] *Id.* (brackets added).

hearing, or report." Beyond providing exemplar categories of where an "emergency exists," the statute is silent on any additional requirements that must be satisfied. Here, as is evident from the face of the Emergency Order, and as is consistent with section 202(c)'s text and prior DOE practice, the Secretary exercised his authority under section 202(c) and determined, in his statutory discretion and substantive expertise, that "an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes."[40]

20. The argument that the Secretary can act only when a shortage of electricity is "imminent" makes no sense in the context of his statutory authority under section 202(c) to act to address a "shortage of . . . facilities for the generation . . . of electric energy." As a general matter, some retired generation facilities generally cannot be brought back online in a matter of days. If the Secretary was required to wait until a blackout is "imminent" before addressing a shortage of generation facilities, he will be unable to take any meaningful action to address the blackout. Determining to take action before the retirement of the Campbell Plant, which was necessary to ensure that it would be available to produce electric energy to prevent blackouts in summer peak load periods, falls well within the Secretary's statutory discretion.

21. The definition of "emergency" contained in DOE's regulations at 10 C.F.R. § 205.371 does not supersede the discretion section 202(c) affords to the Secretary to "determine[] that an emergency exists." In any event, those regulations specifically provide that "[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities can result in an emergency as contemplated in these regulations." Accordingly, the Secretary's emergency determination is entirely consistent with the governing statutory requirements in section 202(c) and the DOE's regulations.

22. Similarly, the dictionary definitions cited by Michigan AG[41] and PIOs[42] are not persuasive. Those definitions cannot limit the discretion Congress expressly delegated to the Secretary in section 202(c).

23. The arguments made by Michigan AG,[43] PIOs,[44] and Minnesota and Illinois[45] based on the *Otter Tail Power* and *Richmond Power and Light* decisions likewise are misguided. *Otter Tail Power* did not limit the Secretary's section 202(c) discretion or the meaning of "emergency" because the court held that section 202(c) *did not apply* to the case. Instead, *Otter Trail Power*

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[40] *See* Emergency Order at 1.

[41] Michigan AG Pet. at 25.

[42] PIO Pet. at 26.

[43] Michigan AG Pet. at 25-26.

[44] PIO Pet. 26-27.

[45] Minnesota and Illinois Pet. at 24.

involved section 202(b) of the FPA dealing with permanent interconnection (and not an "emergency" within the meaning of section 202(c)).[46] In *Richmond Power and Light*, the Court of Appeals for the D.C. Circuit held that the Federal Power Commission (FPC) did not abuse its discretion in *declining* to invoke its emergency powers under section 202(c).[47] The court determined that the FPC had discretion to choose a temporary, voluntary program rather than issue an order pursuant to section 202(c), as the circumstance, in the FPC's discretion, did not warrant the use of emergency authority.[48]

24. A more relevant decision is *Board of Trade of the City of Chicago v. Commodity Futures Trading Commission*.[49] In that case, the Court of Appeals for the Seventh Circuit recognized the broad powers of the Commodity Futures Trading Commission (CFTC) to issue emergency actions under section 8a(9) of the Commodity Exchange Act (7 U.S.C. § 12a(9)). Through section 8a(9), the CFTC issued an emergency order for the Board of Trade to suspend trading in a certain wheat futures contracts, citing transportation and warehouse shortages and potential market manipulation.[50] In response, the Board of Trade sought an injunction against the order, arguing that no emergency existed. The district court granted a preliminary injunction, and the CFTC appealed.[51] In its decision to vacate and remand the district court's preliminary injunction, the Seventh Circuit concluded that Congress intended to grant the CFTC discretion in making emergency determinations under the Commodity Exchange Act.[52] The court reasoned: "Congress recognized that regulation of the volatile futures markets could be accomplished effectively only through the use of an expert Commission, that situations could occur suddenly for which the traditional enforcement powers would be an inadequate response, and that therefore the Commission should have emergency powers, the exercise of which is committed to the expertise and discretion of the Commission."[53] In addition, "[t]he fact that the Commission is authorized by Congress to take emergency action is, in itself, a suggestion of Congressional intent to commit

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[46] *See Otter Tail Power Co. v. Federal Power Commission*, 429 F.2d 232 (8th Cir. 1970) (*Otter Tail Power)* (rejecting petitioner's contention that "any proceedings in the instant case must be dealt with in compliance with § 202(c)").

[47] *See Richmond Power and Light v. FERC*, 574 F.2d 610 (D.C. Cir. 1978) (*Richmond Power and Light*) at 615.

[48] *Id.* at 614-15.

[49] *Board of Trade of the City of Chicago v. Commodity Futures Trading Commission*, 605 F.2d 1016, 1025 (7th Cir. 1979)

[50] *See Board of Trade of the City of Chicago v. Commodity Futures Trading Commission*, 605 F.2d 1016, 1025 (7th Cir. 1979) at 1018.

[51] *Id.* at 1019-20.

[52] *Id.* at 1023-25.

[53] *Id.* at 1025.

such actions to the Commission's discretion."[54] Given the similarities between FPA section 202(c) and section 8a(9) of the Commodity Exchange Act, the *Board of Trade* decision confirms the conclusion that Congress intended to grant the Secretary broad discretion to determine when his emergency powers should be applied to protect the public interest.[55]

25. Finally, the assertion of Minnesota and Illinois that the Emergency Order is "novel" and contravenes prior practice wherein section 202(c) was used to address retirements "only when requested" has no merit.[56] On its face, section 202(c)(1) authorizes the Secretary to act "*either upon its own motion or upon complaint*." It is undisputed that section 202(c) has been used in the past to address generation retirements. Under the statute, it is irrelevant whether a utility requested that the Secretary take this action.

26. In sum, the Secretary acted within his authority to determine the existence of an emergency and the statutory meaning of "emergency" has been satisfied here. In its 90-year history, no court has questioned the Secretary's (or, prior to its dissolution in 1977, the FPC's)[57] discretion in this respect, much less overturned the Secretary's determination that an emergency exists. The absence of such circumstances underscores the Secretary's authority as expressly delegated in the statute.

3. **The Factual Basis to Support the Secretary's Emergency Determination**

27. Michigan AG, PIOs, Minnesota and Illinois, and OMS also raise similar objections that there is no factual basis to support the Emergency Order, and that the Secretary is required to submit substantial evidence in support of his emergency determination.[58]

28. *First*, Michigan AG, PIOs, Minnesota and Illinois, and OMS criticize the Emergency Order's references to the 2025 NERC Summer Reliability Assessment.[59] For instance, Michigan AG claims that the Emergency Order fails to explain (1) how NERC's assessment supports an emergency finding, as NERC did not put MISO in the high-risk category; (2) why NERC's designation of "elevated" risk represents a sudden or unexpected circumstance, as MISO has been

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[54] *Id.* at 1023.

[55] *See id.* at 1023-25.

[56] *See* Minnesota and Illinois Pet. at 24.

[57] The FPC was dissolved in 1977, and the FPC's functions were split between FERC and the Department, with the Secretary retaining FPA section 202(c) power.

[58] Michigan AG Pet. §§ IV.A(ii), IV.C; PIO Pet. § IV.A.2; Minnesota and Illinois Pet. § V.A; OMS Pet. § II.A.

[59] Michigan AG Pet. at 27-29, 37; PIO Pet. 32-35; Minnesota and Illinois Pet. at 19-20; OMS Pet. at 2-3. OMS also contends that NERC's long-term and seasonal assessments are unreliable and inconsistent. OMS Pet. at 3.

at this risk level or higher for years; and (3) why the "potential tight reserve margins" identified by NERC constitute an emergency, as MISO exceeded the NERC reference margin level in the 2020-2025 period.[60]

29. *Second*, Michigan AG and PIOs contend that the retirement of the Campbell Plant was not unexpected or sudden, and that generation retirement does not constitute an emergency.[61] Michigan AG further states that MISO approved the retirement of the Campbell Plant after an extensive process.[62]

30. *Third*, Michigan AG, PIOs, and Minnesota and Illinois also assert that the April 2025 MISO Planning Resource Auction does not demonstrate the existence of an emergency.[63] For example, according to Michigan AG, the Emergency Order ignored MISO's conclusion that the 2025/2026 Planning Resource Auction "demonstrated sufficient capacity at the regional, subregional and zonal levels."[64]

31. Minnesota and Illinois also contend that the Emergency Order failed to consider MISO's purported history of performance in several extreme weather events and, according to Minnesota and Illinois, MISO currently is not afflicted by any unexpected outage or extreme weather event.[65]

The DOE's Determination

32. The exigencies that Section 202(c) is designed to address necessarily require that the Secretary's determination is informed by the facts available at the time and by his sound expert judgment as to what situations constitute an emergency. The statute's express exclusion of any notice, hearing, or report requirements prior to issuance of a section 202(c) order confirms the commonsense fact that the Secretary must exercise his section 202(c) authority expeditiously and with broad discretion in responding to emergency situations.

33. In any event, the Secretary's determination that an emergency exists is supported by the factual evidence and the exercise of the Secretary's judgment. The Emergency Order identified the ongoing emergency "in portions of the Midwest region of the United States due to a shortage

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[60] Michigan AG Pet. at 37.

[61] *Id.* at 30, 37; PIO Pet. 29-30.

[62] Michigan AG Pet. at 39

[63] *Id.* at 30-32, 38; PIO Pet. at 30-32; Minnesota and Illinois Pet. at 20-21.

[64] Michigan AG Pet. at 39 (citing Attachment B, MISO, Planning Resource Auction, Results for Planning Year 2025 – 2026 (April 2025) at 12).

[65] Minnesota and Illinois Pet. at 22.

of electric energy, a shortage of facilities for the generation of electric energy, and other causes."[66] Consistent with this determination, the Emergency Order explains the need to increase capacity to meet the increasingly high demands and decreasing generation output.[67]

34. In 2021, Consumers Energy announced that it planned a "speed closure" of the Campbell Plant in 2025, years before the end of its scheduled design life.[68] Specifically, the Campbell Plant was scheduled to retire on May 31, 2025, and thus would not be operational in August, the month the Secretary anticipated heightened demand on the grid.[69] In the Emergency Order, the Secretary noted that the Campbell Plant's retirement was part of an ongoing trend, which has seen 1,575 MW of natural gas and coal-fired generation retired since the summer of 2024, further decreasing the amount of dispatchable generation within MISO's service territory.[70] Although MISO and Consumers Energy have incorporated the Campbell Plant's planned retirement into their supply forecasts, as well as Consumers Energy's acquisition of an existing 1,200 MW natural gas power plant in Covert, Michigan, NERC's 2025 Summer Reliability Assessment still anticipated "elevated risk of operating reserve shortfalls."[71]

35. Michigan AG, PIOs, Minnesota and Illinois, and OMS mischaracterize the 2025 NERC Summer Reliability Assessment's designation of "elevated risk" for the MISO region. This assessment reflects NERC's determination that "resources will not be sufficient to meet operating reserves" in the event of "extreme peak-day demand with normal resource scenarios" or "normal peak-day demand with reduced resources."[72] The NERC assessment of "elevated risk" suggests that there will be significant strain on the grid in the MISO service area even in normal operating conditions. If the Secretary had waited to act until the conditions identified by NERC arose, it would have been too late for him to take any effective action.

36. Petitioners note that MISO and Consumers Energy have incorporated the Campbell Plant's planned retirement into their supply forecasts and acquired a 1,200 MW natural gas power plant in Covert, Michigan. However, NERC's 2025 Summer Reliability Assessment anticipated

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[66] *See* Emergency Order at 1.

[67] *See id.* (noting recent closures of generation facilities in Michigan and uncertain near-term future of generation from the Palisades nuclear power plant).

[68] *See Consumers Energy Announces Plan to End Coal Use by 2025; Lead Michigan's Clean Energy Transformation*, Consumers Energy (June 23, 2021), https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation.

[69] Emergency Order at 1.

[70] *Id.*

[71] *Id.* (citing NERC 2025 Assessment).

[72] NERC 2025 Assessment at 10.

"elevated risk of operating reserve shortfalls" even including the Covert Plant's capacity.[73] The fact that Consumers Energy acquired this existing plant to replace the Campbell Plant did not forestall the emergency.

37. Similarly, MISO's approval of the retirement of the Campbell Plant came before NERC's 2025 Summer Reliability Assessment, which took into account increased demand projections.

38. Michigan AG, PIOs, and Minnesota and Illinois' respective criticisms[74] of the Secretary's reliance on the April 2025 MISO Planning Resource Auction ignore that MISO stated that the summer months reflected the "highest risk and a tighter supply-demand balance" and the results of the auction "reinforce the need to increase capacity."[75] In addition, the May 2025 NERC assessment referenced a Seasonal Outlook issued by the National Oceanic and Atmospheric Administration (NOAA) on April 17, 2025, which estimated that much of the Midwest had a 33%-40% chance to experience above-normal temperatures in the summer.[76] DOE also notes that a Seasonal Outlook released by the NOAA on June 19, 2025 increased this estimate to a 40%-50% chance of above-normal temperatures.[77]

39. Similarly, the argument of Minnesota and Illinois that the MISO region does not face current "extreme" weather events misses the mark.[78] The Emergency Order was based on the facts known at the time it was issued in May 2025, including the projected potential for a shortage of capacity in the summer identified by NERC. In other words, the Secretary was required to act before the shortage actually occurred. Moreover, contrary to the contentions of Minnesota and Illinois, the conditions that actually existed in the summer following issuance of the Emergency Order further confirm the ongoing emergency and sudden increased threats to energy reliability. In June 2025, MISO issued alerts affecting the Central Region on 18 days. For instance, on June 23, 2025, MISO issued an Energy Emergency Alert 1 for the North and Central Regions "[d]ue to the hot weather and high demand" during a heat dome over the eastern portion of the United States.[79] In fact, between June 11 and August 18, MISO issued dozens of alerts to manage grid

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[73] Emergency Order at 1 (citing to NERC 2025 Assessment).

[74] Michigan AG Pet. at 30-32, 38; PIO Pet. at 30-32; Minnesota and Illinois Pet. at 20-21.

[75] *Planning Resource Auction Results for Planning Year 2025-26,* MISO (Apr. 2025). (Corrected and reissued on 05/29/25) available at https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

[76] NERC 2025 Assessment at 9.

[77] *Seasonal Outlook*, NOAA Climate Prediction Ctr., (July 17, 2025), https://www.cpc.ncep.noaa.gov/products/predictions/long_range/seasonal.php?lead=1.

[78] Minnesota and Illinois Pet. at 22.

[79] *See* MISO Energy Emergency Alert 1 (June 23, 2025),

reliability in its Central Region in response to hot weather, severe weather, high customer load, forced generation outages, and transfer capability limits. MISO issued alerts for the Central Region on at least 40 of the 69 days between June 11 and August 18.

40. In addition, the Secretary took section 202(c) action in the context of a National Energy Emergency declared by the President in the months prior to the Emergency Order. In executive orders dated January 20, 2025, and April 8, 2025, the President underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. The President recognized, in Executive Order 14156, "Declaring a National Energy Emergency," that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[80] In view of the National Energy Emergency, in Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," the President explained that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and an increase in domestic manufacturing."[81] Significantly, Executive Order 14262 specifically ordered the Secretary to draw upon "all mechanisms available under applicable law, *including section 202(c) of the Federal Power Act*, to ensure any generation resource identified as critical within an at-risk region is appropriately retained as an available generation resource within the at-risk region."[82] The executive orders informed the Secretary's decision and action, in addition to the other factors outlined in the Emergency Order and this Order.

41. Grid operators, including MISO itself, have likewise acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025 hearing before the House Committee on Energy and Commerce, Jennifer Curran, the Senior Vice President of Planning and Operations for MISO, testified that "the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[83] Ms. Curran also described "much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers

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https://x.com/MISO_energy/status/1937172353118548150.

[80] Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025).

[81] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025).

[82] *Id.* (emphasis added).

[83] Keeping the Lights On: Examining the State of Regional Grid Reliability Hearing Before the House Committee on Energy and Commerce, Subcommittee on Energy, 119th Cong. (Mar. 25, 2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Independent System Operator), at 5, witness-testimony_curran_eng_gridoperators_03.25.2025.pdf.

to support artificial intelligence."[84] She added, "[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them."[85]

42. Finally, DOE's assessment reveals that, if current retirement schedules and incremental additions remain unchanged, most regions—including the MISO region relevant to the Emergency Order—will face unacceptable reliability risks within five years. The action taken in the Emergency Order requiring the Campbell Plant to continue to operate before its planned retirement on May 31, 2025 addresses that risk.[86]

43. In sum, the Secretary's determination in the Emergency Order that continued operations of the Campbell Plant fully complies with section 202(c).

4. **Potential Environmental Impacts**

44. Michigan AG and Minnesota and Illinois raise similar arguments that the Emergency Order fails to comply with section 202(c)'s requirement to ensure that any order "to the maximum extent practicable, is consistent with any applicable Federal, State, or local environmental law or regulation and minimizes any adverse environmental impacts."[87] In particular, Michigan AG and PIOs argue that the Emergency Order fails to identify any specific criteria or conditions for ensuring compliance with environmental regulations or limiting environmental impact.[88]

The DOE's Determination

45. Section 202(c)(2) requires the Secretary to ensure that any section 202(c) order that may result in a conflict with a requirement of any environmental law or regulation to the "maximum extent practicable, [be] consistent with any applicable . . . environmental law or regulation and minimize[] any adverse environmental impacts." Contrary to Michigan AG and Minnesota and Illinois' contentions, the Emergency Order contains certain limitations to minimize the hours of operation and adverse environmental impacts. Specifically, the Emergency Order requires that "[a]ll operation of the Campbell Plant must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible,"[89] and requires daily reporting from MISO on "whether the Campbell

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[84] *Id.* at 6.

[85] *Id.* at 7.

[86] NERC 2025 Summer Reliability Assessment

[87] Michigan AG Pet. at 52 (citing 16 U.S.C. § 824a(c)(2)); Minnesota and Illinois Pet. at 13 (citing 16 U.S.C. § 824a(c)(2)).

[88] Michigan AG Pet. at 54-55; PIO Pet. at 47.

[89] Emergency Order at 3, Ordering Paragraph C.

Plant has operated in compliance with the allowances contained in this Order."[90] These reporting requirements provide a mechanism for the DOE to obtain information concerning any adverse environmental impacts of the Emergency Order, and DOE may modify the Emergency Order to require additional actions as the Secretary deems appropriate.

46. Michigan AG and Minnesota and Illinois argue that the Emergency Order is not tailored to respect environmental considerations, of particular concern to Michigan AG and Minnesota and Illinois are the potential environmental impacts that may be produced by the Campbell Plant.[91] Michigan AG and Minnesota and Illinois provide examples of certain conditions that in their view would, presumably, satisfy the requirements of the statute (*e.g.*, direction to optimize use of pollution control equipment or avoid operations during air quality episodes).[92] These conditions, however, are not required by statute. Congress did not prescribe in section 202(c) how the Department was to fulfill its obligations concerning consistency with environmental laws and minimization of adverse effects. Moreover, Congress recognized, by including the phrase "to the maximum extent practicable," that emergency circumstances would at times make compliance with all Federal, state, and local environmental requirements and minimization of all potential adverse environmental impacts infeasible. This phrase provides the Secretary with discretion in fulfilling its obligations under section 202(c). Accordingly, the Emergency Order's limits on duration and the conditions that authorize only the additional generation necessary and require the operation of the plant to comply with environmental laws to the maximum extent feasible, as well as the reporting requirements that allow DOE to monitor MISO's compliance with the Emergency Order and the environmental impacts such that DOE could take additional action as the Secretary deems appropriate, were sufficient to satisfy its obligation under section 202(c)(2) to ensure that the Emergency Order, to the maximum extent practicable, is consistent with applicable environmental laws and minimizes adverse environmental impacts.

5. Authority to Order Economic Dispatch

47. Michigan AG and Minnesota and Illinois assert that DOE does not have the authority under 202(c)(1) to order the utilization of economic dispatch of the Campbell Plant as a response to an emergency, and that economic dispatch is not an effective or rational measure to address resource shortages.[93] Accordingly, Michigan AG and Minnesota and Illinois contend that economic dispatch is not in the "public interest," as required under section 202(c).[94] In addition, PIOs contend that the Emergency Order's economic dispatch requirement is ambiguous and vague.[95]

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[90] *Id.*, Ordering Paragraph B.

[91] Michigan AG Pet. at 54-55; Minnesota and Illinois Mot. at 26-27.

[92] Michigan AG Pet. at 54; Minnesota and Illinois Mot. at 26-27.

[93] Michigan AG Pet. § IV.D; Minnesota and Illinois Pet. § V.G.

[94] Michigan AG Pet. At

[95] PIO Pet. at 42-43.

Michigan AG asserts that Consumers Energy can subvert the economic dispatch requirement by offering the Campbell Plant on a "must run" status.[96] Michigan AG asserts that, if this happens, the costs to ratepayers will not have been minimized.[97]

The DOE's Determination

48. As noted, section 202(c)(1) affords the Secretary discretion as to what remedy "will best meet the emergency and serve the public interest." The statute expressly delegates the decision on the appropriate remedy to the Secretary's "judgment" (similar to the express delegation to "determine[] that an emergency exists"). In the Emergency Order, the Secretary soundly exercised his judgment in directing "additional dispatch of the Campbell Plant [] necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c)."[98] "This determination [was] based on the insufficiency of dispatchable capacity and anticipated demand during the summer months, and the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety," as discussed above.[99]

49. The Emergency Order directs MISO and Consumers Energy to "take all measures necessary to ensure that the Campbell Plant is available to operate."[100] The Emergency Order then directs MISO "to take every step to employ economic dispatch of the [facility] to minimize [the] cost to ratepayers."[101] The DOE disagrees with arguments that economic dispatch is not effective or rational in this case. The directive regarding economic dispatch ensures that the Campbell Plant can be dispatched instead of more costly generation (if available), reducing electricity costs and serving the public interest. The directive recognizes the fact that MISO uses "a production cost modeling software that produces a unit commitment and security-constrained economic dispatch while optimizing production costs."[102] DOE clarifies, however, that to the extent operational (including safety) limitations prevent the Campbell Plant from being economically dispatched, offering the Campbell Plant on a must run basis may be necessary to ensure the units are available to operate. Under those circumstances, such operation would be consistent with

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[96] Michigan AG Pet. at 49.

[97] *Id.*

[98] Emergency Order at 2.

[99] *Id.*

[100] *Id.*, Ordering Paragraph A.

[101] *Id.*

[102] *MISO Economic Planning Whitepaper* (Oct. 3, 2024), at 3, https://cdn.misoenergy.org/MISO%20Economic%20Planning%20Whitepaper651689.pdf

minimizing the cost to ratepayers because a price taker can decrease (but cannot increase) the market price.

6. Best and Appropriate Means for Addressing the Emergency

50. The Michigan AG and PIOs raise similar arguments that the Campbell Plant is neither the best nor an appropriate means of alleviating the capacity shortfall addressed by the Emergency Order.[103] In particular, Michigan AG and PIOs argue that DOE was required to consider alternatives and evaluate other possible methods for addressing the emergency, which they argue the Emergency Order failed to do.[104] They further argue that there are alternative means by which DOE could have addressed the emergency.[105]

51. PIOs additionally argue that the Emergency Order fails to consider the various policies of the FPA.[106] Specifically, PIO's argue that the Emergency Order fails to provide a reasoned basis for its determination that additional dispatch of the Campbell Plant is necessary to best meet the emergency.[107] PIOs further contend that the Emergency Order does not examine the expense or environmental impact of running the Campbell Plant, or address how the Campbell Plant can meet the emergency.[108]

The DOE's Determination

52. The Secretary, in issuing the Emergency Order, adhered to the process established in FPA section 202(c) in exercising his judgment in directing MISO and Consumers Energy to undertake specific actions as to the Campbell Plant.[109] There is no dispute that the Secretary, as the presidentially-appointed and Senate-confirmed head of the Department (*see* 42 U.S.C. § 7131), is the appropriate individual to determine the existence of an emergency within the meaning of section 202(c) and exercise "[the Secretary's] judgment" as to what Department actions "best meet the emergency and serve the public interest."[110] As discussed above, the Secretary exercised his discretion in responding to an emergency pursuant to an express delegation of authority under

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[103] Michigan AG Pet. at 41; PIO Pet. at 36-37.

[104] Michigan AG Pet. at 41; PIO Pet. at 36-37.

[105] Michigan AG Pet. at 41; PIO Pet. at 41.

[106] PIO Pet. at 37.

[107] *Id.* at 37-41.

[108] *Id.*

[109] *See generally* Emergency Order.

[110] 16 U.S.C. § 824a(c)(1).

section 202(c). Further, as explained below, there is no basis to grant rehearing to review the Secretary's exercise of his judgment in prescribing the required response to the emergency.

53. As noted above, section 202(c)(1) affords the Secretary discretion as to what remedy "will best meet the emergency and serve the public interest." The statute expressly delegates the decision on the appropriate remedy to the Secretary's "judgment" (similar to the express delegation to "determine[] that an emergency exists"). Here, the Secretary soundly exercised his judgment in directing "additional dispatch of the Campbell Plant [] necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c)."[111] "This determination [was] based on the insufficiency of dispatchable capacity and anticipated demand during the summer months, and the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety."[112]

54. That Petitioners have now, after the fact, identified alternatives they deem to be better and more appropriate solutions to the emergency is irrelevant. Section 202(c)(1) delegates a wide degree of latitude for the Secretary to determine the existence of an emergency and to order the means to address such emergency. It does not require the Secretary to engage in a lengthy weighing of options or explanation of the Secretary's actions prior to issuing an emergency order. Indeed, such a process would defeat the very purpose of the emergency power.

7. NEPA Concerns

55. Michigan AG claims that the Emergency Order violates the National Environmental Policy Act (NEPA), as any orders issued under section 202(c) that affect the quality of the environment are considered "major federal actions"[113] that require compliance with NEPA standards and requirements.[114] According to the Michigan AG, these requirements include the "issuance of an environmental impact statement, environmental assessment, categorical exclusion, or special environmental analysis."[115]

56. Michigan AG further asserts that in other section 202(c) orders, DOE has previously sought to comply with NEPA through categorical exclusions, such as categorical exclusion B4.4 for "power management activities," or special environmental assessments—neither of which has been undertaken nor would apply in this instance.[116] Lastly, Michigan AG argues that DOE would not be justified in seeking an extension of the Emergency Order beyond 90 days under section

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[111] Emergency Order at 2.

[112] *Id.*

[113] Michigan AG Pet. at 55-56 (citing 42 U.S.C. § 4336e(10)).

[114] *Id*. at 55-56.

[115] *Id*. at 56 (citing 10 C.F.R. § 1021.102(b)).

[116] *See id*.

202(c)(3), considering "[a]ny justification that NEPA can be sidestepped to address an emergency need fades as DOE's orders extend beyond the initial 90-day period."[117]

The DOE's Determination

57. We disagree with Michigan AG's contention that the DOE "is acting contrary to its own NEPA regulations and to its obligations under NEPA."[118] Although DOE has previously followed the procedures provided in the Department's NEPA regulations governing emergency actions, as described in 10 C.F.R. § 1021.343 (for example, by preparing a special environmental analysis after the issuance of a section 202(c) order), recent amendments to NEPA clarify that agencies are "not required to prepare an environmental document with respect to a proposed agency action if… the preparation of such document would clearly and fundamentally conflict with the requirements of another provision of law."[119] As DOE recently explained in its NEPA Implementing Procedures, "NEPA does not apply to DOE's issuance of emergency Orders pursuant to section 202(c) of the Federal Power Act (16 U.S.C. 824a(c)) because preparing an environmental document under NEPA's generally applicable provisions would clearly and fundamentally conflict with the emergency provisions in the Federal Power Act."[120]

58. As discussed above, under FPA section 202(c), Congress explicitly authorized the Secretary to "with or without . . . report" exercise certain emergency authorities. Requiring compliance with the analytic and procedural demands of preparing an environmental document under NEPA prior to issuing a section 202(c) emergency order fundamentally conflicts with the authorization for emergency action contemplated by FPA section 202(c) and the Congressional authorization to exercise such authorities without report. Accordingly, DOE has determined, in consultation with the Council on Environmental Quality, that "NEPA does not apply to DOE's issuance of emergency orders pursuant to section 202(c) . . . because preparing an environmental document under NEPA's generally applicable provisions would clearly and fundamentally conflict with the emergency provisions in the Federal Power Act."[121]

59. Furthermore, as stated above, section 202(c) specifically provides alternative measures for affording environmental protection by requiring the Secretary to ensure that any such order "to the maximum extent practicable, is consistent with any applicable Federal, state, or local

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[117] *Id.* at 57-58.

[118] *Id.* at 56.

[119] *See* 42 U.S.C. § 4336(a)(3); *see also* Fiscal Responsibility Act of 2023, Pub. L. No. 188-5, § 321(b), 137 Stat. 10, 39 (2023).

[120] *National Environmental Policy Act (NEPA) Implementing Procedures*, U.S. Department of Energy, 6 (June 30, 2025), https://www.energy.gov/sites/default/files/2025-06/2025-06-30-DOE-NEPA-Procedures.pdf.

[121] *See id.*

environmental law or regulation and minimizes any adverse environmental impacts."[122] Again, those environmental obligations were met through the conditions imposed via the Emergency Order's limitation on the duration of the emergency operations, authorization of only the additional generation necessary, requirement that the operation of the plant to comply with environmental laws to the maximum extent feasible, and the requirement that MISO reports to the Department on MISO's compliance with the Emergency Order and corresponding environmental impacts, if any.

8. Deprivation of Fair Notice and Adequate Record

60. PIOs claim that DOE failed to comply with its own procedures to post filings on DOE's 202(c) website within twenty-four hours of receipt, depriving the public of fair notice and a meaningful opportunity to comment.[123] According to PIOs, DOE has not posted materials related to the Emergency Order that it has received, such as "a letter from counsel for Consumers Energy, which stated that MISO and Consumers Energy have not been able to reach agreement on the rate issues relating to the May 23, 2025 Order," among other things.[124] PIOs also argue that DOE's failure to follow these procedures "deprives the public and Public Interest Organizations of fair notice and an adequate record."[125]

The DOE's Determination

61. The subject of the letter PIOs reference was certain rate issues relating to the Emergency Order, as Consumers Energy and MISO have not been able to agree on appropriate rate issues relating to Emergency Order. Because the letter pertained to rate issues, DOE referred the issues to FERC pursuant to 10 C.F.R. § 205.376, by its own letter dated June 13, 2025.[126] Moreover, the letter and other materials identified by PIOs were submitted to the Department after the Emergency Order was issued and, as a result, had no bearing on the issuance of the Emergency Order.

9. Lack of Cost Allocation and Cost Recovery Framework

62. OMS claims that the Emergency Order disclaims responsibility for cost recovery to the FERC, while directly incurring costs through the continued operation of the Campbell Plant. OMS argues that this creates legal, jurisdictional, and equity concerns, by assigning costs to those not

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[122] 16 U.S.C. § 824a(c)(2).

[123] PIO Pet. at 50.

[124] *Id.*

[125] *Id.* (citing *United States v. Nova Scotia Food Prods. Corp.*, 568 F.2d 240, 249 (2d Cir. 1977)).

[126] *See* Ltr. from DOE to FERC, *Consumers Energy Company et al. v. Midcontinent Independent System Operator, Inc.*, FERC Docket. No. EL25-90 (June 13, 2025). In its letter, DOE described the contents of the prior letter from Consumers Energy, explaining that, "[o]n June 10, 2025, DOE received a letter from counsel for Consumers which stated that MISO and Consumers have not been able to reach agreement on the rate issues relating to the [Emergency Order]." *Id.* at 2.

causing the costs or receiving the benefits.[127] Further, OMS alleges the Emergency Order violates FPA sections 205 and 206, which OMS characterizes as requiring rates to be "just and reasonable and not unduly discriminatory or preferential."[128] Lastly, OMS alleges the Emergency Order violates "Cost Causation Principles" as held by courts.[129]

63. MPPA similarly claims it must be able to recover costs incurred due to compliance with the Emergency Order and operating the Campbell Plant beyond the retirement date of May 31, 2025, considering MPPA owns 4.80% of Unit No. 3 of the Campbell Plant and is therefore responsible for a portion of its operating and maintenance costs.[130]

64. According to MPPA, any alterations to the original directive could impact its financial recovery.[131] Additionally, MPPA is an intervenor in a related FERC complaint seeking cost recovery for the Campbell Plant owners and actively supports that complaint.[132] As such, MPPA's interests are unique and not adequately represented by other parties, and it requests party status in this DOE proceeding to ensure its concerns are addressed.[133]

The DOE's Determination

65. Petitioners' arguments are misguided. FPA section 202(c) does not impose any obligation on the Secretary to address cost allocation issues on the face of an emergency order. In any event, MISO's existing tariff already establishes how the costs of all generators dispatched by MISO ordinarily are to be allocated. Nothing in the Emergency Order held otherwise.

66. To the extent that the owners of the Campbell Plant desired additional compensation beyond what MISO's existing tariff provides, FPA section 202(c)(1) provides that: "[i]f the parties affected by [an emergency order issued pursuant to section 202(c)] fail to agree upon the terms of any arrangement between them in carrying out such order, the Commission, after hearing held either before or after such order takes effect, may prescribe by supplemental order such terms as it finds to be just and reasonable, including the compensation or reimbursement which should be paid to or by any such party."

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[127] OMS Pet. at 4.

[128] *Id*. at 5.

[129] *Id*.

[130] MPPA Comments at 1-2.

[131] *Id*. at 2.

[132] *Id*.

[133] *Id*.

67. Consistent with this statutory provision, DOE's regulations concerning generation of electricity to alleviate an emergency shortage of electric power address the procedures that DOE will follow when relevant entities are not able to agree on the rate issues arising from an order issued by DOE pursuant to section 202(c):

> The applicant and the generating or transmitting systems from which emergency service is requested are encouraged to utilize the rates and charges contained in approved existing rate schedules or to negotiate mutually satisfactory rates for the proposed transactions. In the event that the DOE determines that an emergency exists under section 202(c), and the "entities" are unable to agree on the rates to be charged, the DOE shall prescribe the conditions of service and refer the rate issues to the [FERC] for determination by that agency in accordance with its standards and procedures.[134]

68. On June 6, 2025, Consumers Energy filed a complaint (Complaint) pursuant to sections 202(c), 306, and 309 of the FPA and Rule 206 of FERC's Rule of Practice and Procedure, proposing revisions to the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff) to add a provision (Proposed Tariff Provision) to allocate the costs of keeping the Campbell Plant in operation, in response to the Emergency Order.[135] On June 13, 2025, DOE promptly issued a referral on cost allocation to FERC, pursuant to 10 C.F.R. § 205.376, in Docket Nos. EL25-90 and AD25-14.[136] The referral letter specified that "DOE is not referring to the Commission any other matters, including, but not limited to, DOE's finding of an emergency, the prescription of conditions of service, or any other matter arising from DOE's exercise of its authority under section 202(c). In an order issued August 15, 2025, in Docket Nos. EL25-90 and AD25-14, FERC granted the Complaint and determined that the Proposed Tariff Provision is just and reasonable.[137] FERC directed MISO to make a compliance filing, within 30 days of the date of the order, and to adopt the Proposed Tariff Provision.[138]

69. Thus, the cost allocation process established in the Emergency Order worked exactly as contemplated by section 202(c) and DOE's implementing regulations.

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[134] 10 C.F.R. § 205.376.

[135] *Consumers Energy Company et al. v. Midcontinent Independent System Operator, Inc.*, FERC Docket No. EL25-90 (June 6, 2025) (*citing* 16 U.S.C. §§ 824a(c), 825e, 825h, and 18 C.F.R. § 385.206 (2024) (Consumers Energy argued FPA sections 202(c) and 309 provide ample support for their request but moved for Section 206 relief in the alternative)).

[136] *See* Ltr. from DOE to FERC, *Consumers Energy Company et al. v. Midcontinent Independent System Operator, Inc.*, FERC Docket Nos. EL25-90 and AD25-14 (June 13, 2025).

[137] *See Consumers Energy Co. v. Midcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,158 (2025).

[138] *Id.* at 18.

III. Procedural Issues

1. PIOs' Request for a Stay

70. PIOs move for a stay of the Emergency Order pending resolution of judicial review. In support of their request, PIOs contend that (i) absent a stay, they will be irreparably harmed by the Emergency Order, (ii) a stay will not harm any other interested parties, and (iii) the public interest favors a stay.[139]

The DOE's Determination

71. In considering a request for a stay, agencies consider (1) whether the party requesting the stay will suffer irreparable injury without a stay; (2) whether issuing a stay may substantially harm other parties; and (3) whether a stay is in the public interest.[140]

72. By its terms, the Emergency Order terminated on August 21, 2025. Consequently, the stay request is now moot.

73. In any case, DOE finds that a stay is not warranted here because issuing a stay will substantially harm other parties and therefore is not within the public interest. Specifically, the Emergency Order was issued to address a shortage of electric energy, a shortage of facilities for the generation of electric energy in the Midwest region of the United States. As discussed above, this determination is based on the insufficiency of dispatchable capacity and anticipated demand, and the risk to public health and safety presented by the potential loss of power to homes and local businesses in areas that may be affected by curtailments or outages. Imposition of a stay undoubtedly may harm those citizens residing in the Midwest region of the United States who would face potentially critical electric energy shortages, and therefore the stay is contrary to the public interest.

2. Motions to Intervene

74. Michigan AG, PIOs, Minnesota and Illinois, MPPA, and Maryland OPC each moved to intervene in this proceeding, citing various alleged interests which may be affected by the outcome of this proceeding.[141]

The DOE's Determination

75. The motions to intervene are hereby granted for Michigan AG, PIOs, Minnesota and Illinois, and MPPA, but DOE takes no position on whether they are "aggrieved" parties for

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[139] PIO Pet. at 51-53.

[140] *Nken v. Holder*, 556 U.S. 418, 434, 436 (2010); *Ohio v. EPA*, 603 U.S. 279, 291 (2024).

[141] *See* Michigan AG Pet. at 2-3; PIO Pet. at 5-11; Minnesota & Illinois Pet. at 3-8; OMS Pet. at 1-2; Maryland OPC Comments at 1-3; MPPA Comments at 1-2.

purposes of FPA section 313.[142] The motion to intervene by Maryland OPC is denied as DOE maintains that Maryland OPC is not an "aggrieved" party for purposes of FPA section 313.[143]

* * * * *

The Emergency Order is hereby modified upon the issuance of this Order and the result sustained, as discussed in the body of this Order.

Issued at 6:40pm Eastern Daylight Time on this 8th day of September 2025.

Chris Wright

Chris Wright

Secretary of Energy

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[142] *See* 16 U.S.C. § 825*l*(b) ("Any party to a proceeding under this chapter aggrieved by an order issued by the Commission in such proceeding may obtain a review of such order in the United States court of appeals for any circuit wherein the licensee or public utility to which the order relates is located or has its principal place of business, or in the United States Court of Appeals for the District of Columbia, by filing in such court, within sixty days after the order of the Commission upon the application for rehearing, a written petition praying that the order of the Commission be modified or set aside in whole or in part.").

[143] *See,* Resp. in Opp'n to Maryland Office of People's Counsel Mot. to Intervene. *People of the State of Michigan v. U.S. Department of Energy*, No. 25-1162 (D.C. Cir. Sept. 4, 2025).

Planning Resource Auction

Results for Planning Year 2025-26

April 2025

CORRECTIONS

Reposted 05/29/25

Slides Updated: 7, 11, 18-20, 23, 32-34

MISO met the planning year 2025/26 resource adequacy requirements, but pressure persists with reduced capacity surplus across the region and is reflected through improved price signals in this year's auction

Summer
$666.50
–
Fall
$91.60 (North/Central)
$74.09 (South)
–
Winter
$33.20
–
Spring
$69.88
–
Annualized
$217 (North/Central)
$212 (South)

- MISO's Reliability-Based Demand Curve (RBDC) improves price signals, reflecting the increased value of accredited capacity beyond the seasonal Planning Reserve Margin (PRM) target
  - For example, the auction cleared 1.9% above the 7.9% summer PRM target
- Summer price reflects the lowest available surplus capacity
  - Fall price varied slightly due to transfer limitations between the North and South
- Consistent with past years, most Load Service Entities (LSEs) self-supplied or secured capacity in advance and are hedged with respect to auction prices
- Surplus above the target PRM dropped 43% compared to last summer, despite the slightly lower PRM target (7.9% vs. 9.0% last year)
  - New capacity additions did not keep pace with reduced accreditation, suspensions/retirements and slightly reduced imports
- The results reinforce the need to increase capacity, as demand is expected to grow with new large load additions

Auction outcomes are consistent with the design intent of the Reliability-Based Demand Curve (RBDC), and MISO and its members can expect more stable and predictable capacity pricing, especially in surplus situations

In the 2025 PRA, the RBDC…

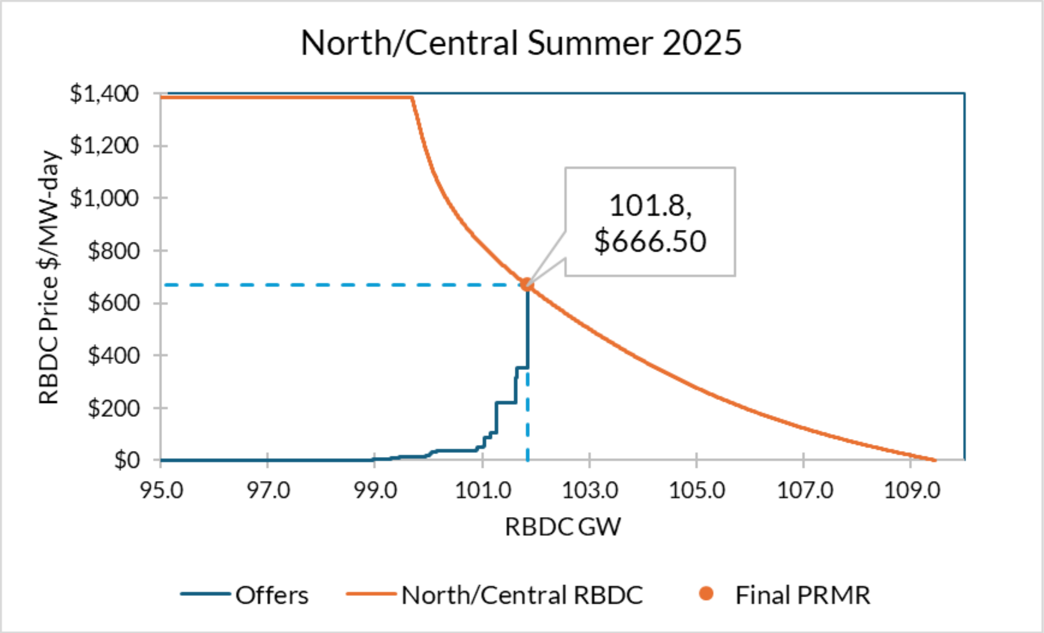
- Delivers competitive prices aligned with seasonal risks and tightening surplus
  - Prioritizes summer availability, the system's highest-risk season (based on 1-in-10 LOLE)
- Values incremental capacity above and below the LOLE target based on its reliability
  - Clears capacity above target Planning Reserve Margin based on its reliability value in each season
- Stabilizes prices in non-summer seasons, avoiding extreme volatility

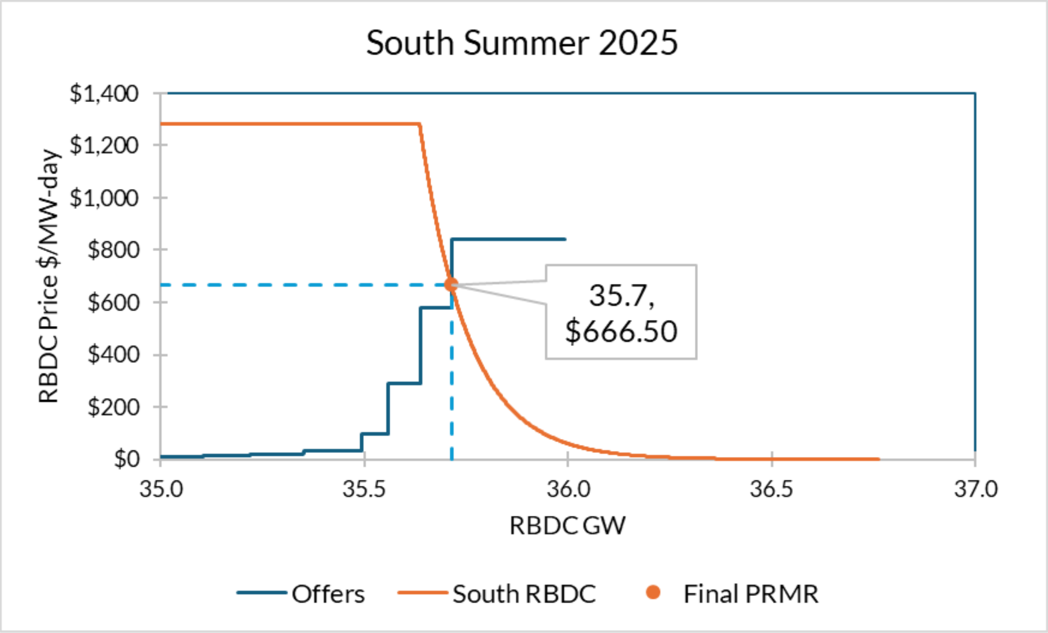
Why it Matters

- Sends clear and stable investment signals across the system, including to external resources
- Provides transparent value for capacity that exceeds the Planning Reserve Margin target
- Reflects subregional capacity needs and clears accordingly across all seasons

LOLE: Loss of Load Expectation

Auction pricing outcomes with the Reliability-Based Demand Curve (RBDC) better reflect value of capacity and resource adequacy risk across seasons



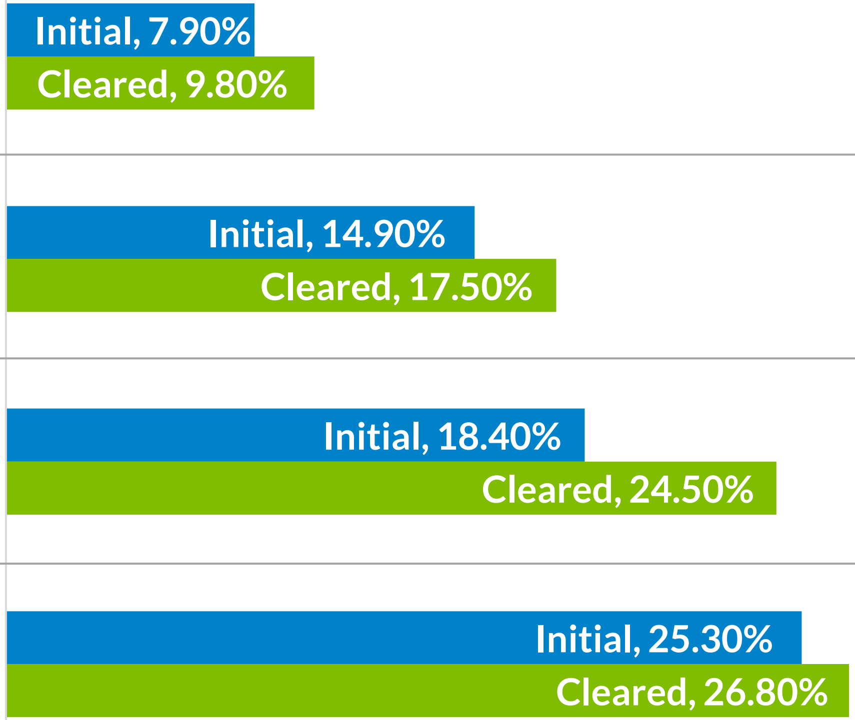


- Summer clearing of $666.50 reflects highest reliability risk and reducing surplus capacity year-over-year
  - Surplus capacity in the summer has reduced from approximately 6.5 GW in 2023, to 4.6 GW in 2024, to 2.6 GW in 2025
- Incremental capacity cleared beyond the target Planning Reserve Margin based on the value it adds to reliability (e.g., North/Central "effective" summer margin at 10.1% and South at 8.7% vs. target 7.9%)
  - A small quantity of capacity, that was offered at a price higher than the reliability value indicated through the demand curve, did not clear

LOLE: Loss of Load Expectation

MISO's Reliability-Based Demand Curve (RBDC) improves price signals, reflecting the increased value of accredited capacity beyond seasonal reliability targets

- Under RBDC, each season has an initial reliability target (PRM%)
- Auction cleared above seasonal final reliability target, representing additional reliability value at cost-competitive prices



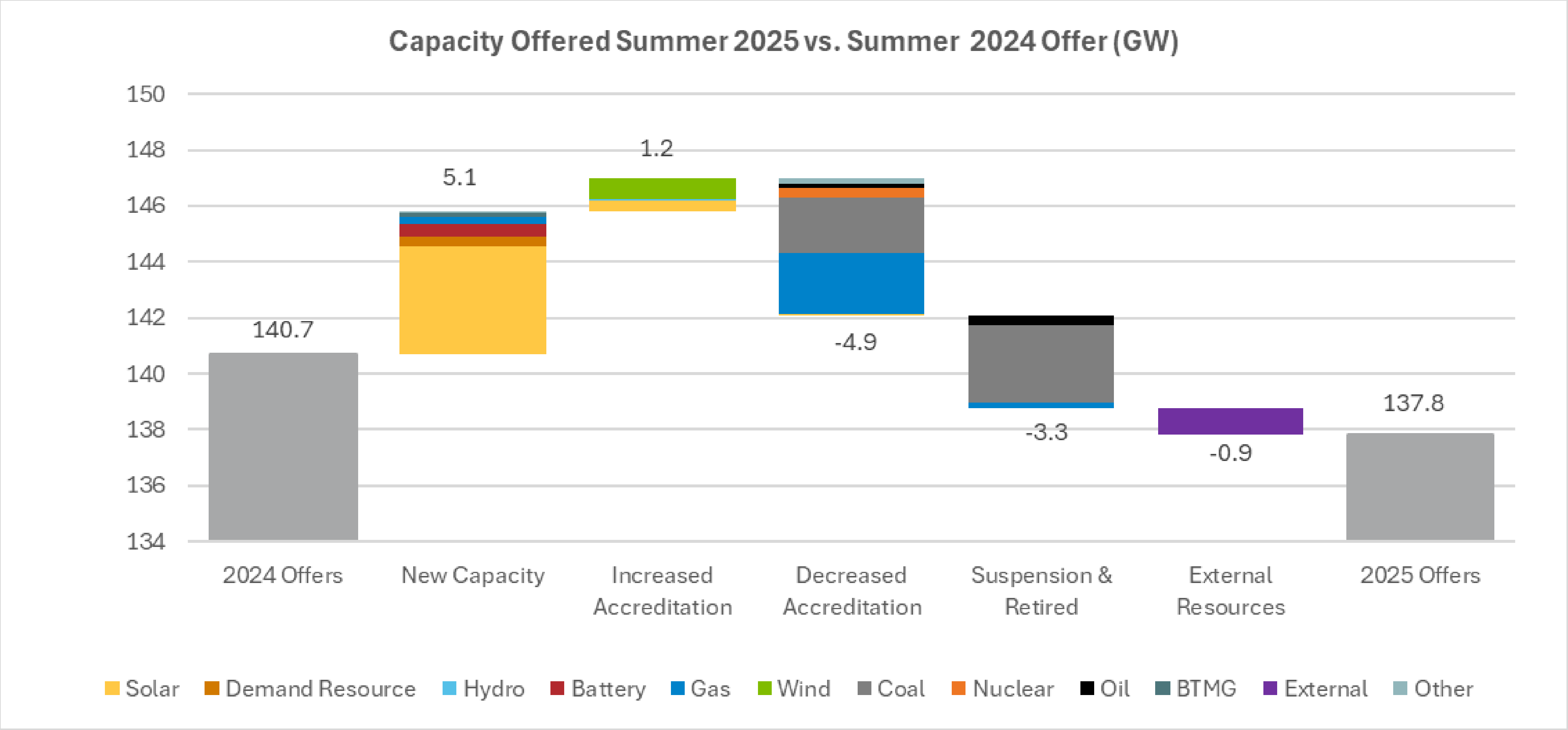
	2025 Planning Resource Auction Initial Target vs. Final Cleared	Additional Reliability	Auction Clearing Price
Summer	Initial, 7.90% Cleared, 9.80%	+1.9%	$666.50
Fall	Initial, 14.90% Cleared, 17.50%	+2.6%	$91.60 N/C $74.09 S
Winter	Initial, 18.40% Cleared, 24.50%	+6.1%	$33.20
Spring	Initial, 25.30% Cleared, 26.80%	+1.5%	$69.88

Annualized
$217 (North/Central)
$212 (South)

PRM: Planning Reserve Margin

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

New capacity additions did not keep pace with decreased accreditation, suspensions/ retirements and external resources



BTMG: Behind the Meter Generation | Capacity indicated is offered accredited value

MISO has taken action on many Reliability Imperative initiatives to address resource adequacy challenges, but there’s more to be done

Ongoing Challenges

- Accelerating demand for electricity
- Rapid pace of generation retirements continue
- Loss of accredited capacity and reliability attributes
- Majority of new resources with variable, intermittent output and high weather correlation
- Delays of new resource additions
- More frequent extreme weather

Completed Initiatives

- ✓ Implemented Reliability-Based Demand Curve in 2025 PRA
- ✓ Non-emergency resource accreditation *(effective PY 2028/29)*
- ✓ Generation interconnection queue cap
- ✓ Improved generator interconnection queue process (*New application portal coming June 2025*)
- ✓ Approved over $30 billion in new transmission lines

Initiatives In Progress

- ☐ Implement Direct Loss of Load (DLOL)-based accreditation
- ☐ Enhance resource adequacy risk modeling
- ☐ Reduce queue cycle times through automation
- ☐ Implement interim Expedited Resource Addition Study (ERAS) process *(June 2025)*
- ☐ Demand Response and Emergency Resource reforms
- ☐ Enhance allocation of resource adequacy requirements

Next Steps

April 28

2025 PRA Results Posted

May 21

Zonal deliverability benefits available at the May RASC
—
MISO publishes cleared Load Modifying Resources to Operations tools

May 28

Posting of PRA masked offer data per Module E-1 69 A.7.4

June 1

2025 PRA prices go into affect
—
New Planning Year starts

Appendix

Table of Contents

Acronyms

ACP: Auction Clearing Price

ARC: Aggregator of Retail Customers

BTMG: Behind the Meter Generator

CIL: Capacity Import Limit

CEL: Capacity Export Limit

CONE: Cost of New Entry

CPF: Coincident Peak Forecast

DLOL: Direct Loss-of-Load

DR: Demand Resource

ELCC: Effective Load Carrying Capability

EE: Energy Efficiency

ER: External Resource

ERAS: Expedited Resource Addition Study

ERZ: External Resource Zones

FRAP: Fixed Resource Adequacy Plan

ICAP: Installed Capacity

IMM: Independent Market Monitor

LBA: Load Balancing Authority

LCR: Local Clearing Requirement

LOLE: Loss of Load Expectation

LMR: Load Modifying Resource

LRR: Local Reliability Requirement

LRZ: Local Resource Zone

LSE: Load Serving Entity

OMS: Organization of MISO States

PO: Planned Outage

PRA: Planning Resource Auction

PRM: Planning Reserve Margin

PRMR: Planning Reserve Margin Requirement

RASC: Resource Adequacy Sub-Committee

RBDC: Reliability-Based Demand Curve

SAC: Seasonal Accredited Capacity

SREC: Sub-Regional Export Constraint

SRIC: Sub-Regional Import Constraint

SRPBC: Sub-Regional Power Balance Constraint

SS: Self Schedule

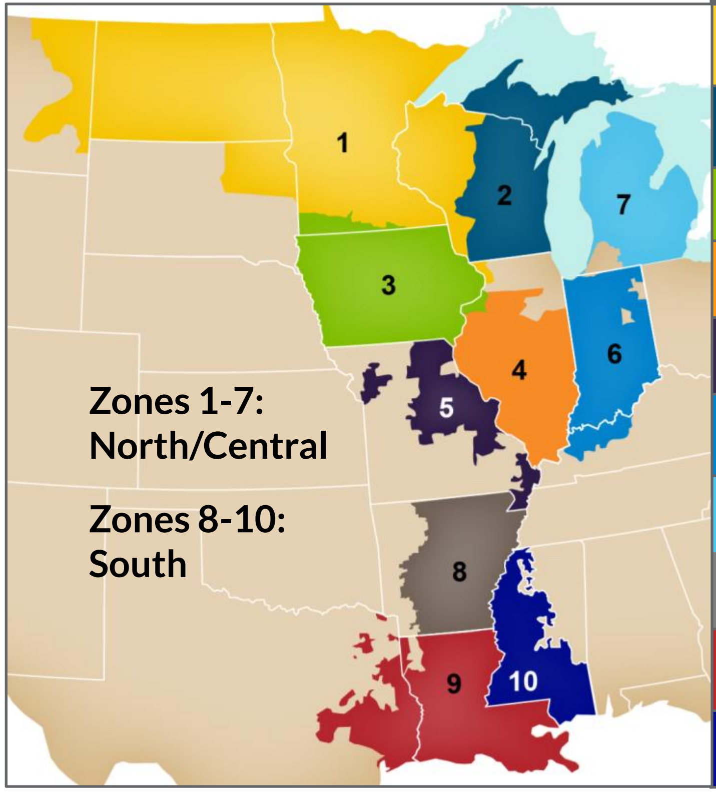
UCAP: Unforced Capacity

ZIA: Zonal Import Ability

ZRC: Zonal Resource Credit

The 2025 PRA demonstrated sufficient capacity at the regional, subregional and zonal levels, with the summer price reflecting the highest risk and a tighter supply-demand balance

MISO Resource Adequacy Zones



Zones 1-7: North/Central

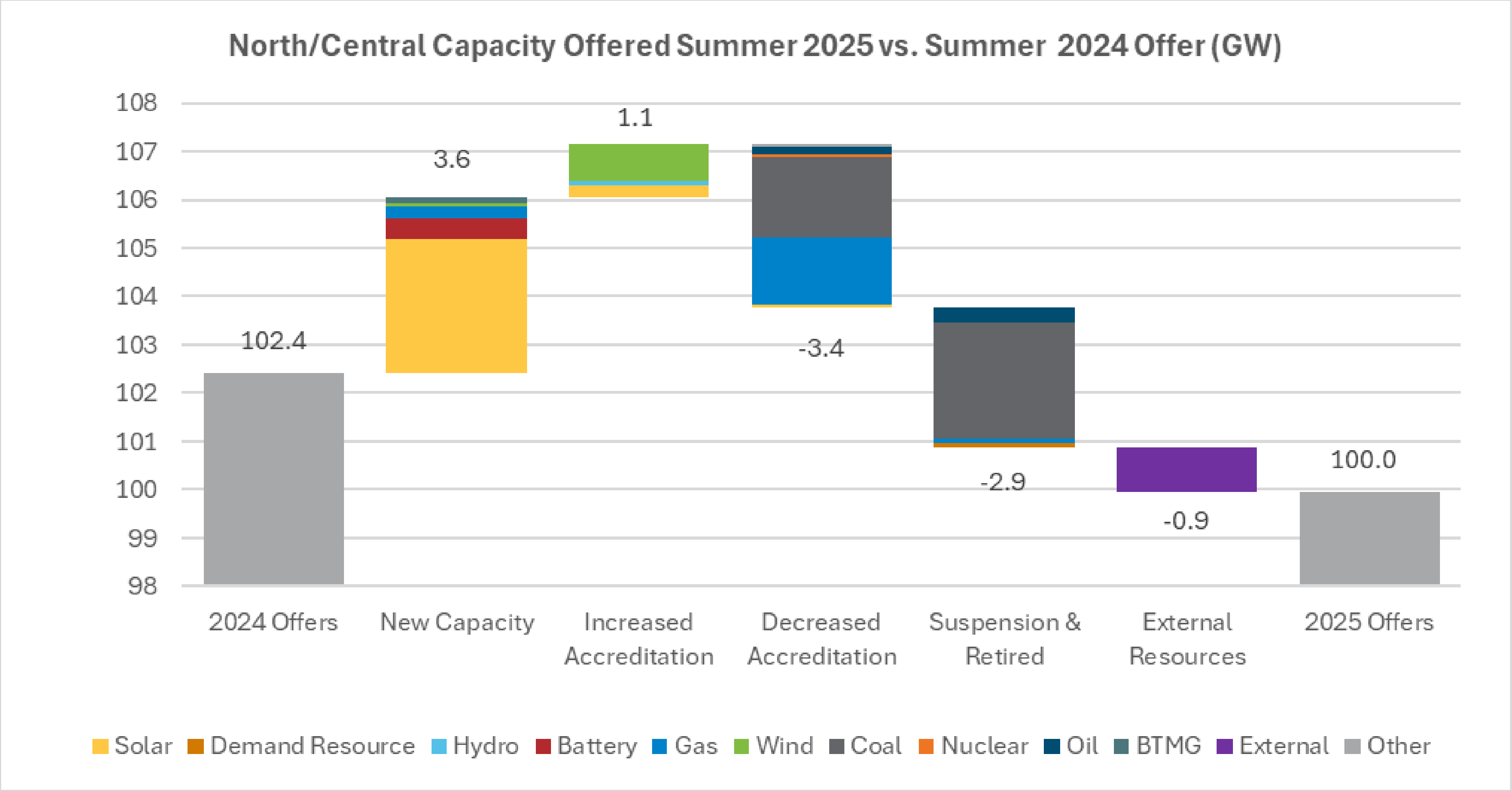
Zones 8-10: South

2025 PRA Results

	Price/MW-Day Summer	Fall	Winter	Spring
1	$666.50	$91.60	$33.20	$69.88
2				
3				
4				
5				
6				
7				
8		$74.09		
9				
10				

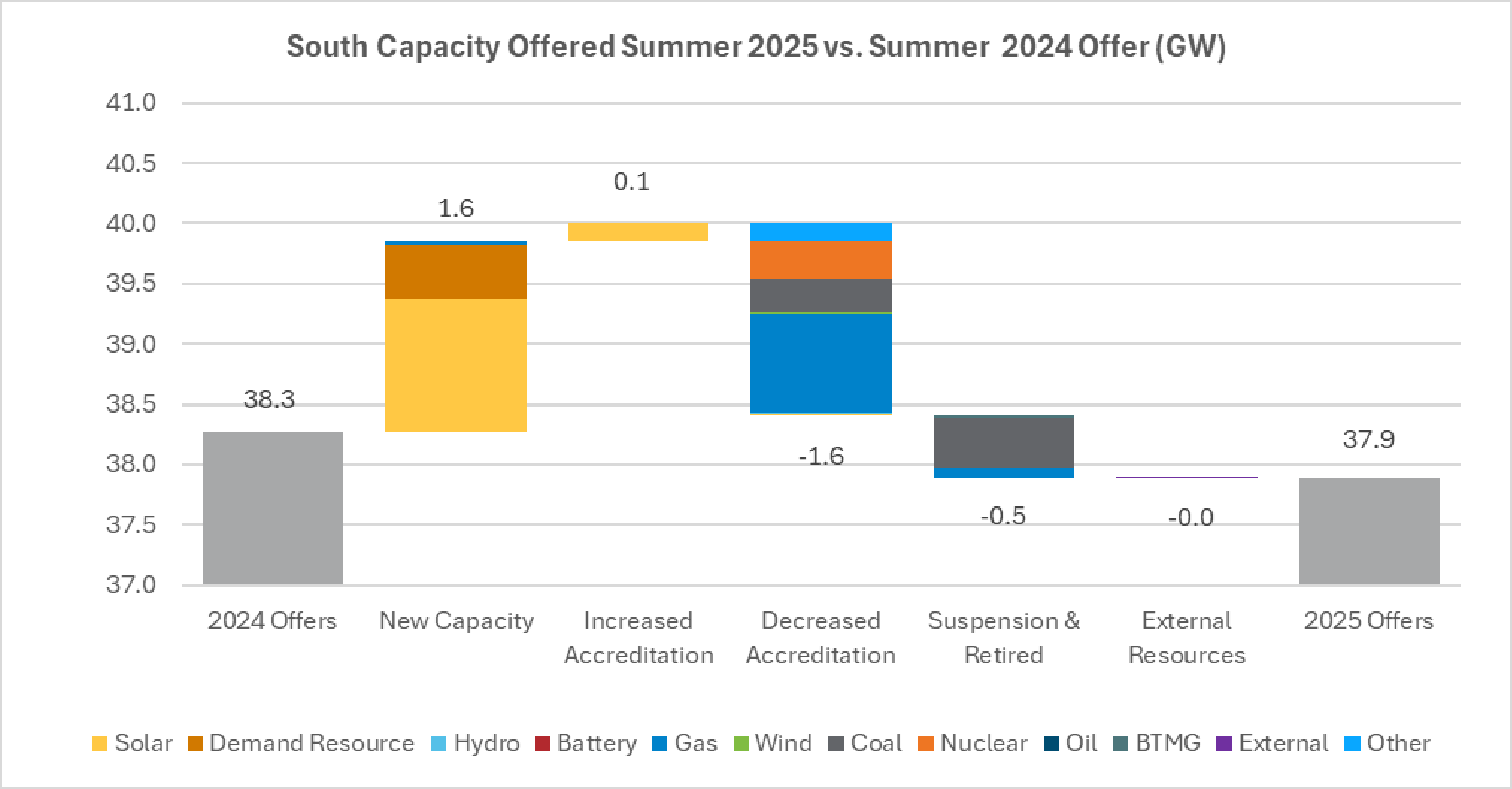
Annualized
$217 (North/Central)
$212 (South)

For North/Central, new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources



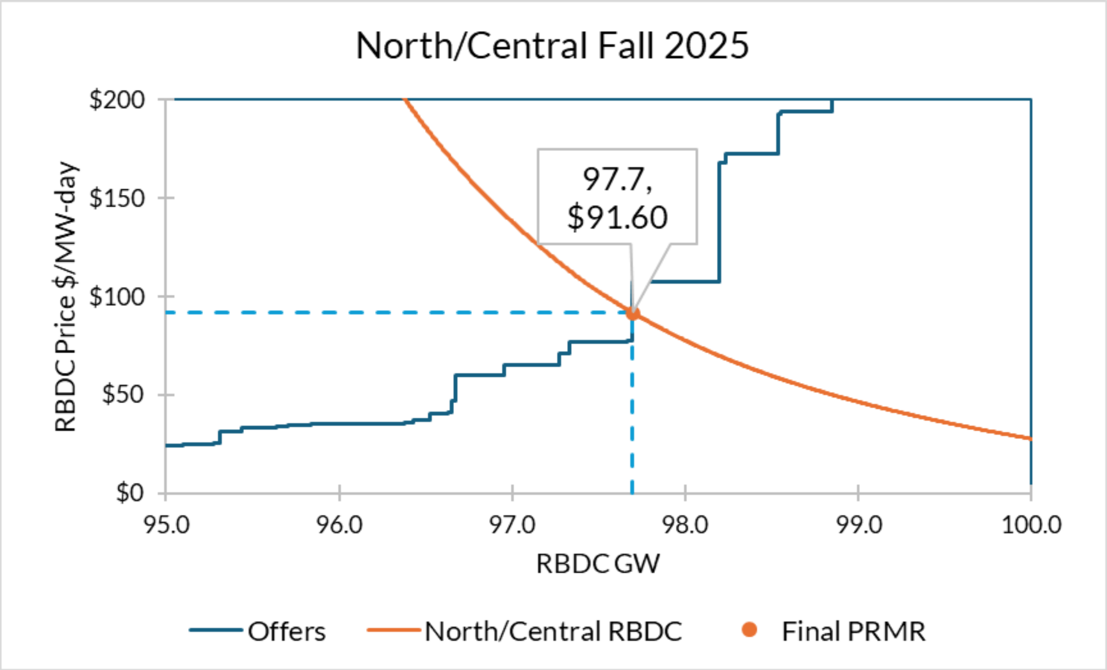
BTMG: Behind the Meter Generation | Capacity indicated is offered accredited value

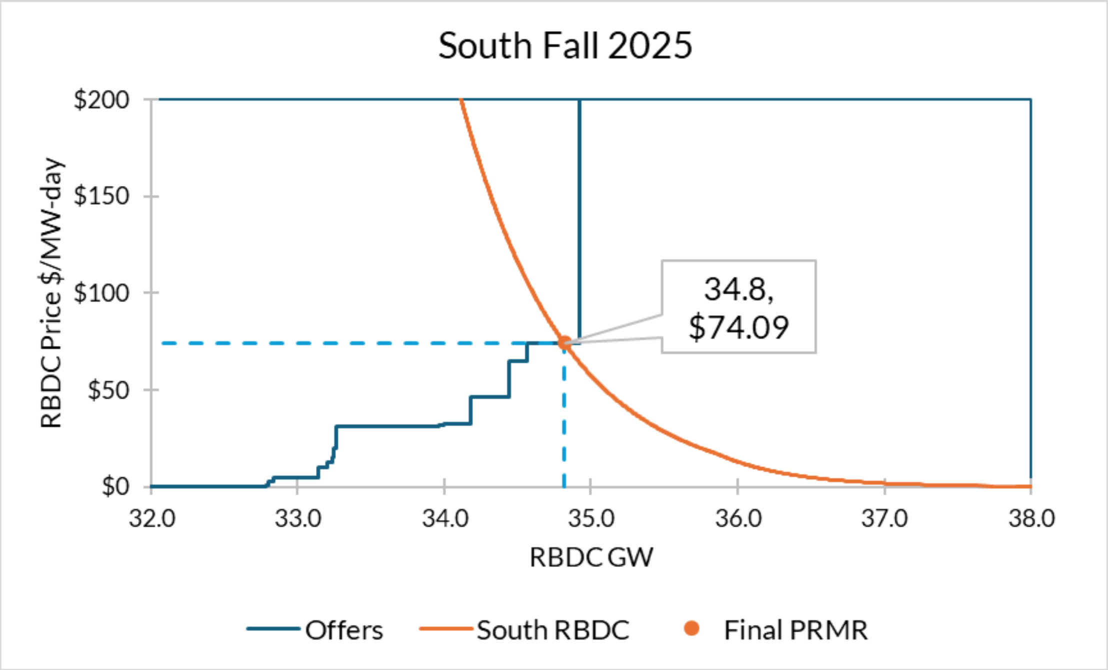
For the South, new capacity additions nearly offset the negative impacts of decreased accreditation, suspensions/retirements



BTMG: Behind the Meter Generation | Capacity indicated is offered accredited value

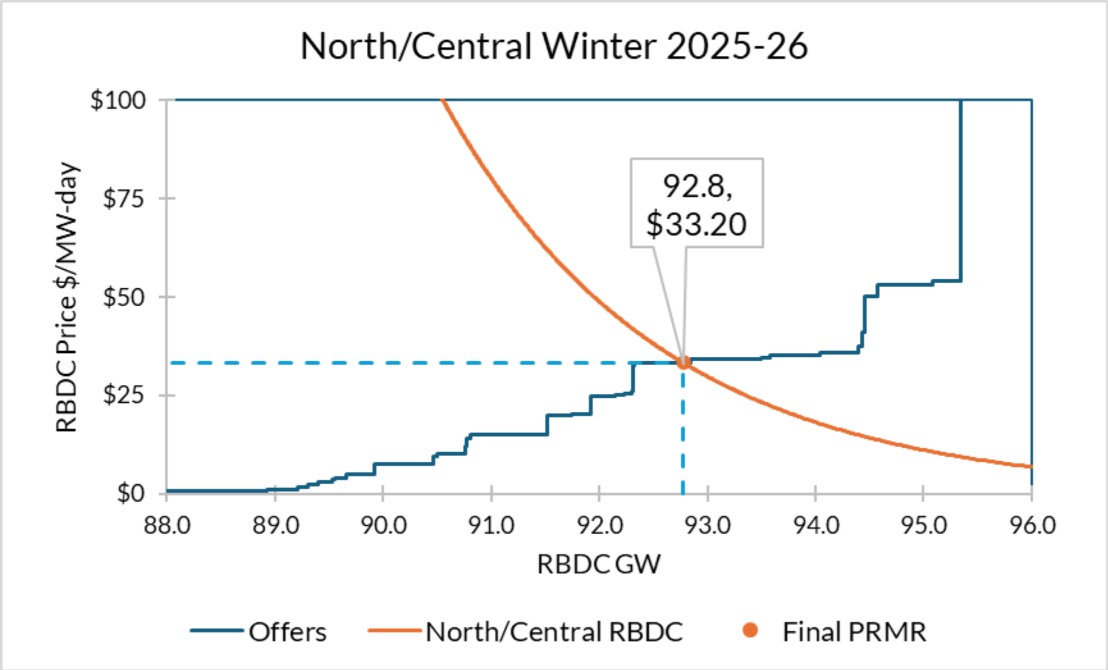
Fall 2025 Reliability-Based Demand Curve, Offer Curves and Auction Clearing Prices

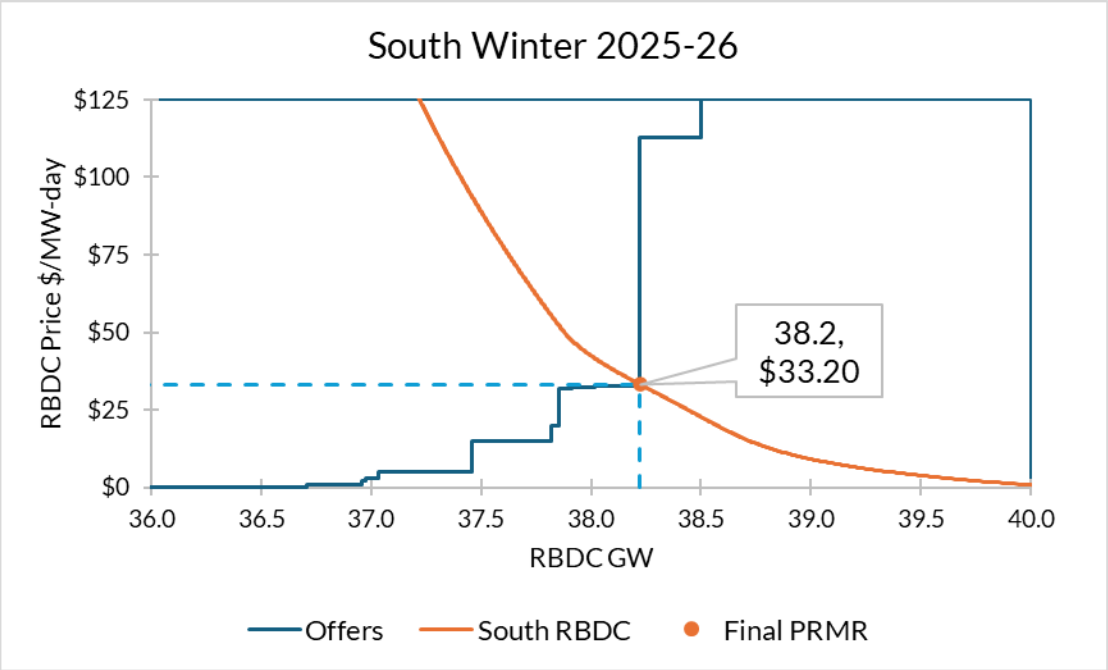

North/Central Fall 2025


South Fall 2025

- Subregional RBDCs are determining clearing for both subregions
- Subregional Power Balance Constraint (SRPBC), South to North, is binding resulting in price separation between North/Central and South subregions in Fall season
    - ACP for North subregion is $91.60, and $74.09 South subregion
    - A marginal resource in the South sets the price in that subregion
- In fall season, “effective” margin for North/Central subregion is at 18.4% and 15.2 % for South subregion vs. target of 14.9%

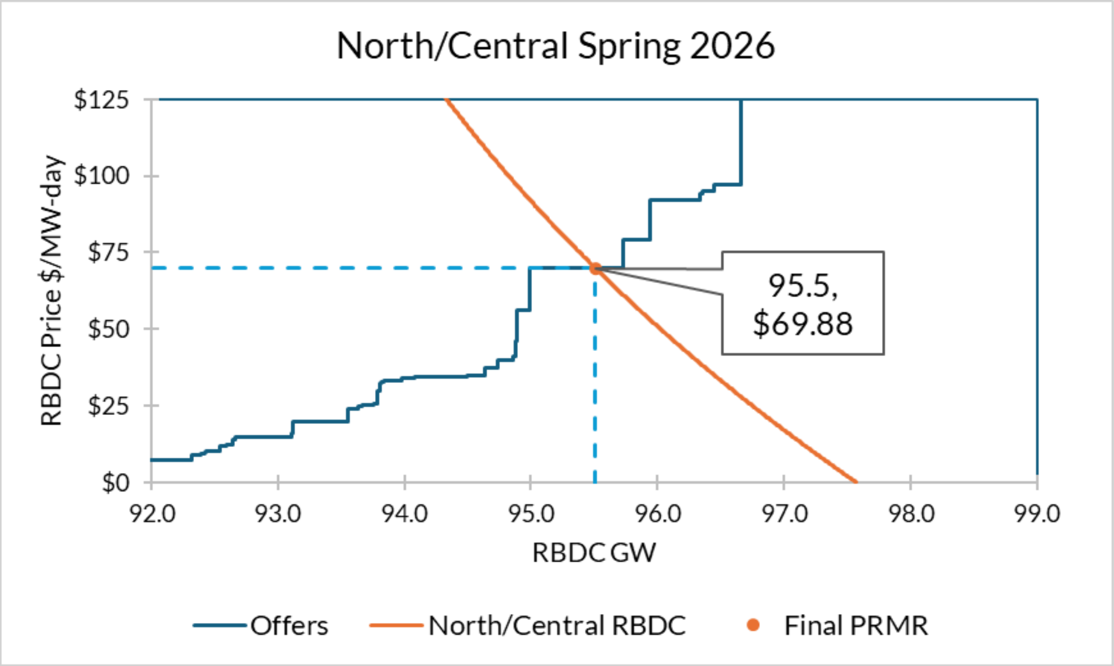
Winter 2025/26 Reliability-Based Demand Curve, Offer Curves and Auction Clearing Prices

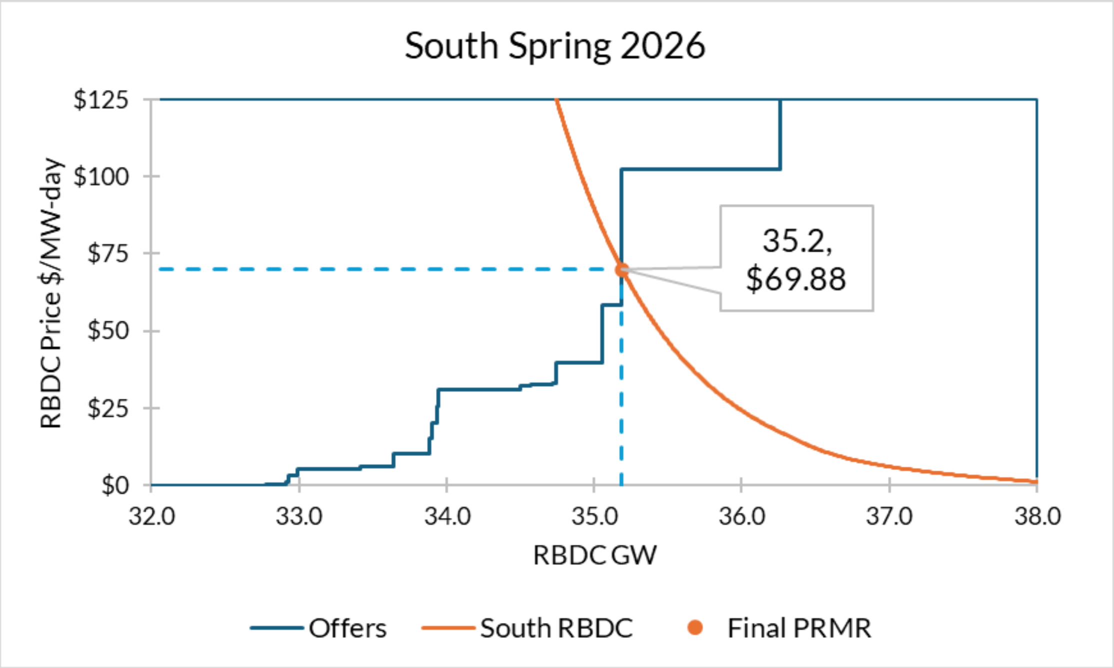




- Subregional RBDCs are determining clearing for both subregions
- No price separation between North/Central and South subregions in winter
  - ACP for both subregions is $33.20
  - Multiple marginal resources, cleared *pro rata*, sets the price
- In winter, “effective” margin for North/Central subregion is at 23.3% and $27.3% for South subregion vs. target of 18.4%

Spring 2026 Reliability-Based Demand Curve, Offer Curves and Auction Clearing





- Subregional RBDCs are determining clearing for both subregions
- No price separation between North/Central and South subregions in spring
  - ACP for both subregions is $69.88
  - A marginal resource sets the price
- In spring, "effective" margin for North/Central subregion is at 27.5% and 25% for South subregion vs. target of 25.3%

Summer 2025 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	North	South	System
Initial PRMR	18,459.4	13,190.2	10,889.2	9,237.6	8,281.3	18,484.8	21,228.0	8,487.8	21,812.2	5,142.9	N/A	99,770.5	35,442.9	135,213.4
Final PRMR	18,843.5	13,464.4	11,116.0	9,430.10	8,453.5	18,868.9	21,669.2	8,552.6	21,978.8	5,182.3	N/A	101,845.6	35,713.7	137,559.3
Offer Submitted (Including FRAP)	19,732.4	14,569.7	11,321.4	9,328.1	6,737.9	16,123.6	20,883.9	11,517.3	20,498.6	5,543.3	1580.1	99,952.6	37,883.7	137,836.3
FRAP	4,619.2	10,252.6	456.9	789.4	0.0	1,080.7	541.3	494.9	157.5	1,507.7	46.8	17,779.2	2,167.8	19,947.0
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Self Scheduled (SS)	4,985.3	3,344.1	10,450.2	7,677.2	6,647.8	11,080.3	20,305.5	10,260.6	17,870.6	3,831.3	1,358.8	65,567.6	32,244,1	97,811.7
Non-SS Offer Cleared	10,127.9	973.0	414.3	861.5	90.1	3,962.6	37.1	761.8	2,193.5	204.3	174.5	16,605.8	3,194.8	19,800.6
Committed (Offer Cleared + FRAP)	19,732.4	14,569.7	11,321.4	9,328.1	6,737.9	16,123.6	20,883.9	11,517.3	20,221.6	5,543.3	1,580.1	99,952.6	37,606.7	137,559.3
LCR	15,696.9	9,719.3	8,049.3	2,577.8	6,071.1	13,051.7	19,681.4	8,487.0	19,615.0	2,523.8	-	N/A	N/A	N/A
CIL	6,025	4,370	5,555	8,525	4,117	8,651	3,569	2,568	4,361	4,474	-	N/A	N/A	N/A
ZIA	6,023	4,370	5,460	7,757	4,117	8,366	3,569	2,358	4,361	4,474	-	N/A	N/A	N/A
Import	0.0	0.0	0.0	101.7	1,715.5	2,745.5	785.5	0.0	1,757.1	0.0	-	1,893.0	0.0	1,580.1
CEL	3,991	4,614	4,618	4,584	3,939	6,881	5,726	6,299	4,286	2,097	-	N/A	N/A	N/A
Export	888.8	1105.2	205.5	0.0	0.0	0.0	0.0	2964.7	0.0	360.9	1,580.1	0.0	1,893.0	-
ACP ($/MW-Day)	666.50	666.50	666.50	666.50	666.50	666.50	666.50	666.50	666.50	666.50	666.50			N/A

Values displayed in MW SAC; ERZ: External Resource Zones | Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.

Fall 2025 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	North	South	System
Initial PRMR	17,290.4	12,086.4	10,179.1	8,950.4	7,898.3	17,939.5	20,493.9	8,019.3	21,578.1	5,142.6	N/A	94,838.0	34,740.0	129,578.0
Final PRMR	17,811.9	12,450.7	10,486.0	9,220.4	8,136.0	18,480.2	21,111.9	8,037.4	21,627.1	5,154.2	N/A	97,697.1	34,818.7	132,515.8
Offer Submitted (Including FRAP)	18,893.1	14,291.7	13,615.9	8,887.5	6,839.6	15,518.1	19,517.6	11,000.8	21,112.5	5,516.6	1,582.1	98,835.3	37,940.2	136,775.5
FRAP	4,233.2	9,259.1	582.7	773.3	0.0	983.1	533.1	459.4	153.4	1,518.3	44.6	16,402.6	2,137.6	18,540.2
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Self Scheduled (SS)	4,646.8	3,423.5	10,580.4	7,036.0	6,706.5	10,590.4	16,911.4	9,029.4	17,788.1	3,286.3	1,208.0	60,831.1	30,375.7	91,206.8
Non-SS Offer Cleared	9,019.0	834.8	2,452.8	1,078.2	133.1	3,728.7	1,089.1	1,512.0	2,406.6	254.9	259.6	18,563.3	4,205.5	22,768.8
Committed (Offer Cleared + FRAP)	17,899.0	13,517.4	13,615.9	8,887.5	6,839.6	15,302.2	18,533.6	11,000.8	20,348.1	5,059.5	1,512.2	95,797.1	36,718.7	132,515.8
LCR	14,691.0	6,591.1	6,331.4	2,588.7	4,857.2	11,725.4	18,196.1	5,006.3	18,963.6	2,577.6	-	N/A	N/A	N/A
CIL	5,740	6,537	7,797	7,773	4,679	8,952	5,115	5,839	4,741	4,508	-	N/A	N/A	N/A
ZIA	5,688	6,537	7,704	7,013	4,679	8,672	5,115	5,675	4,741	4,508	-	N/A	N/A	N/A
Import	0.0	0.0	0.0	332.8	1,296.8	3,178.0	2,578.2	0.0	1,278.9	94.7	-	1,900.0	0.0	1,512.2
CEL	6,115	4,259	5,831	4,309	5,816	5,191	5,168	4,055	4,173	3,164	-	N/A	N/A	N/A
Export	87.2	1,066.8	3,129.9	0.0	0.0	0.0	0.0	2,963.3	0.0	0.0	1,512.2	0.0	1,900.0	-
ACP ($/MW-Day)	91.60	91.60	91.60	91.60	91.60	91.60	91.60	74.09	74.09	74.10	83.24-91.60			N/A

Values displayed in MW SAC; ERZ: External Resource Zones | Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.

Winter 2025/26 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	North	South	System
Initial PRMR	17,823.8	10,789.8	9,889.1	8,549.5	7,954.8	17,939.1	16,123.6	8,545.6	21,864.3	5,136.1	N/A	89,069.7	35,546.0	124,615.7
Final PRMR	18,565.8	11,238.7	10,300.9	8,905.1	8,285.9	18,685.7	16,794.7	9,189.0	23,511.0	5,522.7	N/A	92,776.8	38,222.7	130,999.5
Offer Submitted (Including FRAP)	19,750.7	13,217.2	12,059.1	7,547.1	6,339.9	14,679.5	19,957.3	10,751.9	22,273.0	5,939.7	1,746.5	94,964.8	39,297.1	134,261.9
FRAP	4,683.9	8,342.7	479.4	513.4	0.0	1,176.6	566.3	441.6	130.9	1,822.6	16.1	15,771.2	2,402.3	18,173.5
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Self Scheduled (SS)	5,835.8	3,156.0	10,468.3	6,685.7	6,188.7	9,146.2	18,640.6	10,018.6	18,579.3	4,046.0	1,550.8	61,380.9	32,935.1	94,316.0
Non-SS Offer Cleared	7,977.9	1,062.6	1,044.5	271.5	99.9	4,008.7	397.0	291.7	3,105.5	71.1	179.6	15,007.6	3,502.4	18,510.0
Committed (Offer Cleared + FRAP)	18,497.6	12,561.3	11,992.2	7,470.6	6,288.6	14,331.5	19,603.9	10,751.9	21,815.7	5,939.7	1,746.5	92,159.7	38,839.8	130,999.5
LCR	13,462.0	5,951.6	8,008.4	1,371.4	3,644.7	11,074.8	15,500.2	8,014.7	20,593.7	3,534.1	-	N/A	N/A	N/A
CIL	6,177	6,522	5,877	7,232	4,922	7,927	4,762	3,613	4,418	3,458	-	N/A	N/A	N/A
ZIA	5,575	6,435	5,785	6,457	4,922	7,690	4,762	3,432	4,418	3,458	-	N/A	N/A	N/A
Import	68.0	0.0	0.0	1,434.8	1,997.3	4,354.1	0.0	0.0	1,695.2	0.0	-	617.1	0.0	1,746.5
CEL	2,991	4,706	7,388	4,756	4,814	1,674	5,712	3,602	3,618	2,028	-	N/A	N/A	N/A
Export	0.0	1,322.6	1,691.5	0.0	0.0	0.0	2,809.2	1,562.8	0.0	416.9	1,746.5	0.0	617.1	0.0
ACP ($/MW-Day)	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20			N/A

Values displayed in MW SAC; ERZ: External Resource Zones | Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.

Spring 2026 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	North	South	System
Initial PRMR	17,866.7	12,149.2	10,152.2	8,304.0	7,707.9	17,858.6	19,853.2	7,977.8	22,139.8	5,167.9	N/A	93,891.8	35,285.5	129,177.3
Final PRMR	18,174.5	12,358.6	10,327.0	8,447.2	7,841.0	18,166.7	20,195.5	7,955.2	22,076.1	5,157.7	N/A	95,510.5	35,189.0	130,699.5
Offer Submitted (Including FRAP)	18,662.6	14,525.3	12,333.3	9,178.5	6,118.7	15,824.7	19,451.0	11,495.2	21,064.7	5,864.0	1,542.6	97,313.7	38,746.9	136,060.6
FRAP	4,560.6	9,393.4	529.5	629.6	0.0	1,212.4	512.5	475.3	142.1	1,464.3	45.9	16,877.1	2,088.5	18,965.6
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Self Scheduled (SS)	4,600.8	3,602.8	10,816.2	7,415.0	5,968.5	9,967.6	17,621.9	8,476.0	16,778.9	4,073.9	1,260.8	60,972.6	29,609.8	90,582.4
Non-SS Offer Cleared	8,578.5	1,069.5	589.6	1,133.9	150.2	4,001.0	719.2	1,470.2	2,947.5	325.8	166.1	16,372.9	4,778.6	21,151.5
Committed (Offer Cleared + FRAP)	17,739.9	14,065.7	11,935.3	9,178.5	6,118.7	15,181.0	18,853.6	10,421.5	19,868.5	5,864.0	1,472.8	94,222.5	36,477.0	130,699.5
LCR	12,239.1	6,737.5	5,014.7	1,823.8	4,700.3	10,377.1	16,453.6	4,243.1	19,790.5	3,178.8	-	N/A	N/A	N/A
CIL	6,598	6,439	7,829	8,142	4,453	9,457	5,166	6,289	4,855	4,365	-	N/A	N/A	N/A
ZIA	6,396	6,439	7,726	7,373	4,453	9,176	5,166	6,085	4,855	4,365	-	N/A	N/A	N/A
Import	434.5	0.0	0.0	0.0	1,722.2	2,985.6	1,341.9	0.0	2,210.8	0.0	-	1,288.0	0.0	1,472.8
CEL	5,083	6,119	5,936	5,111	5,797	6,425	5,499	3,520	4,146	3,072	-	N/A	N/A	N/A
Export	0.0	1,707.2	1,608.0	731.2	0.0	0.0	0.0	2,465.6	0.0	710.3	1,472.8	0.0	1,288.0	-
ACP ($/MW-Day)	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88			N/A

Values displayed in MW SAC; ERZ: External Resource Zones | Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.

Summer Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	**Summer 2023**	**Summer 2024**	**Summer 2025**	**Summer 2023**	**Summer 2024**	**Summer 2025**
Generation	122,375.6	123,395.6	121,015.6	116,989.7	119,479.2	120,738.6
External Resources	4,514.6	4,430.4	3,505.9	4,072.5	4,309.8	3,505.9
Behind the Meter Generation	4,175.2	4,180.2	4,282.8	4,129.4	4,143.5	4,282.8
Demand Resources	8,303.5	8,660.2	9,004.4	7,694.6	8,109.4	9,004.4
Energy Efficiency	5.0	22.5	27.6	5.0	22.5	27.6
Total	**139,373.9**	**140,688.9**	**137,836.3**	**132,891.2**	**136,064.4**	**137,559.3**

ZRC: Zonal Resource Credit

Fall Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	**Fall 2023**	**Fall 2024**	**Fall 2025**	**Fall 2023**	**Fall 2024**	**Fall 2025**
Generation	121,403.5	119,745.3	122,283.4	111,713.8	111,791.5	118,309.5
External Resources	4,095.4	4,366.8	2,833.5	3,979.6	3,990.2	2,763.6
Behind the Meter Generation	3,874.2	3,877.9	3,646.8	3,842.8	3,789.7	3,646.8
Demand Resources	6,999.2	6,866.1	7,983.7	6,254.4	5,957.5	7,767.8
Energy Efficiency	4.9	22.5	28.1	4.8	22.5	28.1
Total	**136,377.2**	**134,878.6**	**136,775.5**	**125,795.4**	**125,551.4**	**132,515.8**

ZRC: Zonal Resource Credit

Winter Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	**Winter 2023-2024**	**Winter 2024-2025**	**Winter 2025-2026**	**Winter 2023-2024**	**Winter 2024-2025**	**Winter 2025-2026**
Generation	124,632.7	133,457.4	120,225.1	114,886.6	118,253.8	117,392.0
External Resources	3,937.1	3,973.0	2,808.7	3,334.6	3,313.3	2,793.7
Behind the Meter Generation	3,257.8	3,111.5	3,082.9	3,173.9	2,957.3	3,082.6
Demand Resources	7,644.4	7,866.4	8,112.3	6,702.4	6,822.7	7,698.3
Energy Efficiency	6.7	29.7	32.9	6.7	29.7	32.9
Total	**139,478.7**	**148,438.0**	**134,261.9**	**128,104.2**	**131,376.8**	**130,999.5**

ZRC: Zonal Resource Credit

Spring Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	**Spring 2024**	**Spring 2025**	**Spring 2026**	**Spring 2024**	**Spring 2025**	**Spring 2026**
Generation	119,254.7	121,303.8	120,780.6	110,195.8	113,091.4	115,724.7
External Resources	3,794.1	3,481.8	2,640.1	3,409.1	3,406.5	2,570.3
Behind the Meter Generation	4,096.4	4,201.6	4,133.5	4,058.9	4,180.5	4,133.5
Demand Resources	7,282.9	7602.9	8,475.9	6,720.0	7,087.2	8,240.5
Energy Efficiency	5.3	25.0	30.5	5.3	25.0	30.5
Total	**134,433.4**	**136,615.1**	**136,060.6**	**124,389.1**	**127,790.6**	**130,699.5**

ZRC: Zonal Resource Credit

2025 PRA pricing compared with Independent Market Monitor (IMM) Conduct Threshold and Cost of New Entry (CONE)

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs	System CONE (Seasonal)	North/Central CONE (Seasonal)	South CONE (Seasonal)
Summer 2025	$666.50											$1,353.84	$1,384.36	$1,282.61
Fall 2025	$91.60							$74.09			$83.24-$91.60	$1,368.71	$1,399.58	$1,296.70
Winter 2025-26	$33.20											$1,383.92	$1,415.13	$1,311.11
Spring 2026	$69.88											$1,353.84	$1,384.36	$1,282.61
Cost of New Entry (Annual)	$127,720	$125,090	$121,220	$126,040	$136,170	$124,360	$130,930	$118,960	$117,710	$117,330	$136,170			
IMM Conduct Threshold*	$34.99	$34.27	$33.21	$34.53	$37.31	$34.07	$35.87	$32.59	$32.25	$32.15	-			

- *Zonal Auction Clearing Prices (ACP) shown in $/MW-day*

**Zonal Resource Credit (ZRC) offers that impact pricing should generally stay below the IMM Conduct Threshold and applies to all seasons.*

ERZ: External Resource Zones

Historical Summer Auction Clearing Price Comparison

<table>
<tr><th>PY</th><th>Zone 1</th><th>Zone 2</th><th>Zone 3</th><th>Zone 4</th><th>Zone 5</th><th>Zone 6</th><th>Zone 7</th><th>Zone 8</th><th>Zone 9</th><th>Zone 10</th><th>ERZs</th></tr>
<tr><td>2015-2016</td><td colspan="3">$3.48</td><td>$150.00</td><td colspan="3">$3.48</td><td colspan="2">$3.29</td><td>N/A</td><td>N/A</td></tr>
<tr><td>2016-2017</td><td>$19.72</td><td colspan="6">$72.00</td><td colspan="3">$2.99</td><td>N/A</td></tr>
<tr><td>2017-2018</td><td colspan="10">$1.50</td><td>N/A</td></tr>
<tr><td>2018-2019</td><td>$1.00</td><td colspan="9">$10.00</td><td>N/A</td></tr>
<tr><td>2019-2020</td><td colspan="6">$2.99</td><td>$24.30</td><td colspan="4">$2.99</td></tr>
<tr><td>2020-2021</td><td colspan="6">$5.00</td><td>$257.53</td><td>$4.75</td><td>$6.88</td><td>$4.75</td><td>$4.89-$5.00</td></tr>
<tr><td>2021-2022</td><td colspan="7">$5.00</td><td colspan="3">$0.01</td><td>$2.78-$5.00</td></tr>
<tr><td>2022-2023</td><td colspan="7">$236.66</td><td colspan="3">$2.88</td><td>$2.88-236.66</td></tr>
<tr><td>Summer 2023</td><td colspan="11">$10.00</td></tr>
<tr><td>Summer 2024</td><td colspan="11">$30.00</td></tr>
<tr><td>Summer 2025</td><td colspan="11">$666.50</td></tr>
</table>

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Fall Auction Clearing Price Comparison

<table>
<tr><th>PY</th><th>Zone 1</th><th>Zone 2</th><th>Zone 3</th><th>Zone 4</th><th>Zone 5</th><th>Zone 6</th><th>Zone 7</th><th>Zone 8</th><th>Zone 9</th><th>Zone 10</th><th>ERZs</th></tr>
<tr><td>Fall 2023</td><td colspan="8">$15.00</td><td>$59.21</td><td colspan="2">$15.00</td></tr>
<tr><td>Fall 2024</td><td colspan="4">$15.00</td><td>$719.81</td><td colspan="6">$15.00</td></tr>
<tr><td>Fall 2025</td><td colspan="7">$91.60</td><td colspan="3">$74.09</td><td>$83.24-$91.60</td></tr>
</table>

- Auction Clearing Prices shown in $/MW-Day
- Price separation present in Fall 2025 between the North and South subregions since the Sub-Regional Import Constraint (SRIC) / Sub-Regional Export Constraint (SREC) bound

ERZ: External Resource Zones

Winter Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Winter 2023-24	$2.00								$18.88	$2.00	
Winter 2024-25	$0.75										
Winter 2025-26	$33.20										

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Spring Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Spring 2024	$10.00										
Spring 2025	$34.10				$719.81	$34.10					
Spring 2026	$69.88										

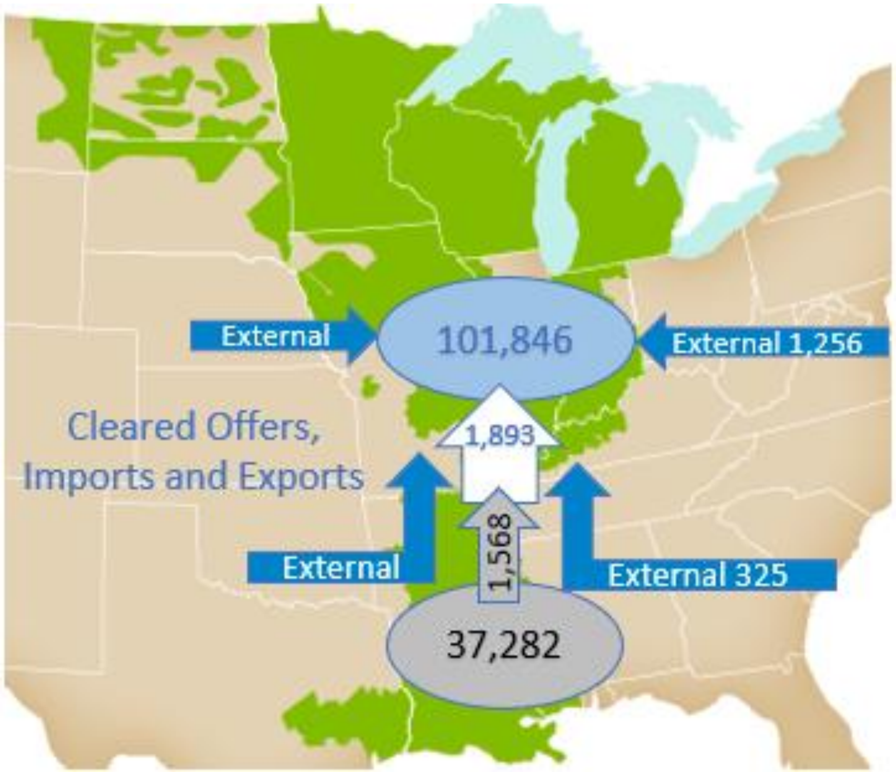
- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Summer 2025 Capacity

Offered Capacity & Final PRMR (MW)

Cleared Capacity, Imports & Exports (MW)



PRMR: *Planning Reserve Margin Requirement*

Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Fall 2025 Capacity

Offered Capacity & Final PRMR (MW)

Cleared Capacity, Imports & Exports (MW)

PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Winter 2025/26 Capacity

Offered Capacity & Final PRMR (MW)

Cleared Capacity, Imports & Exports (MW)

PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Spring 2026 Capacity

Offered Capacity & Final PRMR (MW)

Cleared Capacity, Imports & Exports (MW)

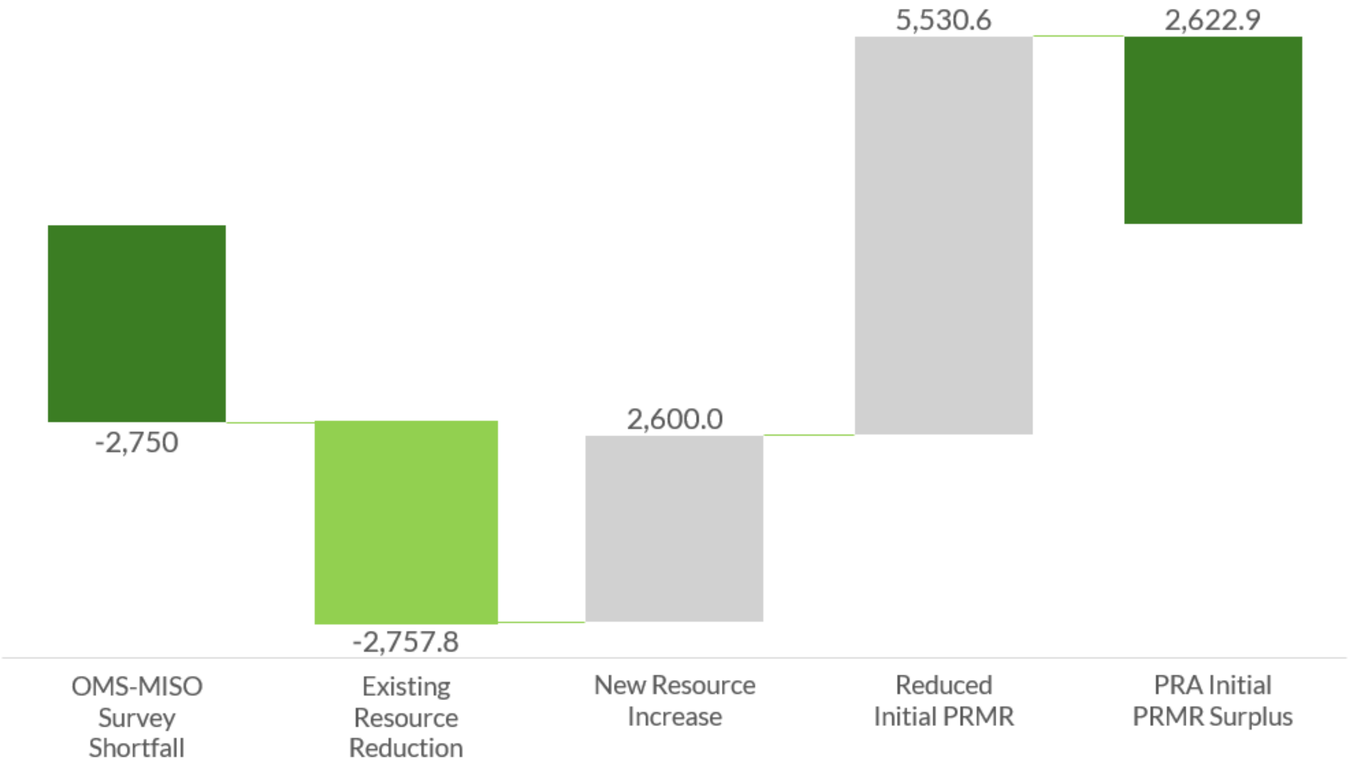
PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

The 2025 auction resulted in a surplus compared to the PRMR target, in contrast to the 2024 OMS-MISO Survey projection of a shortfall

Summer 2025 auction outcomes vs. 2024 OMS-MISO Survey projection for 2025

- Resource offers in the auction were comparable to "High Certainty" values projected in the OMS-MISO Survey
- Incremental accreditation reductions in the auction were offset by incremental increases in new resource additions
- Notably, initial PRMR was lower (5.5 GW) than projected in the OMS-MISO Survey

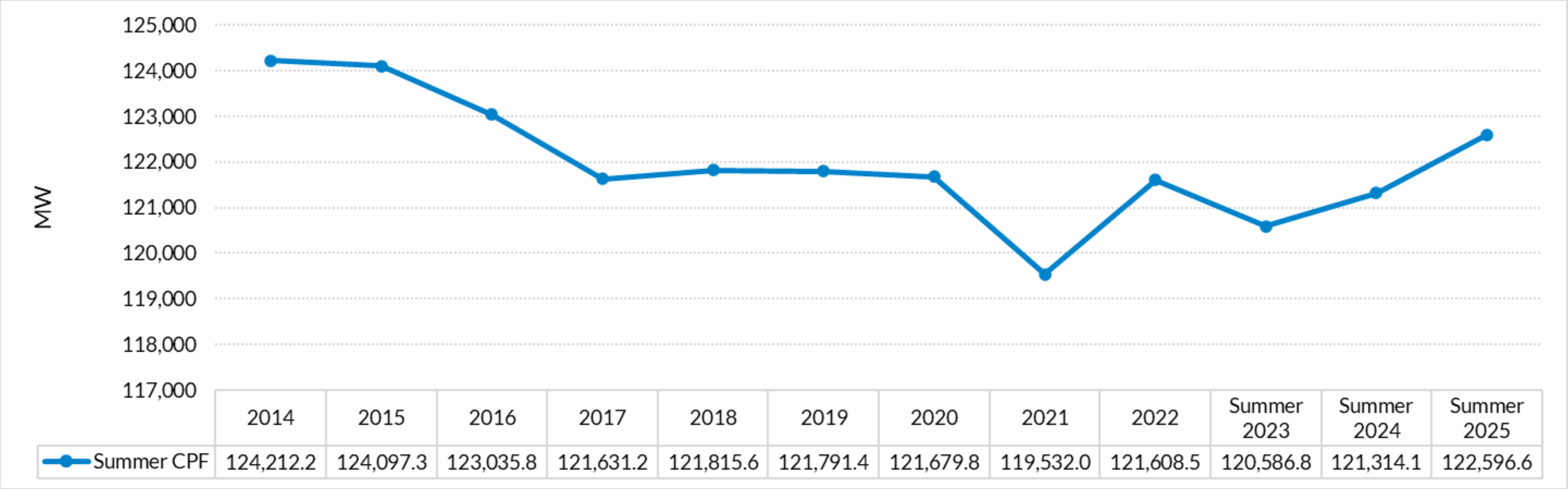
2024 OMS-MISO Survey Projection vs. 2025 PRA Actual PRMR Surplus (MW)



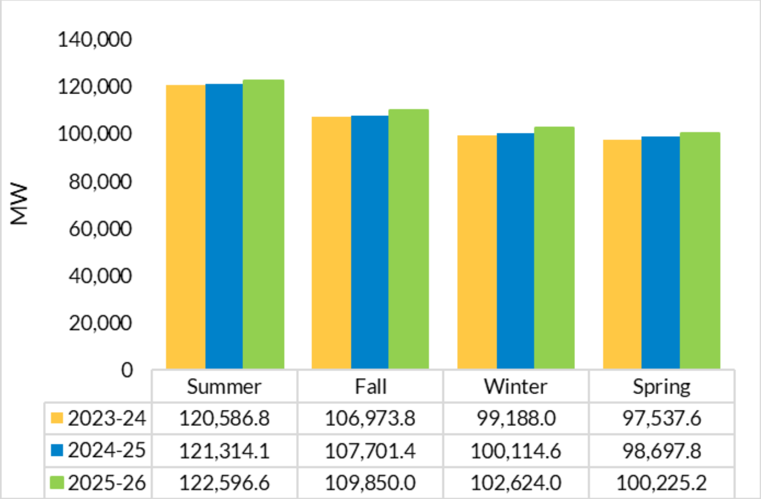
*PRA Shortfall/Surplus relative to Initial PRMR | PRMR: Planning Reserve Margin Requirement

Coincident Peak Forecast

Year over year the Summer CPF (+1.3 GW), PRM (-1.1%) and Final PRMR (+1.5 GW) are higher.



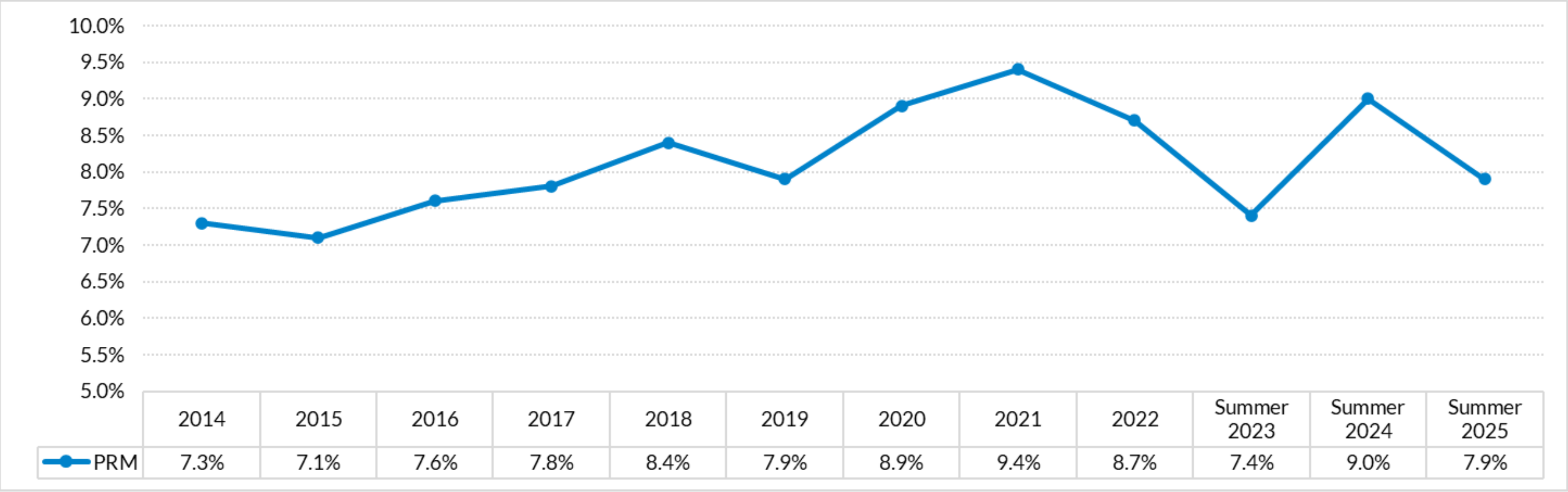
	2014	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023	Summer 2024	Summer 2025
Summer CPF	124,212.2	124,097.3	123,035.8	121,631.2	121,815.6	121,791.4	121,679.8	119,532.0	121,608.5	120,586.8	121,314.1	122,596.6



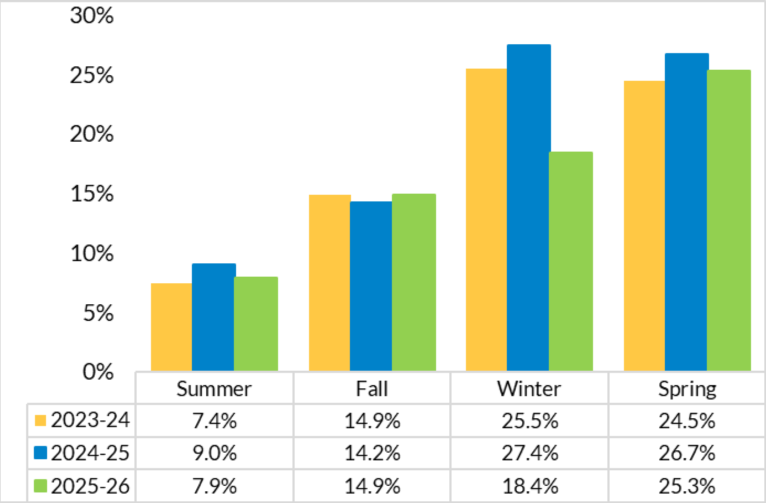
	Summer	Fall	Winter	Spring
🟨 2023-24	120,586.8	106,973.8	99,188.0	97,537.6
🟦 2024-25	121,314.1	107,701.4	100,114.6	98,697.8
🟩 2025-26	122,596.6	109,850.0	102,624.0	100,225.2

PRMR: Planning Reserve Margin Requirement

Planning Reserve Margin (%)

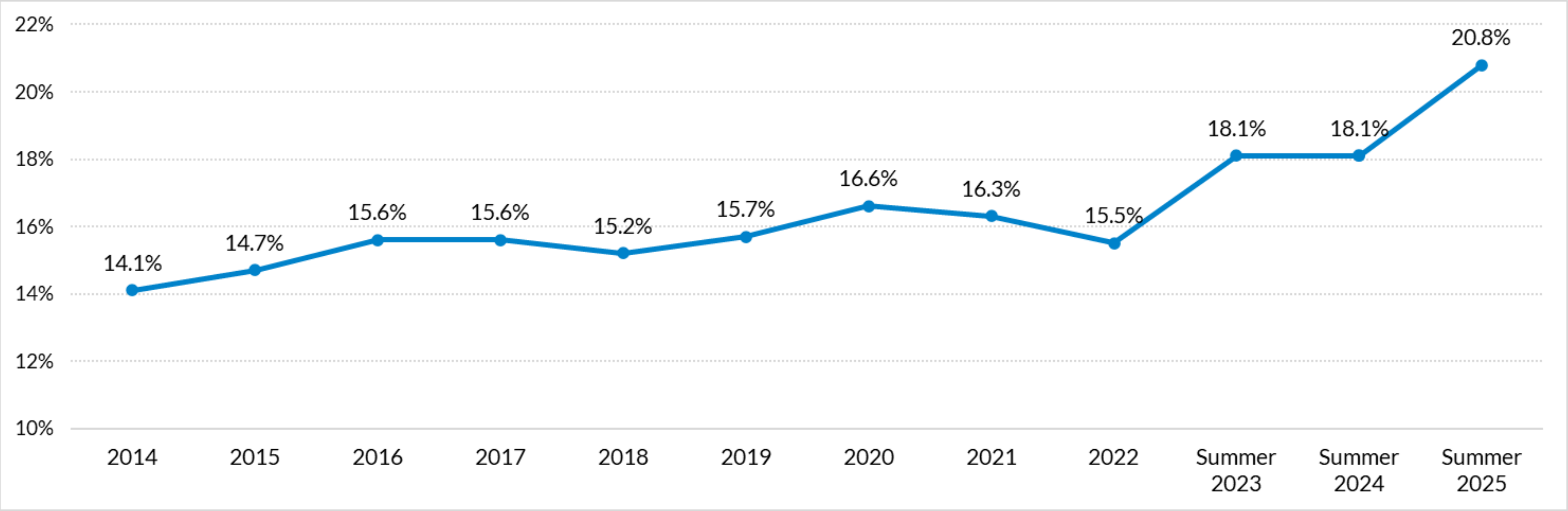


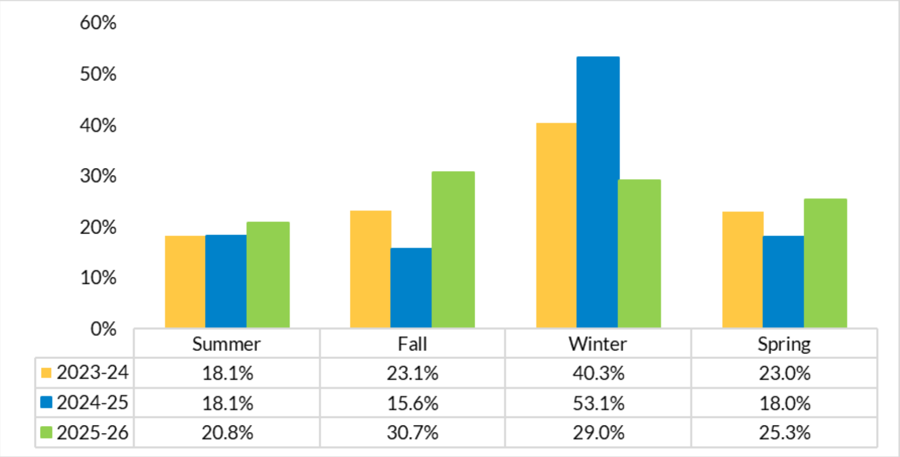
	2014	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023	Summer 2024	Summer 2025
PRM	7.3%	7.1%	7.6%	7.8%	8.4%	7.9%	8.9%	9.4%	8.7%	7.4%	9.0%	7.9%



	Summer	Fall	Winter	Spring
🟨 2023-24	7.4%	14.9%	25.5%	24.5%
🟦 2024-25	9.0%	14.2%	27.4%	26.7%
🟩 2025-26	7.9%	14.9%	18.4%	25.3%

Wind Effective Load Carrying Capacity (%)



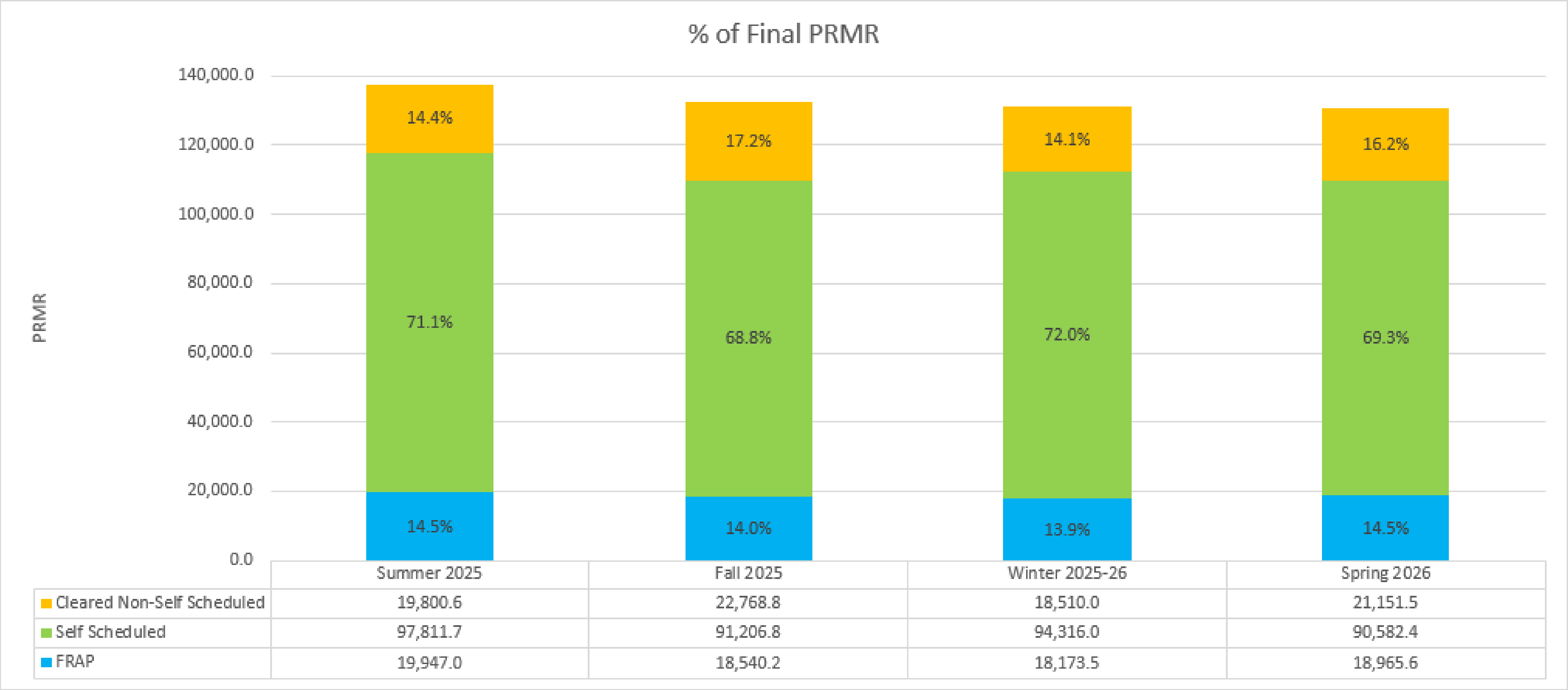


	Summer	Fall	Winter	Spring
🟨 2023-24	18.1%	23.1%	40.3%	23.0%
🟦 2024-25	18.1%	15.6%	53.1%	18.0%
🟩 2025-26	20.8%	30.7%	29.0%	25.3%

- No change to wind or solar accreditation methodology from previous years.
- Methodology applied on a seasonal basis.
- Wind ELCC and new solar capacity is established in the LOLE Study
- New solar class average
    - Summer, fall, spring 50%
    - Winter 5%

ELCC: Effective Load Carrying Capability   LOLE: Loss of Load Expectation

2025/26 Seasonal Resource Adequacy Requirements are fulfilled similarly across all four seasons



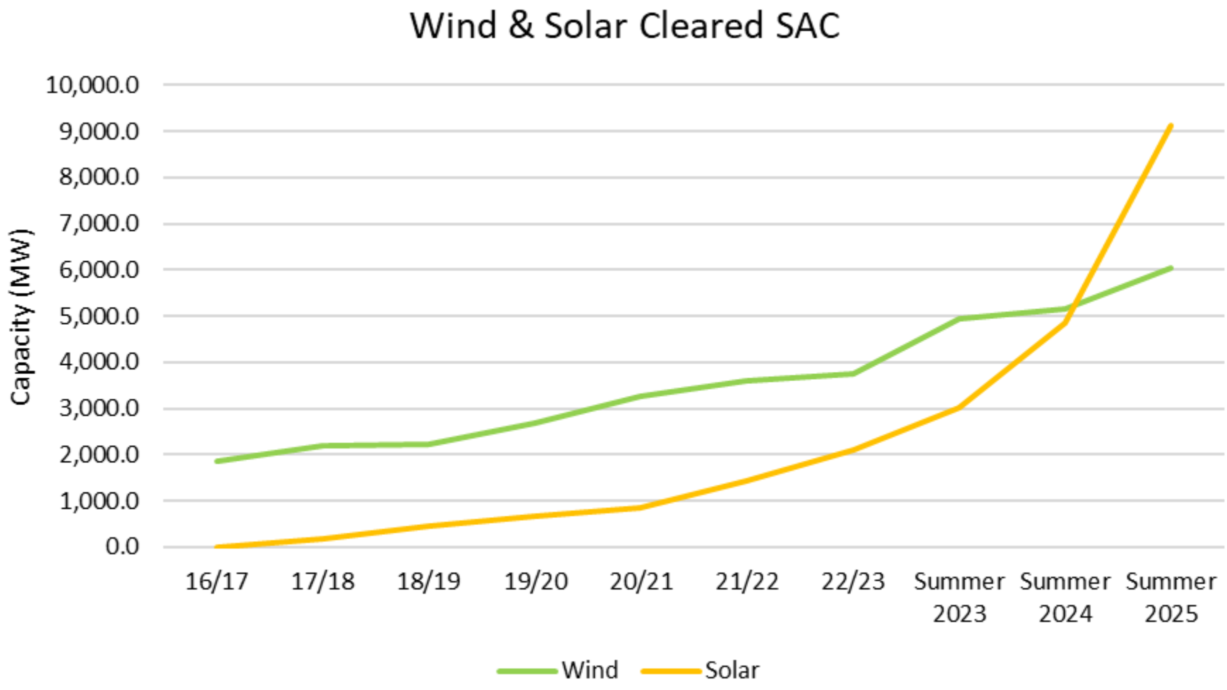
	Summer 2025	Fall 2025	Winter 2025-26	Spring 2026
🟨 Cleared Non-Self Scheduled	19,800.6	22,768.8	18,510.0	21,151.5
🟩 Self Scheduled	97,811.7	91,206.8	94,316.0	90,582.4
🟦 FRAP	19,947.0	18,540.2	18,173.5	18,965.6

PRMR: Planning Reserve Margin Requirement

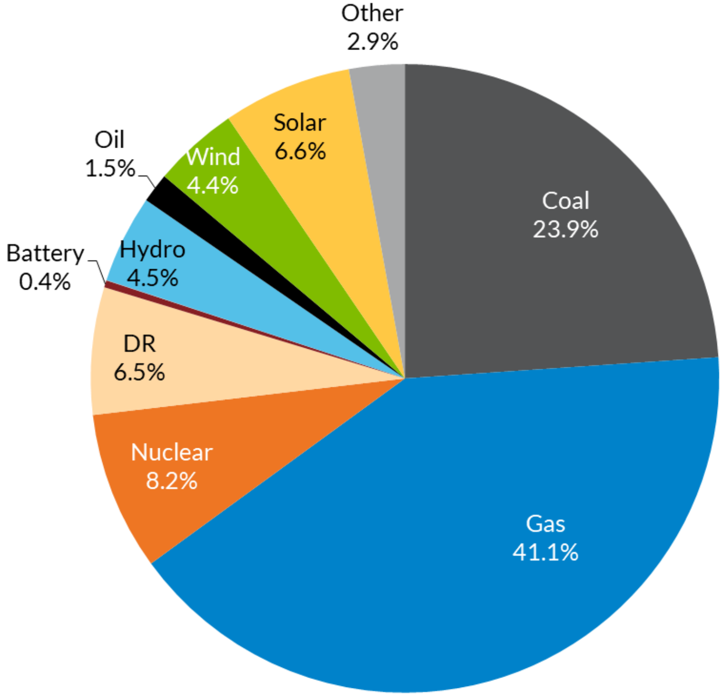
Although conventional generation still comprises most of the capacity, wind and solar continue to grow

- 9.1 GW of solar cleared this year’s auction, an increase of 88% from Planning Year 2024/25 (4.9 GW)

- 6 GW of wind cleared this year, an increase of 17% compared to last year (5.2 GW)



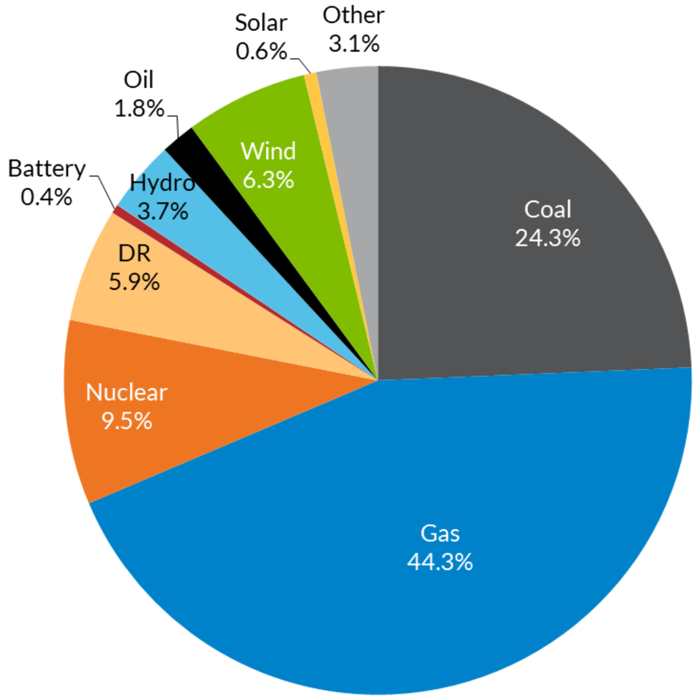
Winter final PRMR is 6.6 GW (4.8%) lower than the summer with fewer solar resources to meet final PRMR in the winter versus the summer



Summer 2025

MISO-wide

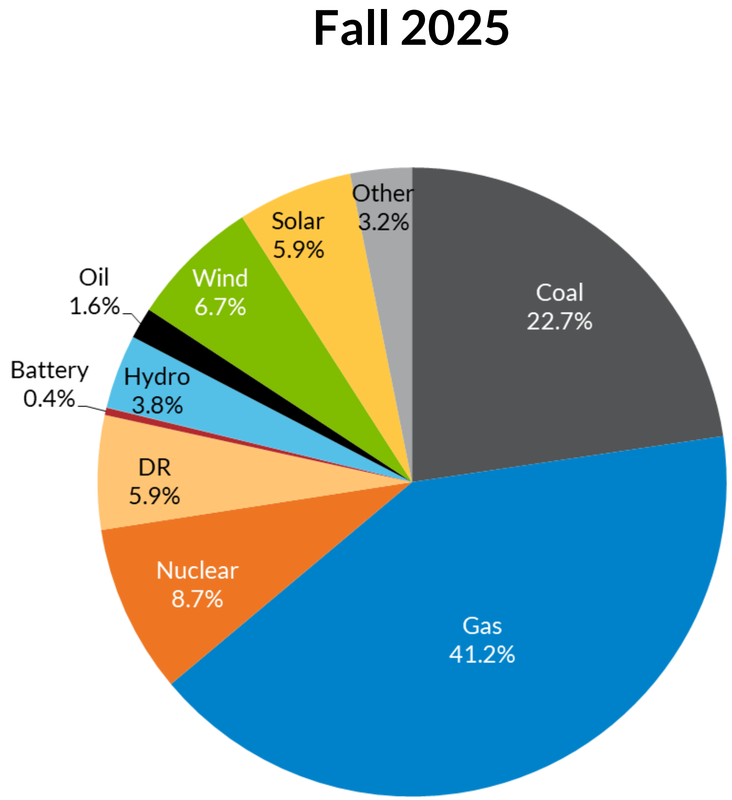
Cleared ZRC	Summer 2025	Winter 2025/26	Difference
Coal	32,909.6	31,887.2	1,022.4
Gas	56,470.0	57,990.5	-1,520.5
Nuclear	11,232.1	12,416.7	-1,184.6
DR	9,004.4	7,698.3	1,306.1
Battery	499.2	588.5	-89.3
EE	27.6	32.9	-5.3
Hydro	6,231.3	4,823.7	1,407.6
Oil	2,088.8	2,315.7	-226.9
Wind	6,039.1	8,282.9	-2,243.8
Solar	9,122.8	847.3	8,275.5
Misc	3,934.4	4,115.8	-181.4
PRMR	137,559.3	130,999.5	6,559.8



Winter 2025/26

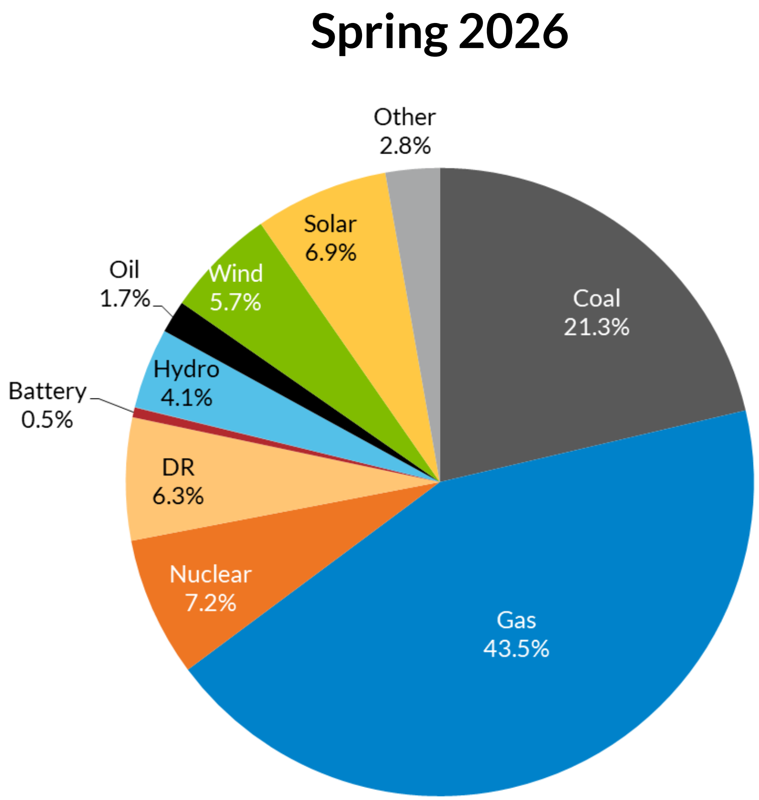
PRMR: Planning Reserve Margin Requirement

Fall 2025 and Spring 2026 - Cleared ZRCs and Final PRMR



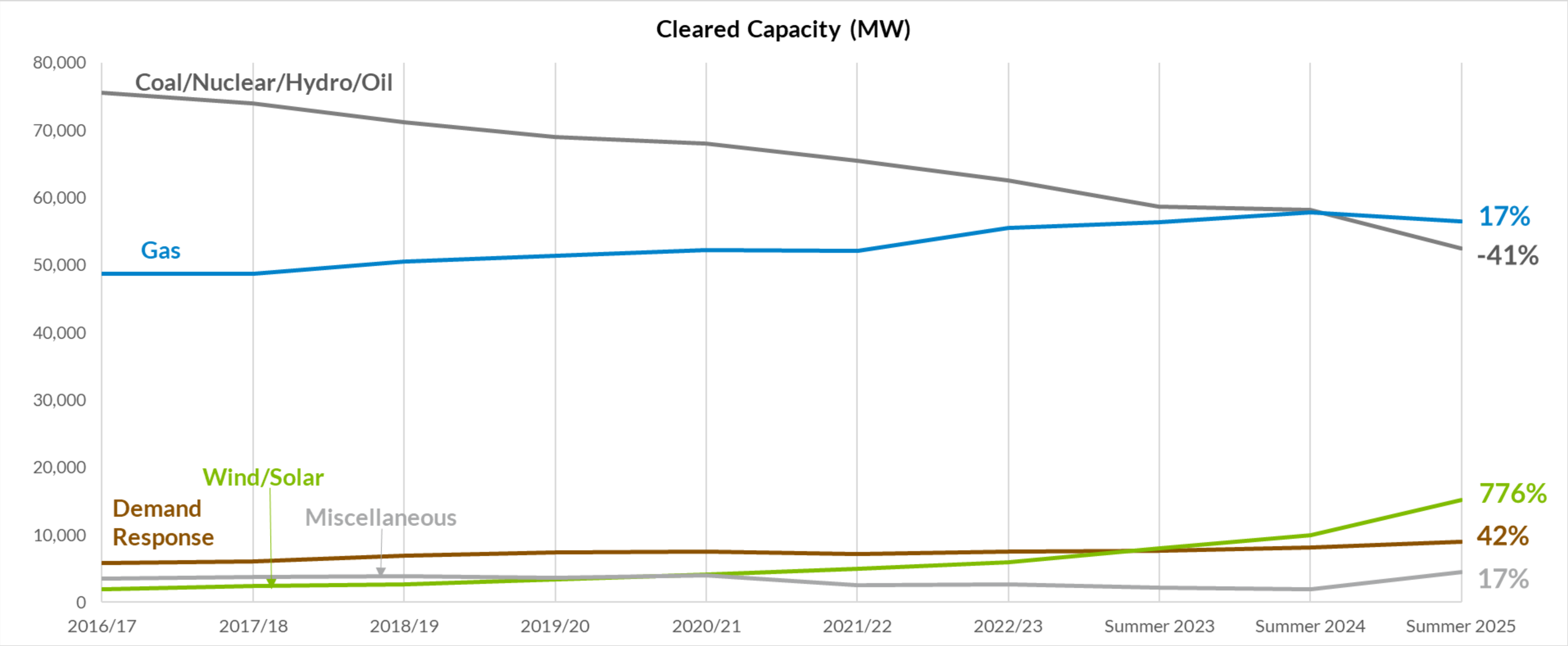
MISO-Wide

Cleared ZRC	Fall 2025	Spring 2026
Coal	30,038.9	27,886.8
Gas	54,636.4	56,820.7
Nuclear	11,482.1	9,405.4
DR	7,767.8	8,240.5
Battery	497.9	663.3
EE	28.1	30.5
Hydro	5,047.4	5,415.8
Oil	2,123.8	2,190.4
Wind	8,864.8	7,438.0
Solar	7,843.8	8,975.1
Misc	4,184.8	3,633.0
PRMR	132,515.8	130,699.5

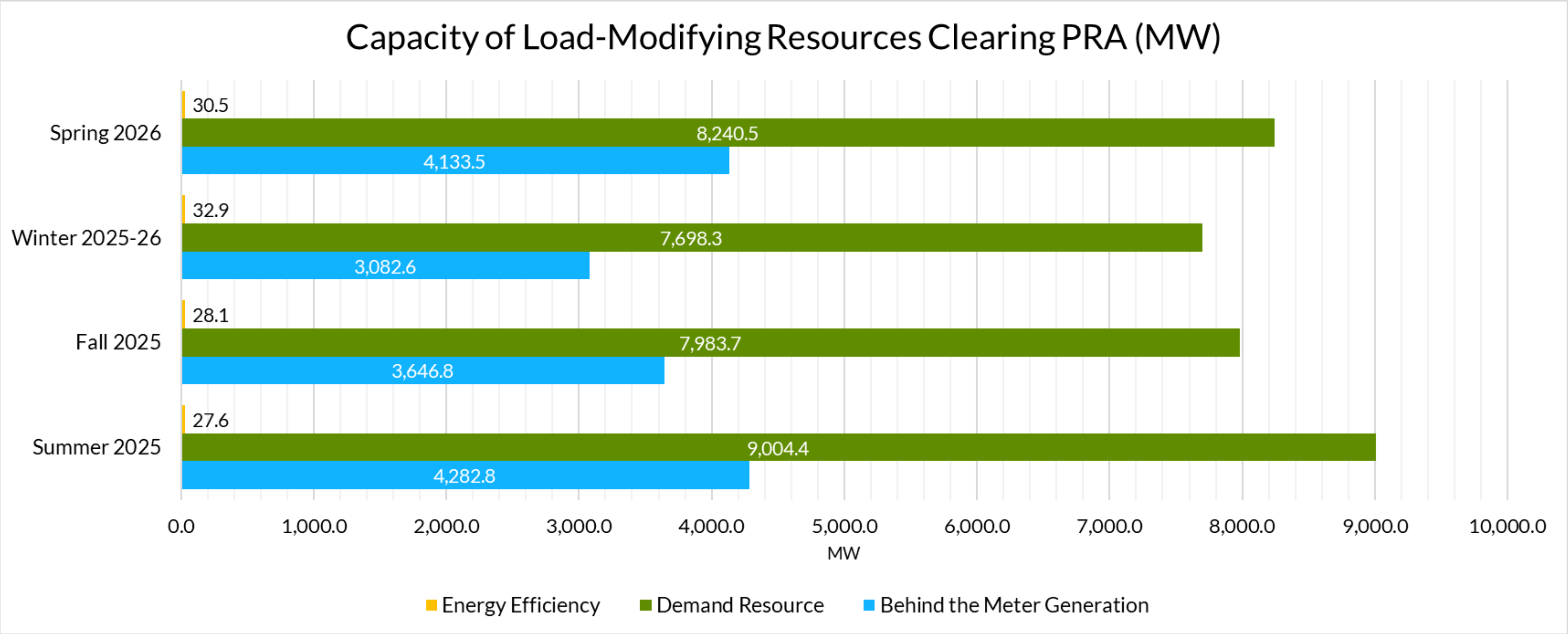


PRMR: Planning Reserve Margin Requirement

The planning resource mix shows the continuation of a multi-year trend towards less coal/nuclear/hydro/oil and increased gas and non-conventional resources



2025/26 Seasonally Cleared Load Modifying Resources Comparison



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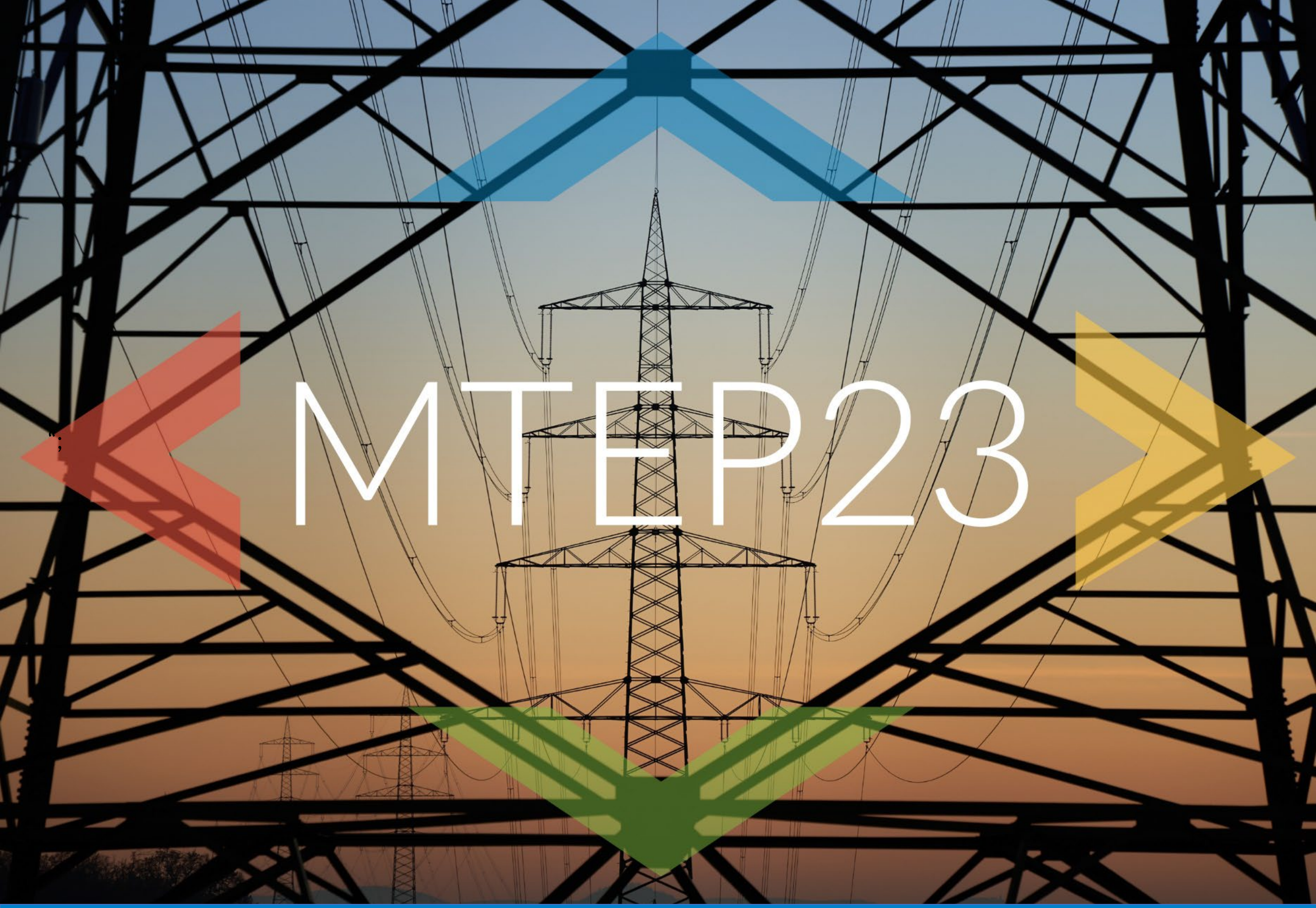
for more information
https://help.misoenergy.org/



MTEP23 REPORT

Highlights

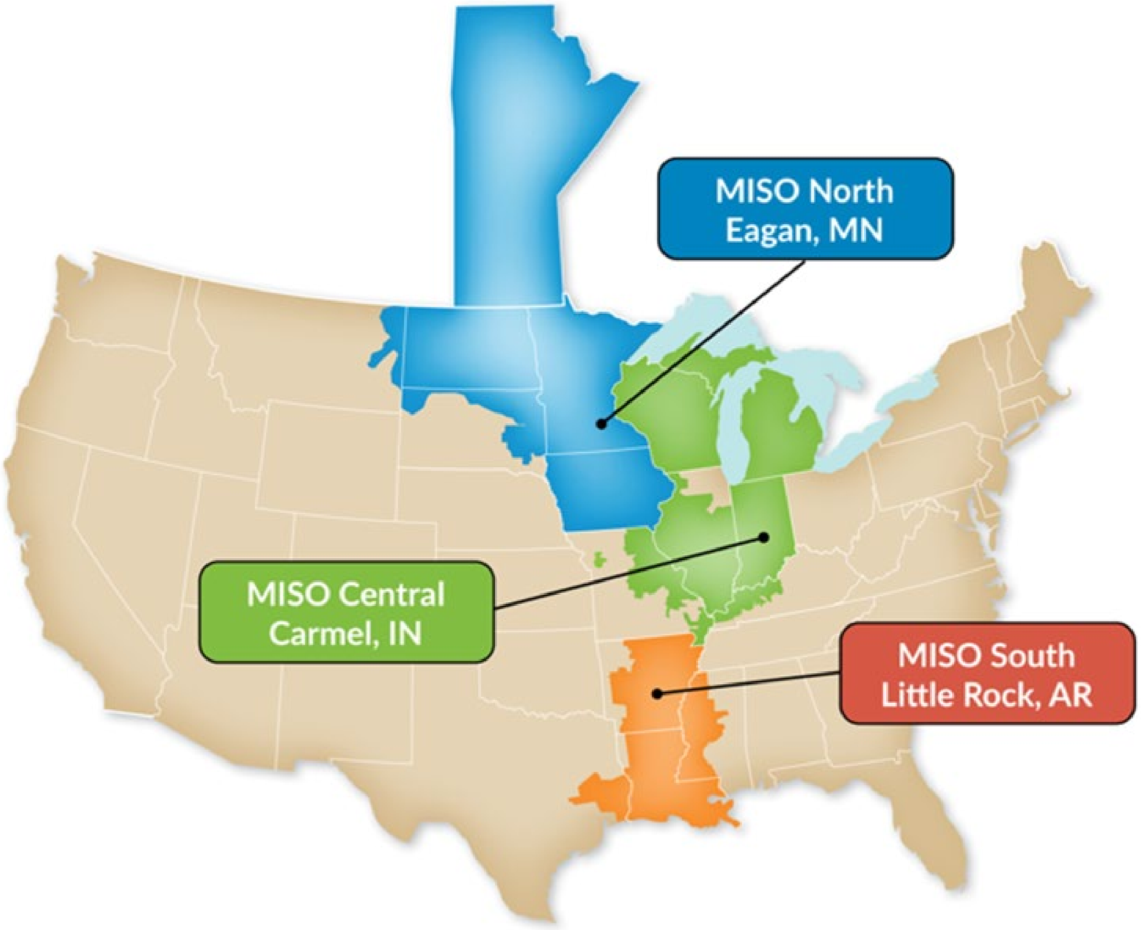
- 572 new projects with an estimated $9 billion investment
- $34 billion in projects constructed in the MISO region since 2003
- Grid evolution drove significant records in MTEP23

MTEP23 Table of Contents

About MISO

Midcontinent Independent System Operator (MISO) is an independent, 501(c)(4) not-for-profit, member-based organization, approved as a Regional Transmission Organization (RTO) by FERC in 2001, with responsibility for keeping the power flowing across its region reliably and cost effectively. The system MISO manages is the largest in North America based on geographical scope, with 471 market participants serving approximately 45 million people across all or part of 15 states and one Canadian province. The MISO energy markets are also among the largest in the world, with more than $40 billion in annual gross market charges.

MISO Reliability Footprint and Regional Control Center Locations



Currently, the MISO region contains nearly 75,000 miles of high-voltage transmission, as well as roughly 199,000 megawatts of electricity generating capacity. MISO does not own any of these assets. Instead, with the consent of our asset-owning members and in accordance with our FERC-approved tariff, MISO exercises functional control over the region's transmission and generation resources with the aim of managing them in the most reliable and cost-effective manner possible. The MISO region is predominantly comprised of traditionally structured, state-regulated utilities.

KEY FACTS

Area Served	15 U.S. States and Manitoba, Canada
Population Served	45 Million
Transmission Line**	75,000 Miles
Generating Units*	6,800+
Record Demand	127.1 GW 7/20/2011
Wind Peak	24.1 GW 11/30/2022
Solar Peak	2.2 GW 8/31/2022
Members	57 Transmission Owners 135 Non-transmission Owners
Market Participants	500+
Carbon Reduction	Approximately 32% since 2014

Corporate data as of August 2023
**Network Model*
***Market Footprint*

CHAPTER 1: TRANSMISSION PLANNING OVERVIEW

1.1 Planning for the Future

Since MISO's articulation of the Reliability Imperative, its members have accelerated the rate of fleet change, demonstrating a need for a stronger, regionally coordinated transition plan. Flexible, thermal resources are retiring more rapidly than expected along with attributes which have historically helped to ensure reliability.

At the same time, regulations, policies and economics create an uncertain environment for the future of thermal generators. Potential future technologies that can provide flexible attributes, such as hydrogen, long-duration storage and small modular nuclear reactors, are not yet commercially available nor deployed at scale. The interconnection queue is predominantly weather-based resources, and resources with interconnection agreements are requesting delays of 36 months and more due to supply chain and regulatory issues, among others.

The MISO region needs a coordinated transition plan to ensure an orderly, efficient transition and the ability to manage the risks associated with a massive change in resources. At the same time, the region is facing an increase in the number and intensity of severe weather events, which further magnify the need to coordinate the transition.

During this time, MISO remains focused on working with states, regulators and stakeholders on the response to the Reliability Imperative, which is designed to:

- Ensure the totality of the resource portfolio can be operated reliably under all conditions;
- Enable the construction of appropriate transmission to integrate changing resources;
- Redesign the market to ensure proper signals are sent to all market participants to inform efficient investment and reliable operations; and
- Transform its systems and processes in anticipation of the regional needs.

Resource Adequacy

While resource sufficiency was demonstrated through this year's Planning Resource Auction, the first conducted under the new seasonal construct, it was primarily achieved through resource decisions that are difficult to repeat. These include delayed resource retirements, new firm imports committed to MISO load, accreditation increases for wind resources, a lower Planning Reserve Margin Requirement, and decline in summer peak load.

Looking forward, there is a continued risk of resources retiring faster than replacement resources are able to come online due to supply chain delays and permitting constraints. Additionally, new, replacement resources will need to bring sufficient characteristics to balance the system. Further, additional work may be needed to ensure that future load estimates that apply to transmission planning and resource adequacy processes reflect actual load increases. And the concept of "resource adequacy" must be expanded to not only include capacity but also the various grid services that different technologies and resource types can bring to the system.

Acceleration of the fleet transition

MISO continues to work with its members to better understand the future resource fleet and the pace at which this change will occur. Policy goals made in public announcements and Integrated Resource Plans, verified through interviews with member utilities, are reflected through MISO's most recent projection of the fleet transition, known as Future 2A (Figure 1.1-1). This Future, reflecting current trajectory of member carbon and renewable energy goals, is accordingly more ambitious than MISO's earlier Future 2. Significant growth in renewable generation (with subsequent modest growth in accredited capacity owing to lower capacity factors of wind and solar generators compared to legacy resources), retirements of thermal resources, and load growth owing to electrification are hallmarks of this new future. Some 250 GW (installed capacity) of resource additions, mostly renewable, are expected.

Put into perspective, MISO's interconnection queue process has historically added 2 to 2.5 GW installed capacity of resources to the system each year. To reach the buildout suggested in Future 2A, such additions to the system would require additions five to ten times that size each year over the course of twenty years. The approximately 50 GW of approved resources in the current queue, which have delayed commercial operation by an average of 650 days (owing primarily to supply chain, regulatory and contractor issues), suggest that existing approval processes and supply chains are already strained.

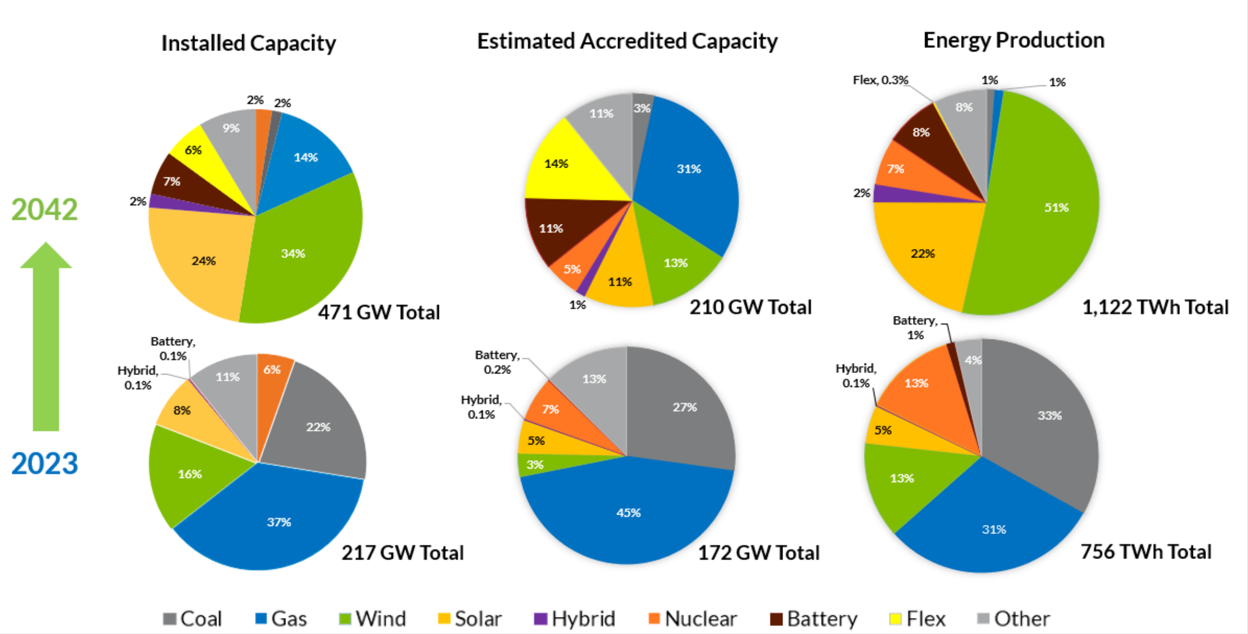


Figure 1.1-1: MISO's Future 2A anticipates significant renewable additions, controllable retirements and load growth.[1]

In addition to the magnitude of the resource shift, the timeline in which these changes are to be realized has shortened. Future 2A suggests that renewable penetration milestones will be achieved much sooner than initial estimates (Figure 1.1-2). MISO's earlier Renewable Integration Impact Assessment (RIIA) found that in annual energy penetrations above 30%, operational complexity dramatically increases and local reliability issues become more widespread as energy adequacy and system stability risks grow (see below.) Further adding to uncertainty are future load growth projections. For example, multiple load additions totaling 100+

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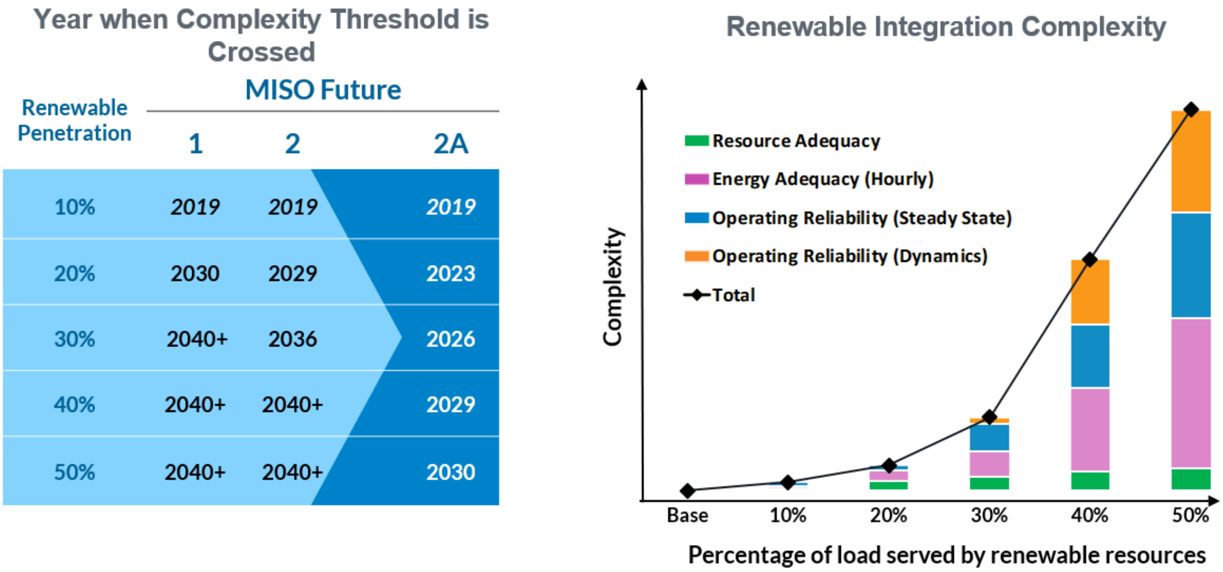
[1] Data as of April 26, 2023. Futures do not account for all operational-level reliability needs and attributes that may require different levels of dispatchable resources. Resource additions may be subject to adjustment based on new accreditation rules. "Other" includes biomass, geothermal, hydro, oil, pumped hydro storage, demand response, non-solar distributed generation, and energy efficiency. Battery energy production includes battery discharging only. However, overall energy production pie graph includes the energy required to charge storage.

MW have been submitted through the Expedited Review Process throughout MTEP23. An accelerated pace of change suggests that work to prepare for the implications must also hasten.



Year when Complexity Threshold is Crossed

Renewable Penetration	MISO Future		
	1	2	2A
10%	*2019*	*2019*	*2019*
20%	2030	2029	2023
30%	2040+	2036	2026
40%	2040+	2040+	2029
50%	2040+	2040+	2030

Figure 1.1-2: Reaching renewable penetration milestones more quickly than initial models implies greater system integration complexity earlier than anticipated. Left – MISO Future 2A shows renewable penetration milestones accelerated. Right – Renewable Integration Impact Assessment (RIIA) shows that as penetrations exceed 30%, integration complexity on the system dramatically increases.

Energy Adequacy

Weather is impacting resources in ways not previously experienced, and energy adequacy is becoming a growing concern. Recent weather events, including Storms Uri, Elliott and this summer's heat, are increasingly frequent, and are having broader impacts on the fleet, often in the form of correlated outages. Wind output varies significantly between weather events, as it did between Winter Storms Uri and Elliott. Gas resources see numerous unplanned outages, as they did during Winter Storm Elliott, in which almost half of those reported were due to fuel supply or transportation issues. Load volatility has also proven to be an emerging issue as models without similar historic weather data can be prone to significant forecast errors, as occurred during Storm Elliott.

Results from the recent 2023 OMS-MISO Survey also point to ongoing energy adequacy concerns. The first survey, conducted on a seasonal basis following the implementation of the seasonal resource adequacy construct, showed a 1.5 GW capacity surplus for the 2024/25 planning year. However, like the Planning Resource Auction results, these gains were made by actions that will be difficult to replicate in the coming year. Additional resources with the necessary attributes and other changes – like market rules – are needed to avoid potential capacity shortfalls in the future.

Looking forward, significant growth in resources that are either variable or energy-limited in the MISO footprint, inaccuracies in long-term load forecasts along with changing weather impacts and operational practices, are shifting risk profiles in highly dynamic ways with implications to resource adequacy and system planning. Ongoing analysis and enhancements are critical to ensure that the resources with needed capability and attributes will be available during the highest risk periods across the year. It is in this context that the MTEP23 transmission planning efforts are undertaken to ensure a reliable and efficient system.

1.2 Planning Process

The MISO Transmission Expansion Plan (MTEP) report must identify and support development of cost-effective transmission infrastructure that is sufficiently robust to meet reliability needs, enable a competitive energy market, support policy goals, and allow for competition among transmission developers in the assignment of transmission projects. MTEP must be created through an inclusive, independent, open process which allows opportunities for stakeholders to participate and provide input on the transmission system. MISO works with its stakeholders and Board of Directors to adopt MISO's Planning Guiding Principles. The most recent Principles, which were reviewed and approved by the Board of Directors in June 2023, are shown below in Figure 1.2-1.

GUIDING PRINCIPLES

FRAMEWORK

- Provide inclusive, open process
- Meet reliability, policy and key needs
- Ensure cost-effective infrastructure
- Enable competitive market
- Allow for transmission developer competition

PRINCIPLES

Market access
Make the benefits of an economically efficient electricity market available to customers by identifying solutions to transmission issues that are informed by near-term and long-range needs and provide reliable access to electricity at the lowest total electric system cost.

Cost allocation
Provide an appropriate cost allocation mechanism that ensures that costs of transmission projects are allocated in a manner roughly commensurate with the projected benefits of those projects.

Planning criteria
Develop transmission plans that will ensure a reliable and resilient transmission system that can respond to the operational needs of the MISO region.

Information exchange
Analyze an appropriate range of system scenarios and make the results available to federal, state, and local energy policy makers and other stakeholders to provide context and to inform choices.

Policy alignment
Support federal, state and local energy policy and member plans and goals by planning for access to a changing resource mix.

Regional coordination
Coordinate planning processes with neighbors and work to eliminate barriers to reliable and efficient operations.

Figure 1.2-1: MISO's Planning Guiding Principles (as adopted June 2023) are shaped by state and federal policy, stakeholder needs and cost efficiency targets.

System Planning

These principles are enacted through MISO's value-based planning approach (Figure 1.2-2), which ensures that local needs are integrated with regional requirements. Its processes consider a range of issues and viewpoints, including analyzing:

- For **local planning,** review and provide transparency on member plans, evaluate system against reliability standards, consider alternatives and verify needs as applicable
- The long-term, broader system needs through MISO's **regional planning** processes, including its Long Range Transmission Planning efforts

- The impact of policies on the transmission system and resource mix in **policy studies**
- System changes needed to accommodate new resources in **resource planning, and**
- Planning issues shared with its neighbors in **interregional planning**

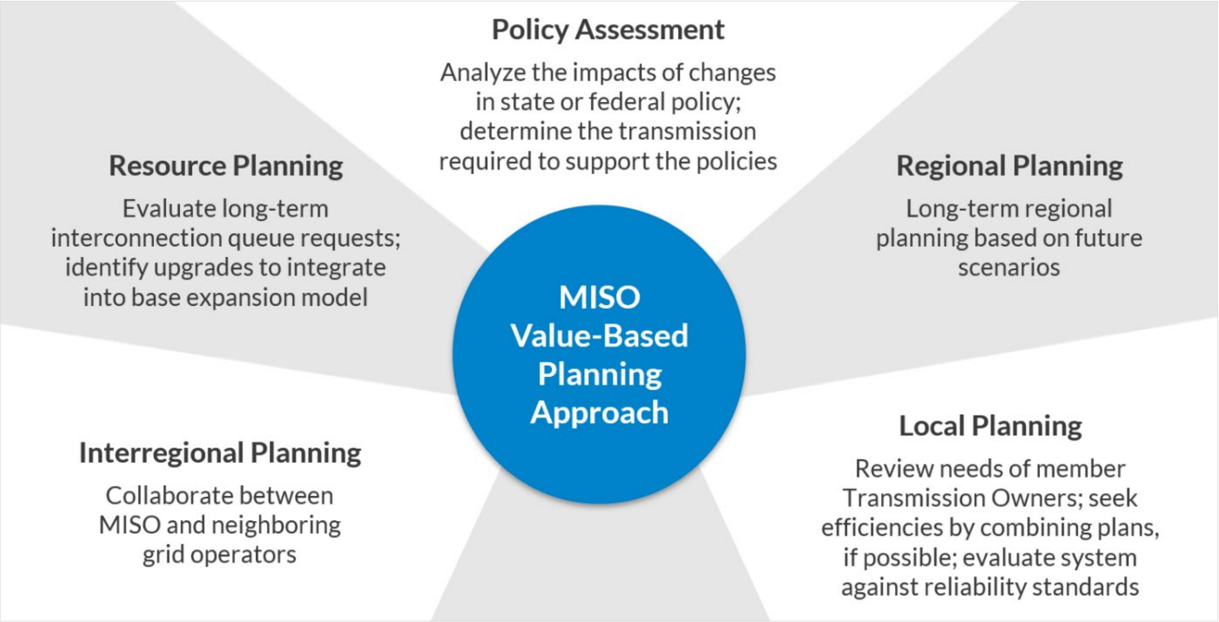


Figure 1.2-2: MISO's Value-Based Planning Approach

MISO's various planning approaches cannot operate independently of each other. The goal of the transmission planning process is to identify a least-regrets outcome that meets its member plans, provides reliable power delivery, and appropriately balances local versus regional solutions to ensure a cost-effective outcome for customers.

MISO's comprehensive planning process spans short to long term horizons depending on study objectives and need drivers (see Figure 1.2-3). The process encompasses multiple planning functions that address different timelines and aspects of transmission and resource planning. Each process informs the others to cover the entire planning horizon.

Figure 1.2-3: MISO Value-Based Planning Approach Study Horizons

Transmission Planning & Coordinated Process

MISO develops this annual regional expansion plan, which is known as the MISO Transmission Expansion Plan ("MTEP"), based on expected use patterns and analysis of the performance of the Transmission System in meeting both reliability needs and the needs of the competitive bulk power market, under a wide variety of contingency conditions. MISO uses both a near-term and long-term planning horizon in its processes with the near-term planning horizon (i.e., less than 10 years) mainly focused on local reliability planning, while the long-term planning horizon (i.e., up to 20 years) is focused on broader regional planning. This recommended plan is then subjected to stakeholder scrutiny and feedback to refine it further before it is eventually presented to the MISO Board of Directors ("MISO Board") for review and approval.

MISO strategically set up our local planning processes to assume FERC Order 890 transparency requirements for Transmission Owner submissions, with MISO's role ranging from alternative assessment, need validation, no-harm tests and/or transparency depending on the project submissions. MISO's transmission planning rules are set forth in Attachment FF of the Tariff, which contains MISO's transmission expansion planning protocol, and Appendix B of the MISO Agreement, which contains MISO's planning framework. In addition, MISO maintains a Business Practices Manual ("BPM") that covers the transmission expansion planning processes, which is known as BPM-020, including the study approaches applied by MISO. Finally, some of MISO's local planning approach is driven by North American Electric Reliability Corporation (NERC) reliability standards and reliability standards adopted by Regional Reliability Organizations integrated as part of MISO's role as a Planning Coordinator.

Project Input and Stakeholder Coordination

The planning process, in conjunction with an inclusive, transparent stakeholder process, must identify and support development of a sufficiently robust transmission infrastructure to meet local and regional reliability standards as well as enable competition among wholesale capacity and energy suppliers. Each planning cycle commences with regional model development (see Figure 1.2-4 for MISO footprint planning regions); identification of potential expansions from the local planning processes of the Transmission Owners; identification of transmission issues driven by reliability (e.g., NERC criteria), economic, and public policy requirements; and identification by stakeholders or MISO staff of potential expansions that address the transmission issues. Each cycle concludes with recommendations to the MISO Board of Directors of recommended solutions to the transmission issues evaluated.

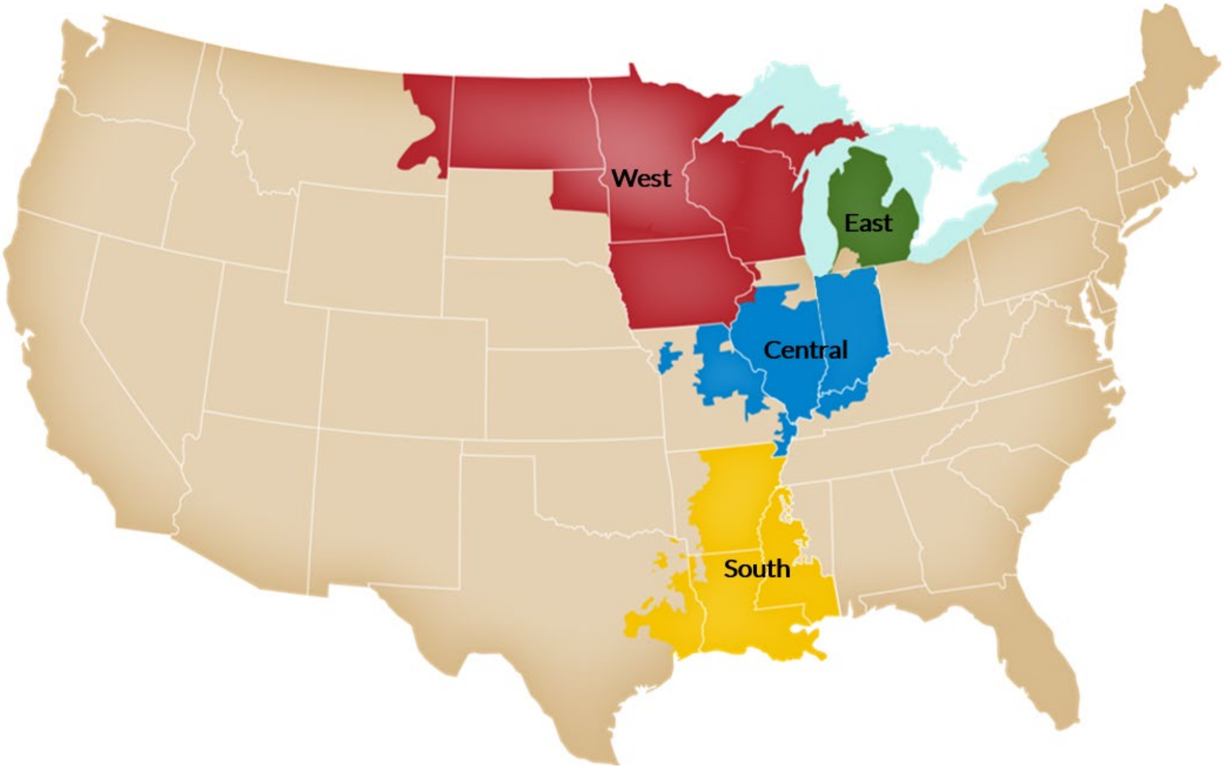


Figure 1.2-4: MISO footprint planning regions

Transmission Owner plans developed through local planning processes are included in the beginning of each regional planning cycle as potential solutions to local transmission issues identified by the Transmission Owners to meet the FERC Order 890 transparency requirements.

MISO's regional planning process makes evaluations — with stakeholder input from the Sub-regional Planning Meetings, the Planning Subcommittee, and the Planning Advisory Committee — throughout the cycle to develop expansion plans to meet the needs of the system. This multi-party collaborative process allows analysis of all projects with regional and inter-regional impact for their combined effects on the Transmission System. Moreover, the design of this collaborative process ensures that the MTEP addresses transmission issues within the applicable planning horizon in an efficient and cost-effective manner, while considering the input of stakeholders.

These various planning functions occur at different times and begin the year before an MTEP report is finalized (see Figure 1.2-5). For example, assessments of generator interconnection and retirements occur on a continuous basis. Others repeat on a regular cycle, but the actual MTEP report is produced once every 12 months. Each MTEP cycle's scope definition actually begins in the summer of the prior year. The months of in-depth research and analysis, combined with many interactions between various work streams and stakeholders culminates in Appendix A.

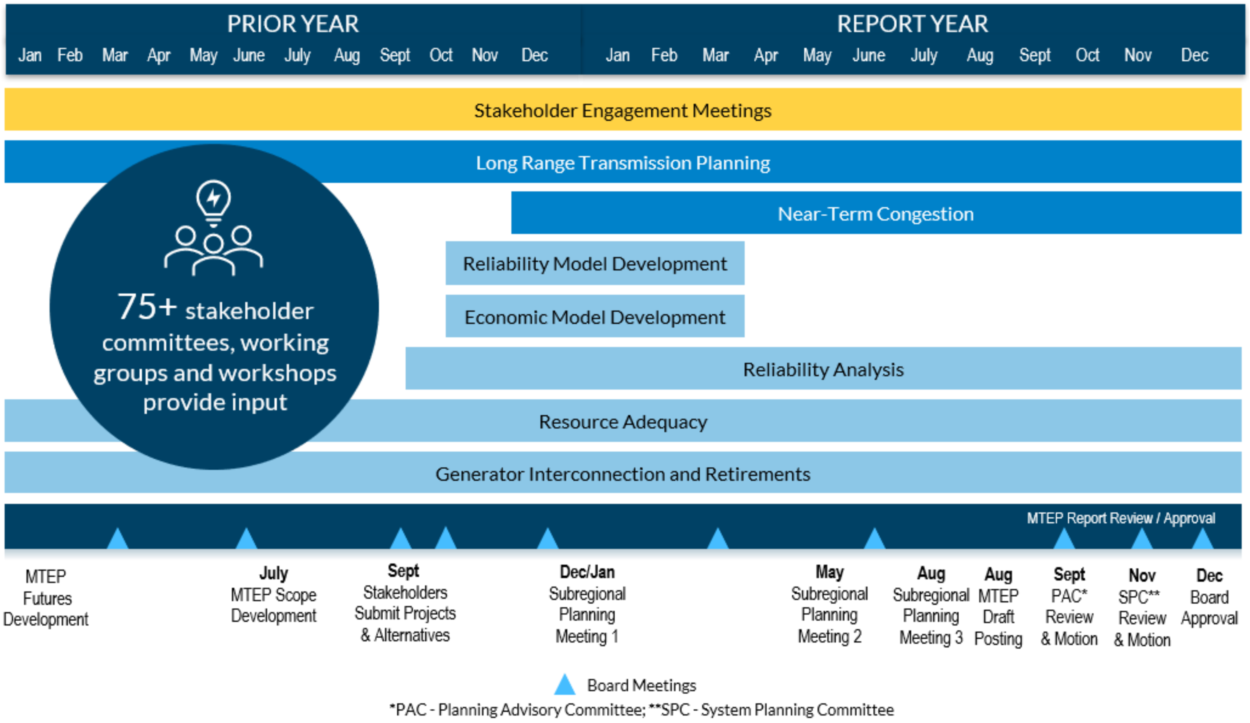


Figure 1.2-5: Typical MTEP cycle is developed in overlapping cycles and delivered annually

Planning Analysis Methods

Planning analyses performed by MISO test the transmission system under a wide variety of conditions using standard industry applications to model key items, such as steady state power flow, voltage stability, and economic parameters, as determined appropriate by MISO to be compliant with applicable criteria and the Tariff. MISO collaborates with Transmission Owners, other transmission providers, transmission customers, and other stakeholders to develop appropriate planning models that reflect expected system conditions for the planning horizon. The local reliability planning process relies on known and committed inputs into the process, while the long-term planning process considers projected inputs (Figure 1.2-6).

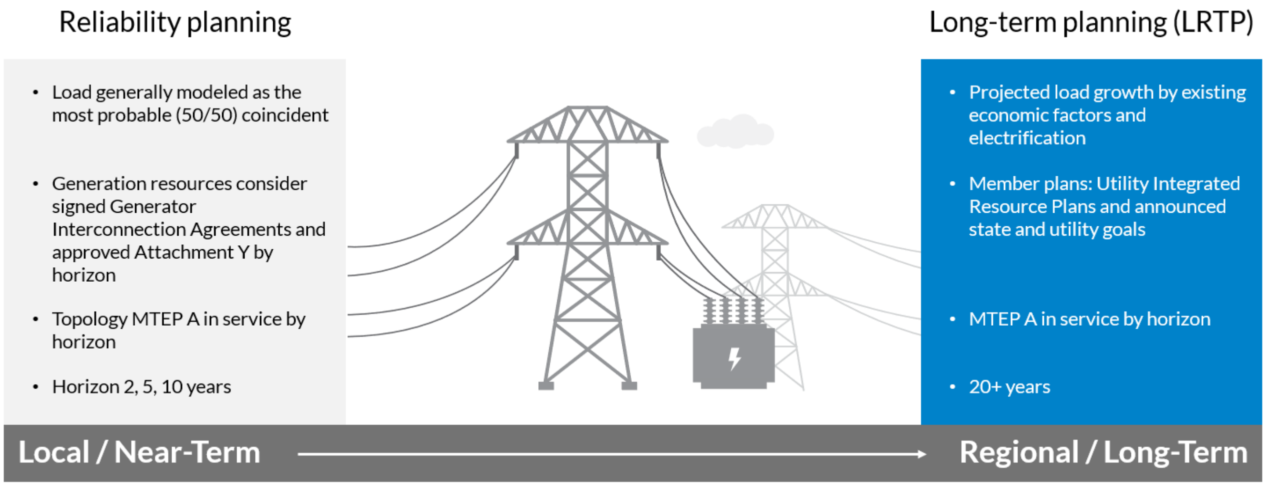


Figure. 1.2-6: Summary of inputs into reliability and long-term planning processes

Models are available to stakeholders with security measures as provided for in the Transmission Planning Business Practices Manual. MISO provides the opportunity for stakeholders to review and comment on the posted models before commencing planning studies.

MISO's review of projects varies depending on project drivers, system needs, opportunities for alternatives, and other factors. Specific to local planning MISO may verify the need, complete a no-harm analysis, or post information for stakeholders.

- **Verify need**: Confirmation of system need identified in project submission, including to meet compliance with applicable National Electric Reliability Organization reliability standards and reliability standards adopted by Regional Reliability Organizations, and applicable within the Transmission Provider Region. MISO must verify the need for alternatives to adequately examine their effectiveness.
- **No harm**: Ensure a submitted project does not create a system issue. Includes projects that create model changes like contingency definitions, line ratings, or line impedances.
- **Post only**: Provided for FERC Order 890 transparency provisions. May include controls equipment to communicate remotely with the facility. This information is not able to be represented with model changes.

Additionally, alternative assessments for projects may be completed by Transmission Owners prior to project submission to MISO, proposed by MISO, or proposed through stakeholder submissions. In MTEP23, MISO identified and evaluated alternatives for facilities that are larger in cost and/or have higher potential impact on the system; staff also evaluates alternatives provided by stakeholders. For example, projects that propose new lines are prioritized for analysis because MISO's experience shows that addressing existing infrastructure is typically a more cost-effective investment than building new lines. Alternatives would be assessed in this situation to ensure that the additional benefits justify the potential higher cost. Some of the criteria to select an alternative considers cost comparisons, feasibility to construct and how reliability needs are resolved. Alternatives do not always result in one project replacing another, but instead tend to be additive to the original project, even when submitted with the thought that they would directly compete. MISO considers alternatives in multiple forms, including like-for-like replacement, regional reliability projects, the combination of multiple local solutions, and other options identified through either MISO analysis or submitted by stakeholders.

Long Range Transmission Planning

Long Range Transmission Planning (LRTP) is an essential element of planning the regional grid to be reliable and efficient with a focus on the long-term (i.e., 20 years) planning horizon. LRTP efforts are launched periodically when needed to address significant changes to future conditions that the grid must be prepared to address. Long Range Transmission Planning results in projects that are regional backbone facilities needed to move bulk power between geographically dispersed areas within MISO. While they provide for a reliable and efficient grid based on forecasted resource developments, they are not intended to resolve all connection issues associated with precise siting of future generation or load.

Long Range Transmission Planning follows MISO's well-established seven-step value-based planning process and is part of MISO's overall MTEP process. Outlined below are the high-level descriptions of each step:

1. **Develop Future Scenarios** – develop scenario-based Futures with resource forecast and siting
2. **Develop Resource Plan and Site Future Resources** – development of planning models utilizing Futures
3. **Identify Transmission Issues** – identify potential transmission issues
4. **Integrated Transmission Development** – proposals for solutions to issues
5. **Transmission Solution Evaluation** – evaluate the effectiveness of various solutions
6. **Project Recommendation and Justification** – recommend preferred solutions for MTEP implementation
7. **Project Cost Allocation** – apply appropriate cost allocation

MISO is working to identify potential grid needs in support of the resource transformation underway and as contemplated under our member's resource plans and defined in the MISO Futures. This extensive stakeholder process includes regularly scheduled workshops, periodic discussions at the Planning Advisory Committee, plus additional stakeholder meetings addressing cost allocation through the Regional Expansion Criteria and Benefits Working Group. Project recommendations resulting from this process will then be presented for Board of Director review and approval over several MTEP cycles as analyses proceed and recommendations are developed.

Details of MISO's Long Range Transmission Planning study progress are summarized in Section 3.1 of the MTEP23 Report.

Project Types and Approval

MTEP Appendix A projects are vetted by MISO through the planning process and project types are determined by criteria in MISO's Tariff. Below is an overview of Tariff-defined project types[2]:

- **Baseline Reliability Project (BRP) -** Projects are Network Upgrades identified in the base case as required to ensure that the Transmission System is in compliance with applicable National Electric Reliability Organization reliability standards and reliability standards adopted by Regional Reliability Organizations, and applicable within the Transmission Provider Region. Baseline Reliability Project costs are allocated to the local Transmission Pricing Zone(s) and recovered through Attachment O by the Transmission Owner(s) developing the projects.

- **Generator Interconnection Project (GIP) -** Projects are New Transmission Access Projects that are associated with interconnection of new generation or the capacity modification of existing generation. Costs are primarily paid for by the interconnection customers with certain exceptions as specified in Attachment FF. Costs of network upgrades rated at 345 kV and above are eligible for 10 percent cost recovery from load on a system-wide basis.

- **Market Efficiency Project (MEP) -** Projects meet Attachment FF requirements for reduction in market congestion and are eligible for regional cost allocation. Projects qualify as Market Efficiency Projects based on cost and voltage thresholds and are developed to produce a benefit-to-cost ratio of 1.25 or greater. Costs are distributed to benefiting pricing zones, in accordance with Attachment FF of the Tariff.

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[2] Additional details on project types are in Section 2.3.1 of the Business Practice Manual.

- **Market Participant Funded Project (MPFP) -** Projects are defined as Network Upgrades fully funded by one or more market participants but owned and operated by a Transmission Owner.
- **Multi-Value Project (MVP) -** Projects meet Attachment FF requirements to provide regional or sub-regional public policy, economic and/or reliability benefits. Costs are shared with loads and export transactions in proportion to energy withdrawals or export schedules.
- **Other -** Projects to address local reliability issues and/or provide local economic benefit, which do not qualify as Baseline Reliability Projects, New Transmission Access Projects, Targeted Market Efficiency Projects, Market Efficiency Projects, or Multi-Value Projects. Project costs are allocated to the local Transmission Pricing Zone(s) and recovered through Attachment O by the Transmission Owner(s) developing the projects.
- **Targeted Market Efficiency Project (TMEP) -** Projects are designed to alleviate historical market-to-market congestion between MISO and PJM Interconnection, while meeting certain cost and construction requirements. The costs of Targeted Market Efficiency Projects are allocated first between MISO and PJM Interconnection by the ratio of each RTO's Day-Ahead and Excess Congestion Fund congestion, offset by historical market-to-market payments. The MISO share of costs for the project is then allocated to beneficiaries using historical nodal load congestion contribution data.
- **Transmission Delivery Service Project (TDSP) -** Projects are required to satisfy a transmission service request. The costs are generally assigned to the requestor.

MISO staff formally recommends a set of projects to the MISO Board of Directors for review and approval after all projects have been posted for transparency. MISO has completed its independent review of proposed projects for need or no-harm as applicable, and staff has addressed any stakeholder feedback received. These projects make up Appendix A of the MTEP report and represent the preferred solutions to the identified transmission needs of the MISO transmission planning process.

Proposed transmission upgrades with sufficient lead times are included in Appendix B for further review in future planning cycles.

Interregional Coordination and Planning Studies

On an annual basis MISO works with the neighboring transmission planning regions, Southwest Power Pool (SPP) and PJM Interconnection (PJM), to identify issues on the seams, perform studies, and jointly evaluate transmission solutions that may be more efficient or cost effective than a corresponding regional solution. While MISO has a separate Joint Operating Agreement (JOA) with both SPP and PJM that details specific processes and criteria, the high-level interregional coordination activities are similar on each seam:

1) Exchange modeling data and other system information (typically performed in Q4).
2) Review identified issues on the seam (typically performed in Q1).
3) Evaluate whether to perform an interregional study based on the identified issues.

MISO performs joint coordinated system plan (CSP) studies with SPP and PJM on a regular basis, in accordance with the timelines and frequencies dictated in their respective JOAs. A CSP study may have a targeted scope or a more complex scope requiring a longer study period, and can include reliability, economic and/or public policy issues. All interregional issues and CSP study efforts are coordinated through a public Interregional Planning Stakeholder Advisory Committee (ISPAC) consisting of representatives and interested parties from each RTO community.

In addition to the joint study efforts with SPP and PJM, MISO performs studies as needed with neighboring entities of the Southeastern Regional Transmission Planning (SERTP) group and the Independent Electricity System Operator of Ontario (IESO). While the study process is less formal, MISO and these entities still meet regularly to review interregional issues and possible areas of collaboration.

Details on planning procedures, on-going studies and stakeholder meetings can be found on the Interregional Coordination page of the MISO public website (misoenergy.org).

New Planning Portal

In October 2023, MISO will deploy a new MTEP Project Portal that will be accessed through the Help Center. This will replace the current Project Portal, accessed through the Market Portal. This new portal will provide a robust user-friendly experience that will support the submission and management of MTEP projects throughout their lifecycle while enabling the integration capabilities for future MISO technologies (see Figure 1.2-7 for a list of enhancements).

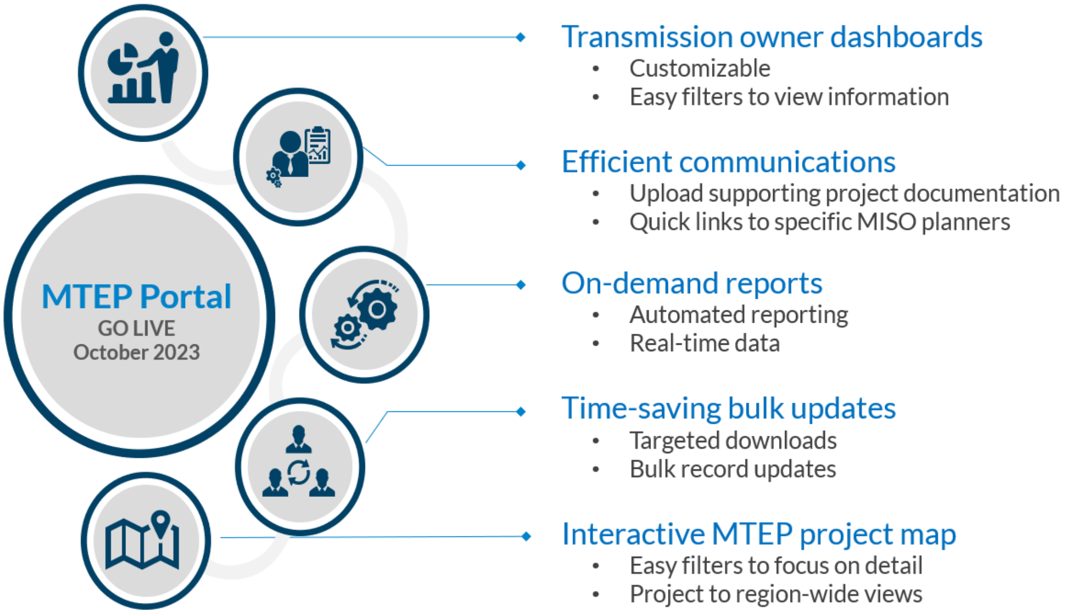

Figure. 1.2-7: Enhancements coming soon with the new MTEP Planning Portal

1.3 Historical Background

MISO Transmission Infrastructure Investment

This iteration of the MTEP report, MTEP23, builds and expands on the 19 prior years of projects since 2003 totaling over $58 billion of investment in the United States (Figure 1.3-1). MISO's proposed new projects for this MTEP cycle would add an additional estimated $9 billion and are detailed in Section 1.4, Chapter 4, and Appendix A of this report.

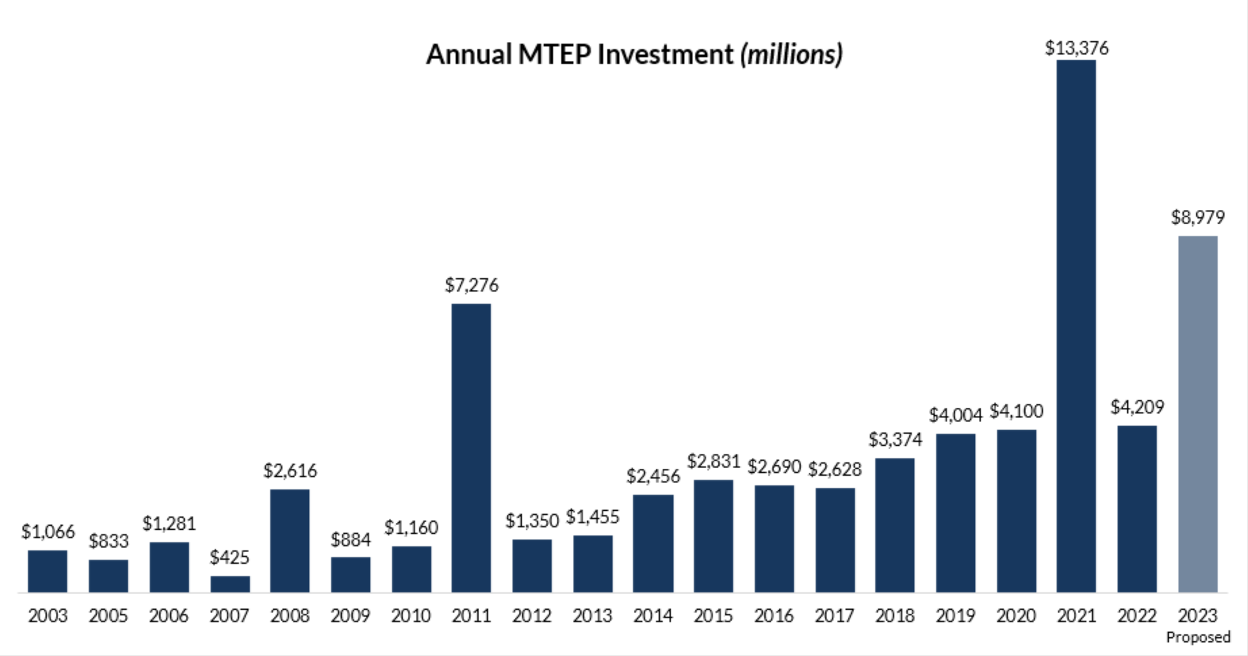

Figure 1.3-1: MTEP annual investment

Highlights in prior MTEP cycles include:

- MTEP11 reflects the approval of the Multi-Value Project portfolio, which accounts for the significantly higher investment totals compared to other MTEPs.
- MTEP14 reflects the inclusion of the new MISO South region projects.
- MTEP21 reflects the MTEP21 Addendum approval of the LRTP Tranche 1 portfolio, which accounts for $10.3 billion of the total.

MISO's transmission planning responsibilities include the monitoring of previously approved Appendix A projects. MISO surveys all Transmission Owners and Selected Developers every quarter to determine the progress of each project. These status updates are reported to the MISO Board of Directors and posted quarterly to the MISO Transmission Expansion Plan page at misoenergy.org[3].

MTEP Approved Projects Status

Since MTEP03, over $34 billion of investment has gone into service and nearly $24 billion of approved projects are yet to be fully placed into service (Figure 1.3-2).

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[3] MISO Transmission Expansion Plan website address: https://www.misoenergy.org/planning/planning/

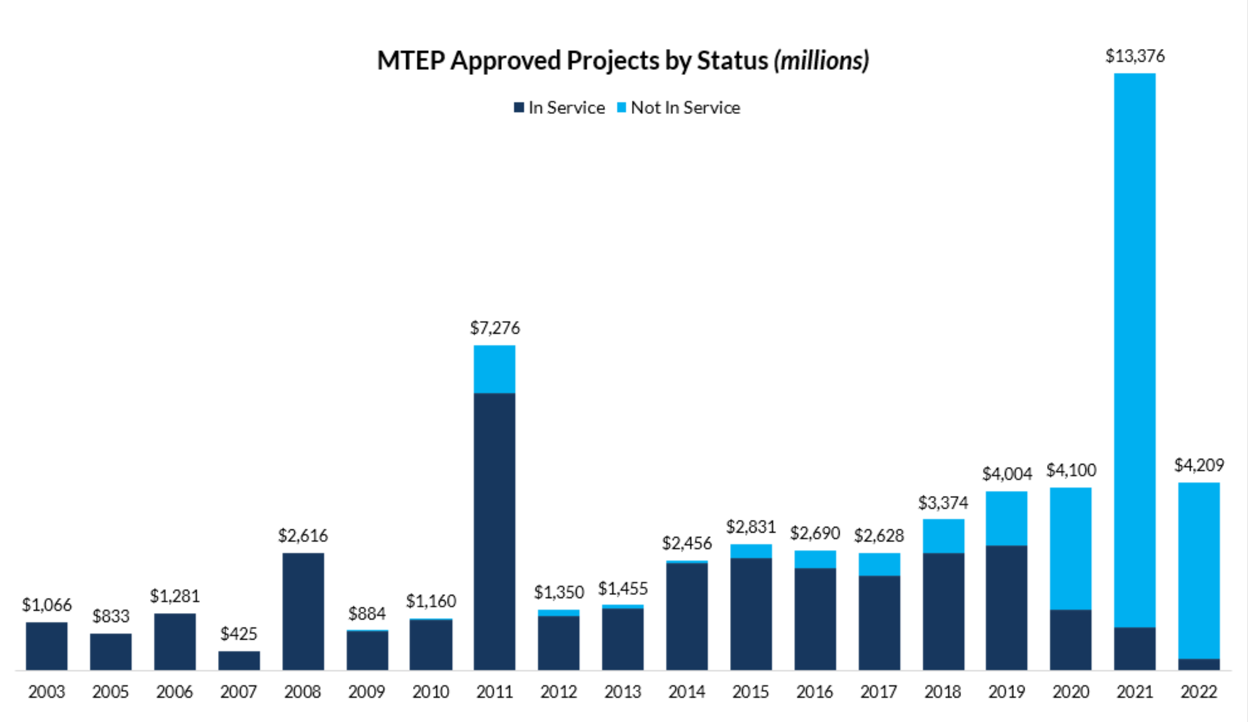


Figure 1.3-2: Appendix A project status (excluding withdrawn)

LRTP Investment Status – Tranche 1

The $13.4 billion investment in MTEP21 as shown above was the result of MISO approval of Tranche 1 of its Long Range Transmission Planning Study comprised at an estimated cost of $10.3B (2022$). Table 1.3-1 reflects those 18 approved projects as of October 2023. Going forward, as engineering and construction plans are finalized and applicable regulatory proceedings complete, MISO anticipates receiving more substantive quarterly project updates from the constructing Transmission Owners, including updates on project cost and in-service dates. Transmission Owners will continue to provide quarterly project updates until the project is placed into service.

MVP No.	Project Name	State	Estimated in Service Date		Status		Cost		Explanation
			MTEP Approved	Current Date	State Regulatory Status	Construction	MTEP Approved ($M)	Current Cost ($M)	
1	Jamestown - Ellendale	ND	12/31/2028	12/31/2028	○		$439	$439	
2	Big Stone South - Alexandria - Cassie's Crossing	SD/MN	6/1/2030	6/1/2030	◐ ○		$574	$574	
3	Iron Range - Benton County - Cassie's Crossing	MN	6/1/2030	6/1/2030			$970	$970	
4	Wilmarth - North Rochester - Tremval	MN/WI	6/1/2028	6/1/2028	○		$689	$689	
5	Tremval - Eau Clair - Jump River	WI	6/1/2028	6/1/2028	○		$505	$505	
6	Tremval - Rocky Run - Columbia	WI	6/1/2029	6/1/2029	○		$1,050	$1,050	
7	Webster - Franklin - Marshalltown - Morgan Valley	IA	12/31/2028	12/31/2028	○		$755	$755	
8	Beverly - Sub 92	IA	12/31/2028	12/31/2028	○		$231	$231	
9	Orient - Denny - Fairport	IA/MO	6/1/2030	6/1/2030	○		$390	$390	
10	Denny - Zachary - Thomas Hill - Maywood	MO	6/1/2030	6/1/2030	○		$769	$769	
11	Maywood - Meredosia	MO/IL	6/1/2028	6/1/2028	○		$301	$301	
12	Madison - Ottumwa - Skunk River	IA	6/1/2029	6/1/2029	○		$673	$673	
13	Skunk River - Ipava	IA/IL	12/31/2029	12/31/2029	○		$594	$594	
14	Ipava - Maple Ridge - Razewell - Brokaw - Paxton East	IL	6/1/2028	6/1/2028	○		$572	$572	
15	Sidney - Paxson East - Filman South - Morrison Ditch	IL	6/1/2029	6/1/2029	○		$454	$454	
16	Morrison Ditch - reynolds - Burr Oak - Leeburg - Hiple	IL/IN	6/1/2029	6/1/2029	○		$261	$261	
17	Hiple - Duck Lake	IN/MI	6/1/2030	6/1/2030	○		$696	$696	
18	Oneida - Nelson Rd.	MI	12/31/2029	12/31/2029	○		$403	$403	
						Total	$10,324	$10,324	

State Regulatory Status Indictor Scale		
○ Pending	◐ In regulatory process or partially complete	● Regulatory process complete or no regulatory process requirements

Table 1.3-1: LRTP Tranche 1 approved project status dashboard as of Oct. 2023.

Future Line Miles Appendix A Projects

Spanning from 2023 -2030, there are approximately 6,250 circuit-miles of planned new or upgraded transmission lines projected in Appendix A (Figure 1.3-3).

- 3,915 circuit-miles of upgraded transmission line on existing corridors are planned of which 59% are ≤230 kV and 41% are ≥345 kV.
- 2,335 circuit-miles of new transmission line on new corridors are planned of which 37% are ≤230 kV and 63% are ≥345 kV.

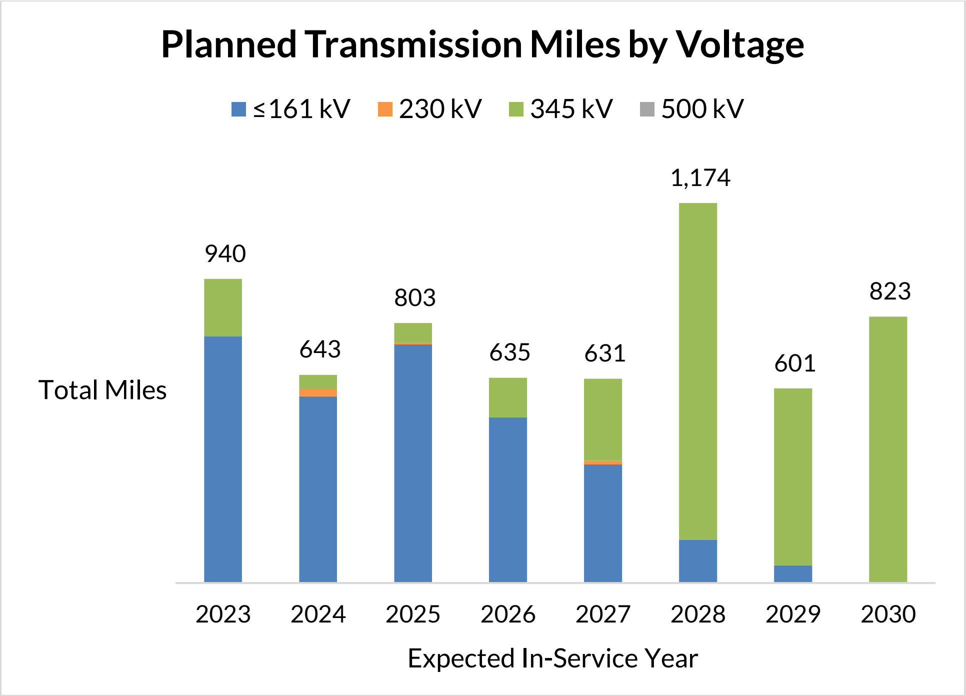


Figure 1.3-3: Active, not yet in-service, project circuit line miles by voltage and expected in-service year.

Existing Line Miles Summary

MISO has approximately 75,000 circuit-miles of transferred functional control transmission lines serving as the backbone of the footprint (Figure 1.3-4) in the United States. Currently, the West region holds 45% of total footprint line miles, the South region holds 22%, the Central region holds 20%, and the East holds 13%.

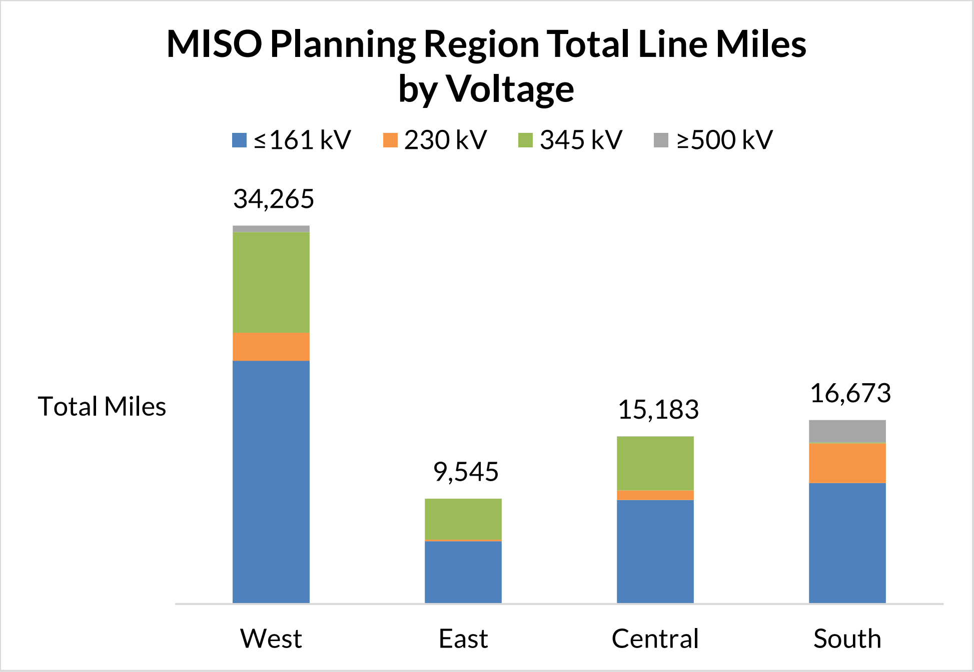


Figure 1.3-4: 2023 in-service transferred circuit miles by voltage class

Transmission Facility Investment

Of the over $58 billion total investment that remains active or in-service, $29 billion of that investment, or 50%, has occurred in the last five MTEP cycles. In the first 13 MTEP cycles, the predominant investment was in new line assets at 53% or $15.3B. There was a shift in investment in the last 6 cycles (MTEP17-MTEP22), including the approval of the Tranche 1 portfolio of projects, with the leading investments in substation (38%) and line upgrades (35%), and new lines only representing 27% of the total investment. Looking back in total (MTEP03-MTEP22), Figure 1.3-5 below reflects the current asset investments at substations representing 34%, new lines at 39% and line upgrades at 27% of the total investment.

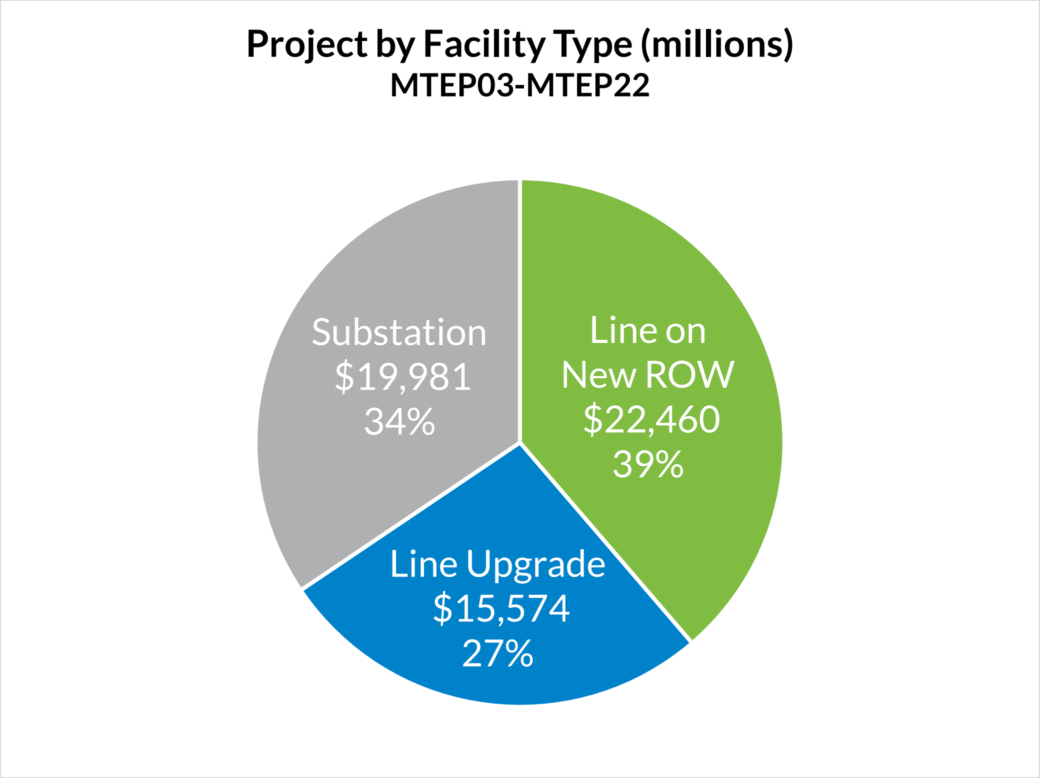


Figure 1.3-5: Appendix A project facility investment dollars in all MTEP cycles.

Full archived files of previous MTEP Reports can be accessed via the MISO Transmission Expansion Plan page at misoenergy.org.

1.4 MTEP23 Investment Summary

The MTEP23 cycle proposes 572 new Appendix A projects (Figure 1.4-1) and represents roughly $9 billion in transmission infrastructure investment for the MISO region. If approved, this will be the largest investment in MISO's history, except for the two MTEP cycles that included Multi-Value Project portfolios, due to significant projects to serve new load. Forty-seven percent of the investment is located in the South region.

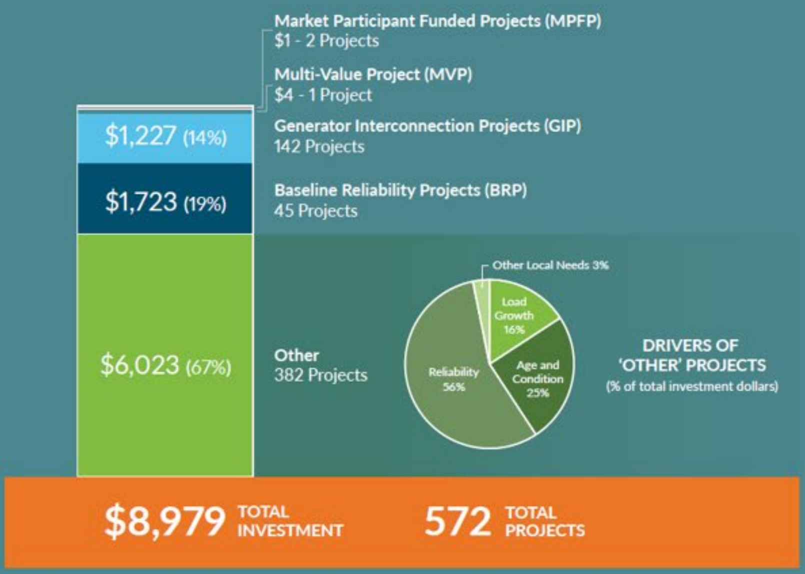
Of the 572 new Appendix A projects proposed in MTEP23, 382 are classified as Other projects, 142 as Generator Interconnection Projects, 45 as Baseline Reliability Projects, two as Market Participant Funded Projects, and one Multi-Value Project. The single Multi-Value Project is a like-for-like replacement of communication equipment for a MTEP11 Multi-Value Project.

Of the roughly $6.0 billion investment in Other projects, 56% are driven by reliability issues, including those caused by a reliability of load additions and generation retirements, and 25% by age and condition. The majority of Other projects address localized reliability issues that are due to load serving needs, local specific reliability needs, and aging transmission infrastructure.

Except for the larger than usual 47% share of total investment dedicated to projects in the South subregion, the distribution of investment across MISO's footprint is generally consistent with recent MTEP cycles – 25% of the total Central subregion projects, 20% for the West and 8% for the East.

MTEP23 Appendix A Project Investment Summary

(Data as of September 29, 2023; $M, % of total investment dollars)



MTEP23 Appendix A Project Investment Summary

($M, and number of projects)

Planning Region	Baseline Reliability Projects (BRP)	Generator Interconnection Projects (GIP)	Market Participant Funded Projects (MPFP)	Multi-Value Project (MVP)	Other Projects	Total	# of Projects
Central	$178	$374	-	-	$1,714	$2,266	153
East	$60	$307	-	-	$371	$739	97
South	$1,335	$351	-	-	$2,483	$4,168	78
West	$150	$195	$1	$4	$1,455	$1,806	244
Total	$1,723	$1,227	$1	$4	$6,023	$8,979	572

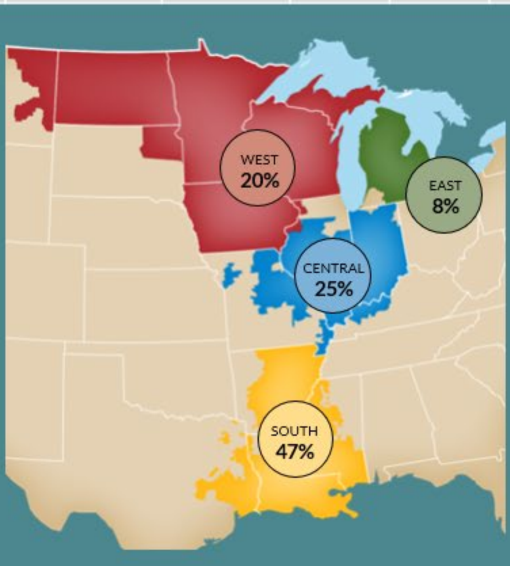
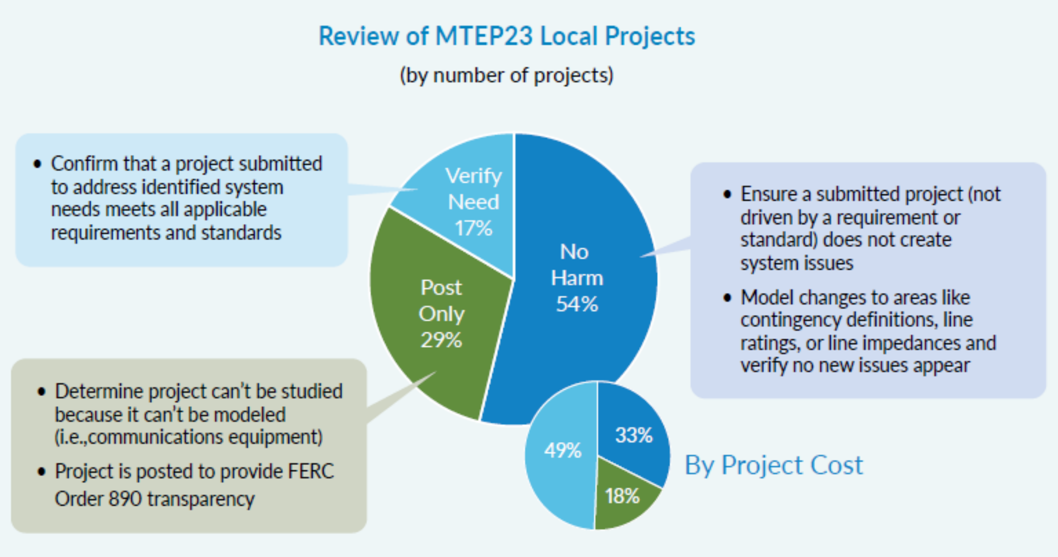


Figure 1.4-1: Appendix A project investment summary (data as of 9-29-2023)

MISO considered alternatives (see Figure 1.4-2) and verified the need for a portion of the Other projects in addition to verifying the need for all the Baseline Reliability Projects.



- Confirm that a project submitted to address identified system needs meets all applicable requirements and standards

- Ensure a submitted project (not driven by a requirement or standard) does not create system issues
- Model changes to areas like contingency definitions, line ratings, or line impedances and verify no new issues appear

- Determine project can't be studied because it can't be modeled (i.e.,communications equipment)
- Project is posted to provide FERC Order 890 transparency

Figure. 1.4-2: Types of reviews MTP23 local projects went through.

Analysis of twelve MTEP projects for alternative solutions resulted in the re-submission of one project to address a larger set of needs, one lower-cost project, and one project that is pending further analysis.

Within MTEP23 proposed projects, the top ten projects represent roughly 43%, or $3.9 billion of the total $9 billion investment (Figure1.4-3).

Top 10 Projects in MTEP23 Appendix A

Rank	Project Name	Project Driver	Cost *(millions)*
1	Amite South Reliability Project - Phase 1 - Alternative	Other – Reliability	$1,700
2	Southeast Texas Area Reliability Project	Baseline Reliability	$1,111
3	Amite South Reliability Project - Phase 2	Other – Reliability	$290
4	New Baldwin Area Reactive Support	Other – Reliability	$170
5	New South Central Illinois Transmission Expansion	Other – Reliability	$168
6	New Slugger 138 kV Load	Other – Load Growth	$124
7	New Kokomo Fusion Phase 1 – 230/69 kV Substation	Other – Load Growth	$92
8	Rebuild Sioux-Meppen North-Hull 138 kV Line	Other – Age and Condition	$78
9	New Seminary – Wittenberg – Grand Tower 138 kV	Baseline Reliability	$68
10	Southland Expansion and Upgrades	Other – Load Growth	$58

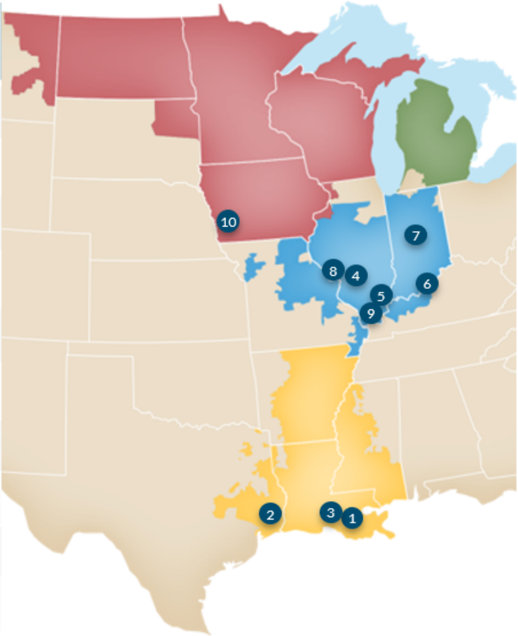


Figure 1.4-3: List of top ten proposed MTEP23 projects as of September 29, 2023, blanket renewal projects excluded from ranking.

Of the total projects proposed for MTEP23, over 70% percent are projected to go into service within the next three years (Figure 1.4-4).

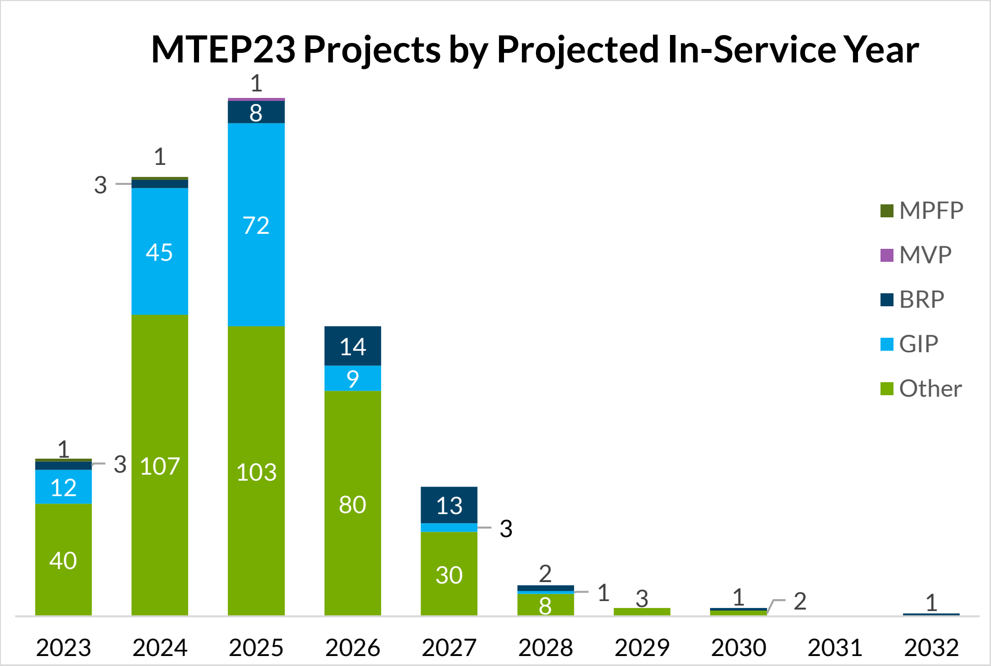


Figure 1.4-4: MTEP23 Projects by In-Service Year (data as of 9-29-23)

New Appendix A projects are spread over 14 states, with two states in the south scheduled for approximately $3.9 billion in new investment (Figure 1.4-5). These geographic trends vary greatly year to year as local planning dictates blanket asset renewal programs or as existing transmission capacity in other parts of the system is consumed and new build becomes necessary.

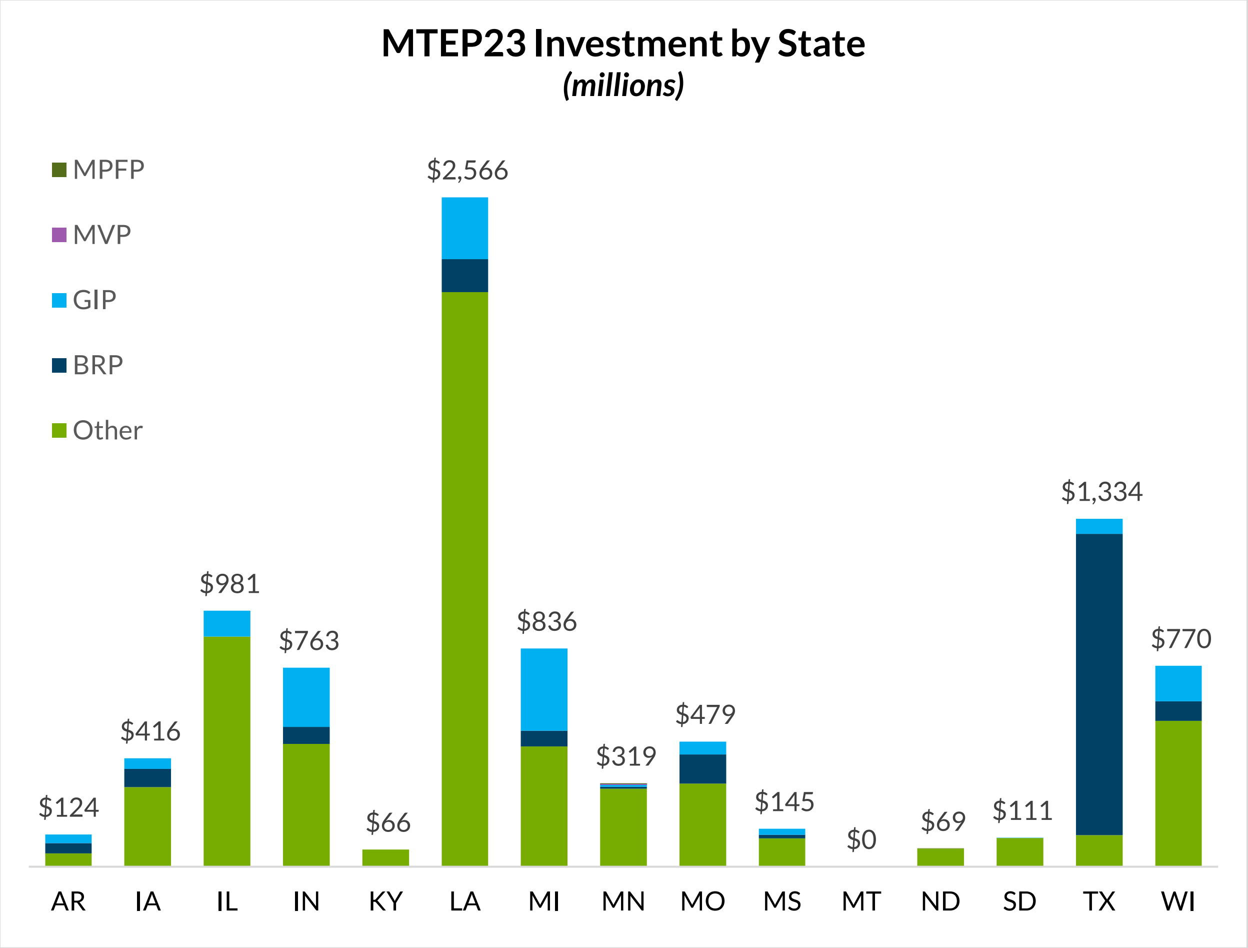


Figure 1.4-5: MTEP23 Appendix A investment categorized by state (data as of 9-29-23)

Facility Type

Each MTEP project is composed of one or more facilities, where each facility represents an individual element of the project. Examples of facilities include substations, transformers, voltage devices, circuit breakers or various types of transmission lines (Figure 1.4-6).

The largest share (44%) of facility investment in the MTEP23 cycle is dedicated to new lines on new right-of-way in MISO. Thirty percent is dedicated to substation or switching station related construction and maintenance. This includes completely new substations as well as terminal equipment work, circuit breaker additions and replacements. Twenty percent is dedicated to line upgrades which includes rebuilds, conversions, and relocations. The remaining six percent of facility costs are dedicated to voltage devices, transformers, and miscellaneous categories.

MTEP23 Transmission Investment by Facility Type

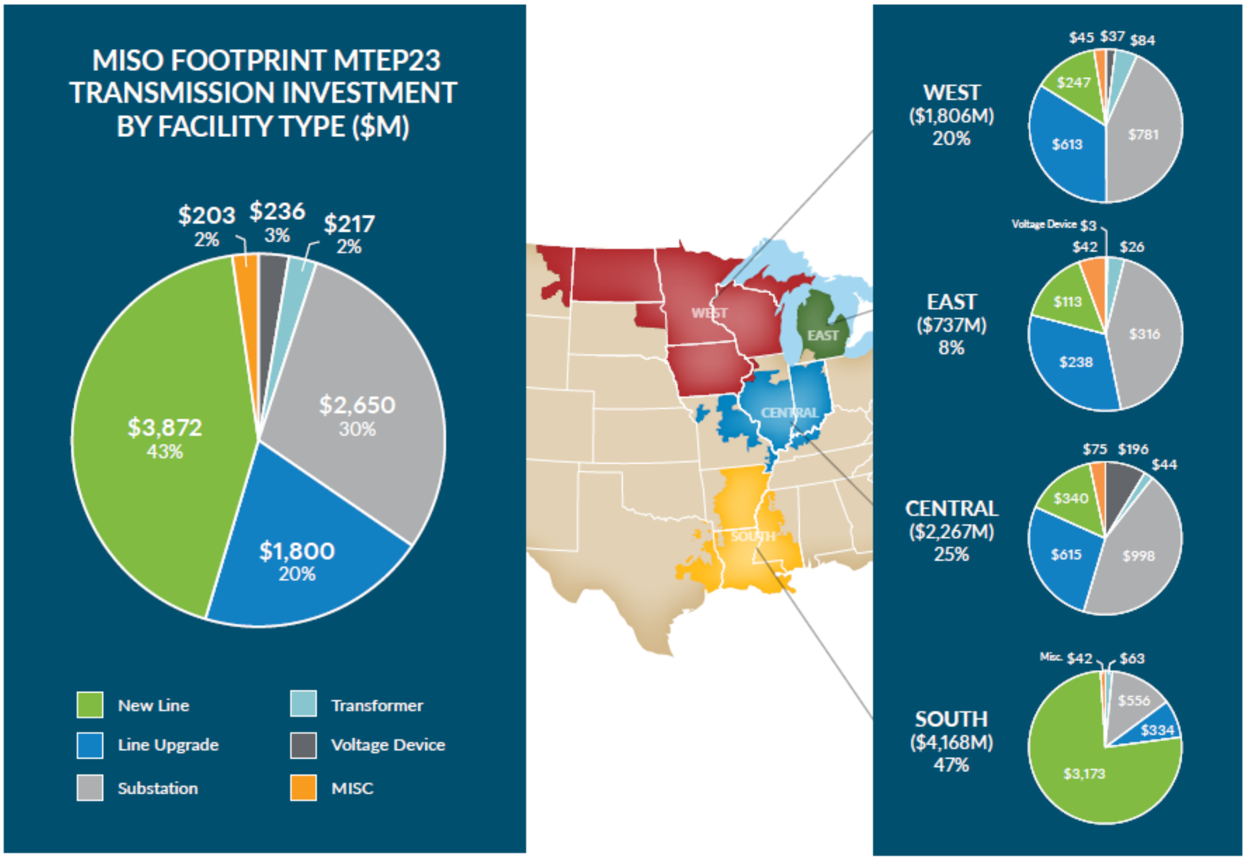


Figure 1.4-6: Facility type investment for new MTEP23 Appendix A projects by planning region (data as of 9-29-23)

MISO receives projects each year, each project has multiple facilities and the facilities determine the impact a project may have on a powerflow model (which is what we use to assess system impact) and our ability to review alternative solutions. MISO considers the facilities that make up a project to understand what type of analysis may be required, including verifying a project's need, ensuring the project does not create reliability concerns (e.g., no harm), or providing transparency (e.g., post only). In general, post only projects consider miscellaneous and substation projects that do not impact the physics of the transmission system. Alternative analysis is targeted primarily at larger projects in areas with multiple future need drivers; smaller projects to serve radial load or 'like for like' replacements are unlikely to have economic alternatives. Alternatives analysis also requires a defined reliability need, as MISO must verify this need to adequately examine alternatives and their effectiveness. The remaining projects include a combination of projects verifying needs and no harm.

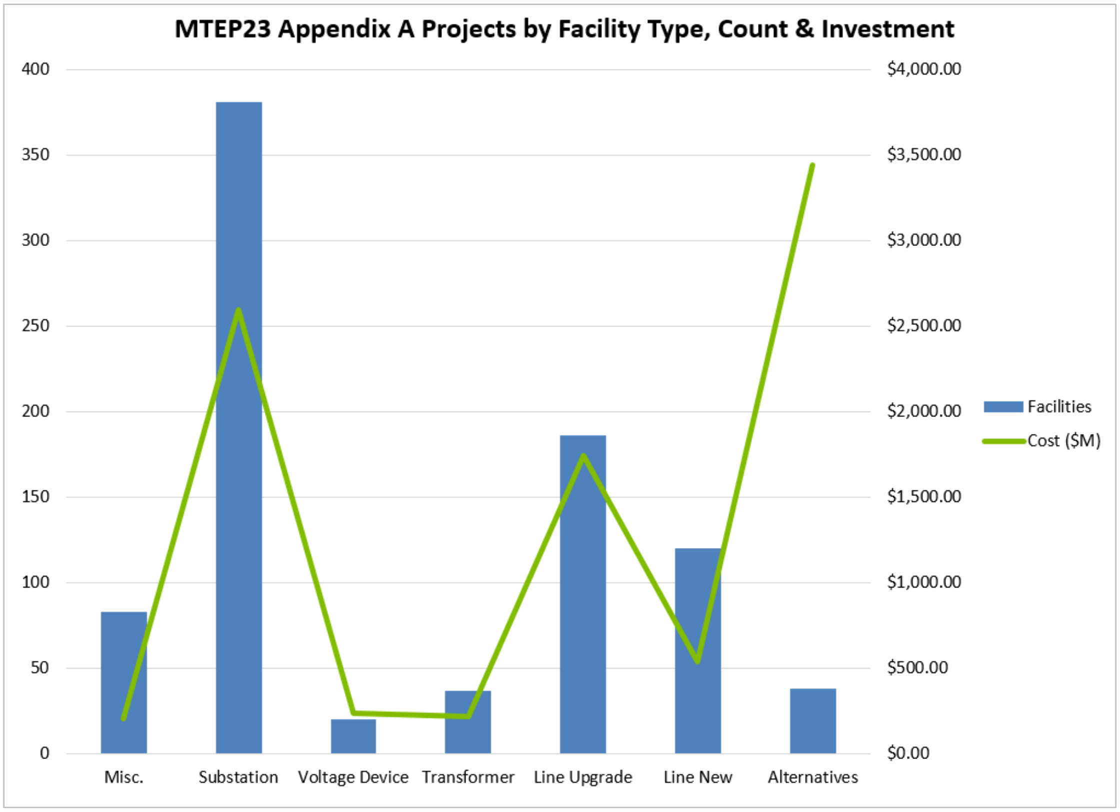


Figure 1.4-7: MTEP 23 Appendix A projects by facility type, count and investment

In addition to system adjustments allowed by NERC, MISO focuses analysis for alternative solutions on facilities that are larger in cost and in their potential impact on the system. Figure 1.4-7 demonstrates this as a small number of facilities with a large total investment of $3.4 billion are analyzed for alternative solutions resulting in alternatives selected for two projects.

MTEP23 New and Upgraded Line Miles

MTEP23 Appendix A projects total approximently 742 miles of new or upgraded lines (shown in Figure 1.4-8). Of the total, fifty-five percent of new or upgraded line miles will go into service within the next three years, or 86% within five years. There are 643 line miles, or 87% of the total line miles, that are 161 kV or below. Seventy-six line miles are projected at 230 kV or above.

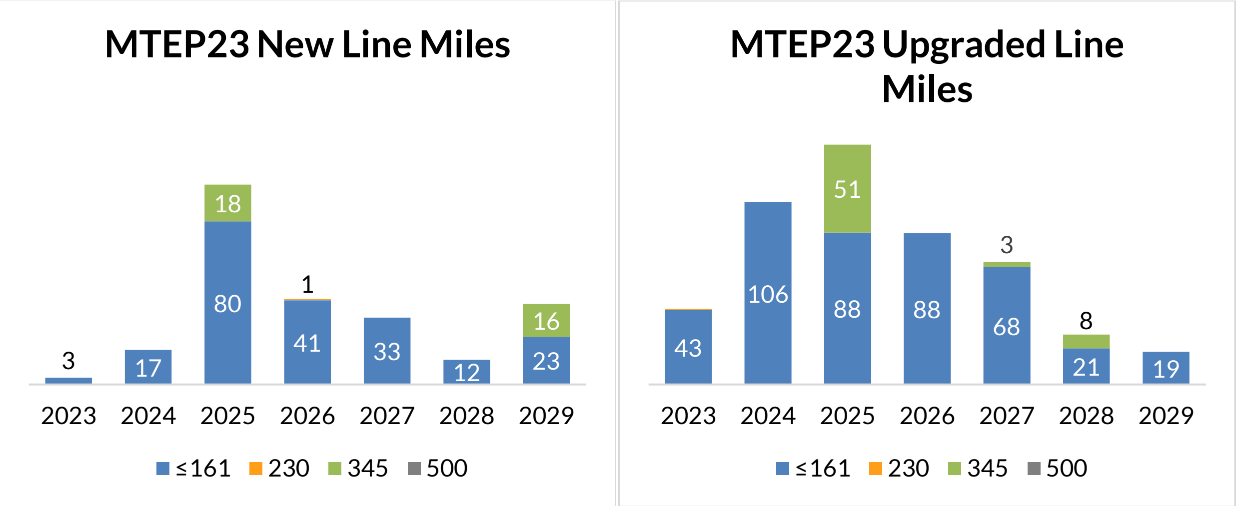


Figure 1.4-8: New and upgraded line miles proposed in MTEP23 Appendix A (data as of 9-29-23)

Allocation of Costs

MTEP23 includes a total of 62 new cost-share eligible Generator Interconnection Projects (GIPs) for Appendix A. GIP costs are primarily paid for by the interconnecting customer (generator), however, a portion of the costs for certain network upgrades are eligible for regional cost allocation under Attachment FF of the MISO Tariff. Detailed allocations by pricing zone are provided in Appendix A1.

Indicative rates related to past MTEP cost-shared projects are calculated on an annual basis. Please refer to the reports (indicative forecasts of annual charges) posted on the MISO public website[4].

MTEP Appendix B

MTEP Appendix B contains all projects that have been validated by MISO as the preferred solution to address an identified system need based on current information and forecasts, but where it is prudent to defer the final recommendation of a solution to a subsequent MTEP cycle.

This generally occurs when the preferred project does not yet need a commitment based on anticipated lead-time and there is still some uncertainty as to the prudence of selecting this project over an alternative project given potential changes in projected future conditions. MTEP Appendix B is limited to Baseline Reliability Projects and Other Projects and will be reviewed by MISO in subsequent cycles.

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[4] Cost Allocation updates web address: https://www.misoenergy.org/planning/planning/schedule-26-and-26a-indicative-reports/

CHAPTER 2: PORTFOLIO EVOLUTION

2.1 MISO Futures

To perform analysis on the bulk electric system twenty years into the future, many assumptions must be made to bridge what is known about the system today to what it could be two decades from now. Complicating matters is the uncertainty of future developments.

MISO has developed a method to address this uncertainty—the use of forward-looking scenarios to provide a range of future outlooks. Within MISO, these forward-looking scenarios are called the "Futures". These Future scenarios establish ranges of economic, policy, and technological possibilities—such as load growth, electrification, decarbonization, generator retirements, renewable energy levels, fuel prices, and generation capital costs—over a twenty-year period.

Future Scenarios

MISO Futures are the inputs for multiple MTEP cycles, the LRTP initiative, and other planning studies. These Futures form the basis for the Reliability Imperative, such that MISO and its stakeholders can plan to a consistent set of scenarios across transmission, markets, and operations. In 2023, MISO introduced a new naming convention for the MISO Futures. Cohorts of Futures are now referred to by series.

The Series 1 MISO Futures developed in 2019-20 culminated an 18-month joint effort between MISO and its stakeholders. This effort aligned Futures development with the ongoing fleet transformation and incorporated the plans of MISO's members and states, while also creating future scenarios that can be utilized over several years. Therefore, the Series 1 MISO Future scenarios were used in LRTP Tranche 1.

Within this context, no new Future scenarios were developed specifically for MTEP23. Rather, within the framework of LRTP Tranche 2, the development of Series 1A commenced in Summer 2022. Originally known as the Futures Refresh, Series 1A focused on refreshing certain input data around generation and economics while maintaining the load, number, and definition of Futures established in Series 1. Specifically, LRTP Tranche 2 will develop a portfolio that meets the needs of Future 2A (F2A) within Series 1A.

The following figures show effects from refreshed input data in F2A. Driven largely by updated member plans, F2A illustrates the continuing impacts of the energy transition, with significant acceleration in thermal retirements, renewable capacity buildout and energy production, and decarbonization.

Series 1A and subsequent Futures Series will continue to capture transformation within the MISO footprint, reflecting the system's evolution and serving as the foundation for forthcoming MISO initiatives. Iterations of Futures are a product of continued collaboration between MISO and its stakeholders.

More information on the MISO Futures, including reports and Series 1A assumptions, is found here. Additionally, the 2023 Series 1A Futures Report will be incorporated once published.

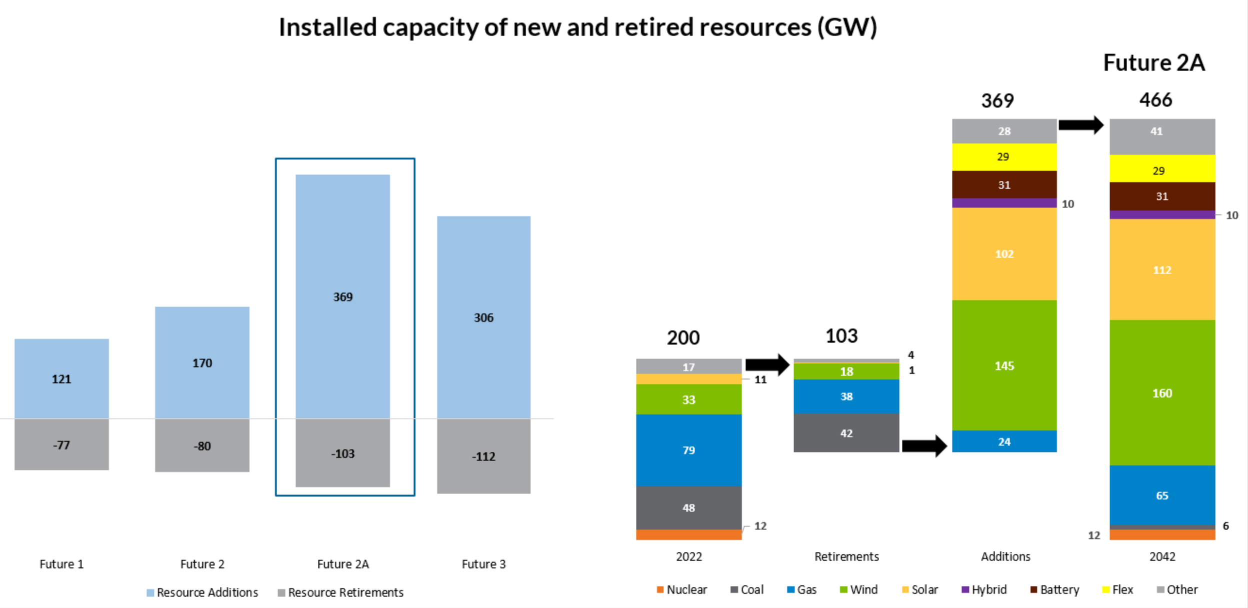

Figure 2.1-1: This figure from Future 2A analysis shows that F2A's expansion surpasses those of Series 1 Future 3, while F2A's retirements approaches those of F3.[5]

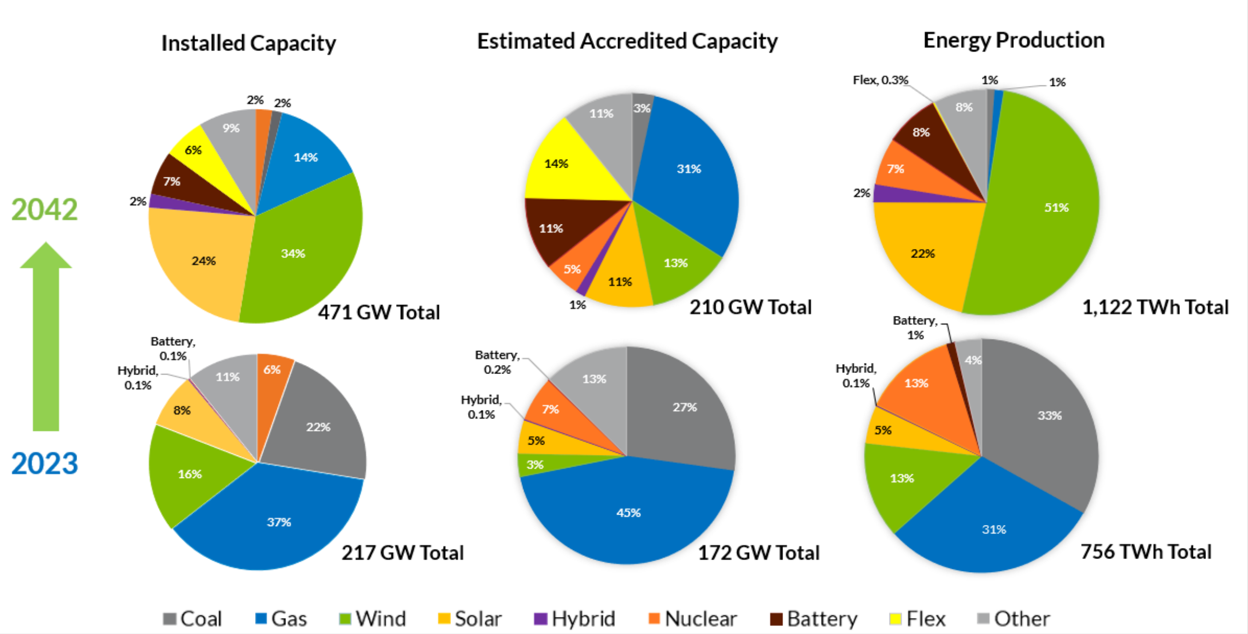

Figure 2.1-2: This figure from Future 2A analysis shows the changing energy and capacity mix as the generating fleet continues to evolve.[5]

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[5] Data as of April 26, 2023. Futures do not account for all operational-level reliability needs and attributes that may require different levels of dispatchable resources. Resource additions may be subject to adjustment based on new accreditation rules. "Other" includes biomass, geothermal, hydro, oil, pumped hydro storage, demand response, non-solar distributed generation, and energy efficiency. Battery energy production includes battery discharging only. However, overall energy production pie graph includes the energy required to charge storage.

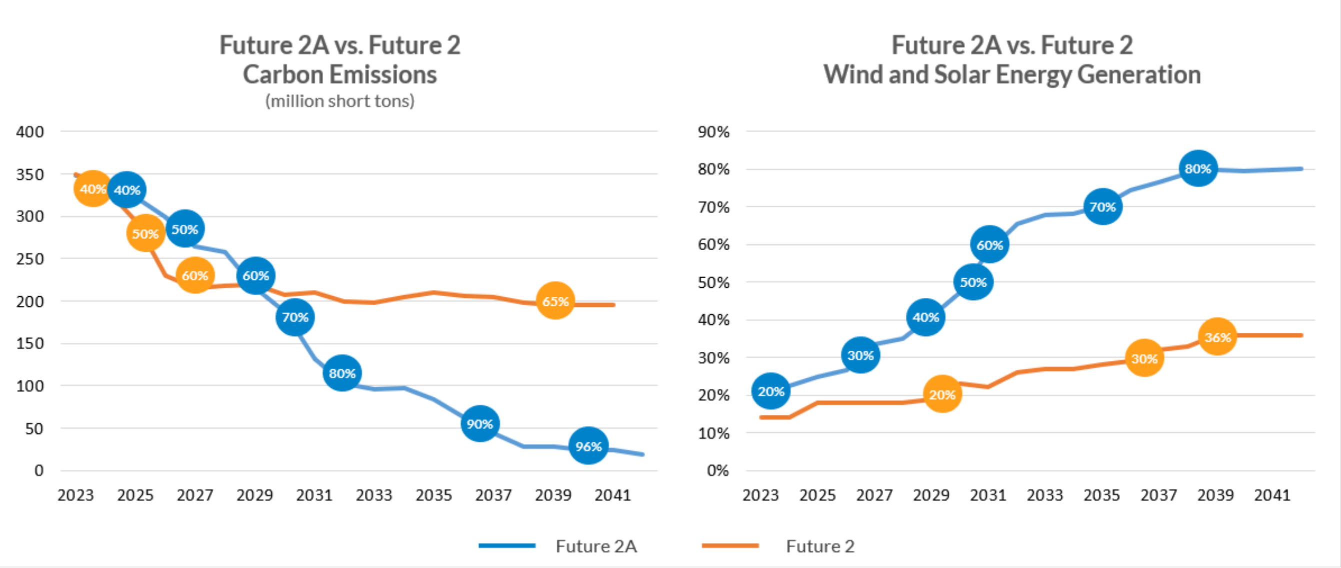

Figure 2.1-3: This figure from Future 2A analysis shows that F2A's decarbonization and renewables generation far outstrips that of Series 1 Future 2.[6]

2.2 Retirement Trends and Future Outlook

One aspect of resource evolution that MISO assists its membership in managing is the retirement of generation facilities, to ensure that the broader MISO footprint remains reliable after resources are removed from service. Through the process articulated in Module C Section 38.2.7 of the MISO Tariff, resource owners submit a request to retire generation resources for MISO approval, which triggers an assessment into the impact that the requested resource would cause once it is retired from service. As a result of these analyses, any reliability issues are addressed through transmission reinforcements or other needed mitigation measures. If the reliability issue cannot be addressed prior to the planned retirement date, MISO may require the resource to remain in service as a system support resource (SSR) until the upgrade is complete, or mitigation is available. As the generation mix continues to evolve, more generating resources are expected to retire, increasing the number of Attachment Y requests MISO receives. This may increase the need for SSR-designated units. Since September 2022, MISO has established two SSR units to maintain reliability of the region.

In 2022, MISO proposed improvements to the Attachment Y process. These improvements were accepted by FERC, which extended the advance notice timeline from 26 to at least 52 weeks to allow MISO more time to process the increased number of Attachment Y requests. MISO also proposed and gained approval for a quarterly study period system. These changes better allow for forecasting workload internally. MISO made other proposals around the studies included in the retirement process and the mitigations used in the studies have reduced reliance on load shed and redispatch. While MISO has not proposed any new studies for the base reliability study process, the extended advance notice timeline will allow for additional studies as situationally necessary. Lastly, MISO appreciates the need for greater transparency into the retirement process while maintaining a great deal of confidentiality for its members. As part of the Attachment Y improvements, MISO will be communicating the number of requests received by quarter and the number of megawatts requesting suspension or retirement.

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[6] Data as of March 7, 2023. Futures do not account for all operational-level reliability needs and attributes that may require different levels of dispatchable resources. Resource additions may be subject to adjustment based on new accreditation rules.

Aging coal-fired generating resources have experienced increased retirements in recent years due to cost pressures of operation and competition from gas-fired generation. Renewable generating resources have become more economically and environmentally attractive sources of generation in recent years, putting further pressure on carbon-based generation. Since 2010, MISO has experienced the retirement of 30.8 GW, of which 21.9 GW was coal-based (Figure 2.2-1). The age of generating facilities retired in 2021 declined to an average of 32 years compared to an average of 44 years in 2011. Advancements in technology and interest in renewables are expected to continue the current trend.

A trend since 2020 is the utilization of the new Generating Facility Replacement process. This process was approved by FERC in 2019 to allow the owners of an existing facility to use their existing interconnection service to replace the existing generator with a new generating facility at the same injection point without going through the MISO Generator Interconnection queue. Since 2020, MISO has received 32 generator replacement requests to replace a total of 6.1 GW of existing generation, which otherwise would have been retired through the traditional resource retirement process.

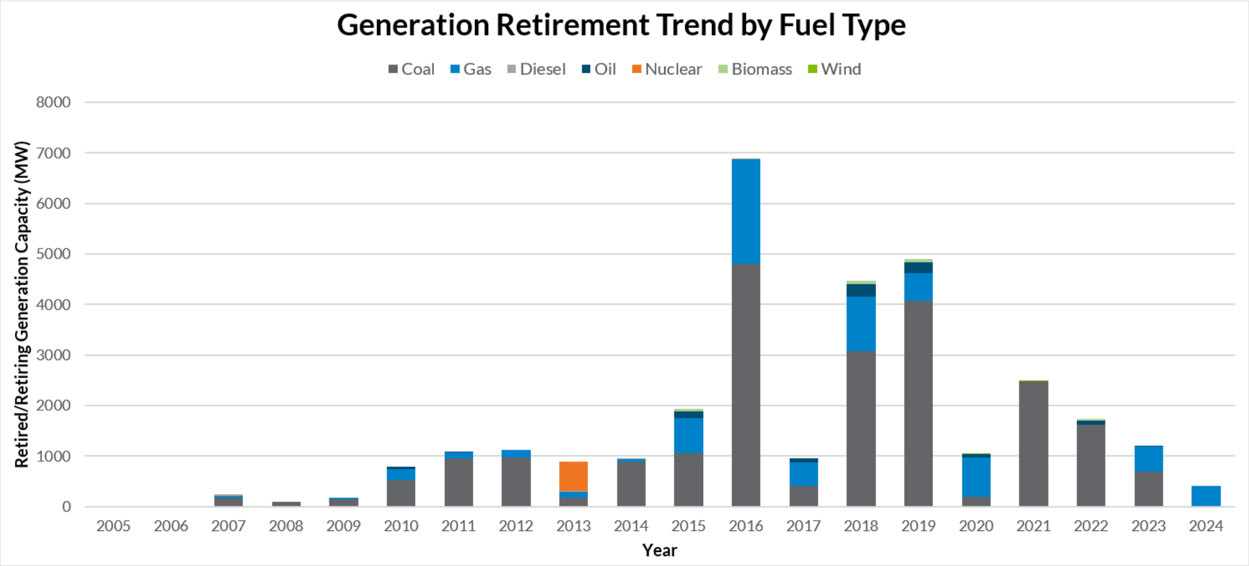

Figure 2.2-1: MW Generation Retirement by Fuel Type

2.3 Resource Outlook

Load Serving Entities (LSEs) in the MISO region must have sufficient resources to meet their forecasted demand plus their required levels of reserves. Every year, MISO administers a Planning Resource Auction (PRA) that LSEs may use to purchase or sell resources for that purpose. LSEs can also opt out of the PRA and use their own resources or negotiate bilateral contracts with other entities. Regardless of how LSEs procure their needed resources, all this information is rolled up into the PRA to demonstrate whether the region will be resource-adequate for the upcoming MISO Planning Year, which runs from June 1 to May 31 of the following year.

This year's PRA was the first to reflect MISO's new four-season resource adequacy construct, which is designed to plan for and address risks beyond the traditional summer peak-load months. This first-ever seasonal PRA demonstrated that all parts of the MISO region have adequate resources for the 2023-2024 Planning Year. More details on this year's PRA results are available here.

It is important to note that demonstration of adequate capacity for the 2023-2024 Planning Year does not imply that the region will continue to have adequate resources going forward. Actions taken by LSEs such as delaying some previously announced resource retirements, and the region obtaining additional capacity via imports contributed to the positive results this year. Such actions may not be repeatable over the longer-term. Therefore, unless more generation is built—especially controllable resources that have the attributes the system needs—the risks of capacity shortfalls and other reliability issues will continue to grow.

OMS-MISO Survey

The region's forward-looking resource picture is further illustrated by a planning tool called the OMS-MISO Survey, which asks LSEs to provide information on demand forecasts, new generation they plan to build and existing resources they plan to retire. MISO administers the survey once a year in partnership with the Organization of MISO States (OMS), which consists of state regulatory agencies in the region. The survey is a "snapshot in time" instrument that focuses on a five-year forward view, but it also includes 10-year forward data with an understanding that uncertainty increases in the latter five years.

In recognition that forward-looking resource plans can and do change, the survey allows LSEs to indicate different levels of certainty to the information they provide. Taking that uncertainty into account, the survey shows how anticipated resource levels compare to the Planning Reserve Margin Requirement (PRMR) across MISO as a whole and in each of the region's 10 Local Resource Zones (LRZs). Like this year's PRA, this year's survey reflects MISO's new four-season resource adequacy construct. Survey results are expressed in terms of seasonal PRMRs and Seasonal Accredited Capacity (SAC), which reflects the availability of resources during times of highest reliability need in each of the summer, fall, winter, and spring seasons.

This year's survey indicates the MISO region as a whole will have sufficient resources for the 2024-2025 Planning Year, with a surplus of 1.5 GW in the summer (expressed in terms of SAC, as described above). Similar to this year's PRA results, the survey's forecasted surplus in the 2024-2025 Planning Year is based on actions such as delayed retirements and increased imports that may not occur again going forward. In the figure below, the survey shows the region could have a capacity deficit of 2.1 GW (SAC) in the summer of the 2025-2026 Planning Year, with that deficit increasing in subsequent years, which supports the view that actions taken this year to provide capacity may not be available in the future.

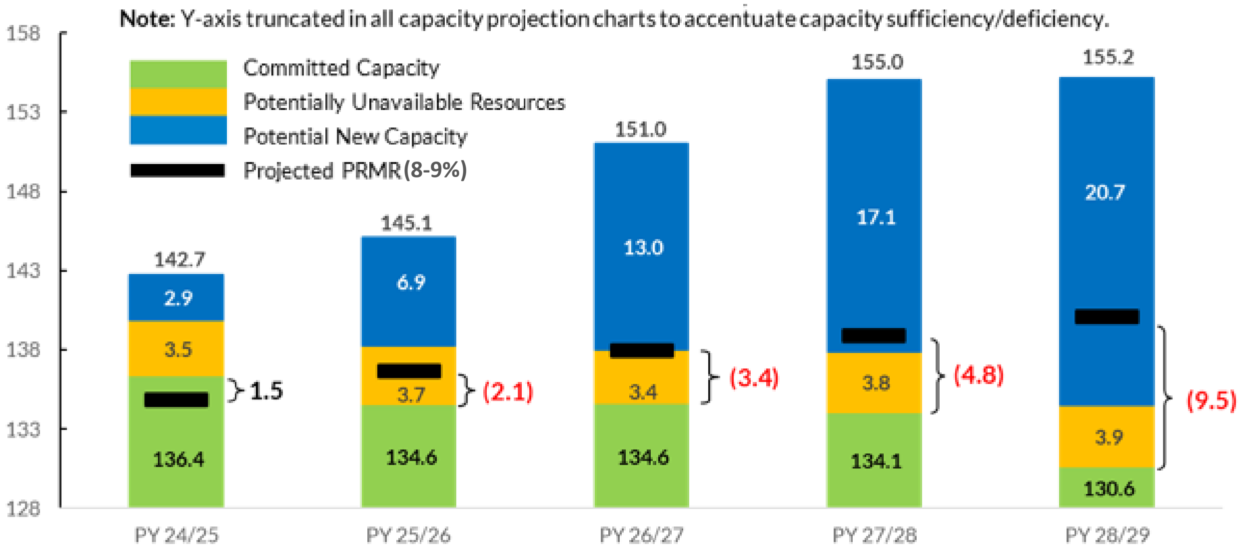

Figure 2.3-2: 2023 OMS-MISO Survey - 5-Year Summer Results

More details about this year's OMS-MISO Survey are available here, including projected capacity levels for the fall, winter, and spring seasons, as well as LRZ-level results.

Regional Resource Assessment

Another tool MISO uses to develop a holistic, forward-looking view of the grid is the Regional Resource Assessment (RRA). The RRA is a recurring study that models how the region's fleet of generating resources might evolve based on the goals that utilities and states have publicly announced to reduce their carbon emissions and/or increase their use of renewable energy. The RRA also models public announcements that utilities and states make to retire specific existing resources and to build new resources going forward.

While the RRA is similar to the OMS-MISO Survey in some regards, there are key differences in their respective designs, purposes, and modeling assumptions. For example, while the OMS-MISO Survey primarily focuses on the next five years, the RRA looks out 20 years. Another difference is that the RRA allows LSEs to submit information about their aspirational decarbonization and/or renewable energy goals. The RRA then uses computer modeling software to "predict" what resources LSEs might build to meet their goals when they have not yet publicly identified enough actual resources. The OMS-MISO Survey does not perform this type of resource-expansion modeling, and instead only includes resources that LSEs specifically identify themselves.

The most recent iteration of the RRA (published in November 2022) yielded findings and insights that align with the results of this year's PRA and OMS-MISO Survey. The key findings of the 2022 RRA are as follows:

- The 2022 snapshot of MISO member plans indicates an increase in the overall amount of installed capacity, but a decline in accredited capacity compared to current levels.
- The RRA modeling indicates a continued near-term capacity risk, highlighting the urgent need for coordinated resource planning and additional investment.
- Wind and solar generation are projected to serve 60% of MISO's annual load by 2041, which would reduce emissions by nearly 80% relative to 2005 levels, but also sharply increase the complexity of reliably operating and planning the system.

- As the solar generation fleet grows, the system will have a much greater need for controllable ramp-up capability. Maximum short-duration up-ramps increase by three times by 2031 and four times by 2041 compared to current levels.
- The capacity contribution of solar generation is forecast to decline rapidly as more solar capacity is added to the system, impacting the region's overall capacity outlook. The contribution of wind generation remains relatively stable as more wind capacity is added.

2.4 Current State of the Queue

The MISO Generator Interconnection (GI) queue provides an active and competitive mechanism to enable resource interconnections that will serve future energy and capacity needs. Projects submitted in the annual queue cycle are evaluated by MISO through an iterative study process to determine the reliability impacts and to identify transmission upgrades needed to support resource integration. Project viability is often tied to the costs of network upgrades, with the most viable candidates successfully executing a Generator Interconnection Agreement (GIA).

The Generator Interconnection queue has experienced extremely high volume over the last several years. In 2022, MISO received 956 individual project requests. Solar, storage, and hybrid applications make up the bulk of the queue.

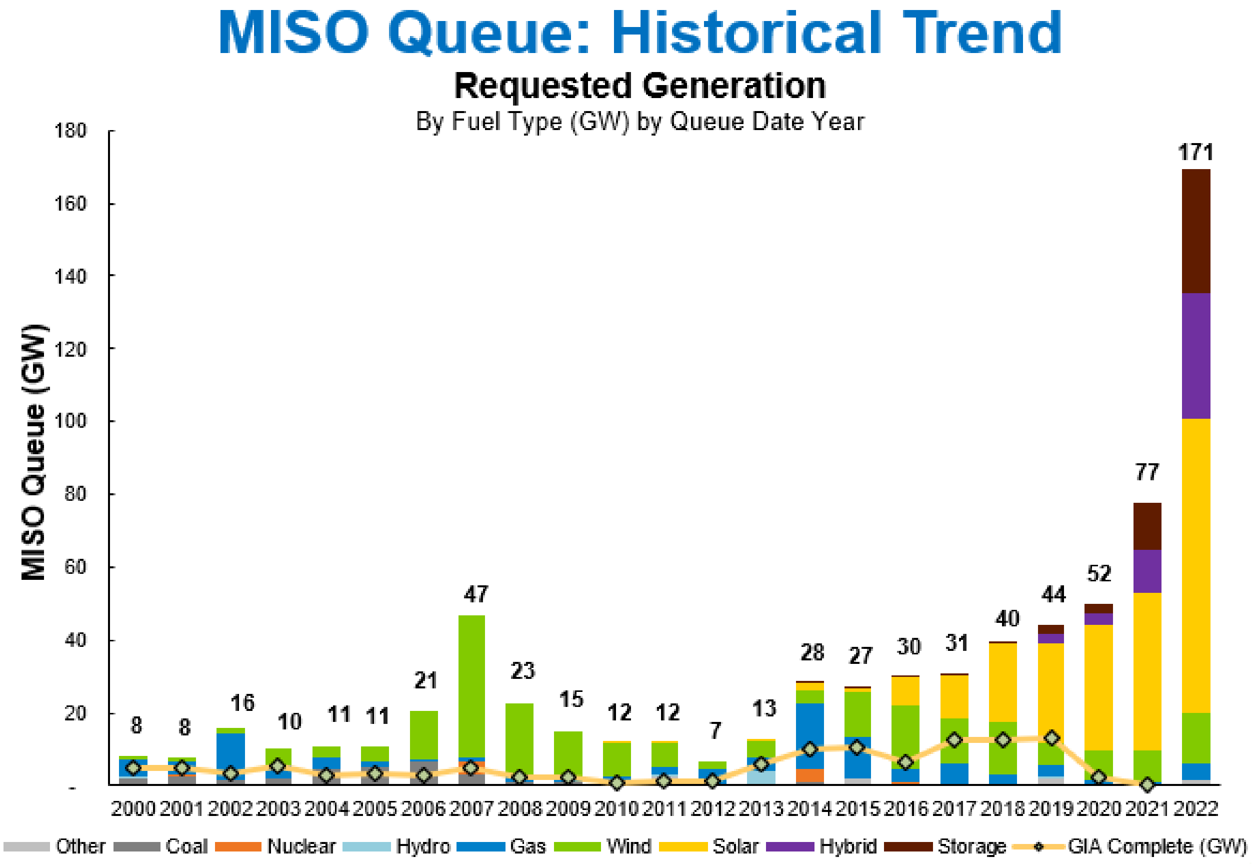

Figure 2.4-1: As of August 2023, the current state of the queue has 1,365 projects representing 235.23 GW of total capacity.

The MISO Active Queue by study area and fuel type (Figure 2.3-2) is available on the MISO website under the [GIQ Web Overview]() link on the [Generator Interconnection Queue]() page. A list of all active projects can also be reviewed on the page. The five study regions in the GI queue currently have 24 active cycles in various stages of the process from the start of the Definitive Planning Phase (DPP) to GIA negotiations.

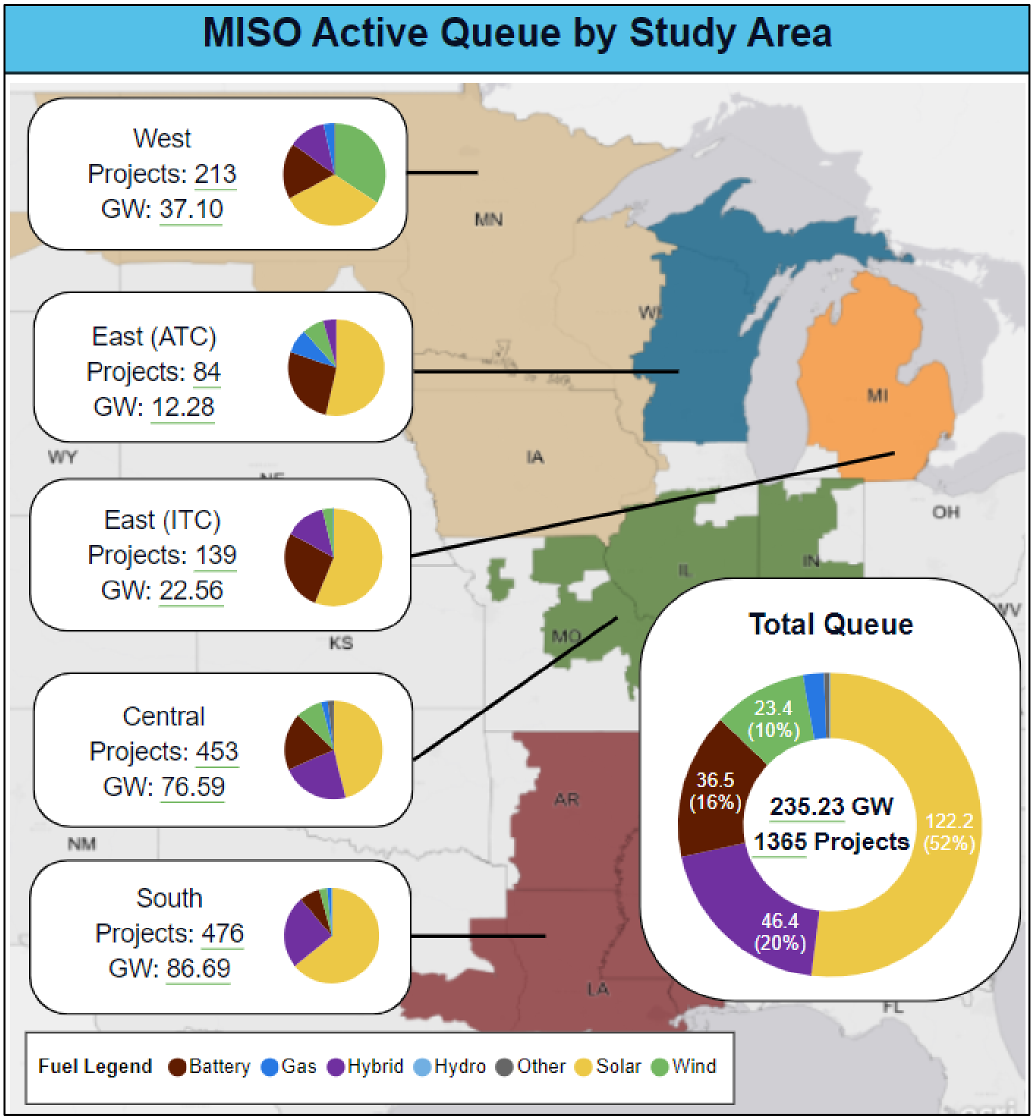

Figure 2.4-2: Active Generation Interconnection Queue by Fuel Type as of August 8 ,2023

Since the pandemic, a troubling new trend has emerged for generators that exit the queue with a GIA. Supply chain and regulatory issues have increased the time it takes for new generators to be built and reach commercial operations. As of August 2023, MISO has nearly 50 GW of new generators with a GIA and not yet online. MISO expects this number to increase to as much as 63 GW by end of 2023. Interconnection Customers and Transmission Owners report that supply chain issues on both the generator and transmission equipment are the main reason for the extended timelines. MISO will continue to track this trend and work with stakeholders on these issues, as this generation will be necessary to support potential resource adequacy shortfalls in the future.

MISO Seeking Additional Queue Reforms

MISO's queue process is constantly being assessed and refined to make improvements and has undergone eight substantive reforms since being instituted. These reforms have made the queue process quicker, more efficient, and less burdensome to our members. In fact, MISO has the shortest end-to-end queue time within our tariff among our peer RTOs and ISOs.

In March 2022 FERC approved MISO's last reform, which reduced the MISO queue timeline schedule from 505 days to either 373 or 463 days, depending on whether a Network Upgrade Facilities Study (NUFS) is conducted in parallel with or prior to the Generator Interconnection Agreement (GIA) negotiation and execution. In either case, the NUFS must be completed before interconnection takes place. Achieving these timelines is contingent upon MISO Transmission Owners completing their studies on time and our neighboring regions completing their Affected System Study (AFS) on schedule. To date, MISO and its TOs have been unsuccessful in meeting these timelines due to the sheer volume of requests in the queue.

In addition to implemented improvements, MISO is now tackling additional reforms to improve entry and exit into the queue to further streamline the GI process and MISO's need to bring new resources onto the system quickly. In May 2023, MISO introduced the need to pursue additional queue reforms in advance of the 2023 queue cycle. Without additional improvements, the 2023 queue cycle could well exceed the record 171 GW that entered the queue in 2022.

MISO continues to work with stakeholders on what rules should be adjusted and what the specifics of those rules should be. The current proposal before stakeholders is to increase the milestone payments needed to enter and stay in the queue, improve site control requirements around the point of interconnection, adjust the calculations around penalty free withdrawal, introduce a mandatory penalty schedule if a project withdraws, and introduce a cap on the size of each queue cycle. These new rules are expected to be filed with FERC within Q4 of 2023 and apply only to new queue submissions. MISO will not announce the 2023 queue submission deadline until after FERC's action on the future filing.

In addition to these future reforms, MISO is also reviewing the recent FERC Order 2023 to improve generator interconnection rules. Order 2023 will certainly improve the interconnection procedures in non-market areas of the United States that have yet to adopt cluster studies. MISO believes the Order does not go far enough, as most of the rules FERC adopted are ones that MISO already uses, but are not as prescriptive as MISO's Tariff. Because of this, MISO believes our additional queue reforms are still needed to further refine our requirements to ensure the efficient processing of the future requests.

CHAPTER 3: REGIONAL AND INTERREGIONAL PLANNING STUDIES

3.1 Long Range Transmission Planning

The Reliability Imperative focuses on preparing the region for industry transformation as the grid evolves toward increased decarbonization goals and renewable resources. As a critical part of this effort, Transmission Evolution assesses the region's future transmission needs and associated cost allocation holistically, including transmission to support member plans and state goals for existing and future generation resources. Long Range Transmission Planning (LRTP) is part of this effort.

The LRTP initiative is MISO's response to the current and future resource evolution that has and continues to affect the bulk electric system. The scale and pace of these changes require prompt attention to develop the most efficient, cost-effective investments that will ensure grid reliability in the future. LRTP sets out to proactively identify key regional backbone transmission projects to support the resource change. This requires MISO to balance regional issues which should be addressed now as part of the LRTP study versus those more localized issues which should be addressed in the future through the interconnection process or in future MTEP cycles as specific load and generation locations are determined. Ultimately, the objective of the LRTP study is to identify a least-regrets transmission build-out evaluated against multiple scenarios to manage uncertainty that achieves member goals, maintains reliability, and minimizes costs.

LRTP Tranche 1 Update

On July 25, 2022, MISO approved Tranche 1 of its LRTP study, which included 18 transmission projects with a total estimated cost of $10.3B (2022$). In the first year after project approval, Transmission Owners have continued to work on more detailed engineering design and construction plans and some Transmission Owners are starting to make regulatory filings with the applicable government agencies. As project updates have been available, Transmission Owners have provided those to MISO for its project reporting, which are shared on MISO's public website.

Additionally, as applicable, MISO has solicited proposals and selected developers for transmission projects in Tranche 1 eligible for the Competitive Transmission Process. Five Request for Proposals for Competitive Transmission Projects resulted from Tranche 1, all which MISO issued within one year of Board approval. In May 2023, MISO selected Republic Transmission to develop a competitive transmission project located in Indiana. In October 2023, MISO will select a developer for a competitive transmission project located in Missouri, and in February and April 2024, MISO will select a developer for each of the remaining three competitive transmission projects. MISO looks forward to future collaboration with Transmission Owners as the transmission projects in Tranche 1 are further designed, constructed, and placed in service.

LRTP Tranche 2 Status

Currently, MISO has moved to the next phase of the LRTP work, referred to as Tranche 2. This next Tranche will continue the work of Tranche 1 focusing on the Midwest Subregion of the MISO footprint. An important distinction from Tranche 1 is that Tranche 2 will utilize Future 2A of the recently developed Series 1A Futures to ensure transmission is available in a timely manner and meets member objectives.

In the time between the start of the Series 1 Futures (2019) and the end of the LRTP Tranche 1 effort (2022), significant changes occurred, namely acceleration of membership decarbonization and renewable plans and State policies. This acceleration drove the need to refresh the Futures and hence the Series 1A was developed.

Tranche 2 kicked off in quarter three of 2022 with the refresh of the MISO Futures. Along the way, many LRTP Workshops have been held as well as discussions at the MISO Planning Advisory Committee (PAC) to engage stakeholders in the LRTP process. Furthering stakeholder communication efforts, MISO also developed a set of Frequently Asked Questions (FAQ) to provide a broad base of information on various LRTP topics. The first key deliverable in the LRTP Tranche 2 study was completion of the updated Future 2A expansion and siting, which is the foundation for the current work on the economic and reliability models. Additional near-term key focus areas include:

- Reliability dispatch methodology and scenarios, see Reliability Modeling Whitepaper for more detail
- Issues identification using economic and reliability models
- Portfolio development to resolve regional issues
- Continued definition and refinement of robustness scenarios to ensure identification of least-regrets solutions
- Identification of benefit metrics for Tranche 2 to demonstrate multiple distinct types of value from the portfolio

Stakeholder engagement will continue throughout the process as transmission system models are completed, analysis is performed and issues identified, necessary grid enhancement solutions are developed, scenarios are analyzed, and benefits of a proposed portfolio are quantified. Tranche 2 efforts are expected to be completed with BOD approval in 2024.

LRTP Tranche 3 Status

MISO's Long Range Transmission Planning (LRTP) effort has multiple workstreams to support the different Tranches going on in parallel. Namely, MISO's current focus is on execution of the competitive process for Tranche 1, modeling and analysis for Tranche 2, and cost allocation discussions for Tranche 3.

In the most recent FERC filing to support the bi-furcated sub-regional MVP cost allocation for Tranches 1 & 2, MISO committed to exploring an alternative cost allocation approach for Tranche 3 focused on MISO South. To effectively pursue adjustments to the methodology, MISO and its stakeholders are actively engaged in evaluating options. These conversations are centered around three main criteria:

- Granularity – alignment on definition and scope of granularity and how it is considered in benefit calculation and allocation methodology
- Feasibility - evaluation tools and techniques available to determine beneficiaries
- Consistency – recognition that benefits and beneficiaries may change over time and applying a cost allocation methodology that remains just and reasonable over time

Ongoing conversations can be monitored in the Regional Expansion and Criteria Working Group (RECBWG). Additionally, we appreciate the ongoing effort of OMS' Cost Allocation Principles Committee (CapCom), Entergy Regional State Committee Working Group (ERSCWG) and other stakeholder groups in the development of a cost allocation approach for use with Tranche 3 focused on MISO South.

3.2 Interregional Studies

MISO-SPP Joint Targeted Interconnection Queue (JTIQ) Study

Introduction and Background

The JTIQ Study is a result of MISO and SPP's cluster study observations which show that transmission systems at the seams are at capacity. While the addition of generation resources and transmission along the SPP-MISO seam provides benefits to the markets, current Tariff and Joint Operating Agreement (JOA) mechanisms do not provide a cost-sharing approach that can facilitate the construction of the large-scale transmission needed to interconnect expected levels of new generation near the seam. Process, criteria, and schedule differences between the respective RTOs contribute to study delays and introduce questions on study results. The JTIQ Study takes these various barriers into consideration.

JTIQ aims to provide cost and timing certainty for generator interconnection customers as affected system costs will be known at the beginning of the MISO or SPP queue studies in addition to the elimination of Affected System Studies (AFS) needed between MISO and SPP. Moreover, this concept will identify more optimized network upgrades as compared to individual AFS clusters in the current process. The full report is available here .

Study Results

Through collaboration between the MISO and SPP Regional Transmission Organizations (RTOs), the study identified a five-transmission-project JTIQ portfolio with a planning level estimated cost of $1.06B required to address the significant transmission limitations restricting the opportunity to interconnect new generating resources near the MISO-SPP seam.

The recommended JTIQ Portfolio is expected to fully address the set of transmission constraints evaluated in the JTIQ Study as being significant barriers to the development of new generation along the MISO-SPP seam. In addition to these substantial reliability benefits, economic analysis conducted by the RTOs show customers can anticipate an Adjusted Production Cost (APC) benefit over a 10-year period of $55.7 million in the MISO footprint and $132.9 million in the SPP region. An estimated 28.7 GW of improved interregional generation enablement would be available to new generator interconnection projects near the seam.

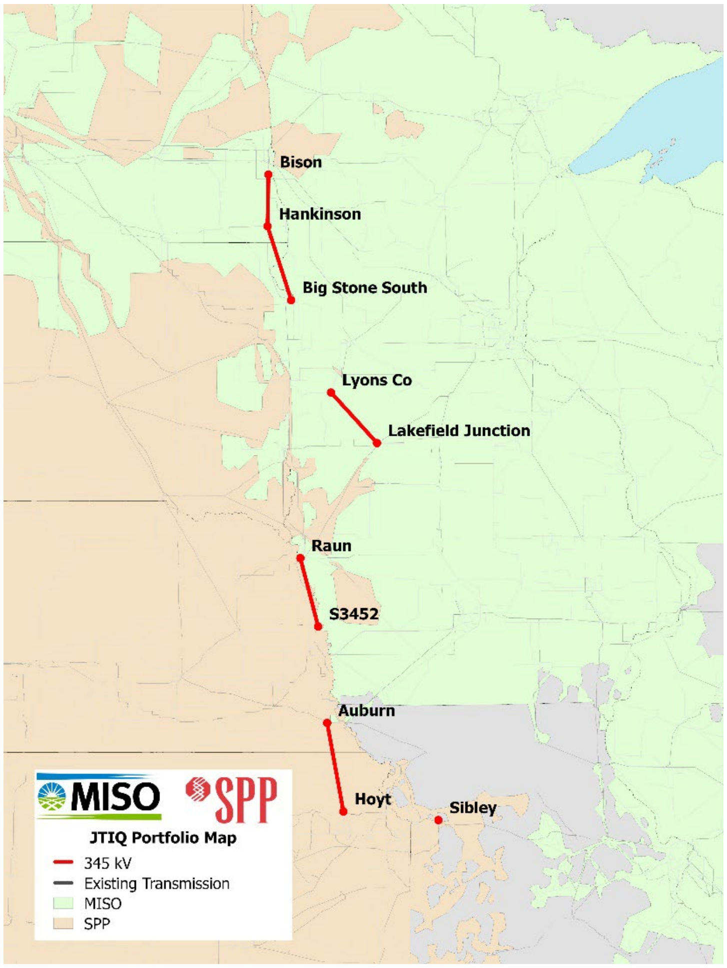

Figure 3.2.1-1: JTIQ Portfolio Map

JTIQ Portfolio	Location by RTO	Cost ($M)
Bison – Hankinson – Big Stone South 345 kV	MISO	476
Brookings Co (*moved to Lyons Co.) – Lakefield 345 kV	MISO	331
Raun – S3452 345 kV	MISO - SPP	144.4
Auburn – Hoyt 345 kV	SPP	90.5
Sibley - 345 kV Bus Reconfiguration	SPP	18.8
Total Cost of Portfolio of Projects	**MISO - SPP**	**1,060.7**

Table 3.2.1-1: List of projects comprising the JTIQ Portfolio

JTIQ Portfolio Update

The original portfolio included the Brookings Co-Lakefield 345 kV JTIQ project which will be replaced by a shorter Lyons Co-Lakefield 345 kV project in the updated JTIQ portfolio due to an approved MISO MTEP 22 project, Brookings Co-Lyons Co 345 kV second circuit on existing structures. MISO and SPP are working on updating the 2023 cost estimates and APC benefit calculations based on the updated model. RTOs will share this information once the data is available.

Cost Allocation and Cost Sharing

Projects in the JTIQ Portfolio are Generator Interconnection Projects, at the 345 kV voltage level, and, accordingly, the costs will be allocated consistent with the existing cost allocation method for Generator Interconnection Projects 345 kV and above. Each generator interconnection customer included in the group and allocated costs of the JTIQ Portfolio will pay their share of capital costs based on the size of their facility in proportion to the total enabled MWs of the portfolio. Non-capital costs associated with the generator interconnection customer's share will be allocated consistent with each RTO's current regional Tariff. MISO and SPP will allocate the share attributable to load based on application of the Adjusted Production Cost metric and each RTO will recover those costs consistent with its regional Tariff.

Department of Energy (DOE) – Grid Resilience and Innovative Partnership Program (GRIP)

In collaboration with SPP, Minnesota Department of Commerce, Minnesota Commission, Transmission Owners and Great Plains Institute, MISO supported the application for partial funding of the JTIQ projects through the DOE Grid Innovation Program. Below is a timeline of this year's activities.

JTIQ Concept Paper Submission	January 2023
DOE Notification to Submit Full Application	March 2023
Application Submitted	May 2023
DOE Notification of Award	Pending

Pending the DOE decision, the GRIP award could match up to 50% of the JTIQ portfolio. MISO and SPP do not anticipate this decision to impact current processes and will work with the DOE and interested parties to integrate any funding as appropriate.

Joint Operating Agreement (JOA) and Tariff updates

The MISO-SPP JOA captures changes in the planning processes, Affected System Study process, and allocation of costs between the two RTOs. MISO and SPP are collaborating with the stakeholders on updating the JOA redlines.

Summary of MISO Tariff Changes:

- Attachment X and related Appendices will be modified and potential new agreements added to incorporate the JTIQ Portfolio consistent with the MISO-SPP JOA changes
- Module A and Attachment FF are clarified and augmented to capture that the existing Generator Interconnection Project category and cost allocation applies to the JTIQ Portfolio of Generator Interconnection Projects
- New Attachments and Schedules will detail how costs will be charged to generator interconnection customers and MISO load, and how costs will be recovered and paid between the two RTOs

3.2.2 MISO-SPP Coordinated System Planning

In Q1 of 2023, MISO and SPP held an Annual Issues Review with the Interregional Planning Stakeholder Advisory Committee (IPSAC) to help determine whether to perform a Coordinated System Plan (CSP) study in 2023. After careful consideration and stakeholder discussion, MISO and SPP mutually determined not to initiate a CSP study based on the following rationale:

- No significant interregional congestion drivers were identified for consideration

- Forgoing 2023 CSP will better allow for the coordination of filing Targeted Market Efficiency Projects (TMEPs) in the MISO-SPP Joint Operating Agreement following the 2022 CSP, which involved developing the TMEP process and completing the first TMEP study with stakeholders
- No appropriate reliability constraints or public policy drivers were identified or planned at this time

3.2.3 MISO-PJM Coordinated System Planning

In Q1 of 2023, MISO and PJM held an Annual Issues Review with the Interregional Planning Stakeholder Advisory Committee (IPSAC) to help determine whether to perform a Coordinated System Plan (CSP) study in 2023. After careful consideration and stakeholder discussion, MISO and PJM mutually determined not to initiate a CSP study based on the following rationale:

- No interregional congestion drivers were identified for consideration as a part of an Interregional Market Efficiency Project study
- A Targeted Market Efficiency Project study was conducted in 2022, MISO and PJM recommended waiting another year before considering completing another study in order to have a full two years of new historical data to utilize
- No appropriate reliability constraints or public policy drivers were identified or planned at this time

3.3 Near-Term Congestion Study Update

Introduction and Background

MISO production cost analysis has traditionally focused on the medium- to long-term planning horizons with past Market Congestion Planning and Long-Range Transmission Planning initiatives. While MISO continues to prepare for the rapidly changing energy landscape of the future, some MISO stakeholders expressed interest in additional analysis focused on the near-term time horizon.

After reviewing the proposed issue in the MISO Interconnection Process Working Group and MISO Market Subcommittee, the issue was eventually assigned to the MISO Planning Advisory Committee (PAC) under PAC-2021-1: Address Congestion at Existing Resources and delegated to the Planning Subcommittee (PSC) for further stakeholder technical discussion. Additional information on stakeholder discussions and presentations on this issue can be found on the MISO website at PAC-2021-1 Address Congestion At Existing Resources.

Stakeholders proposed a similar process to the existing MISO-PJM Targeted Market Efficiency Project (TMEP) study process. TMEPs are quick-hit, low-cost interregional projects to address specific interregional market-to-market congestion issues. Notably for TMEPs, the evaluation process is limited to only a review of historical day-ahead (DA) market data rather than production cost modeling or simulation. To accommodate a more robust analysis of the MISO region (versus the limited Market-to-Market historical-only data review), MISO staff proposed a hybrid approach that would use traditional production cost modeling and simulation to evaluate issues, with a focus on the issues driving historical top congested flowgates.

MISO recreated the top identified flowgates in an available model. To better understand key drivers, additional assumption and model tweaks will be tested prior to determining final study recommendations.

Study Objectives and Scope

The primary objective of this study was to provide insight into recent top congestion issues seen in the MISO Day-Ahead market and identify the challenges of near-term economic modeling. MISO does not plan to recommend projects for approval based on the results of this informational study. Voluntary pursuit of any project proposals by stakeholders based on the study results should be performed in accordance with the planning processes and timelines outlined in the MISO Transmission Planning Business Practice Manual (BPM-020) and the MISO-PJM Joint Operating Agreement (MISO-PJM JOA Article IX). Cost allocation outside of market participant funding for any specific upgrades are not in scope for this effort.

Flowgates studied were determined using the following process:

- Screening Criteria:
    - Historical Day-Ahead market data from 2021 and 2022
    - Congestion cost, binding hours, and shadow prices
    - Data included Market to Market (M2M) flowgates, but was limited to MISO-only facilities
- Flowgates were organized by their binding element and ranked by total congestion cost
- Facilities were removed from consideration using the following criteria:
    - Project went in-service during study window which had a noticeable positive effect on congestion cost
    - Project is planned to be in-service in the near-term at the facility
    - Facility was examined extensively as part of other MISO studies (JTIQ, LRTP, TMEP, etc.) and solutions were identified

Model was developed under the following assumptions:

- We used the following Hitachi PROMOD[7] releases
    - Fall 2021 gen updates and economic data
    - Spring 2022 coal prices
    - PROMOD 11.5 engine
- MTEP23 No Futures Assumptions model
    - Hartburg – Sabine was removed
    - Out of cycle projects were added if in-service date was before study window
- MTEP22 Year 2027 Summer Peak TA powerflow
- Resource utilization – generators with signed GIA additions and finalized retirement studies were included.

Study

Initial Analysis

Ten flowgates were identified for this study based on their historical congestion from 2021-2022 (see Table 3.3-1). Project testing was conducted by running the base case model, then evaluating whether historical day-ahead congestion was duplicated under the Year 5 assumptions. Only one flowgate, the Marblehead North 161/138 kV transformer, was identified as being congested in the base case model.

Monitored Facility	State	Owner	Total MISO DA Congestion Cost ($)	Base Economic Model Congestion Cost* (Year 2027)
Marblehead North 161/138 kV Transformer	IL	Ameren	103,084,055	$283,232
Johnson Junction – Graceville 115 kV	MN	GRE	71,148,820	

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[7] PROMOD, Hitachi Energy owned, is a chronological security constrained unit commitment and economic dispatch tool that adheres to a wide variety of operating constraints.

Monitored Facility	State	Owner	Total MISO DA Congestion Cost ($)	Base Economic Model Congestion Cost* (Year 2027)
Cayuga 345/230 kV Transformer	IN	Duke	39,638,357	
Irvine – Beacon 161 kV	IA	Alliant West	39,602,576	
Jefferson County – Woody 161 kV	IA	Alliant West	30,763,191	
Cayuga – Hillsdale North 230 kV	IN	Duke	29,928,665	
Murphy Creek – Hayward 161 kV	MN	SMMPA/ALTW	28,681,570	
Stone Lake 345/161 kV Transformer	WI	Xcel	28,385,411	
Fox Lake – Rutland 161 kV	MN	SMMPA/ALTW	23,485,327	
Woody – Appanoose	IA	Alliant West	23,098,944	

Table 3.3-1: Top 10 List of Most Congested MISO Flowgates in 2021-2022
*Annual average shadow prices x number of binding hours

Outage Analysis

Congestion at each binding facility was further reviewed to identify outage driven congestion. MISO noted congestion that may be driven by outages due to a significant number of nearby outages during similar periods of congestion. Transmission Owners of the monitored facilities in the study provided additional insight into the impacts of outages or general cause of congestion (see Table 3.3-2).

Monitored Facility	MISO Identified Outage Impacts	Additional Information from Facility Owner
Marblehead North 161/138 kV Transformer	X	
Johnson Junction – Graceville 115 kV	X	The Johnson Junction to Graceville congestion issue was directly related to the planned construction outage on the Johnson Junction to Morris line which occurred between Oct 1,2021 and Feb 1, 2022. The normally open line segment north of Graceville was closed in to accommodate this construction outage leading to congestion on the Johnson Junction to Graceville line. Thus, the congestion correlates the construction of the Johnson Junction-Morris construction outage and grid reconfigurations. It is understood that when upgrading transmission facilities to accommodate the changing grid, it is often necessary to alter the normal operations of the transmission system which can lead to temporary economic congestion in order to ensure continued grid reliability. (GRE)

Monitored Facility	MISO Identified Outage Impacts	Additional Information from Facility Owner
Cayuga 345/230 kV Transformer	X	Congestion was likely related to Cayuga Unit 1 outage and MTEP Project 22226 is expected to relieve this congestion. (Duke)
Irvine – Beacon 161 kV		Congestion was highly correlated to several outages including MEC Diamond Trail-Hills 345 kV, MEC Montezuma-Ottumwa 345 kV, and ITC Beacon-Tri County 161 kV line upgrade outages. Ottumwa Generation outages may have also increased congestion on the line. (ITC)
Jefferson County – Woody 161 kV		Congestion was likely related to MEC Diamond Trail-Hills 345 kV line and Ottumwa Generation outages. (ITC)
Cayuga – Hillsdale North 230 kV	X	Congestion was likely related to Cayuga Unit 1 outage and MTEP Project 22226 is expected to relieve this congestion. (Duke)
Murphy Creek – Hayward 161 kV	X	Congestion was likely related to XCL Crandall-Wilmarth 345 kV line upgrade outage and ITC Adams 161 kV bus outage to connect a new generator. (ITC)
Stone Lake 345/161 kV Transformer		Facility owner confirmed minimal outage impacts. Congestion may have some relation to Manitoba Hydro flows. Congestion in 2023 has not been as extensive likely due to the refurbishment of the Eau-Claire - Arpin 345 kV line. MTEP Project 20229 is expected to further reduce binding on this line. (Xcel)
Fox Lake – Rutland 161 kV	X	Congestion was likely related to XCL Crandall-Wilmarth 345 kV and ITC-Lakefield-Dickinson County 161 kV line upgrade outages. (ITC)
Woody – Appanoose		Congestion was likely related to MEC Diamond Trail-Hills 345 kV line and Ottumwa Generation outages. (ITC)

Table 3.3-2: Outage Analysis of Study Flowgates

Final Results

The final results for the 2023 Near-Term Congestion study, as shown in Table 3.3-3, provides the changes in Adjusted Production Costs (APC) when ratings are increased for the identified flowgates.

Monitored Facility	State	Owner	APC Change ($M) *
Marblehead North 161/138 kV Transformer	IL	Ameren	-5.053
Johnson Junction – Graceville 115 kV	MN	GRE	-
Cayuga 345/230 kV Transformer	IN	Duke	2.064
Irvine – Beacon 161 kV	IA	Alliant West	0.396
Jefferson County – Woody 161 kV	IA	Alliant West	-0.139

Monitored Facility	State	Owner	APC Change ($M) *
Cayuga – Hillsdale North 230 kV	IN	Duke	0.487
Murphy Creek – Hayward 161 kV	MN	SMMPA/ALTW	1.021
Stone Lake 345/161 kV Transformer	WI	Xcel	0.159
Fox Lake – Rutland 161 kV	MN	SMMPA/ALTW	0.469
Woody – Appanoose	IA	Alliant West	0.382

Table 3.3-3: Final Results of Near-Term Congestion Study
*Positive numbers represent an economic benefit and negative numbers represent an economic loss

There were three flowgates of note in the final results of this study: Marblehead North 161/138 kV Transformer, Johnson-Junction-Graceville 115 kV, and the Cayuga 345/230 kV Transformer.

- Upgrades to the Marblehead North 161/138 kV Transformer create economic losses of approximately $5 million for the system in this study. Results also show that PJM and SPP see combined economic benefits of about $3 million from the upgrade at this transformer. Additional analysis is needed to understand the results and identify opportunities for coordination with MISO interregional and JTIQ teams.
- Upgrades to the Johnson Junction-Graceville 115 kV line result in no economic changes to the system. Analysis showed this line is located between two other limiting elements on the system that are preventing increased flow on the line even with an upgrade. Additional analysis of those nearby elements is needed to assess congestion relief opportunities for this line.
- Upgrades to the Cayuga 345/230 kV Transformer result in about $2 million of economic benefits. The upgrade allowed for reduced renewable curtailment on the system. PROMOD did not identify the Cayuga 345/230 kV as a binding constraint in the base model. Additional analysis is needed to identify how the PROMOD solution did not identify congestion but did find economic benefits to upgrading the facility.

Study Takeaways

The MISO economic planning process is geared towards long-term planning horizons rather than near-term planning horizons. In addition to adjustments that are needed in model development to better reflect the near-term, topology changes can shift or eliminate congestion making it challenging to use historical data to identify near-term issues and solutions.

Working with stakeholders to forecast future congested flowgates outside of historical day-ahead congestion may provide additional value. Additional analysis and coordination with MISO interregional and JTIQ may also provide some insight into issues identified in the 2023 Near-Term Congestion Study.

In 2023 Q4 MISO will publish a separate Near-Term Congestion Study Report with additional insight and context on the study process.

CHAPTER 4: RELIABILITY STUDIES

4.1 Reliability Assessment and Compliance

MISO, in collaboration with its transmission-owning members and stakeholders, performs annual reliability assessments to identify transmission infrastructure upgrades needed to ensure the continued system reliability in compliance with applicable local and regional reliability standards. The reliability assessment process for MTEP23 (shown in Figure 4.1-1) began with a roll-up of issues and potential solutions from the NERC assessment of the prior MTEP cycle and from the local planning processes of TOs. Following this step, MISO conducted an independent reliability assessment to evaluate and integrate the TO local planning information into the development of the overall MTEP.

MISO closely coordinates the annual reliability assessment with other planning efforts to ensure the transmission expansion plan is identified in an efficient and cost-effective fashion. A variety of factors are considered as part of MISO's transmission expansion plan development, including but not limited to, urgency of needs, cost effectiveness of solutions, system performance of solution alternatives to address identified transmission issues, and other considerations such as lead time to develop a project, right-of-way (ROW) or substation impacts, expandability, operational flexibility, etc.

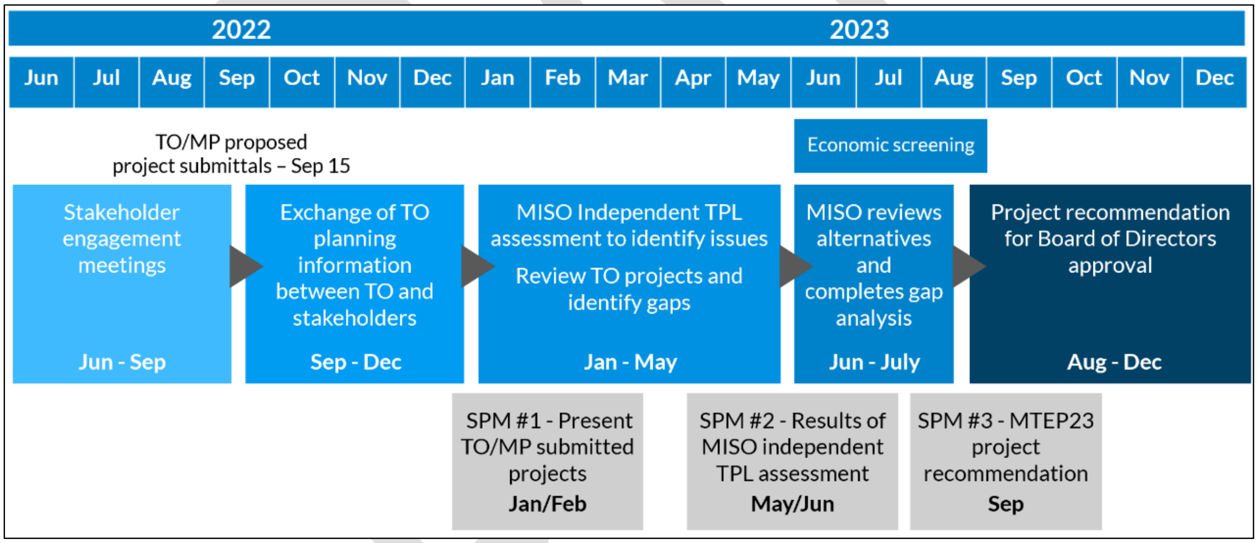


Figure 4.1-1: MTEP23 reliability assessment process

In conjunction with the MTEP planning process, an inclusive, transparent stakeholder process is utilized to facilitate open discussions and allow stakeholders to provide early and meaningful inputs into the development of transmission solutions in each planning cycle. The results of MISO's independent reliability assessments, along with proposed solution alternatives, are presented to stakeholders through a series of public Sub-regional Planning Meetings (SPM), and additional Technical Study Task Force (TSTF) meetings as needed, for each of the four MISO planning sub-regions: Central, East, South, and West.

MISO strategically set up our local planning processes to assume FERC Order 890 transparency requirements for Transmission Owner submissions resulting in different study approaches based on the types of projects submitted by Transmission Owners.

- **Verify need:** Confirmation of system need identified in project submission including to meet compliance with applicable National Electric Reliability Organization reliability standards and reliability standards adopted by Regional Reliability Organizations, and applicable within the Transmission Provider Region. MISO must verify the need for alternatives to adequately examine their effectiveness.
- **No harm:** Ensure a submitted project does not create a system issue. Includes projects that create model changes like contingency definitions, line ratings, or line impedances.
- **Post only:** Provided for FERC Order 890 transparency provisions. May include controls equipment to communicate remotely with the facility. This information is not able to be represented with model changes.

Alternatives for projects may be completed prior to submission to MISO by the Transmission Owners, proposed by MISO, or proposed by stakeholders. Alternative criteria considers cost comparisons, feasibility to construct and how reliability needs are resolved. Alternatives do not always result in one project replacing another, instead they tend to be additive to the original project, even when submitted with the thought that they would directly compete. MISO considers alternatives in multiple forms, including like-for-like replacement, regional reliability projects, the combination of multiple local solutions, and other options identified through either MISO analysis or submitted by stakeholders.

After MISO completes its independent review of all proposed projects and associated alternatives and addresses stakeholder feedback received through SPM discussions, MISO staff formally recommends a set of projects to the MISO Board of Directors for review and approval. These projects make up Appendix A of the MTEP report and represent the preferred solutions to the identified transmission needs of the MISO reliability assessments. Proposed transmission upgrades with sufficient lead times are included in Appendix B for further review in future planning cycles.

The complete results of MTEP23 reliability assessments are detailed in Appendices D3-D10 of the MTEP23 report, which are available on the MISO ShareFile site and subject to Critical Energy Infrastructure Information (CEII) and non-disclosure agreements. These results serve as compliance evidence for a variety of NERC planning standards listed on the MISO public website.

As appropriate, an executive summary of results for the appendix will be available on the MISO website under the Appendices tab.

Appendix	Title
D3	Steady State CEII
D4	Voltage Stability CEII
D5	Transient Stability CEII
D6	Generator Deliverability CEII
D7	Contingency Coverage CEII
D8	Nuclear Plant Interface Coordination CEII
D9	Planning Horizon Transfer Capability CEII
D10	Short Circuit Analysis CEII

MTEP23 project recommendations

As the result of the MTEP23 reliability assessments, 45 Baseline Reliability Projects totaling $1.7 billion are included in the MTEP23 proposed Appendix A, accounting for 19% of total transmission infrastructure investment in MTEP23. The vast majority of the recommended projects are driven by reliability (either baseline or local reliability), load growth and age and condition, and are expected to be in service within three years.

Out of the 572 MTEP23 projects submitted in this cycle, MISO Planning Engineers received and evaluated 35 Expedited Project Review (EPR) requests which is double the requests received last year. These expedited projects were submitted by Transmission Owners who determined that system conditions warrant the urgent development of system enhancements within the current MTEP cycle. New load interconnections account for over 60% of the EPR requests submitted.

Project justification details of the recommended Appendix A projects are summarized in the following subsections for each of the four MISO planning sub-regions. Figure 4.1-2 provides a quick glance into MTEP23 Appendix A project investment summary by category and planning region.

Planning Region	Baseline Reliability Projects (BRP)	Generator Interconnection Projects (GIP)	Market Participant Funded Projects (MPFP)	Multi-Value Project (MVP)	Other Projects	Total
Central	$178	$374	-	-	$1,714	**$2,266**
East	$60	$307	-	-	$371	**$739**
South	$1,335	$351	-	-	$2,483	**$4,168**
West	$150	$195	$1	$4	$1,455	**$1,806**
Total	**$1,723**	**$1,227**	**$1**	**$4**	**$6,023**	**$8,979**

Figure 4.1-2: MTEP23 Appendix A new project investment by category and planning region (data as of 9-29-2023)

In the following pages, the majority of the region's MTEP23 projects are categorized into three categories, Baseline Reliability, Other, and Generator Interconnection. The definition of each of these categories are detailed below.

Baseline Reliability Projects

According to Attachment FF of the MISO Tariff, "Baseline Reliability Projects are Network Upgrades identified in the base case as required to ensure that the Transmission System is in compliance with applicable national Electric Reliability Organization (ERO) reliability standards and reliability standards adopted by Regional Reliability Organizations and applicable within the Transmission Provider Region."

MISO identifies the need (verifies the need) or violations (noted in tables with "Limiting Element") that are required to be resolved per NERC Transmission Planning Standards and reliability standards adopted by

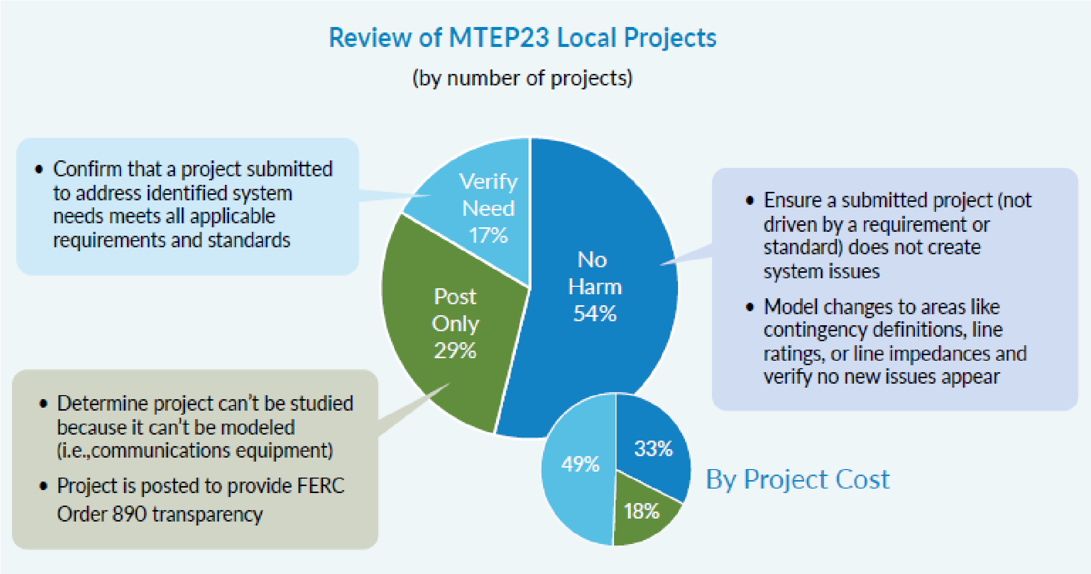
Regional Entities. MISO then reviews the effectiveness of the identified solution that resolves the violations. This is completed by reviewing the impacts to a powerflow model with and without the project. Sometimes the needs or violations were identified in a previous MTEP cycle. All costs for Baseline Reliability expansion projects are recovered through Attachment O by the Transmission Owner(s) developing such projects.

Other Projects

The "Other" projects category are projects that do not meet the criteria to be considered as Baseline Reliability Projects (BRP), New Transmission Access Projects, Market Efficiency Projects, or Multi-Value Projects. Other projects may include projects to satisfy Transmission Owner and/or state and local planning criteria other than NERC or regional reliability standards, interconnection of new Loads, relocate transmission facilities, address aging transmission infrastructure, replace problematic transmission plant, improve operational performance or address other operational issues, address service reliability issues with end-use consumers, improve aesthetics including but not limited to undergrounding overhead transmission facilities, address localized economic issues, and address other miscellaneous localized needs. The tables of project information are broken down by four general categories of project drivers; Local Reliability, Age and Condition, Load Growth, and Other Local Need, but note that these four drivers are not defined in the MISO Tariff.

MISO generally completes a "no-harm" analysis for Other projects, this means that the project information is added to a powerflow model and a test is performed to see if the addition of the project causes a new violation or "harm" for the reliability of the system. If there are no new violations created by the addition of the project, the project is able to move forward. If violations exist, then those will need to be resolved. Some projects, such as improving aesthetics or communication equipment do not result in changes to information applied to powerflow models and are not analyzed and are posted only for FERC Order 890 transparency. All costs for Other projects are recovered through Attachment O by the Transmission Owner(s) developing such projects, unless other cost recovery agreements are entered into.

In MTEP23, there were a few Other projects that required analysis beyond "no-harm" to verify that the projects resolved the identified system needs, or consideration of an alternative project submitted by stakeholders. Figure 4.1-3 highlights the projects and what type of review MISO completed.



- Confirm that a project submitted to address identified system needs meets all applicable requirements and standards

- Ensure a submitted project (not driven by a requirement or standard) does not create system issues
- Model changes to areas like contingency definitions, line ratings, or line impedances and verify no new issues appear

- Determine project can't be studied because it can't be modeled (i.e.,communications equipment)
- Project is posted to provide FERC Order 890 transparency

Figure 4.1-3: Types of reviews MTEP23 local projects went through

Generator Interconnection Projects

According to Attachment FF of the MISO Tariff, "Generator Interconnection Projects are New Transmission Access Projects that are associated with interconnection of new, or increase in generating capacity of existing, generation." These represent facilities necessary to physically interconnect the generation resource to the transmission system as well as network upgrades required to facilitate reliable delivery of the output to ultimate load.

The Generator Interconnection Projects (GIPs) noted in the following sections of this chapter have been evaluated through the Generator Interconnection Queue and the associated Generator Interconnection Agreements (GIAs) have been signed. Similar to the process for "Other" projects a no-harm analysis is completed for Generator Interconnection Projects (GIPs).

Generator Interconnection Projects are network upgrades associated with interconnection of new, or increase in generating capacity of existing, generation under Attachment X and FF of the Tariff. These projects are driven by interconnection study procedures and agreements. The Interconnection Customer is responsible for 100% of the costs of network upgrades rated below 345 kV and 90% of the costs of network upgrades rated at 345 kV and above (with the remaining 10% being recovered on a system-wide basis).

1.5 4.2 Project Justifications – Central Region

Central Region Overview

The MISO Central planning region consists of seventeen Transmission-Owning members spanning four states: Missouri, Illinois, Indiana, and Kentucky. These Transmission Owners are:

American Electric Power Service Corporation (AEP)

Ameren Illinois (AMIL)

Ameren Missouri (AMMO)

Big Rivers Electric Corp. (BREC)

City of Columbia, Mo. (CWLD)

City of Springfield, Ill. (CWLP)

Duke Energy Corp. (DEI)

GridLiance Heartland LLC (GLH)

Henderson Municipal Power & Light (HMPL)

Hoosier Energy REC Inc. (HE)

Indianapolis Power & Light (IPL)

Northern Indiana Public Service Co. (NIPSCO)

Pioneer Transmission (PTx)

Prairie Power Inc. (PPI)

Republic Transmission (RTx)

Southern Indiana Gas & Electric (SIGE)

Southern Illinois Power Cooperative (SIPC)

Wabash Valley Power Association Inc. (WVPA)

The Bulk Power System (BPS) within these states consists of an extensive 765 kV, 345 kV, 230 kV, 161 kV, and 138 kV networked transmission system. The 345 kV network spans Missouri, Illinois, and Indiana, both north to south and east to west. The 230 kV network spans through Indiana, both north to south and east to west. The 161 kV network spans north to south and east to west in Missouri, Illinois, and Kentucky, and the 138 kV networks span both north and south, and east to west in Illinois, Indiana, and Kentucky. All of Ameren, BREC, CWLD, CWLP, GLH, HMPL, and SIPC belong entirely in the SERC Region. All of DEI, HE, IPL, NIPSCO, PTx, RTx and SIGE belong entirely in the ReliabilityFirst Region. Wabash Valley is split between both ReliabilityFirst and SERC Regions.

Major load pockets in the MISO Central planning region are St. Louis, MO; Peoria, IL; Springfield, IL; Evansville, IN; and Indianapolis, IN (shown in Figure 4.2-1).

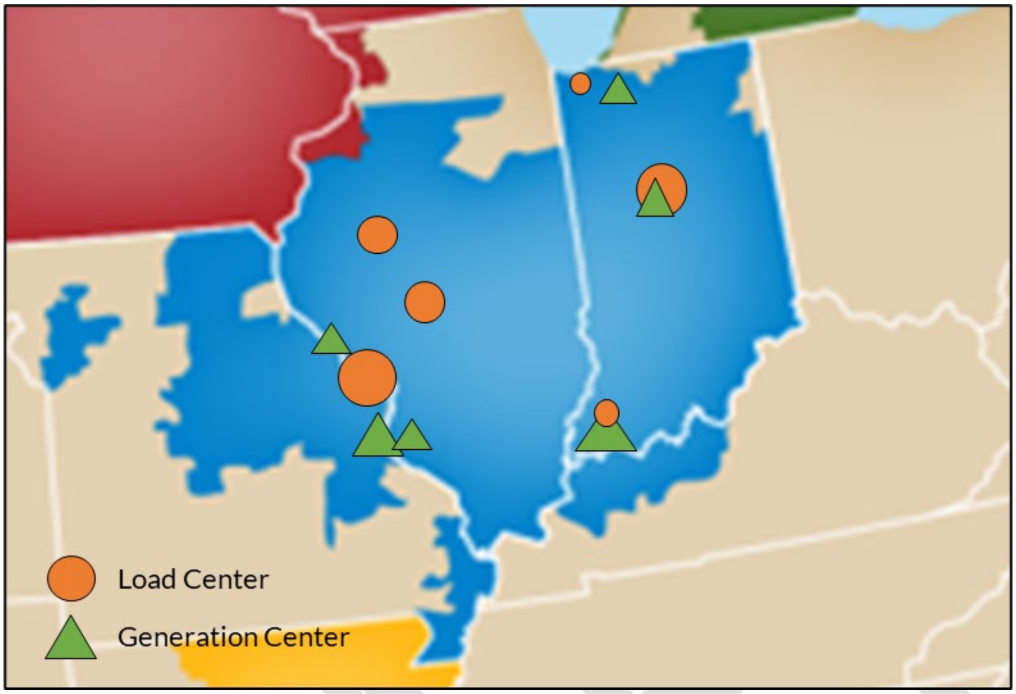


Figure 4.2-1: Generation and load centers in the Central planning region

For MTEP23, MISO Transmission Planning is recommending 153 projects from the Central region for inclusion in Appendix A at an estimated cost of $2.3 billion. Of these, 12 are Baseline Reliability Projects (BRP), 36 are Generator Interconnection Projects (GIP), and 105 are Other Projects. MISO considered alternatives for some projects in the Central region including the New South Central Illinois Transmission Expansion project. The alternative proposed transmission projects were determined to be less cost-effective than the original project.

Of the 153 projects within the Central region that are being recommended in MTEP23, 13 have an estimated cost of less than $1 million, 50 have an estimated cost between $1 million and $5 million, and the remaining 90 projects are estimated to cost greater than $5 million (indicated in Figure 4.2-2 below).

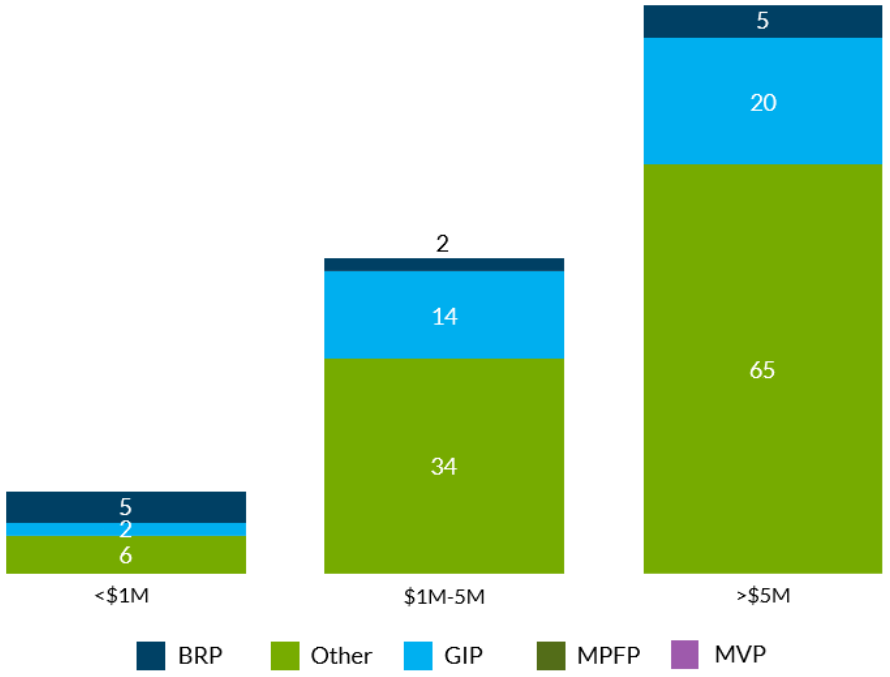


Figure 4.2-2: Project counts by cost category of MISO Central region MTEP23 projects (data as of 9-29-2023)

The majority of the projects in the MISO Central planning region are expected to go in service in the next three years (shown in Figure 4.2-3).

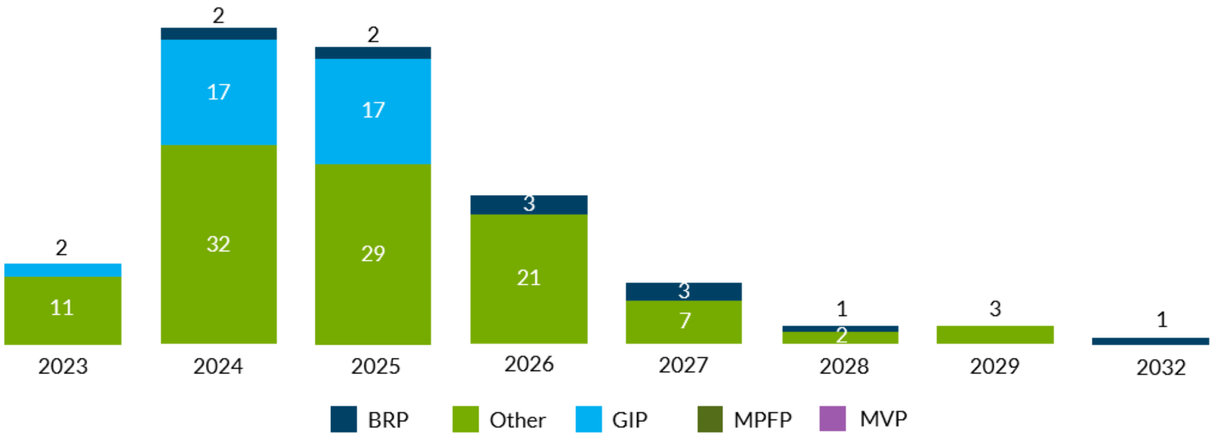


Figure 4.2-3: Central region MTEP23 projects by in-service date (data as of 9-29-2023)

In accordance with Attachment FF of the tariff, in the event a Transmission Owner determines that system conditions warrant the urgent development of system enhancements, an expedited review of the impacts of the project can be requested. MISO shall use a streamlined approval process for reviewing and approving projects proposed by the Transmission Owner(s) and decisions will be provided to the Transmission Owner within 30 Days of the project's submittal to MISO unless a longer review period is mutually agreed upon. During the MTEP23 cycle, generally due to voltage issues associated with the Rush Island generator retirement, MISO received the following projects through the Expedited Project Review (EPR) process:

1. Project 23971, Upgrades at Hannibal W and Effingham NW-Neoga 138 kV line
2. Project 22813, Coffeen N-Roxford 345 kV Rebuild
3. Project 23632, New Beehive – Dupo Ferry 138 kV line
4. Project 22946, New Alta-Pioneer 138 kV line
5. Project 24172, Re-route HMPL Sub 4 to HMPL Sub 4 Tap 161 kV Transmission Line

Also, in accordance with Attachment FF Section VIII.A.3, none of the projects were identified as an Immediate Need Reliability Project and excluded from the competitive developer selection process. The ten largest project investments in the MISO Central region represent $890 million (39%) of the $2.3 billion total recommended projects for the Central region in MTEP23, or 10% of the $9 billion total recommended in the MISO footprint. The locations of these projects are shown in Figure 4.2-4 and the investment is spread across the Central planning region. Projects that are blanket expenditures (relays, physical security, etc.) are excluded from this list.

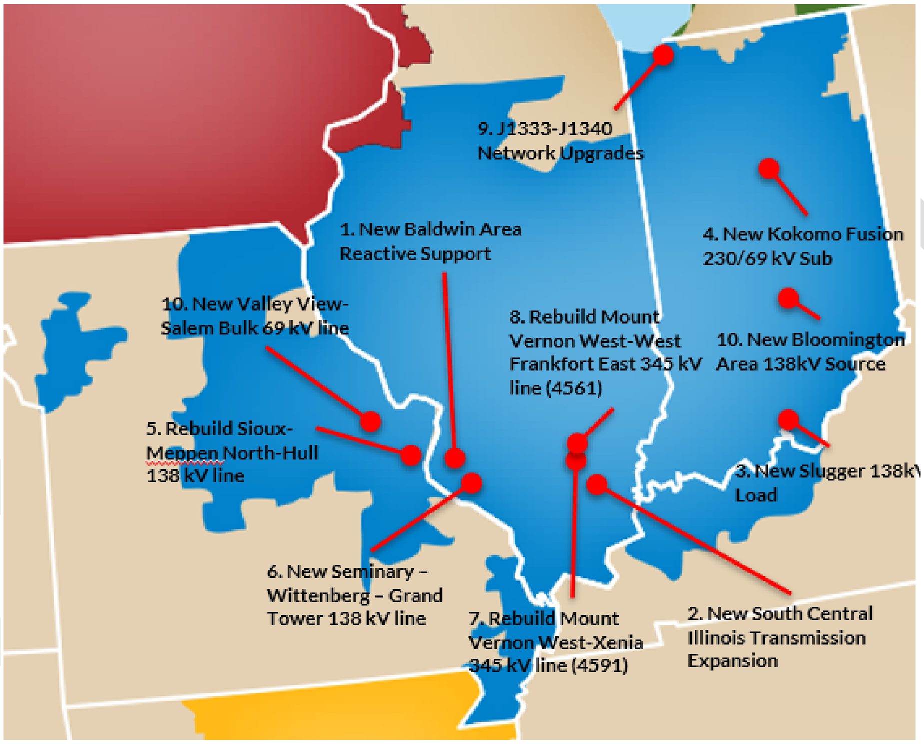


Figure 4.2-4: Central region top ten projects by cost (data as of 9-29-2023)

4.2.1 American Electric Power Service Corporation (AEP)

American Electric Power Service Corporation did not submit any new projects for MTEP23.

4.2.2 Ameren Illinois

After MISO's independent reliability analysis, MISO and Ameren Illinois recommend 47 projects at an estimated cost of $957.4 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, one is a Baseline Reliability Project, 26 are Other Projects, and 20 are Generator Interconnection Projects with signed Generator Interconnection Agreements. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Baseline Reliability Projects

Project 23846 – New Seminary – Wittenburg – Grand Tower 138 kV line

Project Description: This project will include building a new Perryville (Seminary) - Wittenberg - Grand Tower 138 kV line that crosses the Missouri/Illinois Border. The total estimated cost of this project is $68 million and has an expected in-service date of December 31, 2026.

Project Need: This project is needed to mitigate multiple Transmission System Planning Performance Requirements for (TPL-001) low voltage violations.

Alternatives Considered: No alternatives were considered.

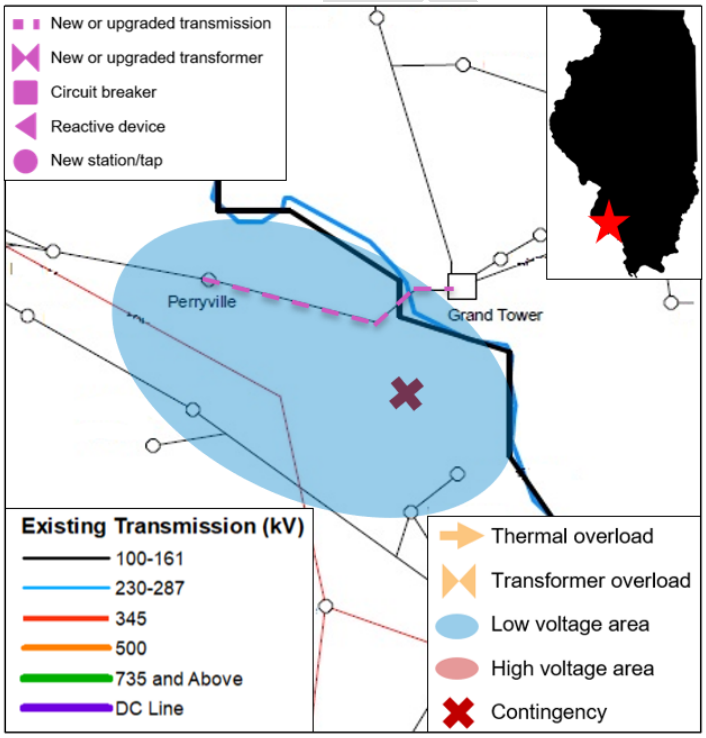


Figure 4.3.1-1: P23846 Geographic transmission map of project area

Cont Type	Limiting Element	Rating (pu)	Pre-Project Loading (pu)	Post-Project Loading (pu)
P6	[AMMO] Seminary 138 kV	0.95	0.8623	0.9921
P6	[AMMO] New Bourbon 138 kV	0.95	0.8951	0.9881

Table 4.3.1-1: P23846 voltage loading drivers

Other Projects

Project 23026 South Central Illinois Transmission Expansion

Project Description: Construct a new 138 kV substation as an ultimate six-position ring bus requiring one 3000 A 138 kV breaker initially adjacent to the Continental Tire facility. Construct approximately a 3.5-mile 138 kV line from Mt. Vernon 42nd St. to the new substation ~0.3 miles NE of the Continental Tire facility with minimum 2,000 Amp summer emergency capability. Add a new 3,000 Amp 138 kV breaker at Mt. Vernon 42nd St. for this new 138 kV line position.

Estimated Cost: $167.85 M

Expected ISD: June 1, 2028

Alternative Considered: Double Circuit line to Mt. Vernon could be utilized and is longer than the proposed path to 42nd Street. Note: This option was not chosen because the longer path would require additional conductor and therefore, cost more than the proposed option on an already high-cost project.

Estimated Alternative Cost: Increased cost due to additional conductor required for the further connection point.

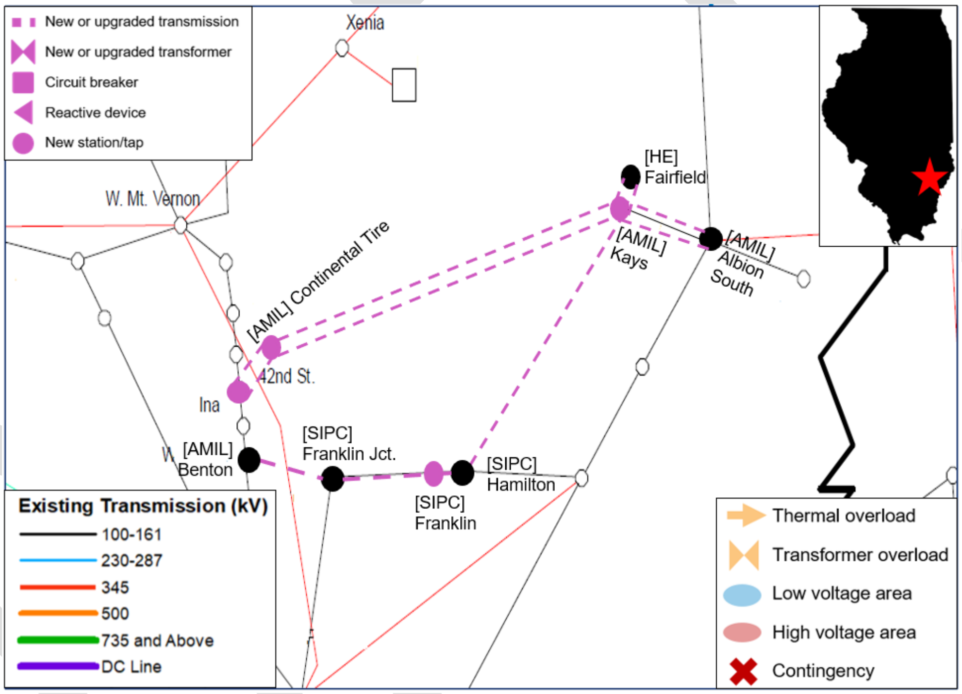


Figure 4.3.2-1: P23026 Geographic transmission map of project area

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
22186	Upgrade South Ottawa 138 kV Substation to Ring Bus	Create a 5 position 6 ultimate ring bus at the existing South Ottawa substation.	6/1/2025	$9.3
22667	New PPI – Forest City 138 kV Interconnection	Construct a new 138 kV substation in ring bus configuration on the existing Ameren Havana-Cincinnati-1352 138 kV line. A	12/1/2025	$8.5

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		position will feed PPI Forest City 138/69 kV.		
22728	Reconfigure Decatur North 27th St. 138 kV substation	Rebuild this station to a 7 position BAAH, minimum 8 position ultimate BAAH. New name is Boxcar.	6/1/2025	$19.8
22848	Rebuild Hutsonville-Heath 138 kV line (1311)	Rebuild the Hutsonville-Heath-1311 138 kV line from Hutsonville-Str. 95 with conductors capable of 2000 amps at Summer Emergency and OPGW.	6/1/2025	$12.5
22888	Upgrade Edwards 345 kV substation	Install a new 345 kV Ring Bus near Edwards Switchyard to support the transmission system in the Peoria area. Reroute ~0.75 miles of the existing Mapleridge-Tazewell-4528 345 kV line on the west side of Edwards Switchyard to avoid conflicts with the existing 138 kV crossings. Remove the existing failed 345 kV underground cable between Str. 123 and 124. Design and build the rerouted line to support 2 - 345 kV circuits to support MISO planning needs. All new conductors should be minimum 3000 amp Summer Emergency rated.	6/1/2027	$32
22891	Rebuild Tibbs-Steeleville 138 kV line	Repair issues found during inspections. Replace existing 477 ACSR conductor in line.	12/1/2024	$37
22946	New Alta - Pioneer 138 kV Line	Construct a new 138 kV line from Alta to Pioneer. Rebuild Alta 138 kV substation as a 4-position initial, 6-position ultimate 138 kV ring bus. Rebuild Pioneer 138 kV substation as 5-position initial, 6-position ultimate 138 kV ring bus. TP5161 was created to rebuild Pioneer as a ring bus to address aging infrastructure. The aging infrastructure will be addressed by this project.	12/1/2025	$26.7
22966	New Baldwin Area Reactive Support	Add 4 138 kV dynamic reactive 250 MVAR each located at Turkey Hill, Moro, Jarvis, and Granite City 23rd Street.	6/1/2027	$170

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23971	Upgrade Effingham NW-Neoga 138 kV line	Upgrade terminal equipment at Hannibal West, replace two structures and shunts in Neoga – Effingham NW 138 kV line. These are Non-SSR related needs.	12/1/2024	$1.75
23072	Rebuild Newton-Tanner 345 kV line	Rebuild the Newton-Tanner 345 kV line with conductors capable of 3000 amps Summer Emergency rating and two OPGWs.	12/1/2026	$29
23207	Rebuild Mattoon West-Tuscola West 138 kV line	Rebuild the 24.6-mile Mattoon West-Tuscola West-1 138 kV Transmission Line with T2 conductor rated at 2,000 amps Summer Emergency Conditions and 2 EA 72-Fiber OPGW shield wires.	12/1/2025	$18.5
23504	Rebuild Castro-Canton-138 kV line	Rebuild the 11.4-mile Vermillion-Tilton Energy Center-1572 138 kV Transmission Line with T2 conductor rated at 2,000 amps Summer Emergency Conditions and 2 EA 72-Fiber OPGW shield wires.	6/1/2024	$13
23632	New Beehive-Dupo Ferry 138 kV line	Install new Beehive to Dupo Ferry 138 kV line. Add breaker to new Dupo Ferry ring bus. Add position at Beehive.	12/1/2024	$6.3

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23286	New [PPI] Paragon 138 kV substation	Add interconnection point to the Pana substation for PPI's new bulk substation which will be called Paragon.	6/1/2025	$0.9

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
22266	Rebuild Clinton-Oreana and Clinton-Goose Creek 345 kV lines	Rebuild existing double-circuit towers on the Clinton-Oreana 345 kV and Clinton-Goose Creek 345 kV line due to deteriorated conditions.	6/1/2024	$34

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
22789	Upgrade Canton South 138 kV substation	Create ring bus, add high side interrupting devices.	6/1/2026	$3.25
22813	Reconductor Coffeen North-Roxford 345 kV line	Reconductor the 51 mile Coffeen North-Roxford-4551 345 kV line with conductor capable of carrying 3,000 amps during Summer Emergency conditions.	12/1/2025	$25
22816	Rebuild Louisville – Newton 138 kV line	Replace the 134 original vintage wood structures on the Louisville-Newton 138 kV line due to age and condition.	12/1/2023	$32
22817	Rebuild Mount Vernon West-Xenia 345 kV line (4591)	Rebuild the Mount Vernon West-Xenia 345 kV line (37 miles) to replace decayed and severely woodpecker damaged wood poles.	12/1/2026	$51
22851	Rebuild Mount Vernon West-West Frankfort East 345 kV line (4561)	Rebuild the Mount Vernon West-West Frankfort East 345 kV line (36 miles).	6/1/2025	$48
22868	Upgrade Quincy South 138 kV substation	Insulators – Strain Bus Suspension (18) – replace.	12/2/2024	$3
23088	Upgrade Quincy East 138 substation	Replace Breaker 1442. Replace switch 1456.	6/1/2024	$1.5
23505	Relocate Bosco 138 kV substation (fka Murdock)	Relocate station due to contamination, build a ring bus at a new location.	6/1/2025	$14.4
23844	Replace Pole and Insulator Program – MTEP23	Pole and Insulator Replacement requested by Maintenance.	12/1/2025	$20
23845	Replace Breakers and Relays Program – MTEP23	Breaker and Relay Upgrades Requested by Maintenance (Missouri and Illinois).	12/1/12025	$5

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23367	New Lincoln Land Energy Center 345 kV substation (J955)	Project will connect to the existing Austin substation. This requires us to install a new 345 kV breaker position. This is a 1165 MW combined cycle project.	12/1/2024	$2.7

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23431	Upgrade Decatur-Main St. 138 kV line (J955)	Replace two wood structures and re-frame 3 others to increase capacity of the Decatur - Main St. 138 kV line.	12/1/2024	$0.5
23635	New Baldwin Solar Interconnection (J1202)	Install one 345 kV terminal in the Baldwin substation. The terminal will consist of all necessary terminal equipment to connect the J1202 lead line to the Baldwin substation 345 kV bus.	6/1/2024	$0.15
23637	New Hennepin Solar Interconnection (J1200)	Install one 138 kV terminal in the Putnam substation. The terminal will consist of all necessary terminal equipment to connect the J1200 lead line to the Putnam substation 138 kV bus. Install upgrades at Putnam substation. Raise existing PUTN-HKOK-1556, PUTN-HENN-1771, PUTN-HENN-1765, PUTN-ESK-1757, and PUTN-BURE-1552 transmission lines.	6/1/2024	$1.8
23676	New Coffeen Solar Interconnection (J1201)	Install one 138 kV terminal in the Coffeen North substation. The terminal will consist of all necessary terminal equipment to connect the J1201 lead line to the Coffeen North substation 138 kV bus. Raise existing Coffeen North-Pana 345kV Transmission line. 44.2 MW solar generator.	6/1/2024	$1.5
23678	New Duck Creek Solar Interconnection (J1199)	Install one 345 kV terminal in the Duck Creek substation. The terminal will consist of all necessary terminal equipment to connect the J1199 lead line to the Duck Creek substation 345 kV bus. Upgrade control and relay fiber panel at the Duck Creek substations as well as the remote end substation.	6/1/2024	$2.5
23982	New Newton Solar Interconnection (J1198)	Install one 345 kV terminal in the Newton substation. The terminal will consist of all necessary terminal equipment to connect the J1198 lead line.	12/1/2025	$1.5
23983	New Bison 345 kV Substation for J1289 Lotus Wind E&P	A 200 MW wind project interconnecting the Ameren Illinois	11/1/2024	$12

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		system along the Turner - Austin 345 kV line.		
24052	New Nile 138 kV Substation for J1208-J1209 Chariot Solar I & II	A 160 MW solar project connecting to a new switching station in Saline County, Illinois.	12/1/2025	$9.25
24133	J1360 Goose Creek Wind PGIA	A 300 MW wind project connecting at the existing Goose Creek substation in McLean County, IL. Install Gas circuit breaker and relocate Rising Line terminal. Newly terminate the Goose Creek-Rising 345 kV transmission line to provide a position for J1360.	6/1/2024	$4.2
24695	New Fauna 345 kV Sub for Flora Solar (J1679)	125 MW solar generation project J1679. Interconnection at Fauna sub on Xenia - Mt Vernon West 345 kV Line 4591.	12/1/2025	$11
24718	New Quotient 345 kV Substation for Casey Fork Solar(J1241)	Construct a new 345 kV Quotient switching station in Jefferson County, IL to provide a Point of Interconnection for the Generating Facility. The new J1241 Interconnection Switching Station will split the existing Xenia – Mt Vernon West 345 kV transmission line.	12/1/2025	$11
24779	New Hoot 138 kV Substation (J1266)	Hoots J1266 Interconnection Switching Station will cut the existing Kinmundy – Salem West 138 kV transmission line.	12/1/2025	$10.5
24780	Fayetteville Bee Hollow Substation (J1311)	The Fayetteville Bee Hollow Substation will be rebuilt to a 4 position (6 position ultimate) 138 kV ring bus to allow J1311 interconnection.	12/1/2025	$8
24781	New Greenwave 138 kV Substation (J1232)	The J1232 Generating Facility will interconnect at the Greenwave substation cutting the Mattoon West-Arland-1539 138 kV Transmission Line.	12/1/2025	$8
24840	New Zeke 345 kV J1263 Interconnection Switching Station	New 345 kV Switching Station on Casey West – Kansas 345 kV for the Generating Facility J1263.	12/1/2025	$10

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24859	Casey West 345 kV- New Position for Union Center Solar(J1204)	A new 345 kV position will be constructed at Casey West Substation to serve as the Point of Interconnection for Union Center Solar, LLC under GIA J1204. The CSYW-NWTY-1 line position will also be moved from the southwest corner of the substation to the southeast corner to avoid line crossing with the IC.	12/1/2025	$1.2
24878	Ashley-IL 138 kV New Position for Ashley Solar (J1216)	This project will tap into the existing Ashley 138 kV 3-position ring bus to serve as the Point of Interconnection for the Interconnection Customer's Generating Facility, Ashley Solar, LLC. The existing ASHL-JORD-1536 138 kV transmission line will be raised to provide adequate space for the new interconnection line. The 138 kV lead line from Ashley Solar, LLC will terminate into the third position.	12/1/2025	$1
24900	Ipava 138 kV New Position (J1383)	Interconnection Facilities shall consist of one 138 kV terminal in the Ipava substation to connect the J1383 lead line.	12/1/2025	$1
24901	Morganfield 138 kV New Position (J1302)	Add 138 kV terminal in the Morganfield substation to connect the J1302 and J1096 lead line to the Morganfield substation.	12/1/2025	$1

4.2.3 Ameren Missouri

After MISO's independent reliability analysis, MISO and Ameren Missouri recommend 30 projects at an estimated cost of $352 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, one is a Baseline Reliability Project, 22 are Other Projects, five are Generator Interconnection Projects with signed Generator Interconnection Agreements, and two are Generator Interconnection projects with Provisional Generator Interconnection Agreements. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Baseline Reliability Projects

P22869 – Rebuild Clark 138/161 kV Substation to 138 kV Breaker and a Half

Project Description: Rebuild Clark 138/161 kV Substation to have a 138 kV BAAH bus with 8 positions (4 existing lines, 2 Transformers, bring in another line) and a 161 kV ring bus with 6 positions (2 existing lines, 2 Transformers, and new line position to Viburnum). The total estimated cost of this project is $44 million and has an expected in-service date of December 1, 2027.

Project Justification: The Mines area transmission network is a 161 kV loop that is supplied by Clark 138/161 kV transformer and Fletcher (AECI) 345/161 kV transformer. The P6 events of losing either transformer combines with certain lines on the loop lead to under voltage issues on 161 kV and distribution buses. This is in violation of TPL-001-4.

Alternatives Considered: There were no alternatives for this project proposal.

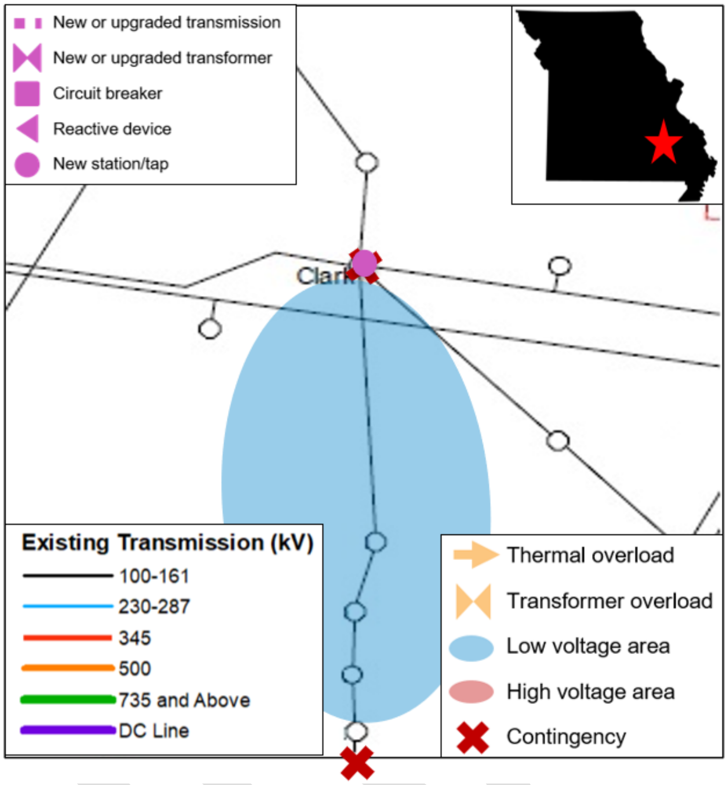


Figure 4.2.3-1: P22869 Geographic transmission map of project area

Cont.Type	Limiting Element	Rating (pu)	Pre-Project Loading (pu)	Post-Project Loading (pu)
P6	[AMMO] Clark 161 kV	0.95	0.9286	0.9975
P6	[AMMO] Viburnum 161 kV	0.95	0.9308	0.9945
P6	[AMMO] Galena 161 kV	0.95	0.9341	0.9938
P6	[AMMO] Buick Mane 161 kV	0.95	0.9341	0.9923
P6	[AMMO] Fletcher 161 kV	0.95	0.9353	0.9869

Table 4.2.3-1: P22869 Project contingency drivers

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
22066	Replace Mason 345/138 kV Transformer No. 1	Replace Mason 345/138 kV Transformer #1 with a 700 MVA Unit.	12/1/2026	$7.8
22787	Upgrade Warson 161 kV substation	Line BKRs on 4-line terminals, High Side interrupting devices on XFMRs 1,2,3,4, Add bus tie 2-3 BKR.	12/1/2026	$8
22790	Reconfigure Moreau 161 kV substation	Construct a four position (six ultimate) 161 kV ring bus at Moreau. New name is Jays.	12/1/2026	$8.5
22791	New McBaine 161 kV substation	New switching station at McBaine tap off LYMT-OVRT-3. New name is Katy.	12/1/2026	$14.4
22806	Upgrade Rush Island 345 kV Substation	Upgrade the Rush Island 345 kV bus to 3000A capability.	4/1/2024	$1.5
22814	Upgrade Guthrie 161 kV substation	Add a 161 kV line breaker to the 161 kV GUTH-LYMT-3 line at Guthrie.	12/1/2024	$2
22866	Upgrade St Francois 345 kV substation	Install a new circuit breaker at St. Francois 345 kV Sub position V43 to complete the ring bus. Replace 138 kV breakers. Upgrade relaying.	6/1/2027	$12.7
22870	Reconfigure Mason-Carrollton-Sioux 138 kV lines	Split the ~2-mile Mason-Carrollton-8/Carrollton-Sioux-8 138 kV lines into two separate circuits to avoid the loss of a single structure causing a long-term outage on both Carrollton supplies.	6/1/2025	$5
22873	Upgrade Oran 161 kV substation	Add 161 kV ring bus to split the Kelso-Morley-3 line into two lines.	6/1/2026	$7.8
22890	Upgrade Selma 161 kV substation	Add line breakers to Selma-Rivermines-2 & DPFE-Selma-1. Add High Side Interrupting devices to XFMR 1 & 2.	12/1/2025	$3
22947	Upgrade Lakeshire 138 kV substation	Add line breaker to Pos. J (Baum-Wat-1).	12/1/2025	$3.4
22926	Upgrade Dardenne 161 kV substation	Add line breakers to Dardenne.	12/1/2027	$5
23006	Upgrade Pilot Knob 161 kV substation	Add circuit switcher for XFMR 1 and line breaker for 161 kV FLET –PKNB -2.	12/1/2025	$4
23087	Rebuild Troy-Pike 161 kV line	Add Dual OPGW to the TROY-PIKE-1 Line from Pike to the Auburn tap (Structure 309 or so). Adding OPGW to the TROY-PIKE-1 line	12/1/2024	$16

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		will require the line to be rebuilt. Since the line is being rebuilt, dual OPGW is to be added. At the Auburn tap the OPGW will be terminated to allow a connection to the AECI Fiber on their portion of the TROY-PIKE-1 line and brought the rest of the way to the new Harley Substation.		
23306	Rebuild Stoddard-Essex 161 kV line	Rebuild the 5.4-mile Stoddard-Essex-3 161 kV Transmission Line with T2 conductor rated at 2,000 amps Summer Emergency Conditions and 2 EA 72-Fiber OPGW shield wires.	6/1/2025	$3.3
23351	New Bugle 138 kV Capacitor (120 MVAR)	120 MVAR Capacitor at Bugle.	12/1/2024	$26
23526	Reconfigure Warrenton 161 kV substation	Install a 161 kV Ring bus at Warrenton Substation.	12/1/2024	$15

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23152	New Copley 138-12 kV Substation	Build a new four position 138 kV Ring bus needed to connect two 13/12 kV transformers.	12/1/2024	$20

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
22801	Rebuild Sioux-Meppen North-Hull 138 kV line	Rebuild the Sioux-Meppen North-4 from Str. 180-Meppen North and the entire Meppen North-Hull-1494 138 kV line to upgrade aging infrastructure and improve system reliability.	12/1/2026	$77.7
22815	Upgrade Hunter 161 kV Substation	Add line breakers and high side transformer interrupting devices.	12/1/2025	$3
22846	Upgrade Sioux 138 kV substation	Upgrade 15H position to higher ampacity to increase available capacity of the 700MVA Auto Transformer.	12/1/2026	$10.5
22927	Convert Viaduct 115 kV facilities to 161 kV	Convert 115 kV facilities at Viaduct to 161 kV.	12/1/2024	$5

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		Eliminate Viaduct 161 to 115 kV transformer T1 by bypassing it, and by changing the taps on Viaduct Transformer 1 from 115 to 161 kV. Replace 115kV OCB #5210 with a 161 kV puffer breaker.		

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
22706	New Huck Finn Solar 345 kV	Connect a 200MW solar farm via 345 kV lead line from Interconnection Customer collector substation to existing Spencer Creek switching station.	6/1/2024	$4.2
23388	New Firebrick Wind Farm (J1026)	J1026 is seeking interconnection service for 380 MW for Wind facility. The Connection will be made at the 345 kV Spencer Creek Substation.	6/1/2024	$1.7
23430	New Zachary generation interconnection FCAs (J1025-J1182)	Install a 2nd Zachary 345/161 kV transformer, construct a 2nd Zachary - Adair 161 kV transmission line, and re-route existing Appanoose-Adair 161 kV Transmission line.	12/1/2025	$17
23470	New Northeast Missouri Wind interconnection (J1025)	Construct the new 345 kV Fabius substation in Knox County, Missouri to provide a Point of Interconnection for the Generating Facility with a terminal that will consist of all necessary terminal equipment to connect the J1025 lead line to 345kV Fabius substation bus. J1025 is a 300 MW Wind project interconnecting to the Zachary-Maywood 345 kV liner.	6/1/2024	$11
23500	New Morris Solar interconnection (J1182)	One 345 kV terminal in the Zachary substation. The terminal will consist of all necessary terminal equipment to connect the J1182 lead line to the Zachary substation bus. J1182 is a 250 MW Solar project interconnecting to the Zachary substation 345 kV bus.	11/1/2024	$2.593
24696	New Vanhorn 345 kV Substation for Wolf Creek Solar (J1352)	Construct the Interconnection Facilities at the J1352 Interconnection Switching Station, line cut-in and relay upgrades. Vanhorn sub on Montgomery-Spencer Creek 345 kV line.	6/1/2025	$11

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24860	Bullion 161 kV Add Breaker Position for Kelso 2 Solar (J1299)	This project will construct a new Point of Interconnection for the Interconnection Customer's Generating Facility, Kelso 2 Solar LLC, to the Bullion Switching Station. The 161 kV lead line from Kelso 2 Solar LLC will terminate into the fourth position.	12/1/2025	$1

4.2.4 Big Rivers Electric Corporation (BREC)

After MISO's independent reliability analysis, MISO and Big Rivers Electric Corporation recommend two Other Projects at an estimated cost of $6.2 million to be approved for inclusion in MTEP23 Appendix A. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23569	New [BREC] McCracken-[GLH] Joppa 161 kV Tie Line	The project will construct one additional terminal at an existing Big Rivers' substation, 2 miles of 161 kV transmission line (Big Rivers owned), and a three-bay switching station (GLH owned). The project will address TPL violations caused by extreme weather and/or a small load increase. In addition to the TPL violation relief and providing needed capacity in the western part of Big Rivers' system, the proposed project will alleviate the need to purchase transmission service from TVA.	7/2/2025	$5.3

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
19007	Upgrade Kansas 69 kV line	Create double circuit from existing radial 69 kV tap.	10/1/2024	$0.9

4.2.5 City of Columbia, MO (CWLD)

City of Columbia, MO, (CWLD) did not submit any new projects for MTEP23. MISO has not identified any issues in CWLD area.

4.2.6 City of Springfield, IL (CWLP)

City of Springfield, IL, (CWLP) did not submit any new projects for MTEP23. MISO has not identified any issues in CWLP area.

4.2.7 Duke Energy Corporation (DEI)

After MISO's independent reliability analysis, MISO and Duke Energy Corporation recommend 33 projects at an estimated cost of $467 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, six are Baseline Reliability Projects, 23 are Other Projects, and four are Generator Interconnection Projects with signed Generator Interconnection Agreements. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Baseline Reliability Projects

Project 23406 - Upgrade [DEI] Bedford 138 kV Bus 9

Project Description: The project will upgrade [DEI] Bedford 138 kV Bus 9. This upgrade will mitigate the overload on the [DEI] Bedford - [DEI] Bedford bus section #3 138 kV line for P6-1-1 NERC defined contingency events of Bulk Electric System (BES) elements. The total estimated cost of this project is $0.53 million and has an expected in-service date of June 1, 2027.

Project Need: The [DEI] Bedford - [DEI] Bedford bus section #3 138 kV line becomes overloaded to one hundred two (102%) percent in year 2024 for a NERC defined category P6-1-1 contingency event of BES elements. Upgrading [DEI] Bedford 138 kV Bus 9 will increase the summer emergency rating of the line from 301 MVA to 511 MVA.

Alternatives Considered: No other alternatives considered; this breaker replacement project is the best and cheapest option to address this reliability issue.

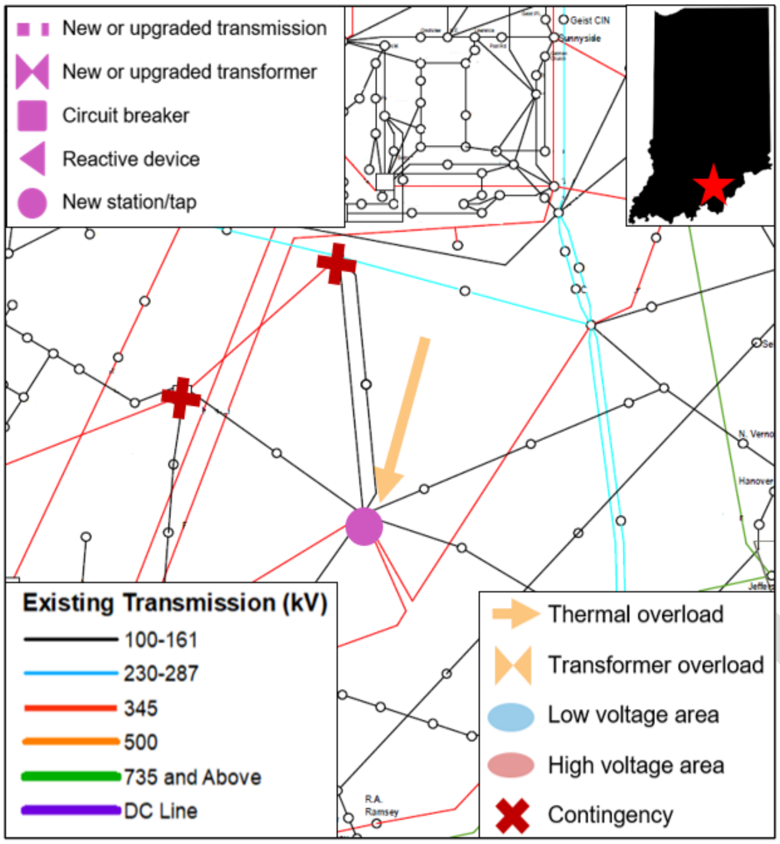


Figure 4.2.7-1: P23406 Geographic transmission map of project area

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-project (post-cont.) Loading (%)	Post-project (post-cont.) Loading (%)
P6	[DEI] Bedford—[DEI] Bedford bus section #3 138 kV line	511	99	51

Table 4.2.7-1: P23406 Thermal loading drivers

Project 23407 – Upgrade [DEI] Bloomington 230 – Bk1 138 kV Bus

Project Description: The project will upgrade the [DEI] Bloomington 230/138 kV transformer. This upgrade will mitigate the overload on the [DEI] Bloomington 230/138 kV transformer for P6-1-1 contingency events of BES elements. The total estimated cost of this project is $0.39 million and has an expected in-service date of June 1, 2024.

Project Need: The [DEI] Bloomington 230/138 kV transformer becomes overloaded to one hundred five (105%) percent in year 2024 for a NERC defined category P6-1-1 contingency event. Upgrading [DEI] Bloomington 230/138 kV transformer will increase the summer emergency rating of the transformer from 151 MVA to 165 MVA.

Alternatives Considered: No other alternatives considered; this breaker replacement project is the best and cheapest option to address this reliability issue.

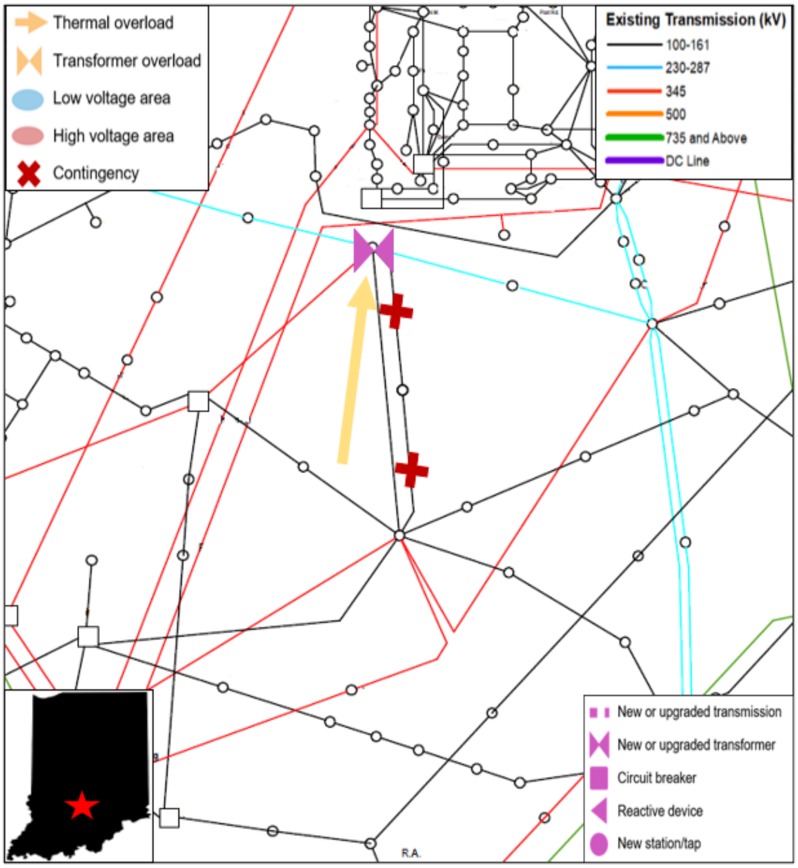


Figure 4.2.7-2: P23407 Geographic transmission map of project area

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	[DEI] Bloomington 230/138 kV transformer	165	100	91

Table 4.2.7-1: P23407 Thermal loading drivers

Project 23861 – Upgrade [DEI] Columbus 345 kV Substation Breakers

Project Description: The project will replace (3) 138 kV Circuit Breakers on transformer Banks 1, 2, and 3 with higher fault interrupting capacity at [DEI] Columbus 345 kV substation. The total estimated cost of this project is $1.5 million and has an expected in-service date of December 31, 2026.

Project Need: These Circuit Breakers were identified in the annual DEI 2022 short circuit study for replacement/upgrade as required by TPL 001-4.

Alternatives Considered: No alternatives were considered.

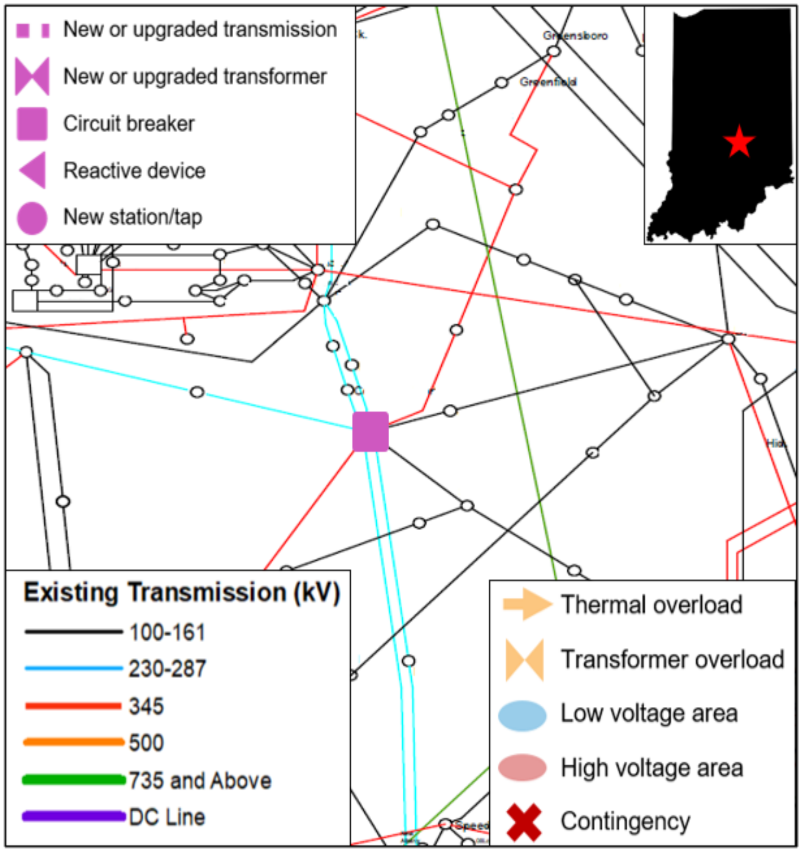


Figure 4.2.7-4: P23861 Geographic transmission map of project area

Project 23862 – Upgrade [DEI] Bedford 345 kV Sub – 138-138 Bus Tie line

Project Description: The project will Upgrade [DEI] Bedford 345/138 kV Bus Tie line. This upgrade will mitigate the overload on the [DEI] Bedford to [DEI] Bedford bus section #2 138 kV line for P6-1-1 contingency events of BES elements. The total estimated cost of this project is $0.7 million and has an expected in-service date of April 1, 2032.

Project Need: The [DEI] Bedford bus section #1 to [DEI] Bedford bus section #2 138 kV line becomes overloaded to one hundred one (101%) percent in year 2032 for a NERC defined category P6 contingency event. Upgrading this line section will increase the summer emergency rating of the line from 573 MVA to 747 MVA.

Alternatives Considered: No other alternatives were considered. This new substation project is the best and cheapest option to address these reliability issues.

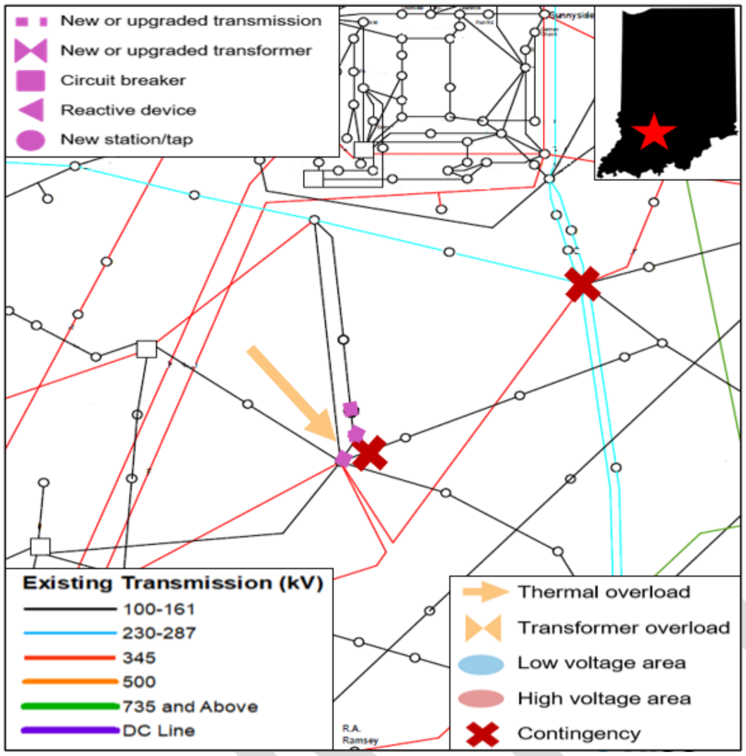


Figure 4.2.7-5: P23862 Geographic transmission map of project area

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-project Loading (%)	Post-project Loading (%)
P6	[DEI] Bedford bus section #1 – [DEI] Bedford bus section #2 138 kV line	747	97	69

Table 4.2.7-5: P23862 Thermal loading drivers

Project 23863 – Upgrade [DEI] Cayuga to [DEI] Nucor 345 kV line

Project Description: The project will Upgrade [DEI] Cayuga to [DEI] Nucor 345 kV line. This upgrade will mitigate the thermal overload on the [DEI] Cayuga to [DEI] Nucor 345 kV line for P6-1-1 contingency events of BES elements. The total estimated cost of this project is $0.32 million and has an expected in-service date of April 1, 2027.

Project Need: The MTEP23 result shows the overload on [DEI] Cayuga to [DEI] Nucor 345 kV line to one hundred one (101%) percent in year 2027 for a NERC defined category P6 contingency event. Upgrading [DEI] Cayuga to [DEI] Nucor 345 kV line will increase the summer emergency rating of the line from 1279 MVA to 1374 MVA.

Alternatives Considered: No other alternatives were considered. This new substation project is the best and cheapest option to address these reliability issues.

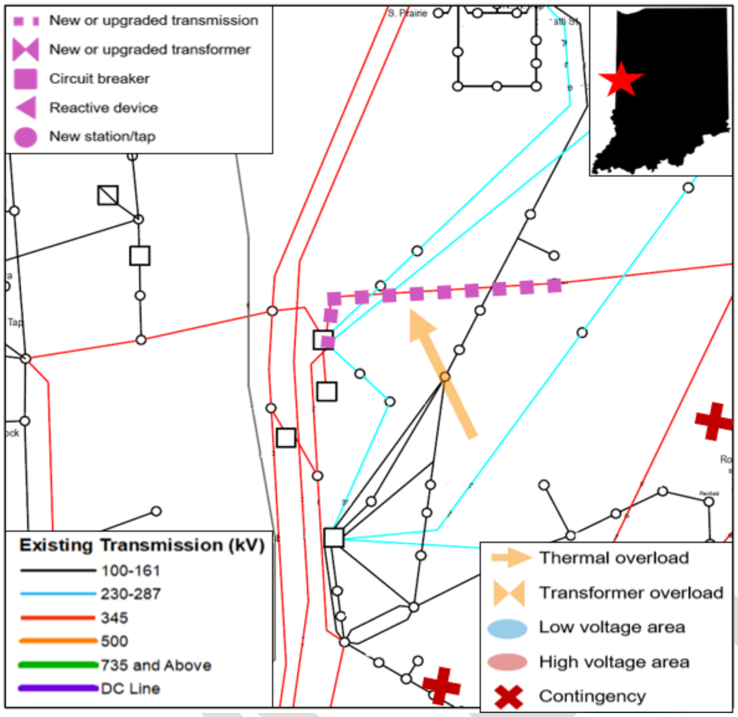


Figure 4.2.7-6: P23863 Geographic transmission map of project area

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-project Loading (%)	Post-project Loading (%)
P6	[DEI] Cayuga – [DEI] Nucor 345 kV line	1374	98	93

Table 4.2.7-6: P23963 Thermal loading drivers

Project 23864 – [DEI] New Bloomington Area 138 kV Source

Project Description: The project will Construct a new [DEI] Bloomington 345/138 kV substation on the west side of Bloomington with one 138 kV line to [DEI] Bloomington Rogers St. This New Substation will mitigate multiple thermal overloads serving [DEI] Bloomington area for multiple P6-1-1 contingency events of BES elements. The total estimated cost of this project is $44.5 million and has an expected in-service date of June 1, 2028.

Project Need: MTEP23 results showed BES facilities serving the Bloomington area are overloaded beyond one hundred (100%) percent for multiple TPL contingency events. New Bloomington Area 138 kV Source will reduce the overload on these BES lines and transformers during the summer peak season.

Alternatives Considered: No other alternatives were considered. This new substation project is the best and cheapest option to address these reliability issues.

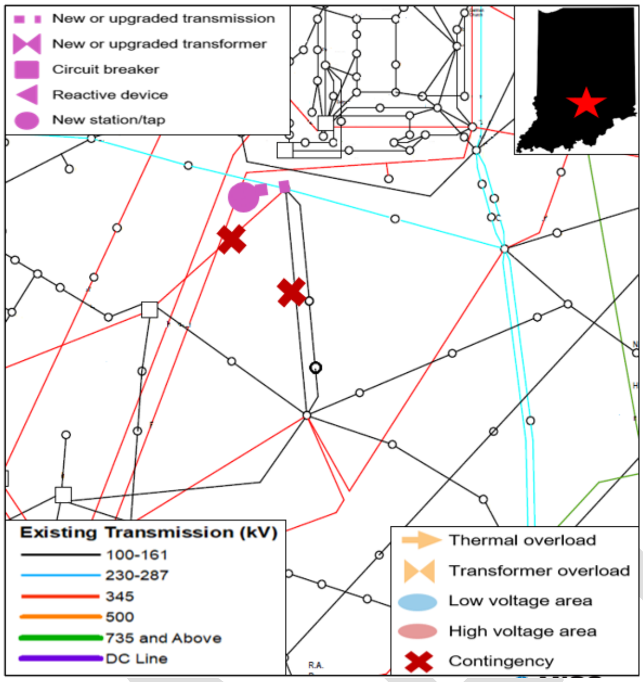


Figure 4.2.7-6: P23864 Geographic transmission map of project area

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-project Loading (%)	Post-project Loading (%)
P6	[DEI] Bedford – [DEI] Harrodsburg 138 kV line	243	98	57
P6	[DEI] Bloomington Rogers St – [DEI] Bloomington Rockport Road 138 kV line	198	103	53
P6	[DEI] Bloomington Rockport Rd - [DEI] Bedford bus section #3 138 kV	198	109	58
P6	[DEI] Bloomington 230/138 kV transformer	151	111	48
P6	[DEI] Bloomington – [DEI] Bloomington NW 138 kV line	151	106	44

Table 4.2.7-6: P23864 Thermal loading drivers

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23833	New Edinburgh Industrial Park 69/12 kV sub	DEI to construct high-side and loop 69 kV lines into a new IMPA-owned Edinburgh Industrial Park substation; one 69/12 kV 20MVA transformer;	6/1/2025	$4.6

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		SCADA controlled MOLB 69 kV line switches; two 69 kV buses with a manually operated 69 kV bus tie switch; 69 kV connections from the 6950 and 69146 circuits.		
23848	Rebuild WVPA Montclair to Montclair Jct. 69 kV	WVPA Montclair to Montclair Jct. 69134 69 kV Rebuild: rebuild 69 kV line section.	12/18/2023	$8.9
23850	Rebuild WVPA Lee Hanna to Lee Hanna Jct 69 kV (Phase 3)	Rebuild 5.6 miles of 69 kV to match line conductor for Fortville to Mohawk line. (954 ACSR)	10/31/2023	$3.3
23868	New WVPA IPC to 69162 Tap loop 69 kV	Build 69 kV from IPC to 69162 Tap 2.8 miles. Add 2 ATO switches at IPC tap & 3 switches at 69162 line tap. 90 amps minimum. 477 ACSR.	12/31/2023	$6
23892	Rconfigure Shelbyville Northeast 138 kV Ring bus	Shelbyville Northeast: build 138 kV ring bus; replace CIR 6946, 6976, 69183, 13803, 13865 relays, replace OCBs 6946, 6976, 69183, 69138-1, 13803, replace Bank 1 ground switch with circuit switcher, and station battery.	6/30/2026	$10.8
23923	New WVPA Vandalia 69/12 kV Substation	Vandalia (Fillmore) Substation - Incorporate SCADA operated 69 kV flow-through switches into 6996 line between Greensboro and Amo.	7/15/2024	$5.5
23962	Rebuild 6958 Line 69 kV for FAA	6958 Line Rebuild as required by FAA - Rebuild 39 Structures and replace conductor from HE Whitehall to structure 815-1069-01. Replace individual poles 815-1060 and 815-1061. Install monitored FAA warning lights on 37 of the poles. Install 36 marker balls on the static wire.	6/1/2025	$3.4
23966	Reconfigure Greensburg 138 kV Ring Bus	Greensburg 138 kV expand sub and reconfigure to (4) breaker ring bus.	6/1/2023	$5.9
23970	Rebuild 69100 Greensfork to HE Jacksonburg Jct 69 kV	Rebuild 69100 from Greensfork #1 switch (pole #862-3176) to Jacksonburg Jct switch (pole #862-3074) using light duty steel poles, 477ACSR and OPGW.	10/9/2025	$10.8
23978	New Bargersville North 69 kV Switching Station	Build new Bargersville North 69 kV three breaker ring bus switching station in the 69102 line.	12/31/2025	$11.7

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23979	New Trafalgar 69 kV Ring Bus	Convert the existing Trafalgar 69 kV switching station to a three-breaker ring bus.	3/3/2026	$10
23980	New Glenwood West 10.5MVA 69/12 kV Sub	Glenwood West (new) - Install 10.5MVA, 69-12kV non-LTC transformer; build/re-route the existing 6920 line to loop through the new substation with ATO/TLS switches.	12/29/2023	$1.4
23981	New Saint Paul Northwest 10.5MVA 69/12 kV Sub	Saint Paul Northwest (new) - Install 10.5MVA, 69-12 kV non-LTC transformer; build/re-route the existing 6937 line to loop through the new substation with ATO/TLS switches	11/6/2025	$1.4

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23867	Rebuilding WVPA Anderson Grain 69/12 kV Sub	Relocate transmission and add in&out with SCADA switches for new Anderson Grain substation. Install 69 kV circuit switcher and relaying for high side protection.	8/7/2024	$1.75
23922	Rebuild WVPA Bringhurst 69/12 kV Sub	Rebuild Bringhurst 69/12 kV substation. 4.5MVA loading on 6.25MVA existing bank. Possibly bring #1 & #2 sectionalizing line switches inside of substation for an in&out. WVPA owns the loop through portion of the substation.	4/3/2024	$5.8
23953	Rebuild WVPA Greencastle 69/12 kV Substation	Rebuild the existing 69-12.47 kV Greencastle Substation with 69 kV flow-through in another location due to size of site. Replace bank with 14.4 MVA.	5/31/2024	$4.83
23965	Replace 13832 Line Structure 138 kV	Replace 14 structures in the 13832 line: 849-2103 thru 2106, and 849-2113 thru 2122	5/1/2024	$2.57

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23871	New WVPA NSC Lick Creek 69/12 kV Sub.	Build new WVPA NSC (Ninestar Connect) Lick Creek substation; Install 22.4MVA 69/12 kV sub with 3-way switches at line jct.; preliminary plan is to be fed from the 69198 circuit.	10/31/2026	$6.9
23925	New Slugger 138 kV Load	Project Slugger - large new customer load - early phases to be served from 138 kV system followed by 345/138 kV transformation as load projections increase.	12/31/2029	$123.5
23964	New Kokomo Fusion 230/69 kV Sub	Kokomo Project Fusion new 230/69 kV substation for large new customer load: inserted in the 23022 circuit. with 4-CB ring (between Greentown and Kokomo Webster St.); (2) 150MVA -230/69 kV transformers; (14) 69 kV breakers in a breaker and one-half layout; loop 69172 circuit. (Between Kokomo East and Kokomo Chrysler North) through new sub; also loop the 69174 circuit. (Between Kokomo Touby Pike Tap 1 and Chrysler North Jct.); (3) 60MVA - 69/34.5 kV transformers .	6/1/2025	$92.1
23968	New Greensfork East 69/12 kV Sub	Greensfork East new 69/12 kV - 22.4MVA Sub: looped-through feed from 69100 circuit.	8/8/2028	$1.4
23969	New Williamsport 69/12 kV Sub	Williamsport new 69/12 kV - 22.4MVA sub: looped-through feed from the 6936 circuit.	10/2/2026	$3.2

Projects Driven by Local Needs

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
3382	Vincennes Vigo St. 138 kV Dist Sub	Build new radial 138 kV line and add breaker at Vincennes 138 kV sub to convert Vigo St. sub from 34 kV to 138 kV.	7/14/2026	$10.9

Generator Interconnection Projects:

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23886	New J1234 - J1235 IN Solar 1	J1234 - J1235 IN Solar 1 – 150 MW net solar farm (100 MW for J1234 and 50 MW for J1235).	12/31/2023	$17.2
23887	J1378 Crossroads Solar	J1378 Crossroads Solar – 200 MW: 230 kV connection at existing Veedersburg West sub.	11/15/2024	$6
23963	Rebuild 6932 Potato Creek to Thorntown 69 kV	6932 Rebuild Potato Creek to Manson Jct to Clarks Hill to Thorntown with 954ACSR conductor.	5/17/2024	$41.8
23967	J1295 Gibson Solar	J1295 Gibson Solar farm 280 MW +/- w/ 345kV POI between Gibson and Francisco in circuit 34516 (3-breaker ring); Includes required relay work at Gibson.	6/1/2024	$17.7

4.2.8 GridLiance Heartland LLC (GLH)

After MISO's independent reliability analysis, MISO and GridLiance Heartland LLC recommend three Other Projects at an estimated cost of $59.7 million to be approved for inclusion in MTEP23 Appendix A. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23827	New 3-breaker ring bus substation	Build new 3-breaker ring bus switching station near Heath, KY bisecting Joppa - Shawnee 161 kV circuit 1 line with one terminal for connection with Big Rivers Electric McCracken station. Additionally, add 1-161 kV breaker at Joppa TS station and remove existing Joppa - Joppa TS - Shawnee 161 kV circuit 1 three terminal in Illinois by bringing line in and out of Joppa TS station.	12/31/2026	$15.9

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23765	Rebuild Joppa-Joppa TS-Grahamville 161 kV line (854)	Rebuild the GridLiance Heartland portion of Joppa - Joppa TS - Grahamville 161 kV circuit 854 three terminal line.	12/31/2026	$21.9
23826	Rebuild Joppa - Grahamville 161 kV line (804)	Rebuild the GridLiance Heartland portion of Joppa - Grahamville 161 kV circuit 804 line.	12/31/2026	$21.9

4.2.9 Henderson Municipal Power & Light (HMPL)

After MISO's independent reliability analysis, MISO and Henderson Municipal Power & Light recommend one Other Project at an estimated cost of $0.16 million to be approved for inclusion in MTEP23 Appendix A. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24172	Re-route HMPL Sub 4 to HMPL Sub 4 Tap 161 kV Transmission Line	HMPL to reroute the HMPL Sub 4 to HMPL 4 Tap 161 kV transmission line due to BREC Pratt Paper Project. HMPL is required to proceed with engineering/construction of the affected transmission line to meet BREC project schedule.	7/1/2023	$0.16

4.2.10 Hoosier Energy REC, Inc. (HE)

After MISO's independent reliability analysis, MISO and Hoosier Energy REC, Inc. recommend one joint Other Project with AMIL and SIPC at an estimated cost of $167.9 million to be approved for inclusion in MTEP23 Appendix A. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023. Further details are provided in Section 4.2.2 Ameren Illinois.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23026	New South Central Illinois Transmission Expansion	Construct a new 138 kV substation as an ultimate six-position ring bus requiring one 3000 A 138 kV breaker	12/1/2025	$167.9

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		initially adjacent to the Continental Tire facility. Construct a ~3.5-mile 138 kV line from Mt. Vernon 42nd St. to the new substation ~0.3 miles NE of the Continental Tire facility with minimum 2000 A summer emergency capability. Add a new 3000 A 138 kV breaker at Mt. Vernon 42nd St. for this new 138 kV line position.		

4.2.11 Indianapolis Power & Light Company (IPL)

After MISO's independent reliability analysis, MISO and Indianapolis Power & Light Company recommend 11 projects at an estimated cost of $161 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, two are Baseline Reliability Projects, seven are Other Projects, and two are Generator Interconnection Projects with signed Generator Interconnection Agreements. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Baseline Reliability Projects:

Project 23568 – Replace [IPL] Southwest 138 kV #16 Breaker

Project Description: The project will replace one (1) #6 breaker at [IPL] Southwest 138 kV. The total estimated cost of this project is $0.9 million and has an expected in-service date of December 31, 2025.

Project Need: Breaker fault violation at [IPL] Southwest 138 kV for outages of BES elements were identified in the annual IPL 2022 short circuit study for replacement/upgrade as required by TPL 001-4.

Alternatives Considered: No other alternatives were considered.

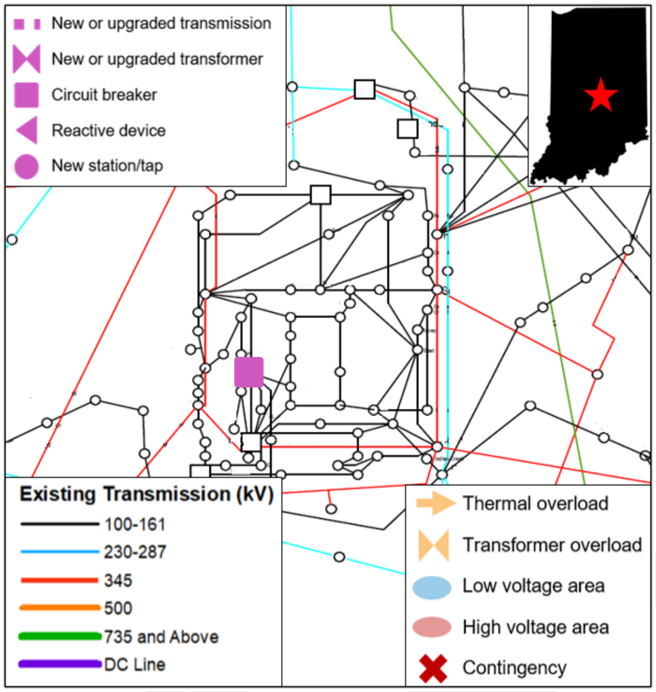


Figure 4.2.7-6: P23568 Geographic transmission map of project area

Project 23825 – Reconfigure Rockville 138 kV Substation

Project Description: The project will convert [IPL] Rockville 138 kV Substation to a ring bus configuration. This substation reconfiguration will mitigate multiple thermal overloads for spare equipment contingency events of BES elements. The total estimated cost of this project is $8.5 million and has an expected in-service date of December 1, 2024.

Project Need: The BES buses become overloaded beyond one hundred (100%) percent in year 2024 for unavailability of Long-Lead Time equipment of [IPL] Thompson Substation autotransformer in combination with Internal Breaker Fault at [IPL] Rockville Substation. Reconfiguring the [IPL] Rockville 138 kV Ring Bus will reduce the overload on the BES lines during the summer peak season.

Alternatives Considered: Purchase of a spare autotransformer for Thompson Substation; Reconductor AES Indiana 138 24 Mooresville to Eagle Valley Transmission. This alternative was not selected, because Reconfiguring Rockville 138 kV substation to ring bus configuration was cheaper than purchasing spare autotransformer and reconductoring the transmission line.

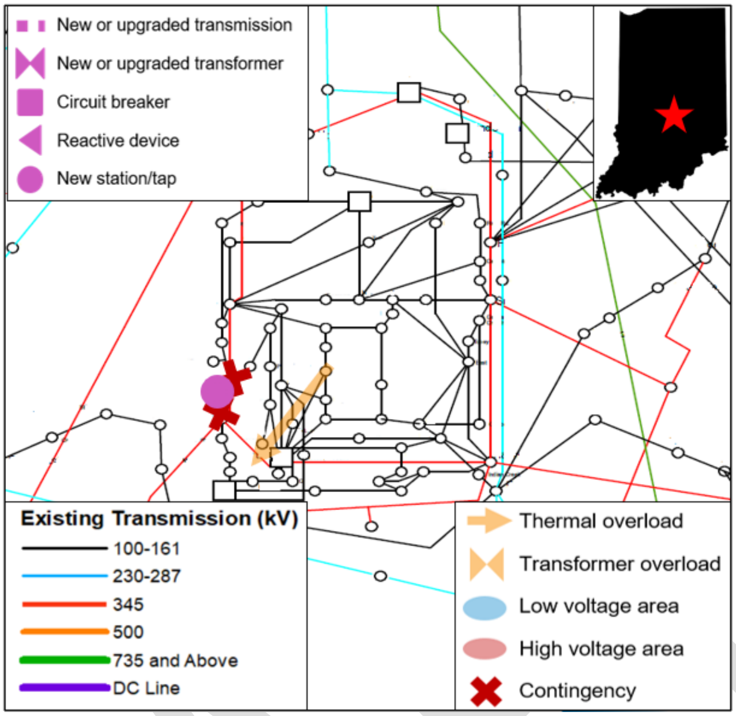


Figure 4.2.7-6: P23825 Geographic transmission map of project area

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-project Loading (%)	Post-project Loading (%)
Spare Equipment	[IPL]Heartland Crossing Tap – [IPL] Eagle Valley 138 kV line	242	106	57
Spare Equipment	[IPL]Heartland Crossing Tap – [IPL] Mooresville 138 kV line	242	103	54

Table 4.2.7-6: P23825 Thermal loading drivers

Other Projects

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23766	New IU Health Substation 138 kV	New 138 kV, two 40 MVA transformer, three-breaker straight bus substation to serve customer load.	12/31/2023	$15
23831	New Gillette 138 kV Substation	New 138 kV, two 40 MVA transformer, three-breaker straight bus substation to serve customer load.	11/1/2024	$15

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23832	New 138/13.2 Transformer at Thompson Substation	One new 138/13.2 kV 40 MVA distribution transformer with one new 138 kV breaker.	11/1/2023	$16
23834	New Valley Avenue 138 kV Substation	New 138 kV, two 40 MVA transformer, three-breaker straight bus substation to serve customer load.	12/31/2024	$15
23893	New Winding Ridge 138 kV Substation	New 138 kV, two 40 MVA transformers, 8 breaker, breaker and a half substation to serve AES-IPL customer load and provide transmission service to TOs whom have requested as such.	12/31/2024	$15
24273	New – 138 kV - Airtech Substation	New 138 kV, two 20 MVA transformer, three-breaker substation.	12/31/2026	$10.7
24293	New - 138 kV - New Pleasant Acres Substation	New 138 kV, two 40 MVA transformers, 4 breaker, ring bus substation to serve WVPA load.	12/31/2025	$10

Generation Interconnection Projects:

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23107	New J993 Brickyard Solar 345 kV	Interconnection Customer shall install a 217 MVA solar facility.	12/1/2023	$20
23852	New Petersburg Energy Center 138 kV (R1011)	Interconnection Customer shall install a 279.45 MVA generator facility.	12/31/2025	$35

4.2.12 Northern Indiana Public Service Company (NIPSCO)

After MISO's independent reliability analysis, MISO and Northern Indiana Public Service Company recommend five projects at an estimated cost of $97.3 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, two are Baseline Reliability Projects and three are Generator Interconnection Projects with signed Generator Interconnection Agreements. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Baseline Reliability Projects:

Project 23471 – Upgrade [NIPS] Roxana to [NIPS] Mittal 138 kV Line

Project Description: The project will Upgrade [NIPS] Roxanna to [NIPS] Mittal Steel Indiana Harbor West 138 kV line. This upgrade will reconduct two miles of [NIPS] Roxanna to [NIPS] Mittal 2 138 kV line. The upgrade will mitigate the overload on [NIPS] Roxanna to [NIPS] Mittal Steel Indiana Harbor West 138 kV line for multiple events of BES elements. The total estimated cost of this project is $5.65 million and has an expected in-service date of May 31, 2025.

Project Need: The [NIPS] Roxanna—[NIPS] Mittal Steel Indiana Harbor West 138 kV line becomes overloaded to one hundred twenty-five (125%) percent in year 2024 for multiple NERC defined contingency events. Upgrading The [NIPS] Roxanna—[NIPS] Mittal Steel Indiana Harbor West 138 kV line will increase the summer emergency rating of the line from 158 MVA to 286 MVA.

Alternatives Considered: No alternatives were considered.

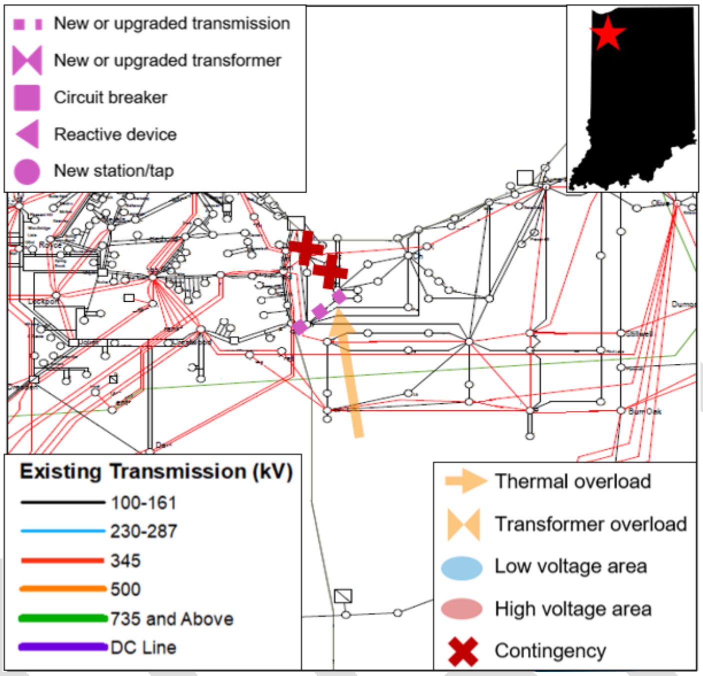


Figure 4.2.7-6: P23471 Geographic transmission map of project area

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-project Loading (%)	Post-project Loading (%)
P6	[NIPS] Roxanna – [NIPS] Mittal Steel Indiana Harbor West 138 kV line	286	124	76

Table 4.2.7-6: P23471 Thermal loading drivers

Project 23472 – Upgrade [NIPS] Leesburg Substation 138 kV

Project Description: The project will Upgrade [NIPS] Leesburg 138 kV Substation. This upgrade will eliminate common breaker at [NIPS] Leesburg 138 kV Substation. The upgrade will mitigate the overload on [NIPSCO] Goshen Junction to [NIPSCO] Forrest G. Hiple 138 kV line for NERC defined P2-3 contingency events of BES elements from MTEP22. The total estimated cost of this project is $2.4 million and has an expected in-service date of December 31, 2026.

Project Need: Voltage drops in multiple BES buses and thermal overload on [NIPSCO] Goshen Junction to [NIPSCO] Forrest G. Hiple 138 kV line to one hundred sixteen (116%) percent in year 2027 for P2-3 NERC defined contingency events. Upgrading [NIPS] Leesburg 138 kV Substation will address the voltage drops and thermal overloads caused by P2-3 contingency events.

Alternatives Considered: No alternatives were considered.

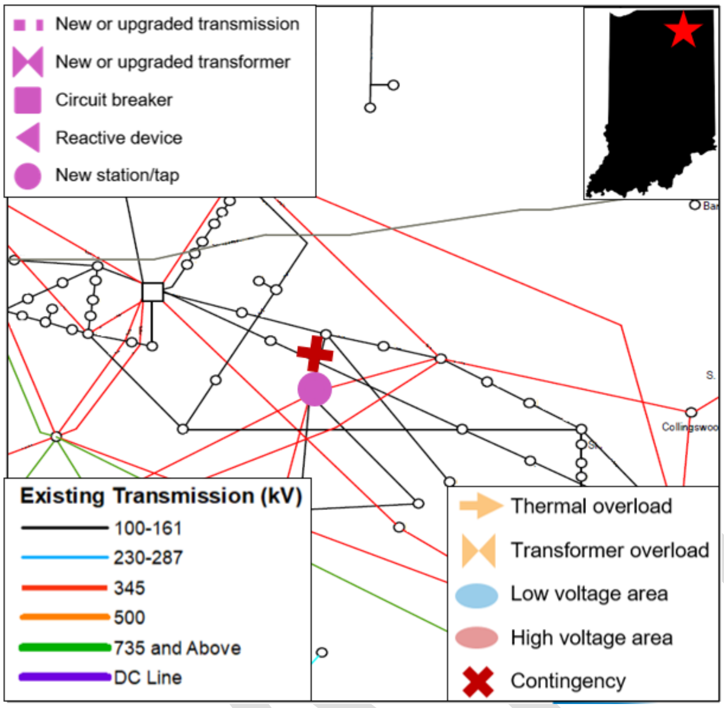


Figure 4.2.7-6: P23472 Geographic transmission map of project area

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-project Loading (%)	Post-project Loading (%)
P2-3	[NIPS] Goshen junction – [NIPS] Forrest G. Hiple 138 kV line	253	127	44
P2-3	[NIPS] Kosciusko – [NIPS] Leesburg 138 kV line	138	102	42

Table 4.2.7-6: P23472 Thermal loading drivers

Cont. Type	Limiting Element	Voltage Limit (pu)	Pre-project Voltage (pu)	Post-project Voltage (pu)
P2-3	[NIPS] Kosciusko 138 kV bus	0.9	0.87	1.00
P2-3	[NIPS] Leesburg 138 kV bus	0.9	0.89	1.00

Table 4.2.7-6: P23472 Voltage drivers

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
22809	J1058 Network Upgrades 345 kV	New Substation (Dinwiddie) and 345 kV line to Connect J1058 to NIPSCO's Schahfer to St. John line.	6/1/2025	$24.1
24032	Upgrade J1482 Network 138 kV	138 kV substation and line work to connect J1482 to Springboro to Monticello 138 kV line.	5/1/2024	$17.9
24562	J1333 -J1340 Network Upgrades	Greenfield 345 kV double breaker double bus station named Hinshaw.	6/1/2024	$47.3

4.2.13 Pioneer Transmission, LLC

Pioneer Transmission, LLC did not submit any new projects for MTEP23. MISO has not identified any issues in the Pioneer Transmission area.

4.2.14 Prairie Power, Inc. (PPI)

After MISO's independent reliability analysis, MISO and Prairie Power, Inc. recommend eight Other Projects at an estimated cost of $70.4 million to be approved for inclusion in MTEP23 Appendix A. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
19947	New Allen - Mason City 69 kV Line	New Allen-Mason City 556 ACSR 69 kV Line in MEC.	12/31/2027	$6.37
19948	New Mason City - Middletown 69 kV Line	New Mason City-Middletown 556 ACSR 69 kV Line in MEC.	12/31/2027	$9.2
23350	New Forest City - Allen Tap 69 kV Line	New Forest City-Allen Tap 556 ACSR 69 kV Line in MEC.	12/31/2027	$2.88
23427	New Disco - Carthage 69 kV Line	New Disco-Carthage 336 ACSR 69 kV line in WIEC.	12/31/2026	$8.32
23428	New Golden - Denver 69 kV Line	New Golden-Denver 336 ACSR 69 kV line connecting AEC to WIEC.	12/31/2026	$12.8

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23429	Upgrade Fieldon 69 kV Substation	Two new motor-operated SCADA-controlled switches on the Hardin Tap to Eldred 69 kV line.	7/1/2023	$0.1
23532	New Pleasant View-Ishi 69 kV Line	New Pleasant View to Ishi 69 kV line in SEC. This line has three-line segments: 1) New Pleasant View to Moweaqua 336 ACSR 69 kV 3.6-mile Line. 2) New Moweaqua to Yantisville 336 ACSR 69 kV 18-mile Line. 3) New Yantisville to ISHI 336 ACSR 69 kV 7.6-mile Line and 1 mile rebuild.	12/31/2029	$23.5

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23567	Rebuild Pearl – Kampsville 69 kV Line	Rebuild Pearl-Kampsville 69 kV line in IEC from 4/0 to 336.4 ACSR.	12/31/2029	$7.29

4.2.15 Republic Transmission, LLC (RTx)

Republic Transmission did not submit any new projects for MTEP23. MISO has not identified any issues in the area.

4.2.16 Southern Indiana Gas & Electric Company (SIGE)

After MISO's independent reliability analysis, MISO and Southern Indiana Gas & Electric Company recommend seven Other Projects at an estimated cost of $37.1 million to be approved for inclusion in MTEP23 Appendix A. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23751	Replace Maryland 69/12 kV T1 and New 69/12 kV T2 transformers	Replace existing 69/12 kV distribution T1 at Maryland due to age and add new 69/12 kV T2 for	12/31/2024	$3.9

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		distribution system contingency support.		
23757	New Garvin 69/12 kV Transformer	Add second 69/12 kV distribution transformer to provide distribution system support and contingency.	12/31/2024	$2.5
23758	New Bergdolt 138/12 kV Transformer	Add second 138/12 kV distribution transformer at the Bergdolt sub to provide distribution system and contingency support.	12/31/2024	$2.5

Projects Driven by Local Need

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23748	Rebuild Y74-1 NE – Modification 69 kV	Rebuild ~1.75 miles of 69 kV line to increase rating for local operational flexibility and contingency support.	12/31/2024	$0.71

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23749	Rebuild Y39 Cato - Winslow 69 kV	Rebuild ~9.5 miles of 69 kV due to aging infrastructure and pole condition (conductor size not changing).	12/31/2024	$14.13
23755	Replace Point Dist. 69/12 kV Transformer	Replace existing 69/12 kV distribution transformer due to age and condition.	12/31/2024	$12.26
23756	Replace Yankeetown 69/12 kV Transformer	Replace existing 69/12 kV distribution transformer T1 due to age and condition.	12/31/2024	$1.1

4.2.17 Southern Illinois Power Cooperative (SIPC)

Southern Illinois Power Cooperative did not submit any new projects for MTEP23. MISO has not identified any issues in the SIPC area.

4.2.18 Wabash Valley Power Association, Inc. (WVPA)

After MISO's independent reliability analysis, MISO and Wabash Valley Power Association, Inc. recommend six Other Projects at an estimated cost of $57.1 million to be approved for inclusion in MTEP23 Appendix A. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
21927	New Kinsey 69/12 kV Substation	Construct New Kinsey 69/12 kV Substation (5/7 MVA). (Within AmerenMO location by TO).	2/6/2025	$1.2
21928	New Valley View-Salem Bulk 69 kV line	Construct New Valley View-Salem Bulk 69 kV line. Construct 69 kV from Salem Bulk 69 kV Substation to Kinsey substation. Construct with 477 kcml ACSR, 21 miles total. (Within AmerenMO location by TO).	2/6/2025	$44.52
23715	New Charmin Bulk 161 kV Sub. Breakers	Add breakers to Charmin Bulk to have two separate 161 kV feeds from Trail of Tears.	2/28/2024	$4.49
23780	Relocate T23 69 kV for Ameren Wittenberg-Whipple Line	Relocate T23 69 kV to allow for Ameren's new 138 kV Line (Wittenberg - Whipple).	12/31/2023	$4.59

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23714	Rebuild Citizens 69 kV Line (Groups C & E)	Rebuild 69 kV line group on CEC 69 kV System - Phase 2.	12/31/2024	$0.68
23779	Rebuild Citizens 69 kV Line (Groups A & B)	Rebuild 69 kV line group on CEC 69 kV System - Phase 1.	12/31/2023	$1.6

4.3 Project Justifications – East Region

East Region Overview

The MISO East Planning Region consists of six Transmission-Owning members within Michigan. These Transmission Owners are:

ITC Transmission (ITCT)

Michigan Electric Transmission Co. (METC)

Wolverine Power Supply Cooperative Inc. (WPSC)

Michigan Public Power Agency (MPPA)

Michigan South Central Power Agency (MSCPA)

Lansing Board of Water & Light (LBWL)

The region contains 9,830 circuit miles of transmission lines ranging from 120 kV to 345 kV. It also contains 1216 circuit miles of 69 kV sub-transmission system. The MISO East Region is interconnected with non-MISO systems: Hydro One Networks Inc. and American Electric Power to the east.

The 2023 Summer Peak planning model indicates the region contains more than 30.3 GW of generation. Installed generation capacity in the region consists mostly of coal, gas, and wind. Figure 4.3-1 shows the major load centers and generation pockets within the East Region. The load centers are typically found around larger cities in the region, i.e., Detroit, Lansing, and Grand Rapids. According to the 2023 Summer Peak planning model, the region's load exceeds 20.56 GW.

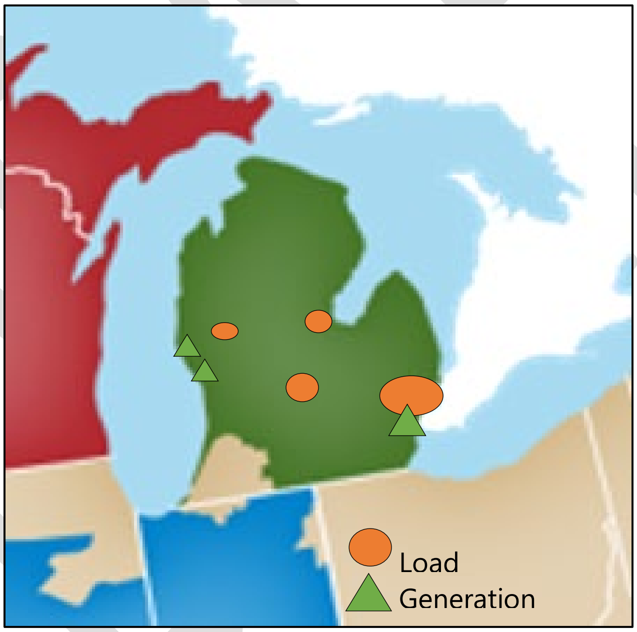


Figure 4.3-1: Generation and load centers in the East planning region

For MTEP23, MISO Transmission Planning is recommending 97 projects from the East region for inclusion in Appendix A at an estimated cost of $739 million. Of these, nine are Baseline Reliability Projects, 47 are Generator Interconnection Projects, and the remaining 41 projects are classified as Other Projects. MISO considered alternatives for one project in the East region, the Elephant Load Interconnect. The partial alternative was determined to be more cost-effective when incorporated into the original project. The combined project is detailed below.

Of the 97 projects, that are being recommended to be included in MTEP23, 30 have an estimated cost of less than $1 million, 23 have an estimated cost between $1 million and $5 million, and the remaining 44 projects are estimated to cost greater than $5 million (shown in Figure 4.3-2).

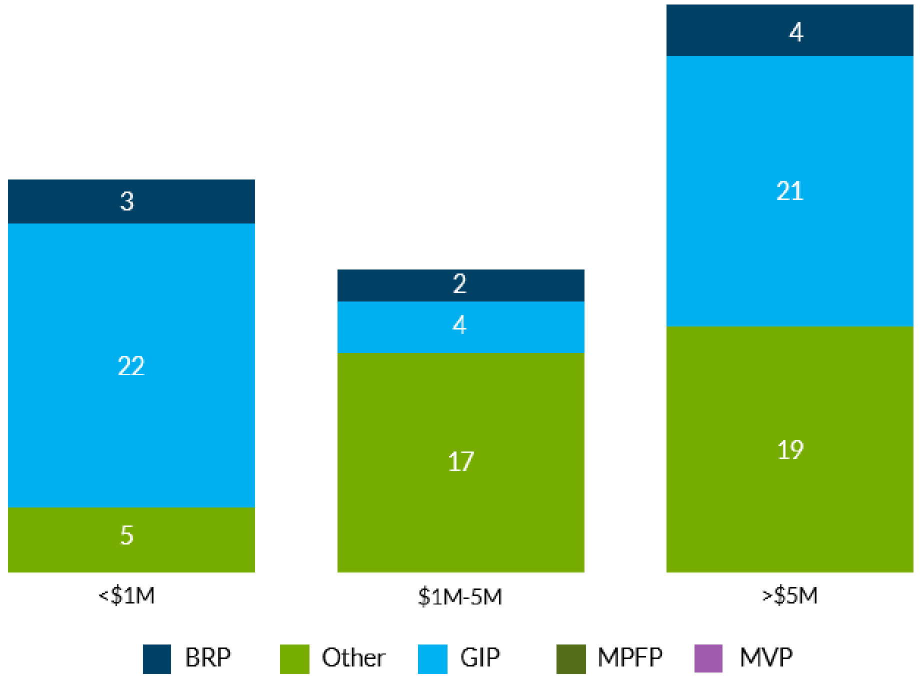


Figure 4.3-2: Project counts by cost category of MISO East region MTEP23 projects (data as of 9-29-2023)

The majority of projects in the MISO East planning region are expected to go into service in the next five years as shown in Figure 4.3-3. There are four GIP projects and two Other projects that are being approved in MTEP23 with an in-service date in 2023. Some projects and in-service dates are still being determined.

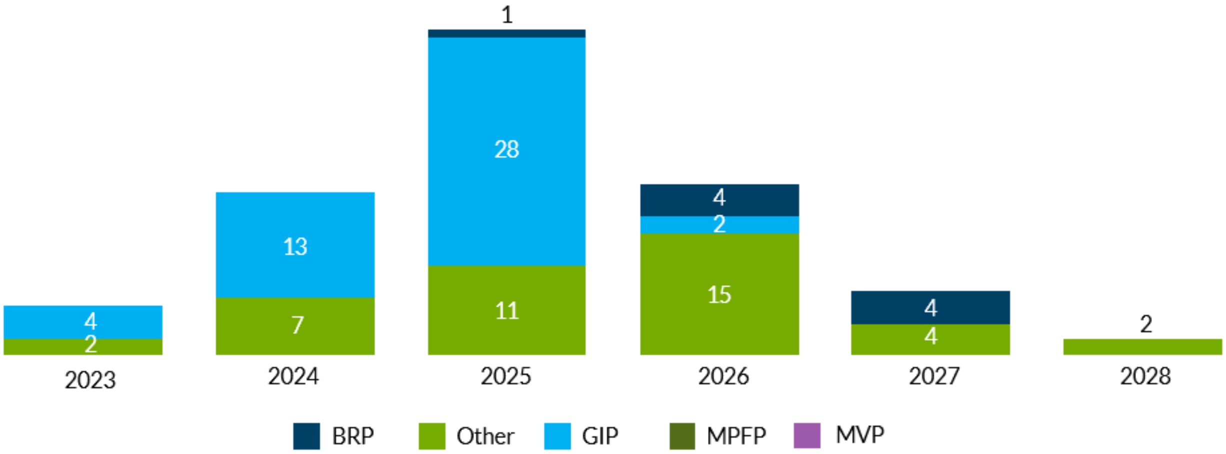


Figure 4.3-3: East region MTEP23 projects by in-service date (data as of 9-29-2023)

In accordance with Attachment FF of the MISO tariff, if a Transmission Owner determines system conditions warrant the urgent development of system enhancements, MISO will perform an expedited review of the impacts of the project. MISO shall use a streamlined approval process for reviewing and approving such projects proposed by the Transmission Owner(s) so that decisions will be provided to the Transmission Owner within 30 Days of the project's submittal to MISO, unless a longer review period is mutually agreed upon. During the MTEP23 cycle, generally driven by load growth and construction relocations, MISO received the following projects through the Expedited Project Review (EPR) process:

1. Project 24673, Project Hickory Load connection
2. Project 25038, Murphy-Orr Road #3 138 kV
3. Project 24115, Mack – Northeast UG Cable Relocation Project
4. Project 24393, I 375 UG Cable Relocation Project
5. Project 24466, MDOT I-96 Construction – Cody – Nolan Structure Relocation
6. Project 24593, GM Orion Plant Expansion
7. Project 23865, METC Elephant – Phase 1

Also, in accordance with Attachment FF Section VIII.A.3, none of the projects were identified as an Immediate Need Reliability Project and excluded from the competitive developer selection process. The ten largest project investments in the MISO East region represent $347million (47%) of the $739 million total recommended projects for the East region in MTEP23, or 4% of the $9 billion total recommended in the MISO footprint. The locations of these projects are shown in Figure 4.3-4 with the investment spread across the East Planning region. Projects that are blanket expenditures (such as relays, physical security, etc.) are excluded from this list.

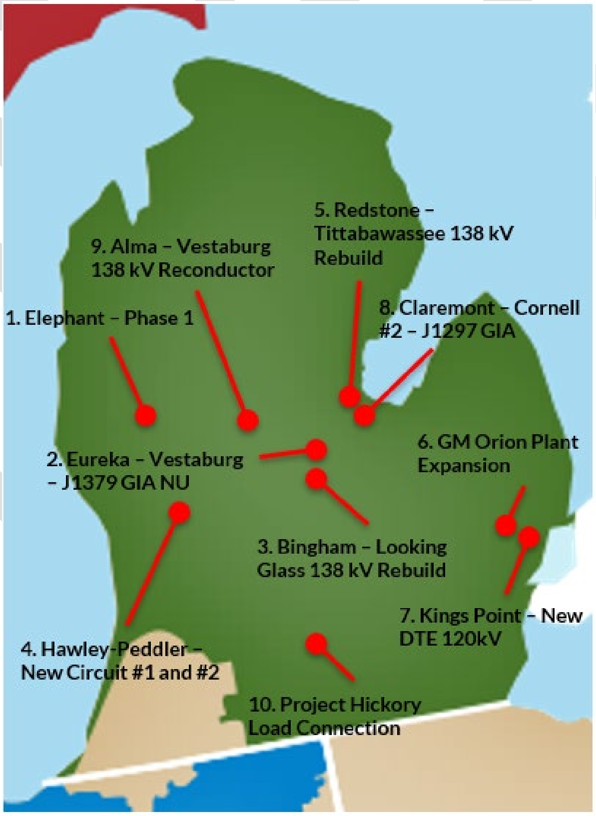


Figure 4.3-4: East region top ten projects, by cost (data as of 9-29-2023)

4.3.1 ITC Transmission (ITCT)

After MISO's independent reliability analysis, MISO and ITC Transmission recommend 27 projects at an estimated cost of $179 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, three are Baseline Reliability Projects, 14 are Other Projects, and 10 are Generator Interconnection Projects with signed Generator Interconnection Agreements. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Baseline Reliability Projects

ITCT 21725 - Horn - Trenton Channel 120 kV Sag Remediation

Project Description: Fully remediate the sag on the Horn – Trenton Channel 120 kV circuit up to the conductor limit. Upgrade station equipment at Trenton Channel position HG. The total estimated cost of this project is $0.32 million and has an expected in-service date of December 31, 2026.

Project Need: The Horn – Trenton Channel 120 kV circuit is projected to be overloaded for P6 contingency during peak and off-peak load conditions. The identified overloaded equipment on this circuit is the sag limit and station equipment at Trenton Channel.

Alternatives Considered: No alternatives were considered.

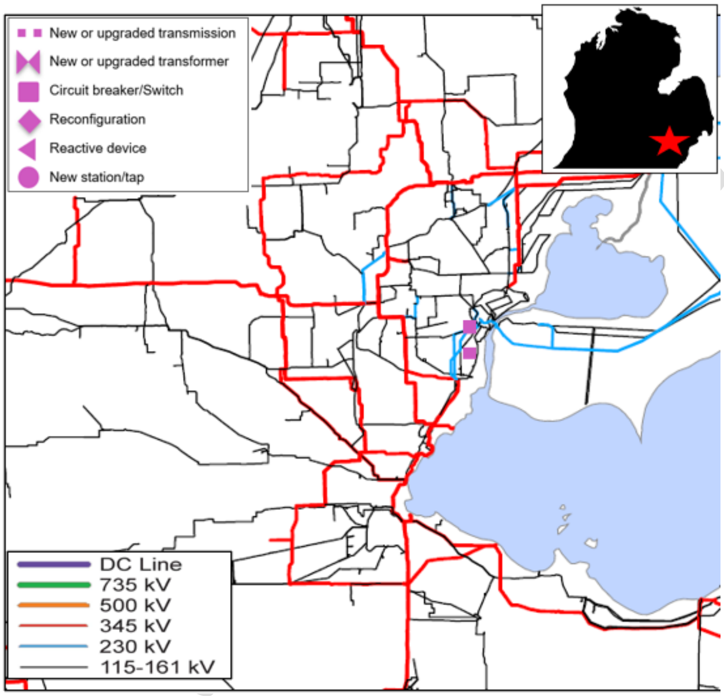


Figure 4.3.1-1: P21725 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	[ITCT] Horn – [ITCT] Trenton Channel 120 kV Ckt 1	283	98	<90

Table 4.3.1-1: P21725 Thermal loading drivers

Project 23828 – Hurst 120 kV 33.3 MVAR Capacitor

Project Description: Install a 33.3 MVAR capacitor at bus 102, position HJ, with a new 120 kV, 40 kA synchronous breaker and associated disconnect switch. Install a 3000 A, 40 kA breaker at position HK on the Hurst – Genoa 120 kV circuit. The total estimated cost of this project is $3.1 million and has an expected in-service date of June 1, 2025.

Project Need: This project is the alternative to the project P#15887 Durant 120 kV 33.3 MVAR Capacitor. The Durant buses are projected to experience low voltages for a shutdown-plus-contingency that takes out Genoa – Madrid 120 kV and Durant – Placid 120 kV lines.

Alternatives Considered: No alternatives were considered.

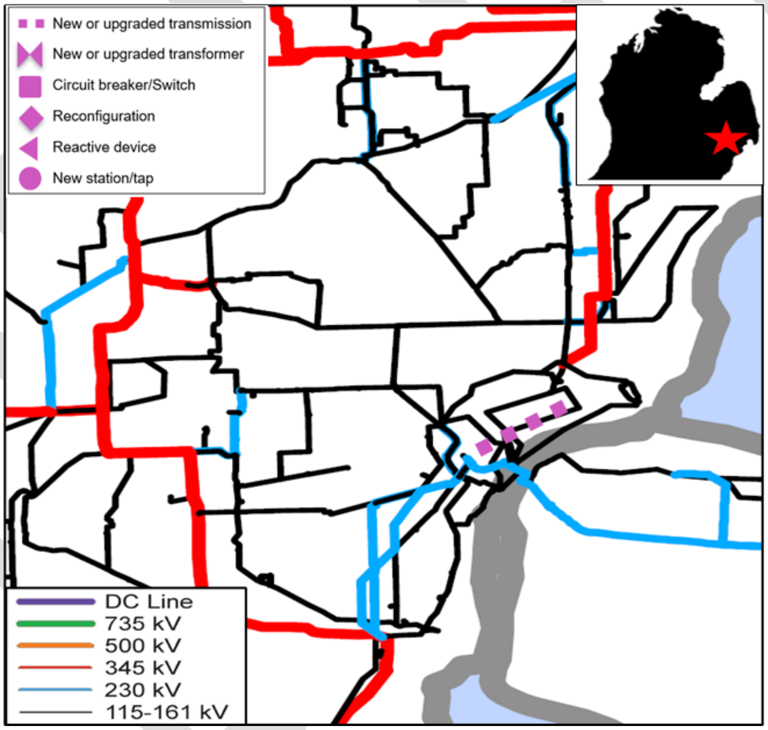


Figure 4.3.1-2: P21745 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (p.u.)	Pre-Project Loading (p.u.)	Post-Project Loading (p.u.)
P6	[ITCT] 19DURANT1 120.0	0.92	0.9089	0.9468

Cont. Type	Limiting Element	Rating (p.u.)	Pre-Project Loading (p.u.)	Post-Project Loading (p.u.)
P6	[ITCT] 19DURANT2 120.0	0.92	0.9089	0.9468

Table 4.3.1-2: P23828 Voltage loading drivers

Project 23697 – Beck – Stephens 120 kV Sag Remediation

Project Description: Remediate the sag limit on the Beck - Stephens 120 kV circuit up to a minimum summer emergency rating of 242 MVA. The total estimated cost of this project is $0.54 million and has an expected in-service date of December 31, 2026.

Project Need: The Beck - Stephens 120 kV circuit is expected to marginally overload for a P24 contingency.

Alternatives Considered: No alternatives were considered.

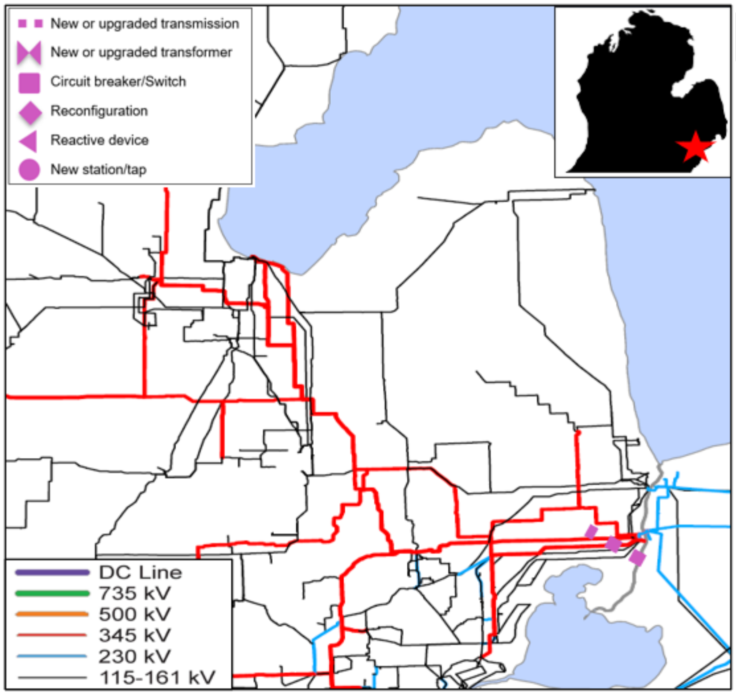


Figure 4.3.1-3: P23697 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P24	[ITCT] 19BECK1 120.00 – [ITCT] 19STEPH3 120.00 ckt 1	230	100.3	<90

Table 4.3.1-3: P23697 Thermal loading drivers

Other Projects

Projects Driven by Local Needs

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
15872	Brownstown-Monroe #2 345 kV Sag Remediation	Remediate the sag on the Brownstown - Monroe #2 345 kV line to at least 1400 MVA and upgrade switches at Monroe "FT" and "FM" positions.	12/31/2026	$2.58
23880	2023 ITCT Line Relocation Blanket	Relocation portions of transmission lines located in public right of way at the government entities mandate.	12/31/2023	$2.4
24115	Mack - Northeast 120 kV UG Cable Relocation	Relocation and replacement of 1230 ft. of 1500kcmil CU cable with 2100 ft. of 2500kmil CU cable of the Mack-Northeast 120 kV circuit to accommodate future interstate infrastructure improvements directed by the Michigan Department of Transportation (MDOT).	6/03/2024	$5.54
24393	MDOT I-375 Construction - Underground Cable Relocation	Relocate a portion of the Alfred-St. Antoine and Esset-St. Antoine 120 kV underground cables currently located in the Larned I-375 bridge to accommodate the reconstruction of I-375 in downtown Detroit as directed by the Michigan Department of Transportation (MDOT).	12/31/2024	$8.2
24466	MDOT I-96 Construction - Cody - Nolan Structure Relocation	Relocate five structures on the Cody – Nolan 120 kV line that are in conflict with the reconstruction and rehabilitation project along US-23 at the I-96/Grand River intersection.	8/01/2024	$1.25

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
22014	ITCT Pole Top Switch Additions/Replacement Program 2024	Installing pole-top switches, or replacing them as appropriate, at tap points of circuits will provide the operational flexibility to sectionalize parts of the line to isolate faults or perform maintenance work on it without having to shut down the entire circuit. This significantly reduces service interruptions to the customers	12/31/2024	$2.4

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		during planned maintenance work or restoration from the aftermath extreme weather events.		
23976	ITCT Pole Top Switch Additions/Replacement Program 2025	Install or replace an existing pole top switch with a new 138 kV, 1-way full-load-break pole top switch at tap points.	12/31/2025	$2.4
24072	Resource Equipment Removal and Bypass	Remove ITC assets at Resource substation. Bypass Resource substation to form a direct Alfred to Frisbie 120 kV circuit.	12/31/2026	$3.5

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23853	Wayne Transformer 301 Replacement	Replace 345/120kV transformer 301 at Wayne station with a new transformer rated at least 750 MVA for summer emergency.	12/31/2026	$5.6
23884	2025 ITCT Transmission Asset Replacement Program	Replace aging and outdated equipment on a cycle that will ensure each piece of equipment is replaced near its expected end of life. Modern equipment can improve reliability, use state of the art technology, and typically will allow for longer maintenance intervals. New equipment is also commonly equipped with better monitoring and alarming functionality giving improved remote supervision. All of this will help to reduce overall maintenance costs.	12/31/2025	$44
23894	Jewell 301 Transformer Replacement	Replace the 345/230 kV transformer #301 at Jewell with a new, standard transformer of similar size.	12/31/2026	$6.6

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
22847	Kings Point – New DTE 120 kV Interconnection	DTE requested a new LDC 120 kV substation interconnection, called Kings Point. ITCT will construct a new 120 kV station and cut the Boyne - Golf 120 kV	3/31/2027	$20

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		line in to accommodate this new interconnection. The configuration for ITCT's 120 kV station will be a straight bus station with one 40 kA section breaker and two 40 kA line breakers. ITCT will relocate a ~ 2.1 miles section of the Boyne-Golf 120 kV circuit by utilizing DTE's existing 40 kV circuit on the North side of 21 Mile Rd, East side of N. Gratiot Ave, and South side of Hall Rd to rebuild this ~2.1 miles to 120 kV with 40 kV underbuilding to loop the Boyne-Golf line into the new 120 kV substation.		
23947	2026 ITCT Customer Interconnections	ITCT will individually evaluate each request to ensure it does not adversely impact reliability. Projects that result in a system solution where the cost estimate is less than $2.5 Million that have an in-service date within the year 2026 will be associated with this project. When Customer Interconnection projects are evaluated to amount in a cost greater than $2.5 Million a separate project will be submitted for approval.	12/31/2025	$2.5
24593	GM Orion Plant Expansion	At Sunbird, expand the existing substation to include 3-120 kV line breakers, 1-120 kV section breaker, and create bus 103. Construct a 2nd Pontiac-Sunbird 120 kV line and install 2-120 kV pole top switches on the Colorado taps on the Pontiac-Sunbird #1 and Sunbird-Bloomfield 120 kV lines. At Pontiac, bypass the existing series reactor and install a line breaker on the new Pontiac-Sunbird #2 line position. Install OPGW between Pontiac and Sunbird.	5/31/2025	$25.8

Generator Interconnection Projects:

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23171	J1319 Generator Interconnection	J1319 generator will utilize the existing POI established for J327 Deerfield Wind Energy at the ITCT Rapson 120 kV substation.	6/01/2023	$0

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23481	S1007 Surplus Generator Interconnection	S1007 Surplus generator will utilize the existing POI established for J202 Starkey Wind Farm at the ITCT Dixon 120 kV substation.	6/01/2023	$0
24280	Greenwood – J1331 GIA NU	Add row P and install two 120 kV breakers rated at 40 kA and four disconnect switches at Greenwood Substation.	2/28/25	$2.88
24299	J1196 Generator Interconnection TOIF	Install required entrance structures and 345 kV disconnect switch at the new Wedge station.	3/3/2025	$0
24313	Greenwood-Rapson (Banner)-J1196 GIA (Wedge) NU	Construct new Wedge 345 kV station. Install three 345 kV breakers rated at 40 kA with associated disconnects and two new bus sections. Cut the ITCT Greenwood – Rapson(Banner) 345 kV circuit into the new Wedge station.	3/3/2025	$12.62
24333	Majestic-Milan – J1224 & J1329 GIA (Neblo) NU	Build a new 345 kV 3 Breaker ring substation cut in from the Majestic-Milan 345 kV line. System changes will require relay upgrades at Majestic 345 kV and Milan 345 kV stations.	12/29/2025	$13.16
24376	Majestic Milan – J1224 & J1329 GIA (Neblo) TOIF	Install a line entrance structure and switch for the generator to connect to position CQ at the Neblo (J1224&J1329) 345 kV station.	12/29/2025	$0
24417	J1350 Generator Interconnection Network Upgrades	Build a new 345 kV 3 Breaker ring substation and cut in the Milan – Lulu 345 kV 345 kV line. System changes will require relay upgrades at Milan 345 kV station.	5/16/2025	13.38
24418	J1350 Generator Interconnection TOIF	Install a line entrance structure and a switch shunt for the generator to connect at position CI.	5/16/2025	$0
24441	J1331 Generator Interconnection TOIF	Install required entrance structures and 120 kV disconnect switch at Greenwood Substation.	2/28/2025	$0

4.3.2 Michigan Electric Transmission Co. (METC)

After MISO's independent reliability analysis, MISO and METC recommend 54 projects at an estimated cost of $506 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, six are Baseline Reliability Projects, 11 are Other Projects, and 37 are Generator Interconnection Projects with signed

Generator Interconnection Agreements. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Baseline Reliability Projects

Project 15752 - Redstone – Tittabawassee 138 kV Rebuild

Project Description: Rebuild ~13.4 miles of the ~21.5 mile-long Redstone – Tittabawassee 138 kV line from 336 ACSR to 1431 ACSR using future double-circuit construction with OPGW. The total estimated cost of this project is $22 million and has an expected in-service date of June 1, 2027.

Project Need: The Redstone - Tittabawassee 138 kV line was shown as overloaded in MISO's MTEP23 Generator Deliverability study. METC's 2022 internal assessment also identified this overload for various contingencies, including N-1.

Alternatives Considered: No alternatives were considered.

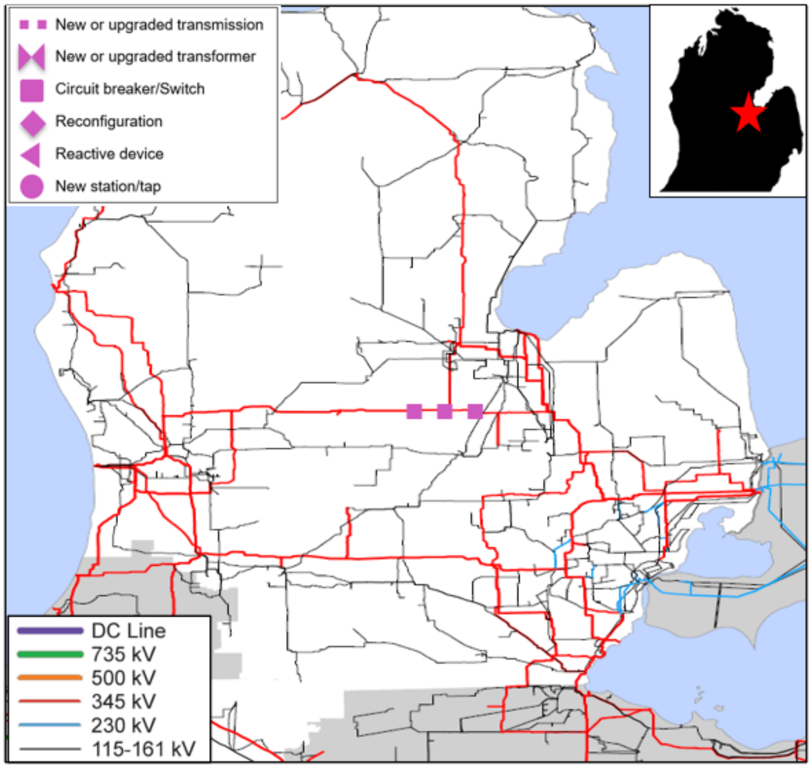


Figure 4.3.2-1: P15752 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P1	[METC] 18TITBAW 138 [METC] 18REDSTONE 138 1	372	154	TBD
P6	[METC] 18TITBAW 138 [METC] 18REDSTONE 138 1	372	128	TBD

Table 4.3.2-1: P15752 Thermal loading drivers

Project 23704 – Abbe Jct – Mio 138 kV Sag Remediation

Project Description: Remediate sag on the 266.8 ACSR to meet or exceed 106 MVA (445 A) on the Abbe Jct. – Mio Dam section of the Airport – Mio Dam 138 kV circuit. The total estimated cost of this project is $1.7 million and has an expected in-service date of December 31, 2026.

Project Need: Abble to Mio Dam 138 kV line is projected to be overloaded for category P6 contingencies in off peak and pumping condition.

Alternatives Considered: No alternatives were considered.

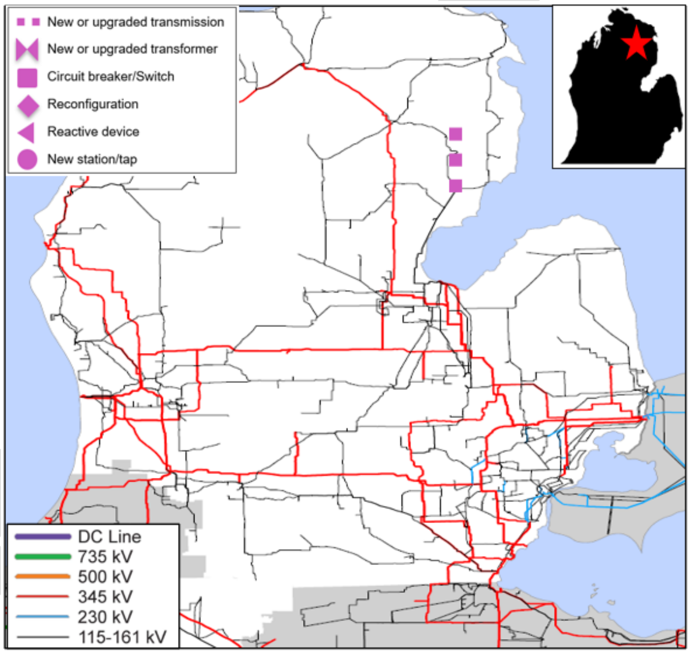


Figure 4.3.2-2: P23704 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P1	[METC] 18ABBEJ 138 [METC] 18MIO 138 1	122	110	TBD
P6	[METC] 18ABBEJ 138 [METC] 18MIO 138 1	122	104	TBD

Table 4.3.2-2: P23704 Thermal loading drivers

Project 23709 – Campbell – Blendon 138kV Loop Into Tyler

Project Description: Loop the Campbell - Blendon 138 kV line into Tyler to create Campbell - Tyler and Tyler - Blendon 138 kV lines. Install (3) new breakers at Tyler and OPGW from Port Sheldon to Campbell. The total estimated cost of this project is $6.9 million and has an expected in-service date of June 1, 2027.

Project Need: The Campbell - Tyler 138 kV #1 line is project to overload for the P6 contingencies during peak and off-peak condition.

Alternatives Considered: No alternatives were considered.

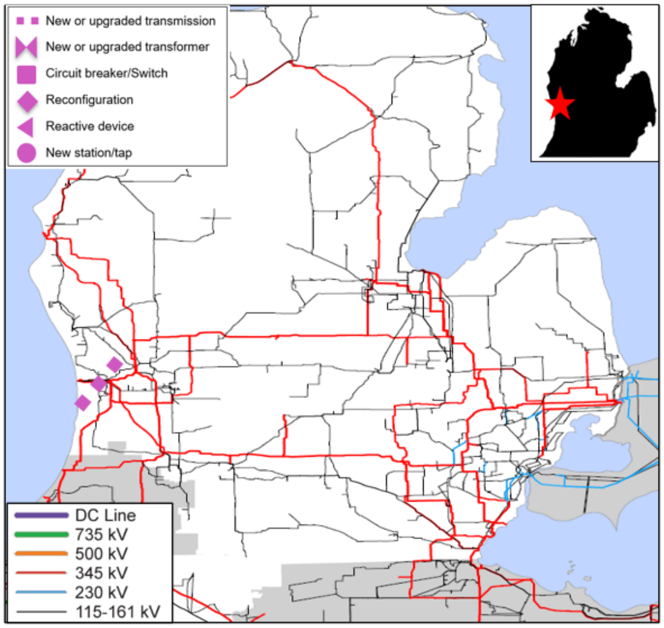


Figure 4.3.2-1: P23709 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	[METC] 18CAMPBELLW 138 [METC] 18TYPLER 138 1	337	112	TBD

Table 4.3.2-1: P23709 Thermal loading drivers

Project 23743 – Deja Junction – Vestaburg 138 kV Rebuild

Project Description: Rebuild 4.3 miles section between Deja Jct. and Vestaburg of the Eureka - Vestaburg 138 kV line. The total estimated cost of this project is $8.8 million and has an expected in-service date of June 1, 2027.

Project Need: The Deja Jct. - Vestaburg section of the Eureka - Vestaburg 138 kV circuit are projected to overload for various contingencies. The identified overloaded equipment on this circuit is the conductor. The thermal violation is only found on off peak pumping condition.

Alternatives Considered: No alternatives were considered.

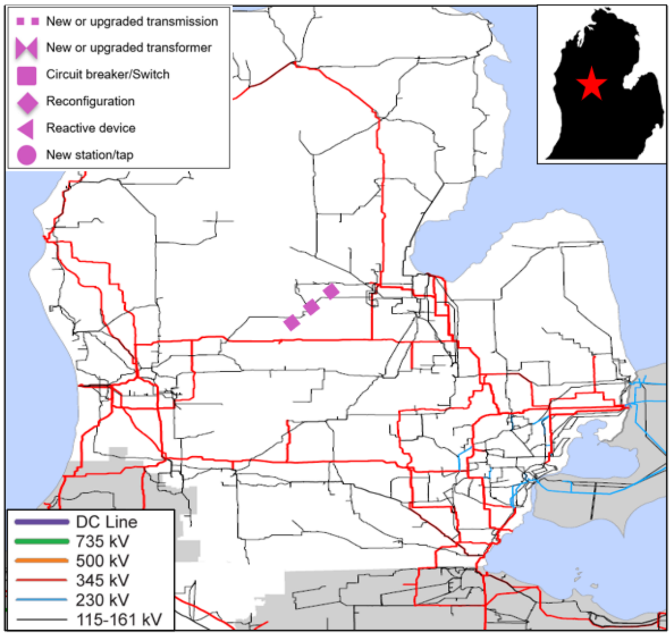


Figure 4.3.2-2: P23743 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
N1	[METC] 18DEJAJ 138 [METC] 18VESTABURG 138 1	288	331	TBD
P6	[METC] 18DEJAJ 138 [METC] 18VESTABURG 138 1	288	345	TBD

Project 23807 – Alma – Vestaburg 138 kV Reconductor

Project Description: Reconductor from Vestaburg to structure #2W8472 (~16.24 miles) from 954 ACSR to 954 ACSS. Also, upgrade 1590 SAC buses and 1200A switches at Alma position “477” to at least 455 MVA for summer emergency rating. The total estimated cost of this project is $16.7 million and has an expected in-service date of June 1, 2027.

Project Need: The Alma-Vestaburg 138 kV circuit is projected to overload for various contingencies, including N-1 in METC's 2022 internal assessment.

Alternatives Considered: No alternatives were considered.

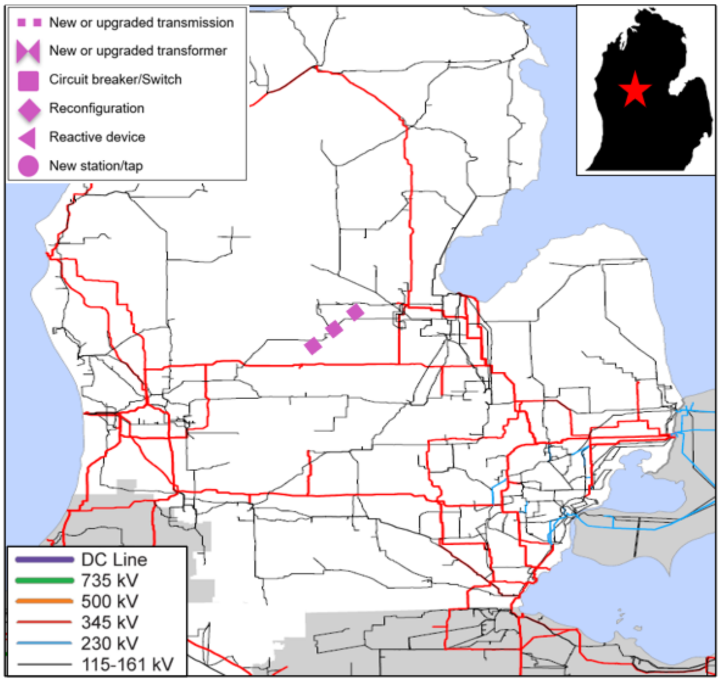


Figure 4.3.2-1: P23807 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
N1	[METC] 18ALMA 138 [METC] 18VESTABURG 138 1	445	104	TBD
P6	[METC] 18ALMA 138 [METC] 18VESTABURG 138 1	445	100	TBD

Table 4.3.2-1: P23807 Thermal loading drivers

Project 23830 – MCV 138 kV Station Equipment Upgrade

Project Description: Upgrade thermal relay at position "3141" to at least 620 MVA. The total estimated cost of this project is $0.19 million and has an expected in-service date of December 31, 2026.

Project Need: The bus-tie section at MCV position "3141" is projected to overload in METC's internal assessment under P21 contingencies.

Alternatives Considered: No alternatives were considered.

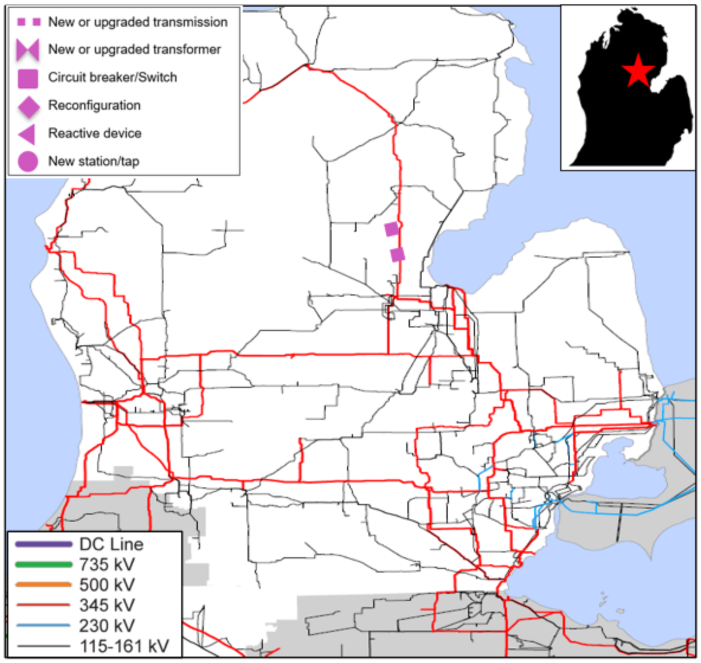


Figure 4.3.2-2: P23830 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
N1	[METC] 18MCV41 138 [METC] 18DOW1 138 1	57	140	TBD

Table 4.3.2-2: P23830 Thermal loading drivers

Other Projects

Projects Driven by Other Local Needs

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23885	2026 METC Customer Interconnections	METC will individually evaluate each request to ensure it does not adversely impact reliability. Projects that result in a system solution where the cost estimate is less than $2.5 Million that have an in-service date within the year 2026 will be associated with this project. When Customer Interconnection projects are evaluated to amount in a cost greater than $2.5 Million a separate project will be submitted for approval.	12/30/2026	$2.5
23950	2023 METC Line Relocation Blanket	Relocation of portions of transmission lines located in public right of way at the government entity's mandate.	12/31/2023	$2.4

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23865	Elephant - Phase 1 (with WPSC Alternative Project 24414)	CE has requested a new 103 MW (expanding to 206 MW) Industrial interconnection near METC's Mecosta substation. To accommodate this request, METC would install a new, 3-row, 138 kV substation near the customer site, and loop the existing Chase-Mecosta 138 kV line approx. 1.5 miles into the new substation. A 138 kV, 54 MVAR cap bank would be installed at the new substation. METC would also rebuild the entire Chase-Mecosta 138 kV circuit (approx. 17.6 miles), and rebuild a 7.8 mile segment of the Croton-Mecosta 138 kV line. WPSC selected Alternative Project discussed in section 4.3.4	3/1/2025	$56
24673	Project Hickory Load connection (EPR)	METC will construct the new 138 kV, 3-row, breaker and a half Charge substation to be fed by looping the existing Highfield-Brooks Industrial 138 kV line approximately 0.2 miles into the new substation.	5/31/2024	$16.6

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23872	Kraft 138 kV Station Equipment Upgrade	Upgrade existing 500 circuit switcher, two line switches with new breakers at Kraft 138 kV station and remove N.O. 3317 PTS.	12/31/2026	$6

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23829	Tompkins 345/138 kV Transformer #1 Replacement	Replace the 345/138 kV transformer #1 at Tompkins with a new, standard transformer of similar size.	12/31/2026	$5.23
23835	Pere Marquette Transformer 2 Replacement	Replace 345/138 kV transformer 2 at Pere Marquette with a new, standard transformer of similar size. Install a 345 kV breaker and associated switch on the high side of the transformer.	12/31/2026	$8.5

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		Also, install a 138 kV switch on the low side of the transformer.		
23847	Bingham – Looking Glass 138 kV Rebuild	Rebuild approximately 19.3 miles of the Bingham – Looking Glass 138 kV circuit to 1431 ACSR conductor utilizing 138 kV double- circuit structures with OPGW. Leave the East side of the double-circuit structures vacant. Connect OPGW at Bingham 138 kV position WM6.	12/31/2026	$35.4
23948	2025 METC Asset Replacement Program	Replace aging and outdated equipment on a cycle that will ensure each piece of equipment is replaced near its expected end of life. Modern equipment can improve reliability, use state of the art technology, and typically will allow for longer maintenance intervals. New equipment is also commonly equipped with better monitoring and alarming functionality giving improved remote supervision. All of this will help to reduce overall maintenance costs.	12/31/2025	$41.8
23949	METC Pole Top Switch Additions/Replacement Program 2025	Install or replace an existing pole top switch with a new 138 kV, 1-way full-load-break pole top switch at tap points.	12/31/2025	$2.4

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
25038	Murphy - Orr Road #3 138 kV Line (EPR)	Construct a 3rd 138 kV circuit from Murphy to Orr Rd utilizing 954 ACSR on the open side of the existing structures currently carrying the Orr Rd-Murphy #2 138 kV circuit. This scope will potentially add some structures at Murphy and Orr Road station ends to terminate the new 138 kV line. Install OPGW on the new circuit and terminate it at both ends. Install a new breaker at Murphy Pos. 4B7, and install a new breaker at Orr Road Pos. 6B7.	3/31/2025	$7.6

Generator Interconnection Projects:

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
22147	Blackstone-Stable-J1310 Generator Interconnection	Build a new 138 kV 3 Breaker ring substation cut in from the Blackstone – Stable 138 kV line. System changes will require relay upgrades at Stable 138 kV and Blackstone 138 kV stations.	10/1/2024	$14.65
22165	Brooks Industrial Mud Lake – J1430 Interconnection – NU	Build J1430 interconnection station as a breaker and half station with three breakers in a ring bus configuration. Brooks Industrial – Mud Lake 138 kV line will be extended to loop in the J1430 Interconnection 138 kV station. Relay upgrades will be required at Mud Lake, Stable, Marshall, and Brooks Industrial 138 kV stations.	8/1/2023	$8.61
23329	R1009 Replacement Generator Interconnection	R1009 generator will replace existing Hillman generating unit and utilize the existing POI established for Hillman Cogeneration connected at the METC Airport-Mio Dam 138 kV line (Progress Street Tap).	12/31/2023	
23785	J1550 Generator Interconnection	Install a new 138 kV switching station. Install five 138 kV breakers rated at 40 kA and two bus sections. Cut the METC Batavia – Barton Lake and Batavia – J1320 (Coldwater) 138 kV circuits into the new 138 kV switching station.	3/3/2025	$15.67
24275	Morocco – J1226 GIA NU	Install two 345 kV breakers rated at 40 kA and associated disconnect switches to complete row 36 in Morocco Substation. Install one 345 kV breaker rated at 40 kA and associated disconnect switch to complete row 34 in Morocco Substation.	06/6/2024	$4.26
24276	Vergennes – Marquette – J1255 GIA (Hawley) NU	J1255 is a 200 MW solar project connecting in Keene Township on the Vergennes – Marquette 138 kV. Build the J1255 Interconnection 138 kV station as a breaker and half station with three 40 kA breakers in a ring bus configuration. Extend the Marquette-Vergennes 138 kV line to loop in the station. Connect the generators at position WM12 as TOIF. Generators are part of the DPP 2019 Cycle 1.	12/31/2025	$6.94

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24277	Gaines – Thompson Road 138 kV – J1292 GIA (Peddler) NU	Build a new 138 kV 3 breaker ring substation cut in from the Gaines – Thompson Road 138 kV line	12/31/2025	$6.93
24279	Claremont – Cornell #2 – J1297 GIA (Hathon) NU	J1297 is a 170 MW solar project interconnecting in Venice Township, Shiawassee, MI. METC will need to build a new 138 kV breaker and half station with three 40 kA breakers. METC will need to extend the Claremont – Cornell #2 138 kV line 0.1 miles to loop in the J1297 Interconnection station for transmission service. Loop in the Cornell – Goss 138 kV line to mitigate anti-islanding at Bell Road. J1297 is queued within the DPP 2019 Cycle 1.	1/28/2026	$18.11
24282	Leoni – Parr Road – J1472 GIA (Vargo) NU	J1472 is a generator interconnection request for a 100 MW Solar Power Plant proposing to connect to the METC Leoni – Parr Road 138 kV Line. J1472 is queued within the DPP 2019 Cycle 1.	11/29/2024	$7.13
24294	Mio Dam – Twining – J1210 GIA (Quarry) – NU	Construct new Quarry 138 kV station. Install five 138 kV breakers rated at 40 kA, associated disconnects, and two new bus sections. Loop in the Mio Dam – Twinning circuit to the new Quarry station. Loop in the Iosco – Karn circuit to the new Quarry station. Remove Twinning 177 sparing and install approximately 4.3 miles of fiber on the Quarry – Twinning circuit.	3/31/2025	$11.05
24295	Marshall – Blackstone (Stable) – J1248 GIA (Bearcat) NU	J1248 is a 100.9 MW solar farm connecting on the Marshal – Stable 139kV line in Calhoun County, MI. Construct J1248 as a breaker and half station with three 40kA breakers in a ring bus configuration. Construct BM14 as a TOIF to connect J1248. Generator is part of the DPP 2019 Cycle 1.	11/30/2025	$9.71
24300	J1320 Generator Interconnection TOIF	Install required line entrance structures and 138 kV disconnect at new Byers switching station.	12/10/2025	
24301	Leoni – Parr Road – J1472 GIA (Vargo) TOIF	Install a line entrance structure and a switch for the generator to connect at position WM13.	11/29/2024	

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24314	Thetford-J1203 GIA NU	Install three 345 kV breakers rated at 40 kA and associated disconnect switches and complete row 29 in the METC Thetford Substation.	5/5/2025	$4.25
24317	DuPont – Cobb – J1375 GIA (Lamos) NU	Construct the new Lamos 138 kV station. Extend the White Lake – DuPont – Cobb 138 kV line to loop in the new Lamos 138 kV station. Install three 138 kV breakers rated at 40 kA and two new bus sections at the new Lamos station. Loop the White Lake – Du Pont – Cobb 138 kV line into the White Lake 138 kV station. Install approximately 3.1 miles of fiber from White Lake to Lamos Switching Station. Implement anti-islanding protection for identified islanding scenarios. Replace an existing bus at White Lake Substation. Install new bus and 500 tie-breaker with associated disconnects at White Lake Substation. Install 677 and 777 breakers with associated disconnects at White Lake Substation. Cut White Lake – Cobb circuit and reconnect to the new bus at White Lake.	5/12/2025	$15
24318	Eureka Vestaburg – J1379 GIA NU	Install a new 138 kV switching station. Install four 138 kV breakers rated at 40 kA and two bus sections. Cut the METC Eureka – Vestaburg 138 kV circuit into the new 138 kV switching station. Rebuild the METC Eureka – Vestaburg 138 kV line from Deja to Eureka. Rebuild the METC Eureka – North Belding 138 kV line. Add a new 138 kV line from the new switching station to North Belding.	5/31/2024	$50.09
24319	Delhi-Thompkins #2 J1399 (Edgar) NU	J1399 Interconnection is a 90 MW solar project in Lesli Township, MI. Build the J1399 Interconnection station as a breaker and half station with three 40 kA breakers in a ring bus configuration. Extend the Delhi – Tompkins 138 kV line to loop in the J1399 Interconnection station. J1399 is queued within the DPP2019 Cycle 1.	12/31/2025	$10.01

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24377	Coldwater – Byers Rebuild (J1320) – Network Upgrade	Rebuild entire J1320 – Coldwater 138 kV line with OPGW. Replace existing 336 and 477 ACSR conductor with 954 ACSR.	12/23/2024	$7.3
24395	Luce – Summerton Line Reconductor (J1379) – Network Upgrade	Reconductor the entire ~10.5 mile-long Luce – Summerton 138 kV line with OPGW. Replace the existing 336 ACSR conductor with new 795 ACSS conductor. Replace any structures as necessary.	11/26/2025	$9.68
24396	J1210 Generator Interconnection TOIF	Install required line entrance structures and 138 kV disconnect switch at the new Quarry station.	3/31/2025	
24419	J1320 Generator Interconnection Network Upgrades	Construct new Byers switching station. Install three 138 kV breakers rated at 40 kA and two new bus sections. Loop in the Batavia – Coldwater circuit to the new Byers station. Remove existing X and Z phase wave traps and tuners at Batavia and Coldwater. Install approximately 6 miles of fiber from Byers Switching Station to Batavia and approximately 2 miles of fiber from Byers Switching Station to Coldwater.	12/10/2025	$14.61
24420	Cobb – Peterson Tap Sag Remediation (J1375) – Network Upgrade	Remediate the sag on the 336 ACSR conductor on the Cobb – Peterson Tap 138 kV line section to meet or exceed a rating of 125 MVA Summer Emergency.	12/23/2024	$0.42
24433	Vergennes – Marquette – J1255 GIA (Hawley) TOIF	Install WM14 line position and disconnect at the Hawley station to interconnect J1255 generation.	12/31/2025	
24434	J1203 Generator Interconnection TOIF	Install required entrance structures and 345 kV disconnect switch at METC Thetford Substation.	5/5/2025	
24435	J1226 Generator Interconnection TOIF	Install required entrance structures and 345 kV disconnect switch at Morocco station.	6/6/2024	
24436	J1375 Generator Interconnection TOIF	Install required line entrance structures and 138 kV disconnect at new Lamos station.	5/12/2025	
24437	Delhi-Thompkins #2 J1399 (Edgar) TOIF	Install a line entrance structure and a switch for the generator to connect at position BM14.	12/31/2025	

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24438	J1401 Generator Interconnection Network Upgrades	Install one 138 kV breaker rated at 40 kA and associated disconnects.	4/5/2024	$1.05
24439	J1401 Generator Interconnection TOIF	Install a line entrance and 138 kV disconnect switch at Wagner Station.	4/5/2024	
24448	Murphy-Styx – J1389 Generator Interconnection – Network Upgrades	Build a new 345 kV 3 Breaker ring substation (Palomino) cut in from Murphy – Styx (J984) 345 kV line.	10/31/2025	$12.38
24453	Hawley-Peddler – New Circuit #1 and #2 (J1255, J1292) – Common Use Network Upgrade	Install two breakers at positions 8B7 and 8W8 at J1292, and two breakers at positions at positions 8W8 and 10B7. Install about 15 miles of 954 ACSR DCT in new Right-of-Way to connect J1292 Interconnection Station to J1255 Interconnection Station.	12/31/2025	$27.72
24454	Leoni – Lark 138 kV Sag Remediation (J1310, J1472) – Network Upgrade	Remediate the sag on the 477 ACSR conductor on the Leoni – Washtenaw Tap 138 kV segment to meet or exceed a summer emergency rating of 179 MVA.	4/5/2024	$0.66
24455	Verona – Mud Lake #1 Rebuild (J1248, J1310, J1430) – Network Upgrade	Replace existing 336 ACSR conductor on the Verona – Mud Lake #1 138 kV line with 954 ACSR including one 48 count OPGW ~ 3.6 Miles. Any new 138 kV towers should be expandable to double circuit in the future.	12/23/2024	$8.77
24456	Marshall – Blackstone (Stable) – J1248 GIA (Bearcat) TOIF	Stable – Install a line entrance structure and switch for the generator to connect at position WM14.	11/30/2025	
24459	J1379 Generator Interconnection TOIF	Install an entrance structure and 138 kV disconnect switch at the new switching station.	5/31/2024	
24493	Claremont – Cornell #2 – J1297 GIA (Hathon) TOIF	Install a line entrance structure and a switch from the generator to connect at position BM10.	1/31/2026	
24514	Murphy-Styx – J1389 Generator Interconnection – TOIF	Install a line entrance structure and a switch for the generator to connect at position RH31.	1/29/2024	

4.3.3 Wolverine Power Supply Cooperative Inc. (WPSC)

After MISO's independent reliability analysis, MISO and Wolverine Power Supply Cooperative Inc. recommend 16 Other Projects at an estimated cost of $54 million to be approved for inclusion in MTEP23

Appendix A. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23575	Pellston Relocation and Upgrades	Project will replace capacity limiting equipment and existing protection system at the Pellston substation and relocate the Pellston to Cross Village line to improve reliability on that line.	12/31/2027	$1.6
23613	2025 WPSC Fiber Retrofit	Installation of fiber on recently rebuilt (post 2006) 138 kV structures utilizing ADSS (All Dielectric Self Supporting) and OPGW (Optical Ground Wire).	12/31/2025	$5
23618	Lake County Protection System Upgrade	Upgrade Lake County Protection system with new line relays.	12/31/2024	$0.08

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23574	Pellston to Cross Village	Rebuild and upgrade 9 miles of 69 kV line to 138 kV standard with steel poles, 336ACSS conductor, and OPGW.	12/31/2027	$9.5
23594	Scottville RTU Upgrade	Replace communication equipment at the Scottville substation.	12/31/2025	$0.04
23595	Weidman TRU Upgrade	Replace communication equipment at the Weidman substation.	12/31/2025	$0.04
23612	Altona Protection System Upgrade	Replace the control building to install modern digital relays and install an additional circuit breaker to increase reliability on Altona to Morley transmission line.	12/31/2026	$1.5
23614	Casnovia to Cedar Springs Rebuild	Rebuild and upgrade 11 miles of 69 kV line to 138 kV standard with steel poles, 795ACSS conductor, and OPGW.	12/31/2027	$9.25
23615	Copemish Protection System Upgrade	Replace the circuit breaker and its associated controls and protective relaying, bringing the station to Wolverine's standard for 138 kV transmission operation.	21/31/2026	$1.5

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23616	Gaylord Protection System Upgrade	Upgrade existing electromechanical relays with digital relays.	12/31/2026	$0.8
23617	Hayes Junction to Hayes Rebuild	Rebuild and upgrade 12 miles of 69 kV line to 138 kV standard with steel poles, 336 ACSS conductor, and OPGW.	12/31/2026	$11.85
23619	Mulliken Jct to Grand Ledge Rebuild	Rebuild and upgrade 4 miles of 69 kV line to 138 kV standard with wood poles, 336ACSS conductor, and OPGW.	12/31/2027	$4.25
23620	North Shade Protection System Upgrade	Upgrade existing electromechanical relays with digital relays.	12/31/2026	$1.25
23621	Redwood TRU Upgrade	Replace communication equipment at the Redwood substation.	12/31/2024	$0.15
23631	Petosky Protection System Upgrade	Upgrade existing electromechanical relays with digital relays.	12/31/2026	$1

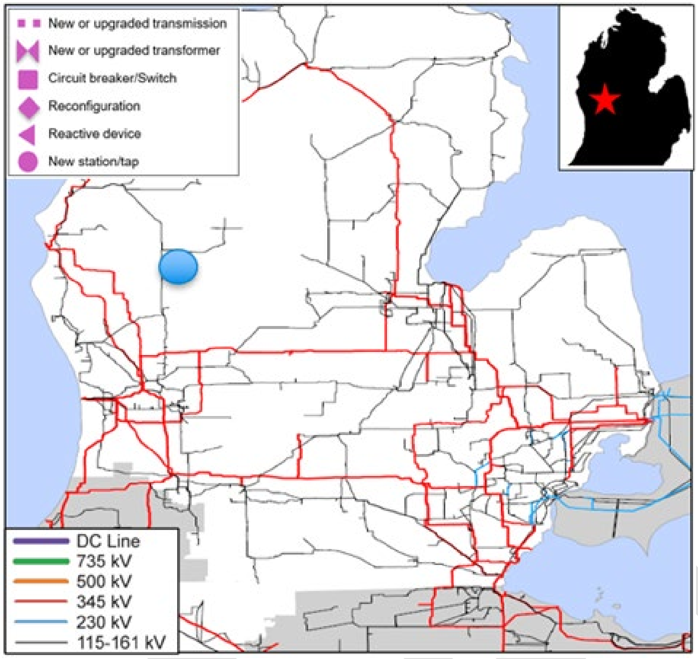
Projects Driven by Local Need

Project 24414- WPSC Elephant Interconnection (Project 23865 Partial Alternative)

Project Description: Consumers Energy Company (CE) has requested a new 103 MW (expanding to 206 MW) Industrial interconnection near METC's Mecosta substation. To accommodate this request, METC would install a new, 3-row, 138 kV substation near the customer site, and loop the existing Chase-Mecosta 138 kV line approx. 1.5 miles into the new substation. A 138 kV, 54 MVAR cap bank would be installed at the new substation. METC would also rebuild the entire Chase-Mecosta 138 kV circuit (approx. 17.6 miles). Wolverine's portion of the project will be to will cut in the Hersey to White Cloud by building four miles of double circuit 138 kV on new ROW. The total estimated cost of this project is $6 million and has an expected in-service date of March 1, 2025.

Project Need: CE requested a new interconnection on METC's Chase-Mecosta 138 kV circuit.

Alternatives Considered: The project is an alternative to the original Project 23865 submitted by METC. Wolverine's Alternative to tie into new Elephant substation eliminates the need to rebuild 7.8 miles of the Croton-Mecosta 138 kV line. The partial alternative was determined to be more cost-effective, reducing the overall cost by $9 million.



Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	CROTON-NINETEEN MILE ROAD J-138kV	288	102	<99

Table 4.3.3-1: P24414 Thermal loading drivers

4.3.4 Michigan Public Power Agency (MPPA)

Michigan Public Power Agency did not submit any new projects for MTEP23. MISO has not identified any open issues in the MPPA area.

4.3.5 Lansing Board of Water and Light (LBWL)

Lansing Board of Water and Light did not submit any new projects for MTEP23. MISO has not identified any open issues in the LBWL area.

4.3.6 Michigan South Central Power Agency (MSCPA)

Michigan South Central Power Agency did not submit any new projects for MTEP23. MISO has not identified any open issues in the MSCPA area.

4.4 Project Justifications – South Region

South Region Overview

The MISO South Planning Region consists of eleven Transmission-Owning members spanning four states, Arkansas, Louisiana, Mississippi, and parts of Texas. These Transmission Owners are:

Arkansas Electric Cooperative Corporation (AECC)
City of Alexandria (AXLA)
CLECO Power LLC (CLEC)
Cooperative Energy (SMEPA)
East Texas Electric Cooperative (ETEC)
Entergy Arkansas LLC (EAL)
Entergy Louisiana LLC (ELL)
Entergy Mississippi LLC (EML)
Entergy New Orleans LLC (ENO)
Entergy Texas Incorporated (ETI)
Lafayette Utilities Systems (LAFA)
City Water and Light Jonesboro (CWLT)

The region contains approximately 16,500 circuit miles of transmission lines ranging from 115 kV to 500 kV. There is also a significant 69 kV sub-transmission network interspersed across the footprint.

In the 2023 Summer Peak planning model, the region contains more than 38.1 GW of generation. The MISO South generation profile consists of mostly combined cycle, nuclear, gas, and coal fuel types, serving major load centers such as Little Rock, New Orleans, etc. Approximately 53% (20.2 GW) of the South region's generation capacity is made up of combined cycle (CC) units. Major generation centers are in central Arkansas, lower Louisiana, and western Mississippi (Figure 4.4-1).

Major load centers are typically found around larger cities in the region such as Little Rock, Jonesboro, and Pine Bluff in Arkansas; Monroe, Alexandria, Lake Charles, Lafayette, New Orleans, and Baton Rouge in Louisiana; Jackson, Hattiesburg, Natchez, Vicksburg, and Greenville in Mississippi. Texas major load centers in the Western load pocket include Bryan and the Woodlands area. The major load center in the WOTAB load pocket portion of Texas is in South Beaumont and the Port Arthur Area (Figure 4.4-1). According to the 2023 Summer Peak planning model, the regional load is over 36.1 GW.

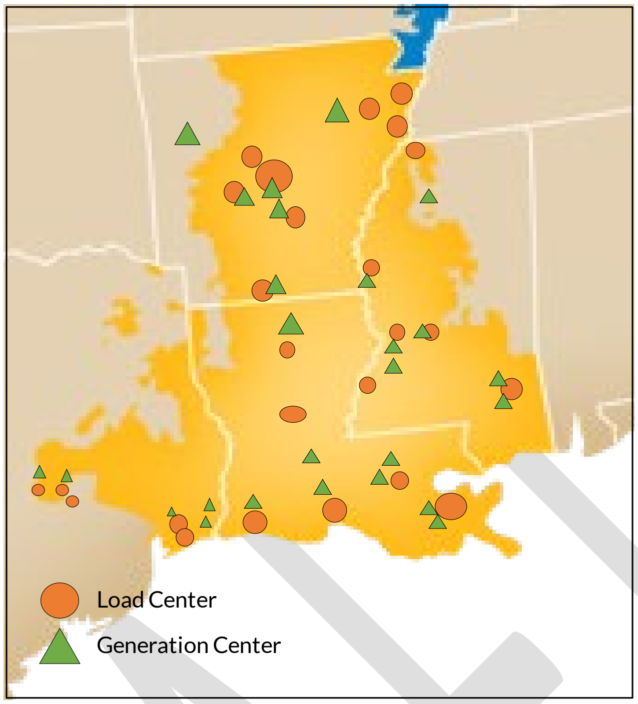


Figure 4.4-1: Generation and load centers in the South planning region

For MTEP23, MISO Transmission Planning is recommending 78 projects from the South region for inclusion in Appendix A at an estimated cost of $4.2 billion. Of these, 15 are Baseline Reliability Projects, 31 are Generator Interconnection Projects, and the remaining 32 projects are classified as Other projects. MISO considered alternatives for multiple projects in the South region. After studying alternatives alongside their corresponding projects, one alternative is selected for the Amite South Phase 1 Alternative project, in place of the Amite South Phase 1, and DSG Reliability & Resiliency projects. All other alternatives were determined to be infeasible, or inferior to the proposed projects. More detail on alternatives studied for each project is available in following sections.

Of the 78 projects, that are being recommended to be included in MTEP23, nine have an estimated cost of less than $1 million, 17 have an estimated cost between $1 million and $5 million, and the remaining 52 projects have an estimated cost greater than $5 million (Figure 4.4-2).

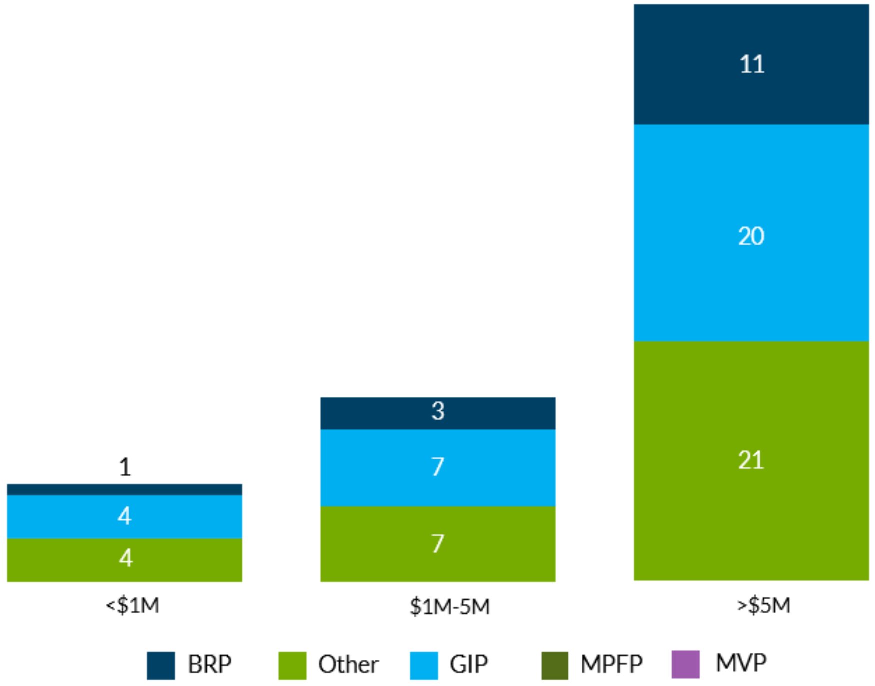


Figure 4.4-2: Project counts by cost category of MISO South region MTEP23 projects (data as of 9-29-2023)

The majority of the projects in the MISO South planning region are expected to go in service in the next three years. (Figure 4.4-3). A few projects and in-service dates are still being determined.

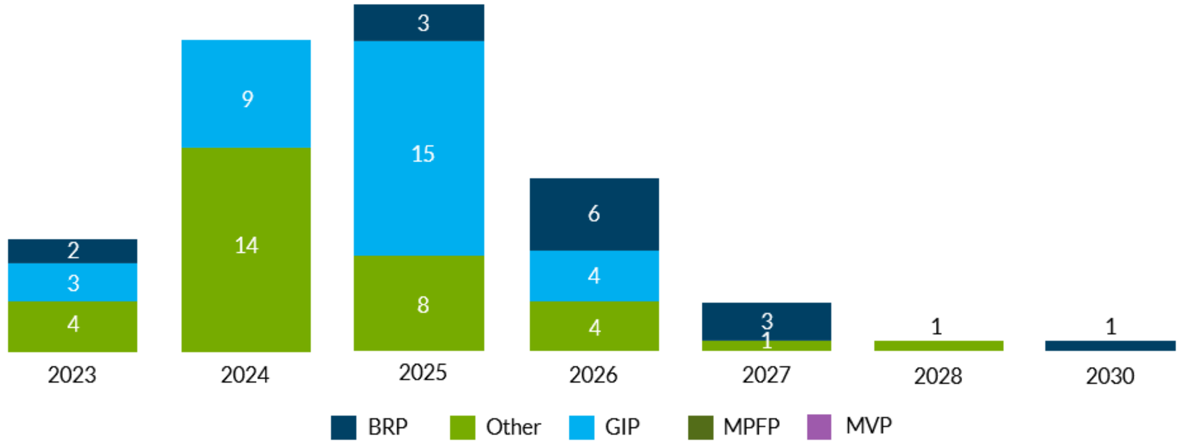


Figure 4.4- 3: South region MTEP23 projects by in-service date (data as of 9-29-2023)

In accordance with Attachment FF of the tariff, in the event a Transmission Owner determines that system conditions warrant the urgent development of system enhancements, an expedited review of the impacts of the project can be requested. MISO shall use a streamlined approval process for reviewing and approving projects proposed by the Transmission Owner(s) and decisions will be provided to the Transmission Owner within 30 Days of the project's submittal to MISO unless a longer review period is mutually agreed upon. During the MTEP23 cycle, MISO received eleven projects in the South planning region through the Expedited Project Review (EPR) process. Nine of these EPRs were needed to meet load growth:

1. Project ID 23348 Grenada Industrial 115 kV: New Station
2. Project ID 23820 Gloster Delivery Point
3. Project ID 24938 Driver - Hybar 230 kV: New transmission line
4. Project ID 24920 Cole Road 138 kV New Customer Station
5. Project ID 24460 Coldspring 138 kV Load Addition
6. Project ID 24415 Ragely Substation
7. Project ID 24192 UIG Load Increase
8. Project ID 24134 Mustang 138 kV New Customer Substation
9. Project ID 24152 Moscow 138 kV Customer Load Addition Project

Two EPRs were needed for Other Local Needs:

1. Project ID 12222 Maxie Delivery Point
2. Project ID 25094 Commerce to Ringier 69 kV Relocation

Also, in accordance with Attachment FF Section VIII.A.3, no MTEP23 projects were identified as Immediate Need Reliability Projects and excluded from the competitive developer selection process.

The 10 largest project investments in the MISO South region represent $3.3 billion (80%) of the $4.2 billion total recommended projects for the South region in MTEP23, or 37% of the $9 billion total recommended in the MISO footprint. The locations of the 10 most expensive projects are shown in Figure 4.4-4 and it is seen that they are spread across the southern part of the South planning region. Projects that are blanket expenditures (relays, physical security, etc.) are excluded from this list.

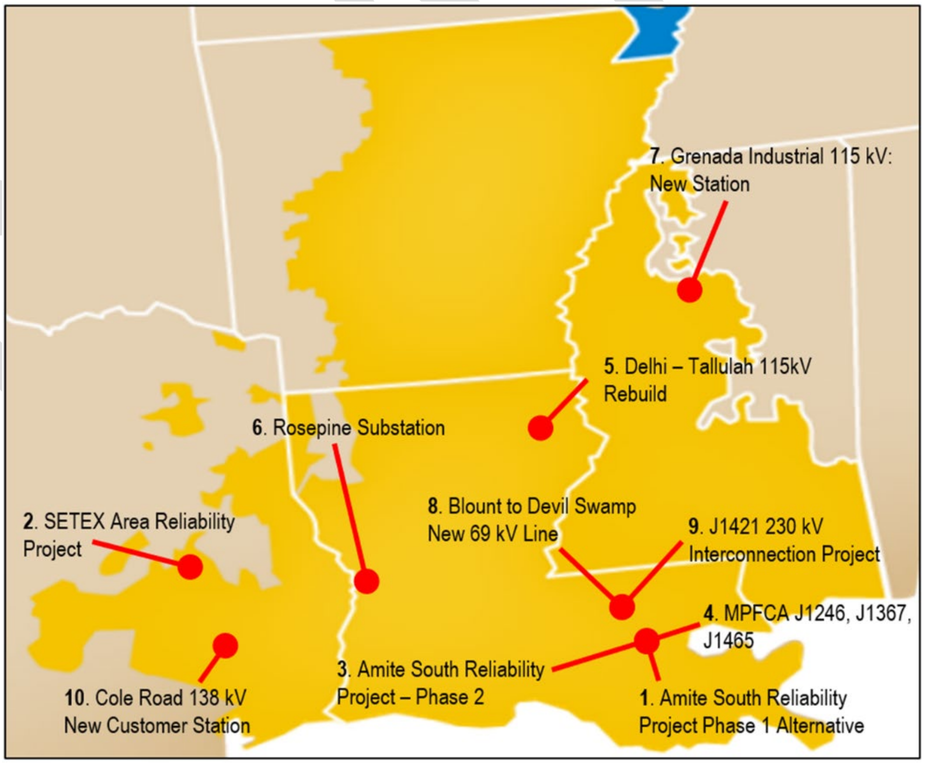


Figure 4.4-4: South region top ten projects by cost (data as of 9-29-2023)

4.4.1 Arkansas Electric Cooperative Corporation (AECC)

After MISO's independent reliability analysis, MISO and Arkansas Electric Cooperative Corporation recommend one Other Project at an estimated cost of $0 million to be approved for inclusion in MTEP23 Appendix A. All costs for this project will be paid by Mississippi County Electrical Cooperative, so there is no investment required by AECC. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Other Projects

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24192	UIG	AECC and Mississippi County Electric will be building out the AECC Barfield substation by adding a new 25 MVA; 161/13.8 kV transformer to support 20 MW of new load. AECC and Mississippi County Electric will also be building out the AECC Hickman North substation by adding a new 40 MVA; 161/13.8 kV transformer to support 30 MW of new load.	4/1/2025	$0

4.4.2 City of Alexandria (AXLA)

City of Alexandria did not submit any new projects for MTEP23. MISO has not identified any open issues in the City of Alexandria area.

4.4.3 CLECO Power LLC (CLEC)

After MISO's independent reliability analysis, MISO and CLECO Power LLC recommend six projects at an estimated cost of $89 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, one is a Baseline Reliability Project, one is an Other Project, and four are Generator Interconnection Projects with signed Generator Interconnection Agreements. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Baseline Reliability Projects

Project 24416- Rosepine Substation 230 kV

Project Description: Build a new 230 kV substation Rosepine tapped into the existing Leesville to Cooper 138 kV line 11.5 miles from Leesville. Build a new 230 kV line 3.4 miles from Rosepine to Deridder. This substation and line will be energized at 138 kV. The total estimated cost of this project is $35.6 million and has an expected in-service date of July 15, 2027.

Project Need: In this area, P6 contingencies involving Nelson to Longville, Cooper to Deridder or Coughlin to Pine Prairie create low voltage and potential overloads when two of the three lines mentioned above are outaged. This issue has resulted in reconfiguration for outages and limited ability to perform maintenance in this area except during times of lower loading. This project adds a fourth line into the area eliminating the P6 issues.

Alternatives Considered: No alternatives were considered.

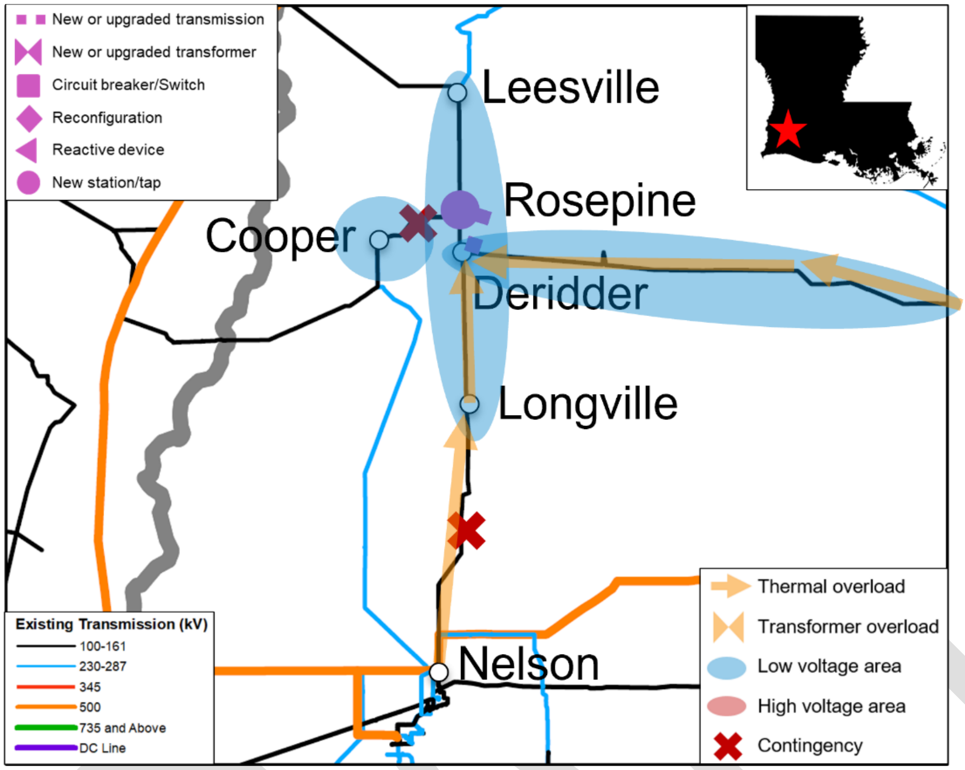


Figure 4.4.3-1: P24416 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	Nelson – Longville 138 kV	243	157	36
P6	Deridder – Longville 138 kV	262	104	2
P6	Caney – Oakdale 138 kV	283	146	40
P6	Caney – Pine Prairie 138 kV	287	147	44
P6	Centennial – Deridder 138 kV	286	110	11
P6	Centennial – Perkins 138 kV	287	110	11
P6	Coughlin – Pine Prairie 138 kV	286	154	50
P6	Oakdale – West Bay 138 kV	284	120	20
P6	Perkins – West Bay 138 kV	287	108	10

Table 4.4.3-1: P24416 Thermal loading drivers

Cont. Type	Limiting Element	Rating (pu)	Pre-Project Voltage (pu)	Post-Project Voltage (pu)
P6	Caney 138 kV	0.9	0.757	1.0129
P6	Centennial 138 kV	0.9	0.583	1.0027
P6	Deridder 138 kV	0.9	0.512	0.9911
P6	Longville 138 kV	0.9	0.47	0.9673
P6	Oakdale 138 kV	0.9	0.738	1.0109
P6	Perkins 138 kV	0.9	0.599	1.0048
P6	Pine Prairie 138 kV	0.9	0.86	1.0170
P6	West Bay 138 kV	0.9	0.684	1.0076
P6	J1205 Substation 138 kV	0.9	0.599	1.0050

Table 4.4.3-2: P24416 Voltage Performance drivers

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24033	J1286 Manuel Expansion	Expand Manuel Substation for the interconnection of J1286 Generation Plant.	4/1/2025	$2.8
24112	J1205 Perkins Substation	Tap the existing Centennial to West Bay 138 kV line and build a new Perkins Substation. J1205 Generation Plant will interconnect to this substation.	10/31/2023	$2.6
24113	J1424 Singer Substation	Tap the existing Cooper to Penton 230 kV line and add Singer Substation. This substation is needed for J1424's generator interconnection.	9/15/2024	$2.95
24114	J1367 Caneland Expansion	Expand Caneland 230 kV substation for the interconnection of J1367 Generation Plant	9/29/2024	$5.1

Other Projects

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24415	Ragely Substation	Tap the existing 138 kV line between Nelson and Longville 11.3 miles from Longville. At this location build a new 138 kV Substation Turps. Build a new 6.1 mile 138 kV line from Turps to a new substation Ragley. This project will also add a 14 MVAR cap bank at Ragley.	7/15/2024	$40

4.4.4 Cooperative Energy (SMEPA)

After MISO's independent reliability analysis, MISO and Cooperative Energy recommend six projects at an estimated cost of $48 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, one is a Baseline Reliability Project, four are Other Projects, and one is a Generator Interconnection Project with a signed Generator Interconnection Agreement. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Baseline Reliability Projects

Project 23786 – Ft Redwood - Rawhide 115 kV Line

Project Description: Tap the Entergy MS owned Flowers - Tinsley 115 kV line and construct a new Cooperative Energy owned 115 kV breaker switching station near Rawhide Road in Warren, MS. Construct a new 115 kV line from a new Cooperative Energy owned breaker 115 kV switching station near the Ft Redwood substation to the new Cooperative Energy owned switching station near Rawhide Road. Rebuild the existing Cooperative Energy owned Redwood - Ft Redwood 115 kV line to support the industrial customer's full load during unplanned on-site generation outages. The total estimated cost of this project is $13.5 million and has an expected in-service date of June 1, 2026.

Project Need: A Cooperative Energy member distribution cooperative serves an industrial customer that has behind the meter on-site generation at its Ft Redwood substation. When the industrial customer's on-site generation has unplanned outages, multiple thermal overloads and voltage violations occur during P1/P2 events on the surrounding area when supporting the full load.

Alternatives Considered: Add a 10 MVAR capacitor at the 115 kV Redwood Substation. This alternative was not selected due to voltage issues still arising in the 28 Spring case and 2028 Shoulder, Average wind case. The Original project provides greater long-term reliability as it adds another transmission path in the area and alleviates all voltage concerns.

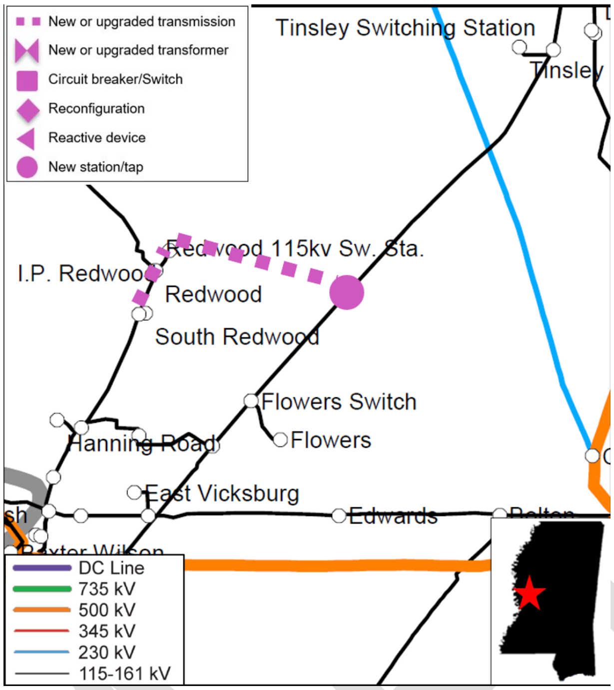


Figure 4.4.4-1: P23786 Geographic transmission map of project area

Cont. Type	Limiting Element	Low Voltage Limit (pu)	Pre-Project Voltage (pu)	Post-Project Voltage (pu)
P3	EES-EMI-3REDWOOD+ 115 kV	0.95	0.91	0.98

Table 4.4.4-1: P23786 Voltage drivers

Other Projects

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23820	Gloster 13.8 kV Delivery Point	A new 13.8 kV feeder breaker will be added at the Entergy Mississippi LLC owned Gloster substation in order to serve Cooperative Energy's distribution member's new customer.	6/1/2024	$0.48

Projects Driven by Local Needs

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
12210	South Hattiesburg Industrial Delivery Point	In order to serve the South Hattiesburg and Hattiesburg Industrial delivery points economically and reliably, service will be established by tapping L161 and constructing a 161 kV breaker switching station. A new distribution station will be constructed adjacent to the 161 kV switching station and the existing distribution feeders from both delivery points will be routed to the new station.	6/1/2025	$13.8
23941	Silver Creek Delivery Point	In order to serve the Silver Creek delivery point economically and reliably, service will be established by tapping the Cooperative Energy owned Line 571 115 kV line. A 115 kV GOAB will be installed at the tap point and a new 115 kV tap line will be constructed to the delivery point.	12/1/2024	$2
12222	Maxie Delivery Point	In order to serve the Maxie delivery point economically and reliably, service will be established by a short transmission feed by tapping the Cooperative Energy Lines 37 and 38 that are near the delivery point.	6/1/2023	$2

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23126	J1249 Morrow Repower	A single steam turbine unit will be repowered at Plant Morrow for combined cycle operation utilizing a new natural gas fired combustion turbine (CT).	3/1/2023	$16

4.4.5 East Texas Electric Cooperative (ETEC)

After MISO's independent reliability analysis, MISO and East Texas Electric Cooperative recommend one Other Project at an estimated cost of $3.7 million to be approved for inclusion in MTEP23 Appendix A. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24460	Coldspring Load Addition	Phase I - Reconductor a 4.25-mile distribution circuit from the 138 kV Coldspring Substation to the customer facility to serve 5 MW of new load. Phase II - Adds power transformer and distribution bay to serve an additional 16.2 MW of new load.	Phase I: 5/31/2023 Phase II: 7/31/2024	Phase I: $1.3 Phase II: $2.4

4.4.6 Entergy Arkansas LLC (EAL)

After MISO's independent reliability analysis, MISO and Entergy Arkansas recommend 12 projects at an estimated cost of $123 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, five are Baseline Reliability Projects, three are Other Projects, and four are Generator Interconnection Projects with signed Generator Interconnection Agreements. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Baseline Reliability Projects

Project 19911 – Dumas – Reed 115 kV: Rebuild Line

Project Description: Rebuild the 15-mile 115 kV line from Dumas - Reed to a minimum through path rating of 259 MVA. The total estimated cost of this project is $18.6 million and has an expected in-service date of June 1, 2025.

Project Need: Thermal overloads on the Dumas - Reed 115 kV line for the loss of the Sterlington - El Dorado 500 kV or Sterlington - El Dorado 500 kV/Sterlington - El Dorado East 115 kV double circuit. (NERC TPL P1.2 and P7.1 events)

Alternatives Considered: No alternatives were considered.

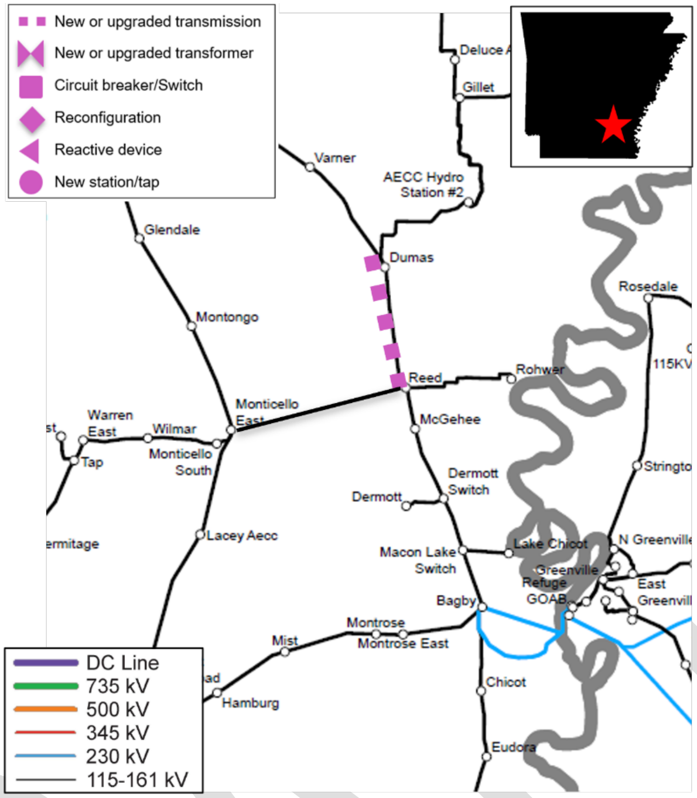


Figure 4.4.6-1: P19911 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P1-2	Dumas – Reed 115 kV	106	119	<99
P7-1	Dumas – Reed 115 kV	106	115	<99

Table 4.4.6-1: P19911 Thermal loading drivers

Project 21807 – Brinkley East Autos: Change Tap Settings 230/115 kV

Project Description: Change the high side taps on the Brinkley East 230/115 kV Auto to 242 kV (230 kV Auto completed on 3/8/2022). The total estimated cost of this project is $0.02 million and has an expected in-service date of March 1, 2023.

Project Need: These tap setting changes are needed to mitigate high voltage around the Brinkley area for the loss of the Walnut Bend Solar plant and the Brinkley East - Marianna 115 kV line section. This is a P2.3 contingency.

Alternatives Considered: No alternatives were considered.

Figure 4.4.6-2: P21807 Geographic transmission map of project area

Cont. Type	Limiting Element	Voltage Limit (pu)	Pre-Project Voltage (pu)	Post-Project Voltage (pu)
P2-3	Brinkley 115 kV Bus	1.05	1.07	1.00

Table 4.4.6-2: P21807 Voltage drivers

Project 23855 – Keo 500 kV Bus Reconfigure

Project Description: Reconfigure the Keo 500 kV substation so that the Keo – White Bluff & Keo - Wrightsville 500 kV lines are not lost for a P2.3 internal breaker fault. The total estimated cost of this project is $15.02 million and has an expected in-service date of December 1, 2027.

Project Need: The P2.3 internal breaker fault resulting in the simultaneous loss of the Keo – White Bluff & Keo - Wrightsville 500 kV lines cause thermal overloads on the Conway S. – Ranchette 161 kV, Jacksonville North – Holland Bottom 115 kV, and Jacksonville North – Sylvan Hill 115 kV line sections as well as near thermal overload on the Fourche – LR East 115 kV line section. Compliance with NERC TPL 001-5.

Alternatives Considered: No alternatives were considered.

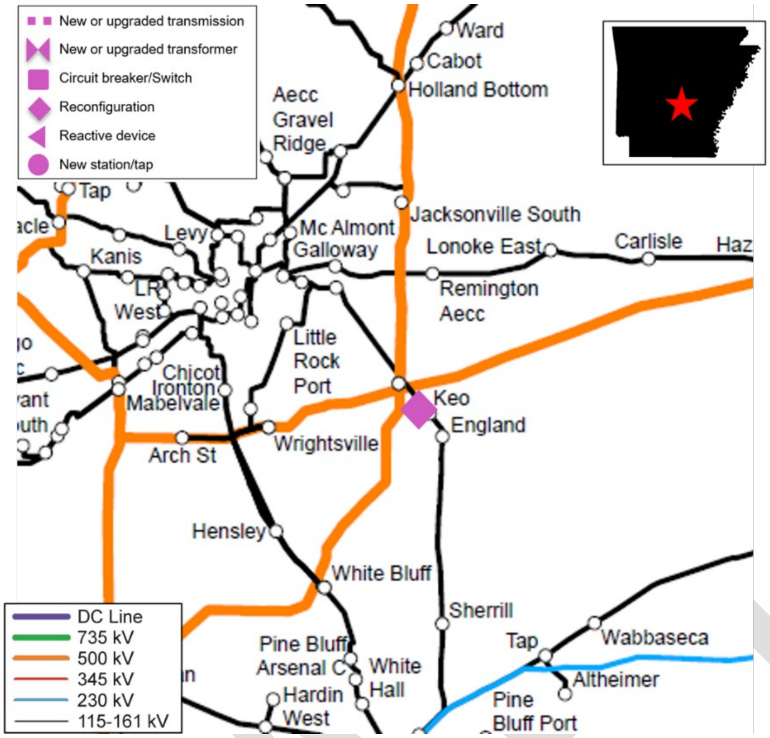


Figure 4.4.6-3: P23855 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P2-3	Jacksonville North – Holland Bottom 115 kV	298	101	<99

Table 4.4.6-3: P23855 Thermal loading drivers

Project 23898 – McNeil 500 kV Relay Improvement SPOF

Project Description: Ensure the McNeil – El Dorado 500 kV line, the McNeil 500/115 kV auto and the McNeil – Etta 500 kV line have redundant high-speed protection. This includes protection schemes with independent CT and PT winding inputs. Ensure dual battery installations or monitoring sufficient to FERC 754 guidelines. The total estimated cost of this project is $3.97 million and has an expected in-service date of December 1, 2026.

Project Need: Potential for up to ~7 GW of generation trip (ANO 1&2, Union CCGT, Ouachita CCGT, Perryville CCGT, Murray Hydro, etc.) for a 3PH fault on the McNeil 500 kV bus with non-redundant relay failure for the McNeil – El Dorado 500 kV line protection, McNeil 500/115 kV auto protection, or the McNeil – Etta 500 kV line protection.

Alternatives Considered: No alternatives were considered.

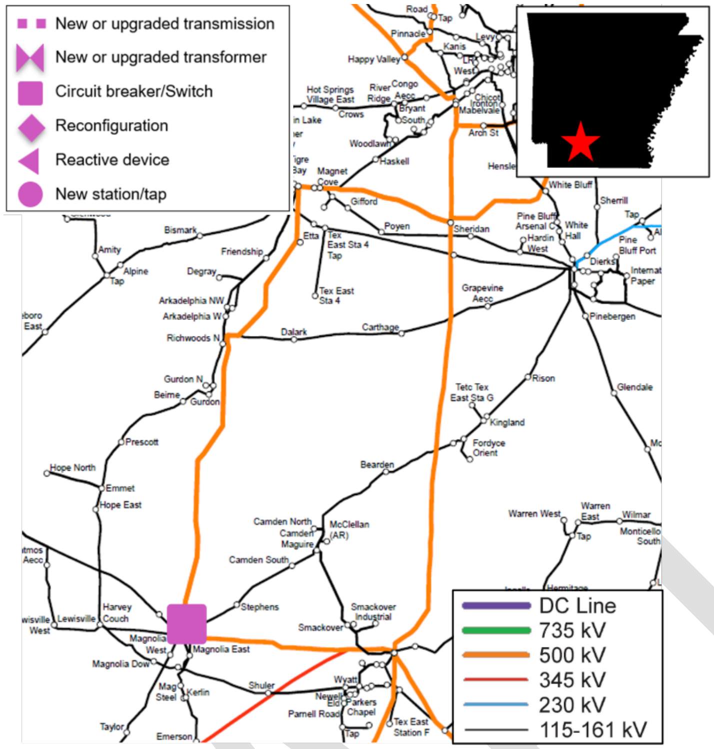


Figure 4.4.6-4: P23898 Geographic transmission map of project area

Project 23900 – Dell 161 kV Breaker Upgrades

Project Description: Upgrade Dell 161 kV Breakers B2240, B2205, and B2235 with a 63 kA breaker. The total estimated cost of this project is $2.52 million and has an expected in-service date of June 1, 2025.

Project Need: The Dell 161kV Breakers B2240, B2205 and B2235 are underrated. This project is to maintain compliance with NERC TPL-001-5 and Entergy's Local Transmission Criteria.

Alternatives Considered: No alternatives were considered.

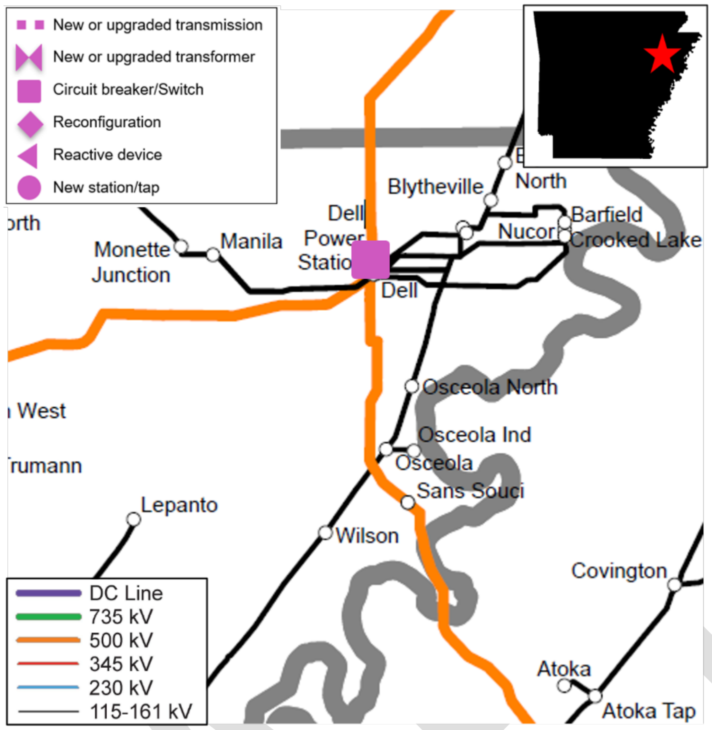


Figure 4.4.6-5: P23900 Geographic transmission map of project area

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
12055	Gum Springs 115 kV: Build Breaker Station	Create a new 115 kV switching station by tapping the Arkadelphia North – Richwood 115 kV and the Arkadelphia West – Dalark 115 kV line sections.	6/1/2026	$14.95

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24938	Driver - Hybar 230 kV: New transmission line	Entergy Arkansas will build a new 2 mile 230 kV radial transmission line from the Driver 230kV substation to a new customer build Hybar 230 kV substation. A new circuit breaker and relay upgrades will be needed at Driver 230 kV substation. Two 500 kV transmission lines will be raised for the new 230 kV line crossing.	5/1/2025	$10.63

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23899	2024 EAL Asset Renewal Program	The AM renewal asset program is to address aging and failing transmission assets across EAL's territory.	12/31/2024	$24.64

Generator Interconnection Projects:

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24697	Aurelle 115 kV: POI for J1612	A new point of interconnection for J1612 100 MW solar project. The interconnection customer will install the SANU. Network Upgrades at El Dorado 115 kV and Sterlington 115 kV will be installed by Entergy as well as the transmission line cut in. New underground fiber will be installed between Strong and Huttig tap stations.	11/27/2024	$13
24879	Prairie Creek 161 kV: POI for J1816	A new interconnection three breaker ring-bus substation will be constructed on the Fisher - Cherry Valley 161 kV transmission line. Line protection and breaker control panels will be installed at Newport and Parkin 161 kV stations. The existing wave trap will be removed from Pecan Street 161 kV station. New underground fiber will be installed between Prairie Creek and Cherry Valley 161 kV substation.	11/1/2025	$12.6
24898	Flat Lake 161 kV J1562: Cut-in Switching Station	The interconnection customer will self-build the switching station needed to interconnect J1562 200 MW solar project. The cut-in will connect the new POI station to the existing Blytheville I-55 and AECC Blytheville North 161 kV line section. Entergy will install a new line protection panel and breaker control panel at Blytheville I-55 161 kV substation and AECC Blytheville North 161 kV substation. Two existing breakers at Blytheville Elm St. 161 kV will also be replaced with new surge arresters, line protection and breaker control panels and a new RTU. New underground fiber will be installed between the new POI station to	1/31/2025	$5.2

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		Blytheville I-55 and AECC Blytheville North substations.		
24918	Hamrick 161 kV J1842: Cut-in Switching Station	The Hamrick 161 kV switching station will be constructed for the 135 MW wind farm (J1842) per the terms of the executed GIA. The wind farm will be connected by a four-mile 161 kV gen-tie line to the new Hamrick 161 kV SS that will be constructed by the Interconnection Customer. Entergy Arkansas will construct the 161 kV cut-in as well as relay settings updates at the remote end stations. New underground fiber will also be installed between Hamrick and Wynne South 161 kV.	10/31/2024	$2.1

4.4.7 Entergy Louisiana LLC (ELL)

After MISO's independent reliability analysis, MISO and Entergy Louisiana recommend 32 projects at an estimated cost of $2.5 billion to be approved for inclusion in MTEP23 Appendix A. Of these projects, five are Baseline Reliability Projects, 12 are Other Projects, and 15 are Generator Interconnection Projects with signed Generator Interconnection Agreements. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Baseline Reliability Projects:

Project 12098 - Delmont to Hazel 230 kV: Upgrade Line

Project Description: Upgrade the Delmont to Hazel 230 kV conductor, bus work at both the stations, line bay bus, jumpers and any station equipment to a minimum of 1600 A. The total estimated cost of this project is $15.6 million and has an expected in-service date of June 1, 2026. This project meets the criteria requirements to be a potential immediate need reliability project (INRP) being a 230 kV BRP, costing more than $5 million dollars, and in service within 36 months. The project has a low lead time due to being a short path to upgrade (1.9 miles).

Project Need: NERC TPL-001-5 Reliability Standards and Entergy's Planning Guidelines and Criteria. For the P3.2 loss of the Exxon to Downtown 230 kV line with the loss of Waterford 3 generation the Delmont to Hazel 230 kV line overloads. P6 Willow Glen-Pecue 230 kV with Willow Glen to Harelson 230 kV will overload the Delmont to Hazel 230 kV.

Alternatives Considered: No alternatives were considered.

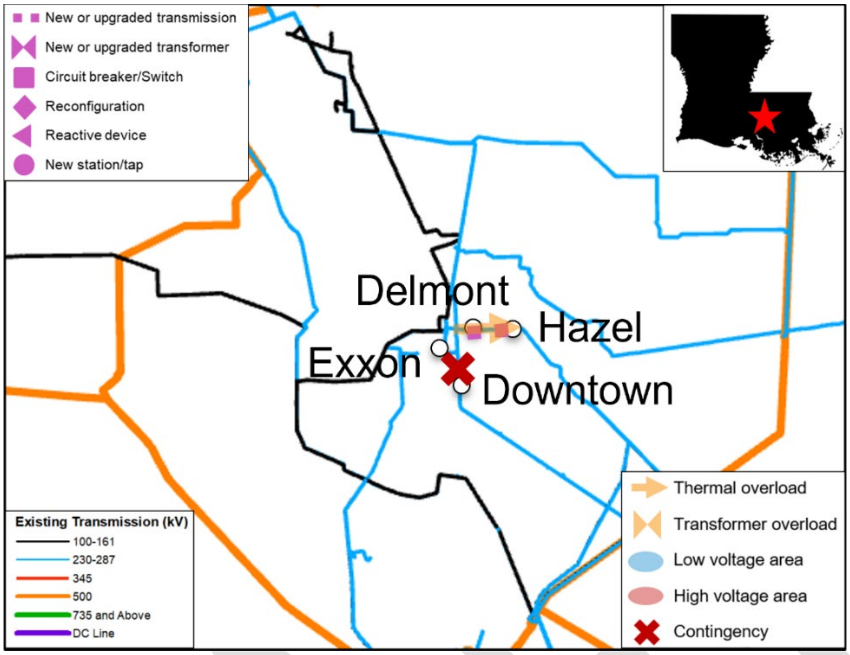


Figure 4.4.7-1: P12098 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P3	Delmont – Hazel 230 kV	361	79	41
P6	Delmont – Hazel 230 kV	361	108	61

Table 4.4.7-1: P12098 Thermal loading drivers

Project 15654 - Delhi - Tallulah 115 kV rebuild

Project Description: Rebuild 20.7 miles of 115 kV line from Delhi to Tallulah. Operate the series reactor at Delhi as normally open. The total estimated cost of this project is $39.9 million and has an expected in-service date of December 1, 2026.

Project Need: NERC TPL-001-5 Reliability Standards and Entergy's Planning Guidelines and Criteria. The P1 loss of Perryville to Baxter Wilson 500 kV line and the P3 loss of the Baxter Wilson - Perryville 500 kV line coupled with the loss of Grand Gulf generation overloads the Delhi to Tallulah 115 kV line.

Alternatives Considered: No alternatives were considered.

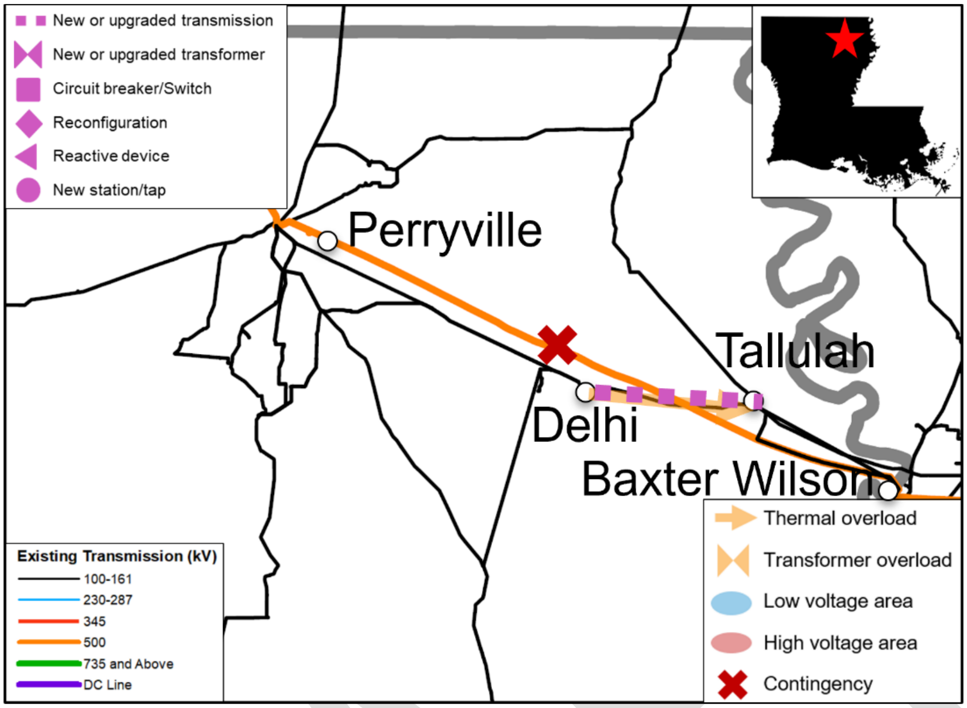


Figure 4.4.7-2: P15654 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P3	Delhi– Tallulah 115 kV	80	126	35

Table 4.4.7-2: P15654 Thermal loading drivers

Project 18236 - Winnsboro to Gilbert 115 kV: Rebuild Line

Project Description: Rebuild approximately 9.5 miles of 115 kV line from Winnsboro to Gilbert. The total estimated cost of this project is $20.9 million and has an expected in-service date of December 1, 2026.

Project Need: NERC TPL-001-5 Reliability Standards and Entergy's Planning Guidelines and Criteria. P7 category event resulting in the loss of Perryville to Baxter Wilson 500 kV & Baxter Wilson to Tallulah 115 kV double circuit lines causes high loading on the Winnsboro to Gilbert 115 kV line in North Louisiana.

Alternatives Considered: No alternatives were considered.

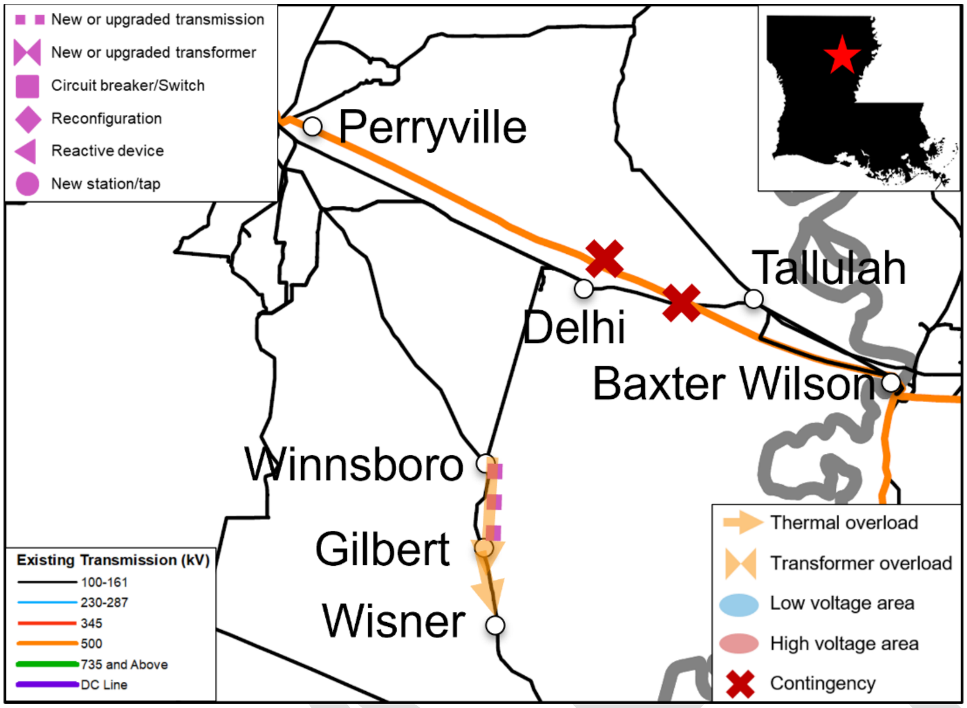


Figure 4.4.7-3: P18236 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P7	Winnsboro – Gilbert 115 kV	111	106	46

Table 4.4.7-3: P18236 Thermal loading drivers

Project 18247 - Gilbert to Wisner 115 kV: Rebuild Line

Project Description: Rebuild Gilbert to Wisner 115 kV line. The line will be built using a double circuit configuration but only strung on one side. The unused side will be reserved for a future 230 kV line. The total estimated cost of this project is $11.9 million and has an expected in-service date of December 15, 2027.

Project Need: NERC TPL-001-5 Reliability Standards and Entergy's Planning Guidelines and Criteria. P7.1 loss of Perryville to Baxter Wilson 500 kV and Tallulah to Baxter Wilson 115 kV line overloads the Gilbert to Wisner 115 kV line.

Alternatives Considered: No alternatives were considered.

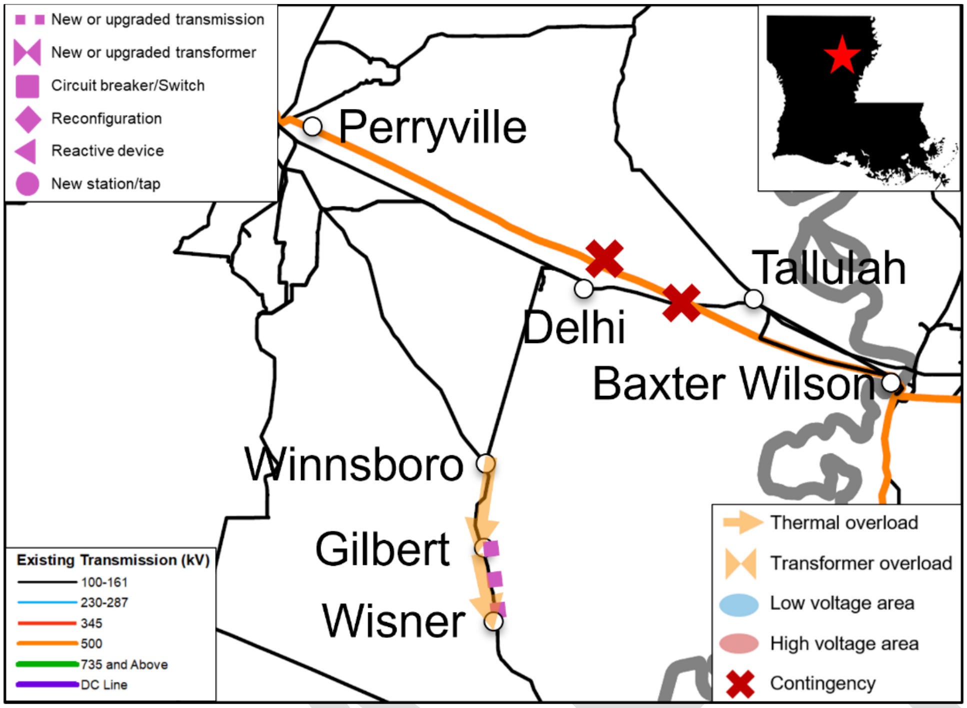


Figure 4.4.7-4: P18247 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P7	Gilbert – Wisner 115 kV	115	97	44

Table 4.4.7-4: P18247 Thermal loading drivers

Project 23937 - Willow Glen 138 kV Reconnect Bus

Project Description: Construct rigid bus to tie in the Willow Glen 138 kV southwest bus and southeast bus together. The total estimated cost of this project is $2.9 million and is currently in service.

Project Need: NERC TPL-001-5 Reliability Standards and Entergy's Planning Guidelines and Criteria. P2 Internal breaker fault at Willow Glen 138 kV causes thermal overload on Willow Glen to Alchem 138 kV line and near overload on Geigy to Stauffer 138 kV.

*In the MTEP22 2025 Summer peak model, Willow Glen – Alchem 138 kV was at 100% loading during the P2 event.

Alternatives Considered: No alternatives were considered.

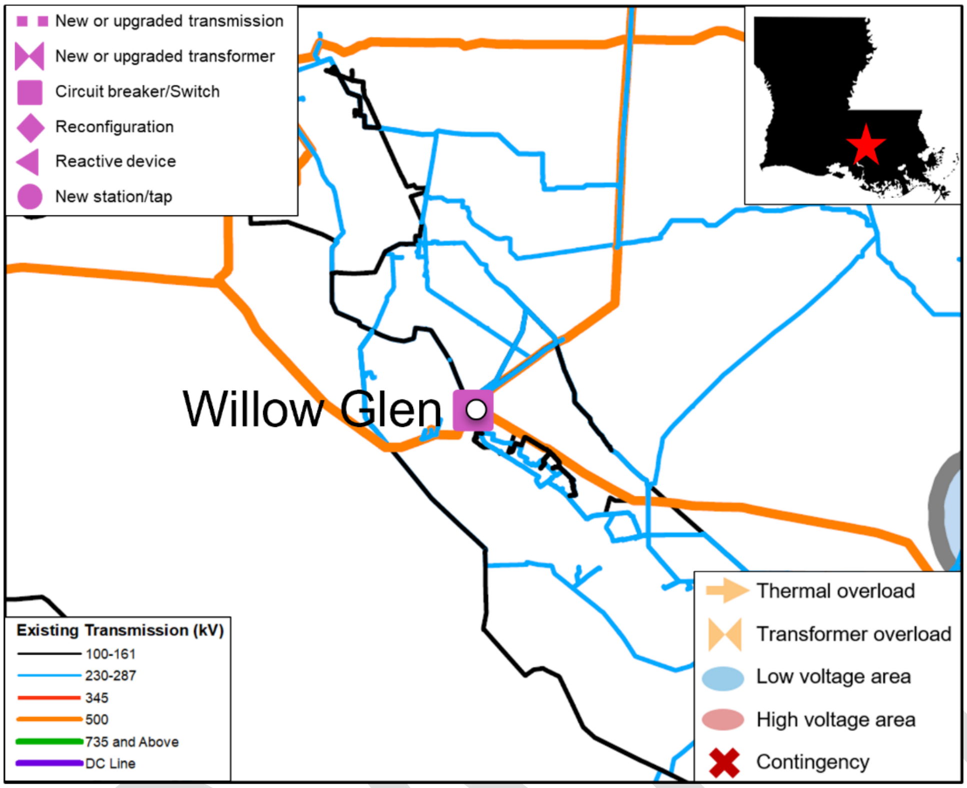


Figure 4.4.7-5: P23937 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P2	Willow Glen – Alchem 138 kV	282	84*	N/A

Table 4.4.7-5: P23937 Thermal loading drivers

Other Projects

Project 25242 - Amite South Reliability Project - Phase 1 Alternative 500/230 kV

Project Description: This project was selected as an alternative to projects 23935 – DSG Reliability and Resiliency and 23954 – Amite South Reliability Project. The scope of the project:

- Construct 500/230 kV Commodore station near the existing Derrick 230 kV Station
    - Cut in Derrick to Iberville and Richardson to Wise 230 kV lines.
    - Cut in the Webre to Bayou Labutte 500 kV line
    - Install one 500-230 kV Autotransformer
    - Commodore 230 kV station will be a breaker and half station
    - Commodore 500 kV station will be a 4 breaker ring

- Construct a new ~60 mile 230 kV line between Commodore and Waterford.
- Construct a new ~85 mile 500 kV line between Commodore and Churchill.
- Expand Waterford 500 kV into a three-breaker ring. Add additional bay at Waterford 230 kV to accommodate the new 230 kV line.
- Construct a new 500 kV four-breaker ring at Churchill, to accommodate two 500 kV lines and two Autotransformers. Install two 500-230 kV Autotransformers.
- Convert existing Waterford to Churchill 230 kV to 500 kV operation.

The total estimated cost of this project is $1.7 billion and has an expected in-service date of July 1, 2028.

Project Need: Improved extreme event resilience - Provides two EHV paths between Baton Rouge and Waterford. Location of line provides geographic diversity that can be useful in restorations during Extreme Weather Events.

Operational flexibility and preparing for future of generation in Amite South/DSG - Addressing generation retirements in Amite South, which could be accelerated by proposed EPA rules. Offers the opportunity to cut multiple sources into existing stations serving customers.

Meet Local Planning Criteria for load serving capability - Increases Load Serving Capability in Amite South. Helps meet needs of increased block load requests on the west bank of the river by providing a new 500 kV and 230 kV path. Only one 230 kV path exists today.

Entergy provided MISO with future generation retirements and future load growth assumptions that do not meet the requirements to be studied through the normal MTEP process. In order to test the reliability of the system, MISO created a set of sensitivity models that included the future generation retirements and load growth assumptions and applied them to the MTEP23 models. MISO verified that this project was needed to alleviate several thermal issues to reliably serve load in the sensitivity models.

Alternatives Considered: Two alternatives, outlined below, were considered for this project. Alternative 2 was determined to be infeasible due to restrictions at the Bayou Labutte station that prevented expansion and was not chosen. Alternative 1 also replaces the DSG Reliability & Resiliency Project and is comparable to the Amite South Phase 1 and DSG projects in terms of cost and feasibility. This project grows the load serving capability in the Amite South and DSG load pockets more effectively than the two projects that it replaces by providing an extended 500 kV circuit through both the Amite South and DSG load pockets and tying the 500 kV and 230 kV systems together at two stations instead of one. Alternative 1 was ultimately selected over the other options.

Alternative 1:

- Construct 500/230 kV Commodore station near the existing Derrick 230 kV Station. Install one 500-230 kV Autotransformer.
- Cut in Derrick to Iberville and Richardson to Wise 230 kV lines. Cut in the Webre to Bayou Labutte 500 kV line.
- Construct a new 60-mile 500 kV line with 230 kV under build between Commodore and Waterford.

- Install a second 500-230 kV Autotransformer at Waterford.

Alternative 2:

- Construct a new 80-mile 500 kV line between Bayou Labutte and Churchill.
- Install two 500-230 kV Autotransformers at Churchill.
- Construct a new 27-mile 500 kV line between Churchill and Waterford.

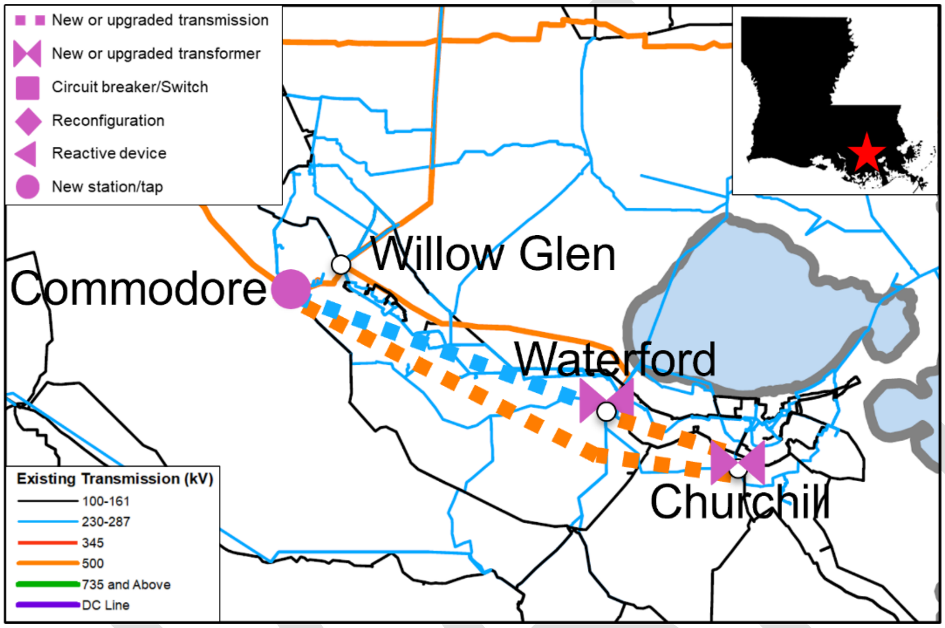


Figure 4.4.7-6: P23954 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P12	Nelson – Gooseport 128 kV	213	100.4	<99
P5	AAC Corp – Luce 230 kV	685	108	<99
P23	Bogalusa – Barkers Corner 230 kV	459	108	<99
P71	Bogalusa – Barkers Corner 230 kV	459	106	<99
P12	Bogalusa – Barkers Corner 230 kV	459	104	<99
P11	Bogalusa – Barkers Corner 230 kV	459	103	<99
P0	Donaldsonville – Bayou Everett 230 kV	459	126	<99
P71	Dow Meter – Tiger 230 kV	429	116	<99
P21	Dow Meter – Tiger 230 kV	429	105	<99

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P12	Dow Meter – Tiger 230 kV	429	105	<99
P23	Dow Meter – Tiger 230 kV	429	105	<99
P12	Evergreen – Wise 230 kV	519	162	<99
P22	Evergreen – Wise 230 kV	519	137	<99
P23	Evergreen – Wise 230 kV	519	136	<99
P11	Fancy Point – Riverbend 230 kV	1194	102	<99
P71	Northline – Cohen 230 kV	361	100	<99
P0	St. James – Sidney 230 kV	456	100.3	<99
P23	Talisheek – Bogalusa 230 kV	641	103	<99
P12	Talisheek – Bogalusa 230 kV	641	102	<99
P12	Vacherie – Waterford 230 kV	640	123	<99
P23	Vacherie – Waterford 230 kV	640	122	<99
P71	Vacherie – Waterford 230 kV	640	121	<99
P12	Waterford Tap – Waterford 230 kV	1195	102	<99
P0	Welcome – St. James 230 kV	418	205	<99
P23	Wise – Bayou Labutte 230 kV	1195	124	<99
P23	Bayou Labutte 500/230 kV	1195	119	<99
P21	Barkers Corner – Ramsay 230 kV	478	106	<99
P23	Barkers Corner – Ramsay 230 kV	478	100.5	<99

Table 4.4.7-6: P23954 Thermal loading drivers

Project 23957 - Amite South Reliability Project - Phase 2 500/230 kV

Project Description: Construct a 14-mile 230 kV line from the Willow Glen substation to the Conway substation. Station work at both Willow Glen and Conway including additional breakers to accommodate the new line. Construct a new 500 kV Station near Conway and install a 1200 MVA 500-230 kV Autotransformer. Build approximately five miles of 500 kV to cut the Willow Glen to Waterford 500 kV station into the new Conway 500 kV station. The total estimated cost of this project is $290 million and has an expected in-service date of June 30, 2026.

Project Need:

- Improved extreme event resilience - Provides an additional hardened path in the Industrial Corridor, that can be useful in restorations during events like a Hurricane. Reduces risk of extreme event involving Gypsy corridor.

- Operational flexibility and preparing for future of generation in Amite South - Addressing generation retirements in Amite South/DSG, which could be accelerated by proposed EPA rules. Provides opportunity to reduce radial exposure to industrial customers during outages.

- Meet Local Planning Criteria for load serving capability - Adds an additional source on the east bank of the river to address growing needs of new block load requests. Increases Load Serving Capability in Geismar area and Amite South.

- Entergy provided MISO with future generation retirements and future load growth assumptions that do not meet the requirements to be studied through the normal MTEP process. In order to test the reliability of the system, MISO created a set of sensitivity models that included the future generation retirements and load growth assumptions and applied them to the MTEP23 models. MISO verified that this project was needed to alleviate several thermal issues to reliably serve load in the sensitivity models.

Alternatives Considered: Two alternatives, outlined below, were considered for this project. Alternative 1 was not chosen due to the higher cost of the river crossing. Planning engineers determined that alternative 2 did not resolve the reliability violations as well as the Amite South Phase 2 project. Neither alternative was determined to be a viable replacement for the proposed project, so neither was selected.

Alternative 1:

- 500 kV tap + Commodore – Conway 230 kV line.

- Scope: Tap the Willow Glen – Waterford line (new 500 kV sub.), five mi. 500 kV line, 500/230 kV AT, expand Conway 230 kV substation, 20 mi. 230 kV line from Commodore to Conway, River Crossing.

Alternative 2:

- Construct a new 500/230 kV substation near Panama 230 kV.

- Add one 500/230 kV transformer.

- Build approximately six miles of 500 kV to cut the Willow Glen to Waterford 500 kV station into the new 500 kV station.

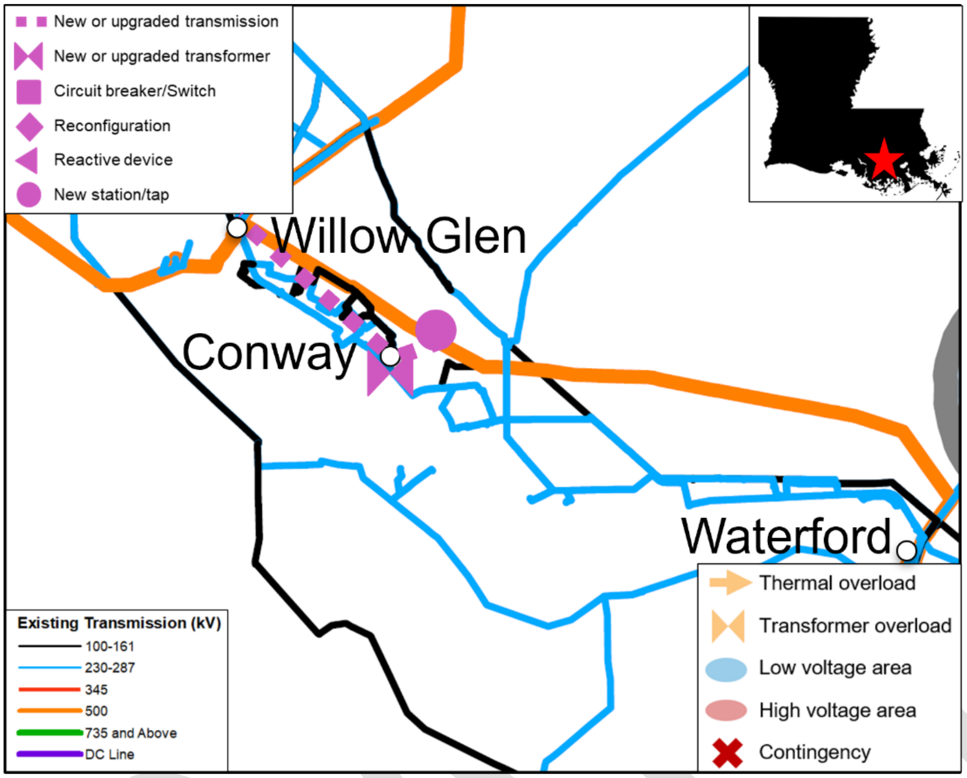


Figure 4.4.7-7: P23957 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P5	AAC Corp – Luce 230 kV	685	108	<99
P23	AAC Corp – Luce 230 kV	685	107	<99
P12	AAC Corp – Luce 230 kV	685	103	<99
P71	Addis – Northline 230 kV	361	104	<99
P12	Bogalusa – Barkers Corner 230 kV	459	102	<99
P23	Bogalusa – Barkers Corner 230 kV	459	101	<99
P71	Dow Meter – Tiger 230 kV	429	105	<99
P21	Dow Meter – Tiger 230 kV	429	105	<99
P12	Dow Meter – Tiger 230 kV	429	105	<99
P23	Dow Meter – Tiger 230 kV	429	105	<99
P71	Northline – Cohen 230 kV	361	100.2	<99
P23	South Port – Ninemile 230 kV	780	100.4	<99

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P5	Vacherie – Waterford 230 kV	640	104	<99
P12	Vacherie – Waterford 230 kV	640	103	<99
P22	Vacherie – Waterford 230 kV	640	103	<99
P23	Vacherie – Waterford 230 kV	640	103	<99
P23	Barkers Corner – Ramsey 230 kV	478	100.5	<99

Table 4.4.7-7: P23957 Thermal loading drivers

Project 23959 - Amite South Reliability Project - Phase 3 230 kV

This project and its alternatives are still under evaluation by MISO and will seek approval after December 2023.

Project Description: Construct a 40-mile 230 kV line from the Adams Creek substation to the Robert substation. Station work at both Adams Creek and Robert including additional breakers to accommodate the new line. The total estimated cost of this project is $260 million and has an expected in-service date of November 16, 2027.

Project Need: Meet Local Planning Criteria for load serving capability - Increases Load Serving Capability in Amite South.

Operational flexibility and preparing for future of generation in Amite South - Addressing generation retirements in Amite South, which could be accelerated by proposed EPA rules.

Improved extreme event resilience - Provides an additional hardened path into Amite South, that can be useful in restorations during Hurricane and other extreme weather events.

Entergy provided MISO with future generation retirements and future load growth assumptions that do not meet the requirements to be studied through the normal MTEP process. In order to test the reliability of the system, MISO created a set of sensitivity models that included the future generation retirements and load growth assumptions and applied them to the MTEP23 models. MISO verified that this project was needed to alleviate several thermal issues to reliably serve load in the sensitivity models.

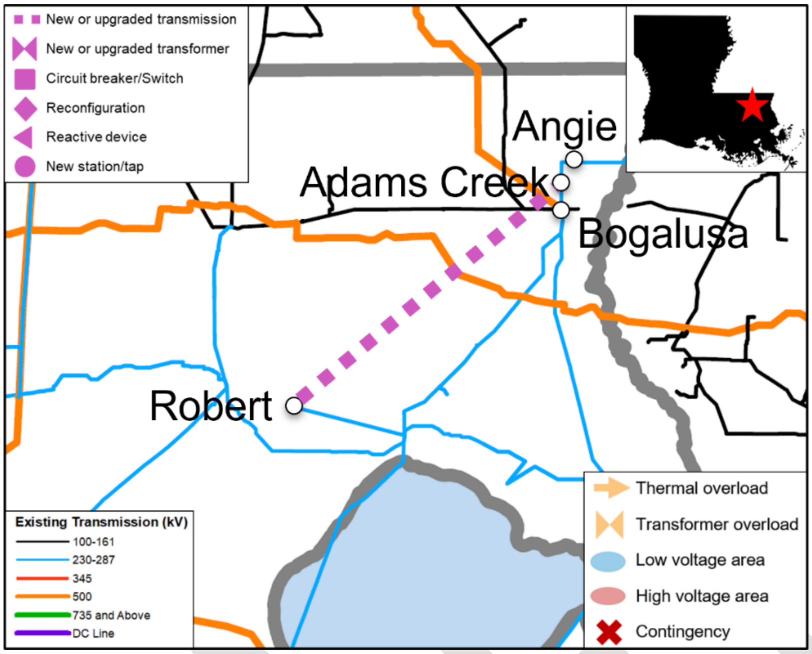


Figure 4.4.7-8: P23959 Geographic transmission map of project area

Alternatives Considered: Two alternatives are being considered for this project.

Alternative 1:

- McKnight/Daniel Tap – Michoud 500 kV line.
- Scope: Expand 500 kV Bogalusa, New 500 kV Bogue Chitto sub, 11 mi. 500 kV line from Bogalusa – Bogue Chitto, Bogue Chitto – Michoud land 27 mi., Bogue Chitto – Michoud lake 18 mi., 500/230 kV AT at Michoud, new 500 kV Michoud sub.

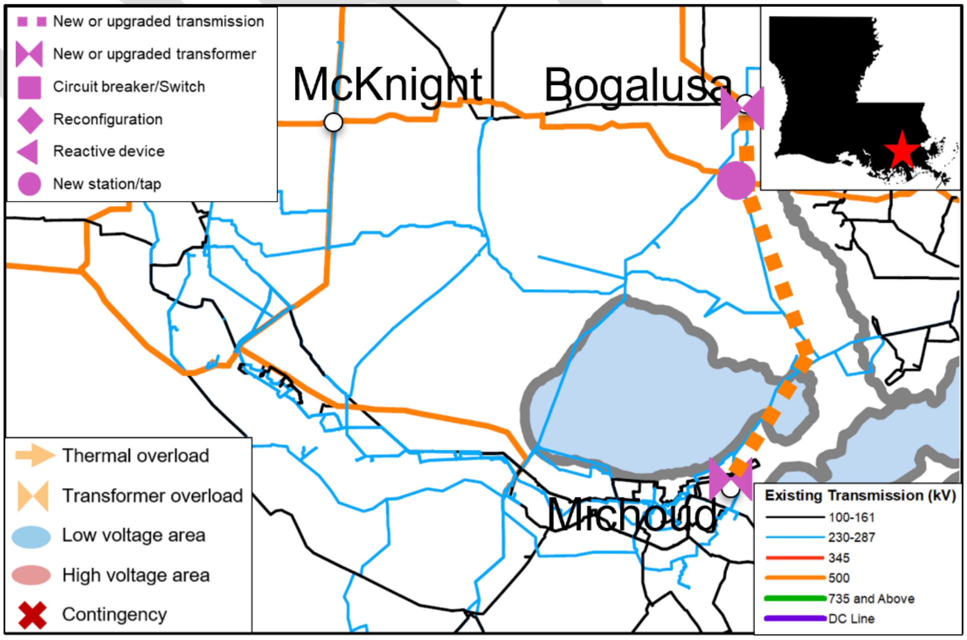


Figure 4.4.7-9: P23959 Alternative 1 Geographic transmission map of project area

Alternative 2:

- Tap McKnight to Daniel 500 kV to create a new substation (Bogue Chitto).
- Build a new 500 kV line between Bogue Chitto and Bogalusa.
- Build a new 500 kV line between Bogue Chitto and Little Gypsy.

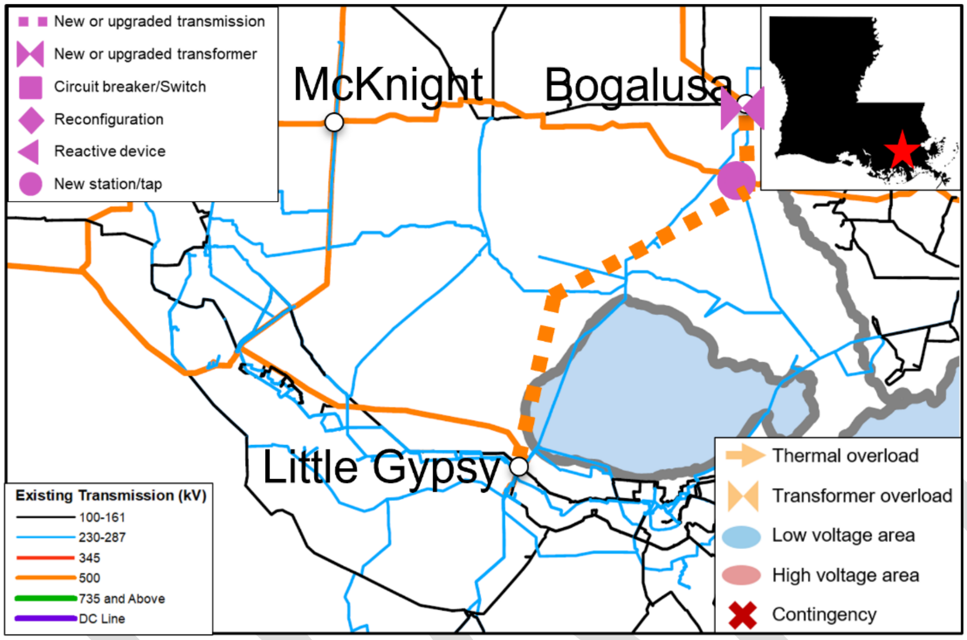


Figure 4.4.7-10: P23959 Alternative 2 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P12	Adams Creek – Bogalusa 230 kV	883	114	<99
P23	Adams Creek – Bogalusa 230 kV	883	113	<99
P23	Bogalusa – Barkers Corner 230 kV	459	120	<99
P71	Bogalusa – Barkers Corner 230 kV	459	120	<99
P21	Bogalusa – Barkers Corner 230 kV	459	120	<99
P12	Bogalusa – Barkers Corner 230 kV	459	120	<99
P5	Bogalusa – Barkers Corner 230 kV	459	116	<99
P12	Dow Meter – Tiger 230 kV	429	100.3	<99
P71	Northline – Cohen 230 kV	361	100.2	<99
P23	Talisheek – Bogalusa 230 kV	641	111	<99

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P12	Talisheek – Bogalusa 230 kV	641	110	<99
P71	Talisheek – Bogalusa 230 kV	641	110	<99
P12	Vacherie – Waterford 230 kV	640	100	<99
P71	Vacherie – Waterford 230 kV	640	100	<99
P23	Barkers Corner – Ramsay 230 kV	478	113	<99
P71	Barkers Corner – Ramsay 230 kV	478	112	<99
P12	Barkers Corner – Ramsay 230 kV	478	110	<99

Table 4.4.7-8: P23959 Adams Creek to Robert 230kV Thermal loading drivers

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
9764	Dixie Baker to Baker 69 kV: Reconductor Line	Upgrade the Dixie Baker to Baker 69 kV line section. This includes a reconductor/rebuild and upgrading substation equipment.	6/1/2026	$12.8
12084	Dixie Baker to Zachary 69 kV: Upgrade Line	Upgrade the ~3.3 mile long line section.	6/1/2027	$18.9
23881	Holiday to Lafayette 69 kV: Reterminate into Elks	Re-terminate the Holiday to Lafayette 69 kV line into the LUS Elks 69 kV substation, creating an Elks to Holiday 69 kV path. Demolish the unused portions of the Holiday - Lafayette 69 kV line. Upgrade/Rebuild Holiday to Elks line.	6/1/2025	$29.4
23882	Barnett Oil Mill 69 kV Relocation	Build new 69 kV T-line from Barnett Oil Mill Sub to a tap point on the existing CLECO Guidry to South Park 69 kV line. Install new 3-way motor operated GOAB switch cut-in to CLECO T-line. Demolish the L-658 69 kV T-line from the BROM Tap to the Barnett Oil Mill substation. Some of the L-658 structures support CLECO distribution facilities. That distribution will be relocated and/or rebuilt.	6/1/2025	$23.7

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23924	Mossville 69 kV Upgrade Breaker 17955	Breaker number 17955 at the Mossville 69 kV substation will be replaced due to the short circuit analysis.	6/1/2024	$3.6
23938	Port Hudson - Jackson 69 kV: Switch upgrades	This project is to upgrade switches on the Port Hudson to Jackson 69 kV line to increase the through path rating of the line.	12/1/2024	$3.9
23939	Blount to Devil Swamp New 69 kV line	Construct new 2.8 mile line from the existing Blount to Devil Swamp 69 kV stations.	6/1/2025	$32.3
23940	Tiger 69 kV: Bus upgrades	Upgrade the Tiger 69 kV bus tie, including breakers and switches, to increase through path rating.	6/1/2025	$1.5

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23934	2024 ELL Asset Renewal Program	This project is for the ELL Asset Renewal Program that will be executed in 2024. The asset renewal programs replace aged and/or degraded transmission line and transmission substation assets. Entergy continuously reviews asset health to prioritize those replacements and the specifics for the 2024 asset renewal plans have not yet been finalized.	12/31/2024	$43.9
23946	MTEP23 ELL Capacitor Bank Retirements	Retire the Snakefarm 115 kV and Jaguar 69 kV capacitor banks.	12/31/2023	$0.0

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24053	J1431 Interconnection Project at Vacherie 230 kV	Facilities required for the interconnection of J1431 at the existing Vacherie 230 kV substation.	5/1/2024	$1.4

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24094	J1463 Interconnection: Bueche 230 kV Station	This project is to support the interconnection of solar project J1463 at the new Bueche 230 kV station on the 230 kV line 731 (Addis to Big Cajun).	11/1/2023	$0.1
24252	MPFCA J1246, J1367, J1465: Install 2nd Bayou Labutte 500-230 kV Autotransformer and Construct New Wise to Bayou Labutte 230 kV Line	Install 2nd 500-230 kV Autotransformer at Bayou Labutte 500 kV, including all associated station and relay work. Construct new Wise to Bayou Labutte 230 kV line, including all associated station and relay work.	9/20/2025	$45.2
24253	MPFCA J1246, J1421, J1463: Willow Glen 230 kV Breaker Replacements	Replace sixteen 230 kV breakers at Willow Glen 230 kV station with IPO circuit breakers rated at 80 kA.	8/9/2025	$16.5
24254	J1465 138 kV Interconnection Station	This project is to support the interconnection of J1465 on 138 kV line between existing Livonia and Colonial Springs stations.	6/1/2025	$14.4
24272	J1421 230 kV Interconnection Project	This project is to support the interconnection of solar project J1421 at a new station cut in between Colfel and Moler 230 kV stations. Convert Moler 230 kV into a four-breaker ring bus. Upgrade the Coly to Moler 230 kV line as identified during the MISO DPP cycle.	3/1/2026	$32.3
24861	J1583 Interconnection on Evergreen to Donaldsonville 230 kV	Facilities required for the interconnection of J1583 on the Evergreen to Donaldsonville 230 kV.	6/1/2025	$5.0
24862	J1644 Generator Interconnection on Champagne to Plaisance 138 kV	Facilities required for the interconnection of J1644 on the Champagne to Plaisance 138 kV.	12/15/2024	$4.3
24985	J1827 Generator Interconnection Bastrop Tap 115 kV	Facilities required for the interconnection of J1827 at the Bastrop Tap 115 kV station.	4/1/2026	$18.5
24986	J1795 Generator Interconnection on Richard to Bayou Cove 138 kV(Ln 258)	Facilities required for the interconnection of J1795 on the Richard to Bayou Cove 138 kV Line 258.	12/4/2025	$17.7
25083	J1794 Generator Interconnection on Richard to Scott 138 kV	Facilities required for the interconnection of J1794 on the Richard to Scott 138 kV.	5/6/2025	$12.8

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
25101	J1564 Generator Interconnection on the Bogalusa to Talisheek 230 kV	Facilities required for the interconnection of J1564 on the Bogalusa to Talisheek 230 kV.	12/22/2025	$18.8
25122	J1542 Generator Interconnection on Vacherie to Chackbay 230 kV	Facilities required for the interconnection of J1542 on the Vacherie to Chackbay 230 kV.	6/1/2026	$19.3
25140	J1669 Generator Interconnection on Lake Charles Bulk to Henning 138 kV	Facilities required for the interconnection of J1669 on the Lake Charles Bulk to Henning 138 kV.	12/4/2025	$16.9
25143	J1602 Generator Interconnection at Rilla 115 kV	Facilities required for the interconnection of J1602 at Rilla 115 kV. The J1602 battery will be interconnected behind the main step up transformer for J1239 (Rilla 115 kV POI).	10/25/2024	TBD

4.4.8 Entergy Mississippi LLC (EML)

After MISO's independent reliability analysis, MISO and Entergy Mississippi recommend six projects at an estimated cost of $97.3 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, three are Other Projects and three are Generator Interconnection Projects with signed Generator Interconnection Agreements. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
15708	North Jackson 115 kV: Install Circuit Breakers	Install Transmission Breakers at North Jackson 115 kV substation.	12/1/2025	$7.3

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23348	Grenada Industrial 115 kV: New Station	Entergy is proposing to construct a new 115 kV substation (Grenada Industrial	12/1/2024	$32.6

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		115 kV Substation) which will serve the industrial customer's 10 MW of new load and future area load growth in Grenada, MS and the industrial park. Entergy will construct a new (4) breaker ring bus substation with (1) – 40 MVA, LTC 115/13.8 kV transformer. The new substation will have (1) main and (3) feeder breakers. The new substation will cut into the current Grenada – Tillatoba 115 kV line.		

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23932	2024 EML Asset Renewal Program	The asset renewal programs replace aged and/or degraded transmission line and transmission substation assets. Entergy continuously reviews asset health to prioritize those replacements and the specifics for the 2024 asset renewal plans have not yet been finalized. Install a 69 kV capacitor bank configuration and associated automatic control features at Vinburn SS.	12/31/2024	$50.4

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24480	Cotton Blossom 230 kV: Solar Interconnection (J1747)	Interconnect a 50 MW solar generation facility to the Cotton Blossom 230 kV substation.	7/31/2024	$0.7
24899	Twinkletown 230 kV: Solar Interconnection (J1748)	Interconnect a 100 MW generation facility to the Twinkletown 230 kV substation.	7/31/2024	$0.7
25086	Tinnin Road 230 kV: Solar Gen Interconnection (J1672)	Interconnect a 150 MW generation facility to the Tinnin Road 230 kV substation.	11/16/2025	$5.5

4.4.9 Entergy New Orleans LLC (ENO)

After MISO's independent reliability analysis, MISO and Entergy New Orleans recommend one Other Project at an estimated cost of $2.2 million to be approved for inclusion in MTEP23 Appendix A. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Other Projects

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23960	2024 ENOL Asset Renewal Program	This project is for the ENOL Asset Renewal Program that will be executed in 2024. The asset renewal programs replace aged and/or degraded transmission line and transmission substation assets. Entergy continuously reviews asset health to prioritize those replacements and the specifics for the 2024 asset renewal plans have not yet been finalized.	12/31/2024	$2.2

4.4.10 Entergy Texas, Inc. (ETI)

After MISO's independent reliability analysis, MISO and Entergy Texas recommend 12 projects at an estimated cost of $1.3 billion to be approved for inclusion in MTEP23 Appendix A. Of these projects, three are Baseline Reliability Projects, five are Other Projects, and four are Generator Interconnection Projects with signed Generator Interconnection Agreements. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Baseline Reliability Projects:

Project 18266 – New Long John to Dayton 138 kV: Rebuild line

Project Description: Rebuild New Long John to Dayton Bulk 138 kV line. The total estimated cost of this project is $24.9 million and has an expected in-service date of June 1, 2026.

Project Need: NERC TPL-001-5 Reliability Standards and Entergy's Planning Guidelines. The N-1-1 contingency involving the loss of the Lewis Creek to Security and Cleveland to Jacinto 138 kV lines results in up to 200 MW of non-consequential load loss.

Alternative Considered: Reconductor Crystal to 45L555T50 138 kV. The alternative was not selected as the alternative was not compatible with the contingency.

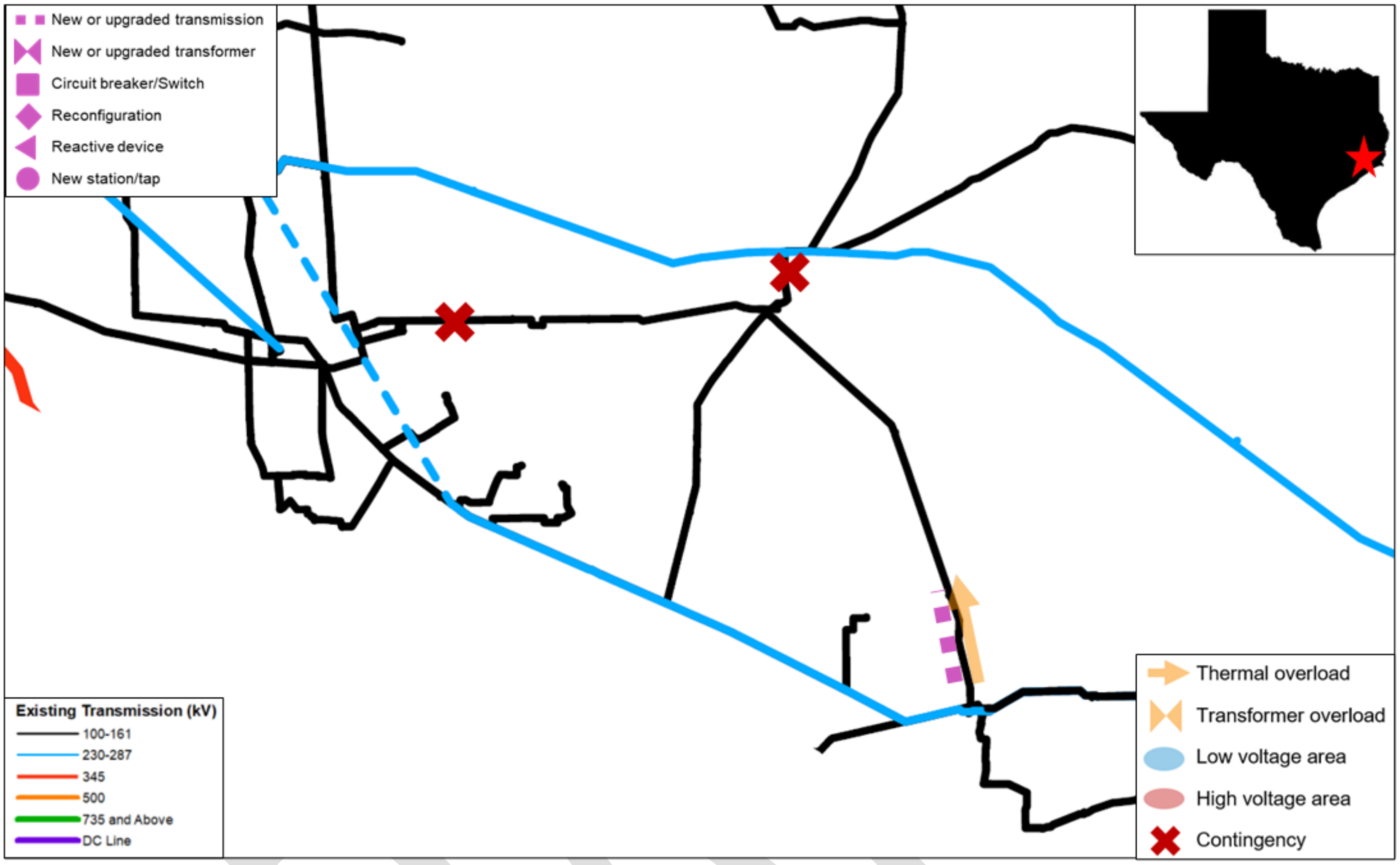


Figure 4.4.10-1: P18266 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	New Long John to Dayton 138 kV	99	259	<99

Table 4.4.10-1: P18266 Thermal loading driver

Project 21844 – Deer to Doucette 138 kV: Upgrade Station Equipment and Line

Project Description: Rebuild the ~6 mile Deer to Doucette 138 kV line. The total estimated cost of this project is $18.4 million and has an expected in-service date of December 1, 2025.

Project Need: NERC TPL-001-5: The G-1 N-1 contingency involving the loss of Montgomery County Power Station and the Rocky Creek to Crockett 345 kV line results in overloads of Deer – Doucette 138 kV line.

Alternatives Considered: No alternatives were considered.

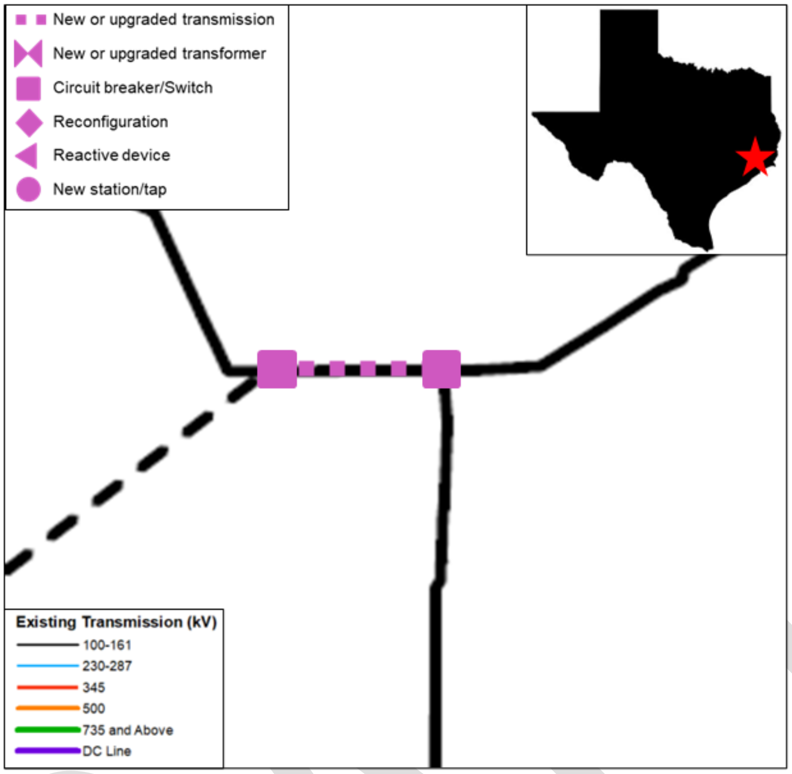


Figure 4.4.10-2: P21844 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P3	Deer to Doucette 138 kV	134	137	<99

Table 4.4.10-2: P21844 Thermal loading drivers

Project 23952 – Southeast Texas Area Reliability Project

Project Description: Construct Babel, a new 500 kV four breaker ring substation on the Layfield to Hartburg 500 kV line near the Toledo Bend Reservoir. Install two 70 MVAR Reactors. East of Lewis Creek, construct a 500-230-138 kV Station named Running Bear. Install a 500-230 kV and 230-138 kV Autotransformer. Cut the Lewis Creek to Peach Creek and Lewis Creek to Porter 230 kV lines into Running Bear 230 kV. Cut the Lewis Creek to Texas, Lewis Creek to Sheawill, and Lewis Creek to Caney Creek 138 kV lines into Running Bear 138 kV. Upgrade Running Bear to Caney Creek 138 kV. Construct a new ~150-mile 500 kV line from Babel 500 kV to Running Bear 500 kV station. The total estimated cost of this project is $1.1 billion and has an expected in-service date of December 19, 2030.

Project Need: The loss of Montgomery County Power Station and Hartburg to Cypress 500 kV overloads multiple elements. The loss of Montgomery County Power Station and Rocky Creek to Crocket 345 kV overloads multiple elements.

Alternatives Considered: Babel to Grimes 500 kV line; Double circuit Rocky Creek to Crockett 345 kV. The alternatives were not selected because the proposed project more completely resolved the limiting element violations resulting from the thermal loading drivers.

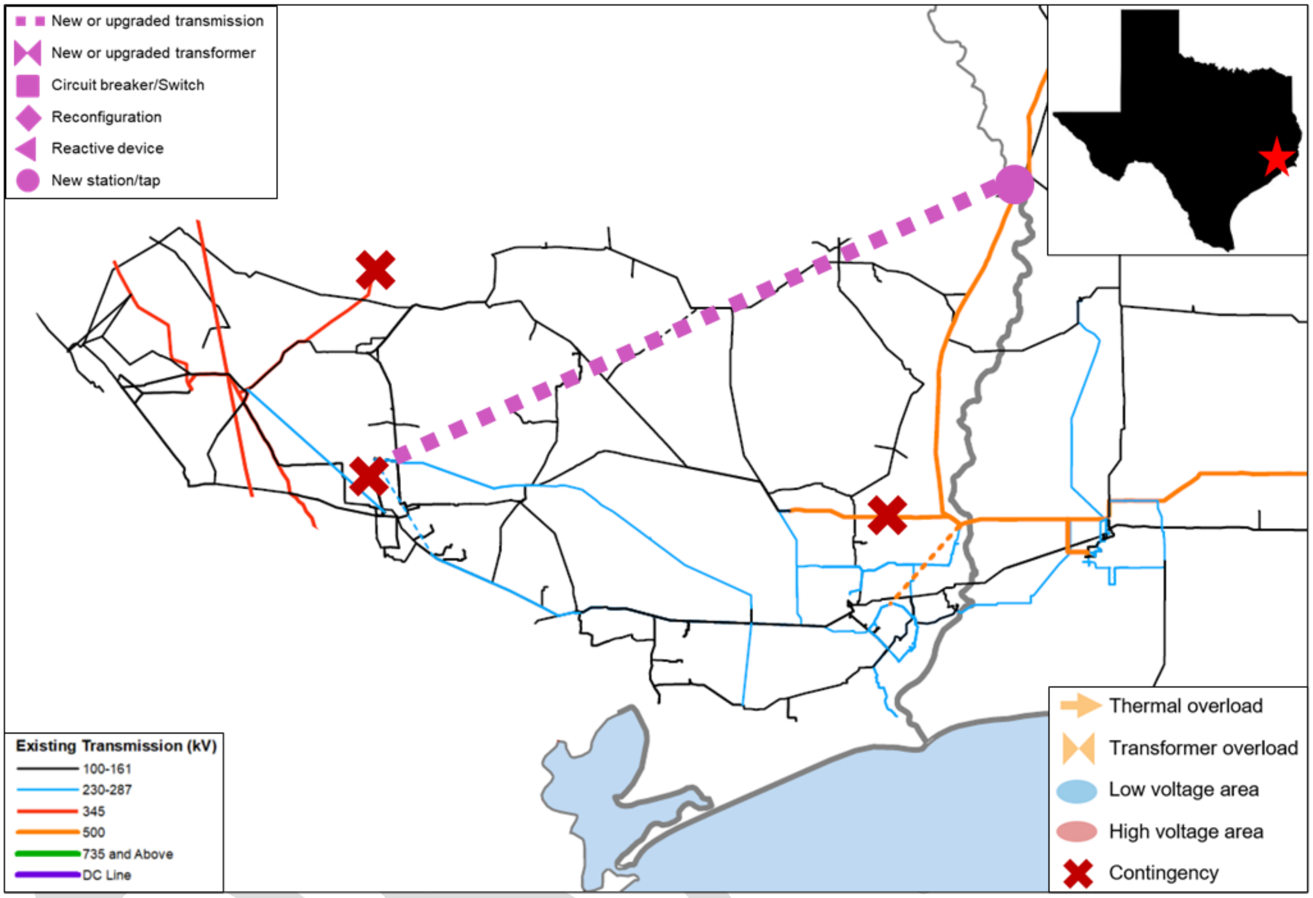


Figure 4.4.10-3: P23952 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P3	Fork Creek to Rayburn 138 kV	137	135.5*	<99
P3	Fork Creek to Rayburn 138 kV	137	137.9*	<99

Table 4.4.10-3: P23952 Thermal Loading drivers (*Case experiences voltage collapse)

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23933	Sabine 230-138 kV Auto Upgrade	Replace the existing 300 MVA 230-138 kV Sabine Autotransformer with a 500 MVA unit.	6/1/2026	$15.5

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23870	This project is for the ETI Asset Renewal Program that will be executed in 2024	Address aging and failing equipment such as structures, breakers, relay panels, RTU's, arresters, circuit switchers, etc.	12/31/2024	$34.2

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24134	Mustang 138 kV New Customer Substation	Entergy is proposing to construct a new 138 kV substation called Mustang, which will serve an industrial customer's 150 MW of new load near Orange, TX. The new Mustang 138 kV station is being laid out as a four bay breaker and a half station with twelve breakers initially installed and cut in on the existing Orange to Bunch Gully 138 kV circuit.	10/30/2024	$28.0
24152	Moscow 138 kV Customer Load Addition Project	Entergy is proposing to construct new 138 kV transmission facilities at the existing Moscow 138 kV substation which will serve an existing industrial customer's new load. The proposed new facilities include installing two 138 kV breakers at the Moscow substation and a new capacitor bank.	6/30/2023	$10.47
24920	Cole Road 138 kV New Customer Station	Entergy is proposing to construct a new 138 kV transmission station called Cole Road 138 kV which will serve a new industrial customer's 10 MW of load near Cleveland, TX. Cole Road 138 kV station will be cut into the Jacinto to Splendora 138 kV line.	10/31/2024	$29.6

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24298	J1442 Interconnection Project on Livingston to Rich 138 kV line	This project is to construct the interconnection station for the solar project J1442 on the Livingston to Rich 138 kV line.	5/1/2025	$15.59
24839	J1671 230 kV Interconnection Project (Rocky Creek to Veteran)	Facilities required for the interconnection of J1671 on the Rocky Creek to Veteran 230 kV.	12/4/2025	$18.85
24984	J1760 Generator Interconnection on Plum Grove to Colony 230 kV	Facilities required for the interconnection of J1760 on the Plum Grove to Colony 230 kV.	6/1/2026	$16.3
25102	J1709 Generator Interconnection at Grimes 138 kV	Facilities required for the interconnection of J1709 at the Grimes 138 kV station.	2/1/2025	$7.2

4.4.11 Lafayette Utilities System (LAFA)

Lafayette Utilities System, LAFA did not submit any new projects for MTEP23. MISO has not identified any open issues in the LAFA area.

4.4.12 City Water and Light Jonesboro (CWLT)

After MISO's independent reliability analysis, MISO and City Water and Light Jonesboro recommend one Other Project at an estimated cost of $0.32 million to be approved for inclusion in MTEP23 Appendix A. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Other Projects

Projects Driven by Local Needs

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
25094	Commerce to Ringier 69 kV Relocation	ARDOT currently has a contract to widen and expand the existing Hwy. 18S. CWLT is required to relocate the Commerce Ringier 69 kV Line.	9/30/2023	$0.32

4.5 Project Justifications – West Region

West Region Overview

The MISO West Planning Region consists of 20 Transmission-Owning members spanning eight states in the upper Midwest. It includes Iowa, Minnesota, Wisconsin, and parts of North Dakota, South Dakota, Montana, Michigan, and Illinois. These Transmission Owners are:

American Transmission Company (ATC)

Cedar Falls Utilities (CFU)

Central Minnesota Municipal Power Agency (CMMPA)

City of Ames, IA (COA)

Dairyland Power Cooperative (DPC)

Great River Energy (GRE)

ITC Midwest (ITCM)

MidAmerican Energy Company (MEC)

Minnesota Municipal Power Agency (MMPA)

Minnesota Power (MP)

Missouri River Energy Services (MRES)

Montana-Dakota Utilities Co. (MDU)

Muscatine Power and Water (MPW)

Northwestern Wisconsin Electric (NWEC)

Otter Tail Power Company (OTP)

Rochester Public Utilities (RPU)

Southern Minnesota Municipal Power Agency (SMMPA)

Wilmar Municipal Utilities (WMU)

WPPI Energy (WPPI)

Xcel Energy (Northern States Power, XEL/NSP)

The West planning region contains approximately 27,300 miles of transmission ranging from 57 kV to 500 kV. In the 2023 Summer Peak planning model, the region contains more than 67.2 GW of generation. Installed generation capacity in the region consists mostly of coal, gas and wind. Approximately 33.4 percent (22.5 GW) of the West region's generation capacity is made up of wind units. Major generation centers are located in central North Dakota; the Twin Cities in Minnesota; and the Quad Cities in Iowa and Illinois, with wind generation located in the eastern Dakotas and western Iowa and Minnesota (Figure 4.5-1).

Major load centers are typically found around larger cities in the region: Minneapolis/Saint Paul, Milwaukee, and Des Moines. According to the 2023 Summer Peak planning model, the regional load exceeds 42.2 GW. Power generally flows from generation-rich areas in the western portion of the region through Minnesota, Iowa, and Wisconsin, toward large load centers in the east. This is especially prevalent in times of high wind output.

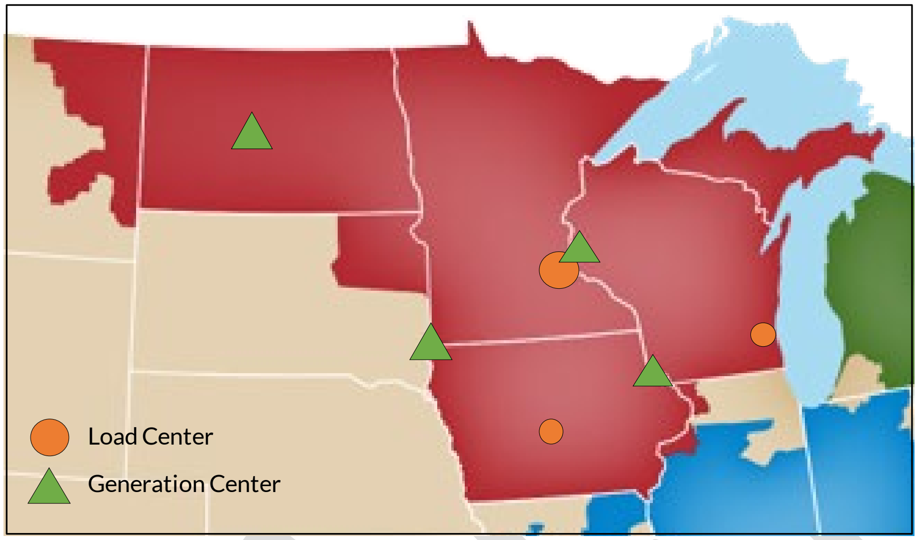


Figure 4.5-1: Generation and load centers in the West Planning Region

For MTEP23, MISO Transmission Planning is recommending 244 projects from the West region for inclusion in Appendix A at an estimated cost of $1.8 billion. Of these, nine are Baseline Reliability Projects, 28 are Generator Interconnection Projects, two are Market Participant Funded Projects, one is a Multi-Value Project, and the remaining 204 projects are classified as Other Projects. MISO considered alternatives for two projects in the west region. The original proposed projects were selected as the results of the alternative analysis.

Of the 244 projects being recommended to be included in MTEP23, 56 have an estimated cost of less than $1 million, 86 have an estimated cost between $1 million and $5 million, and the remaining 102 projects are estimated to cost greater than $5 million (Figure 4.5-2).

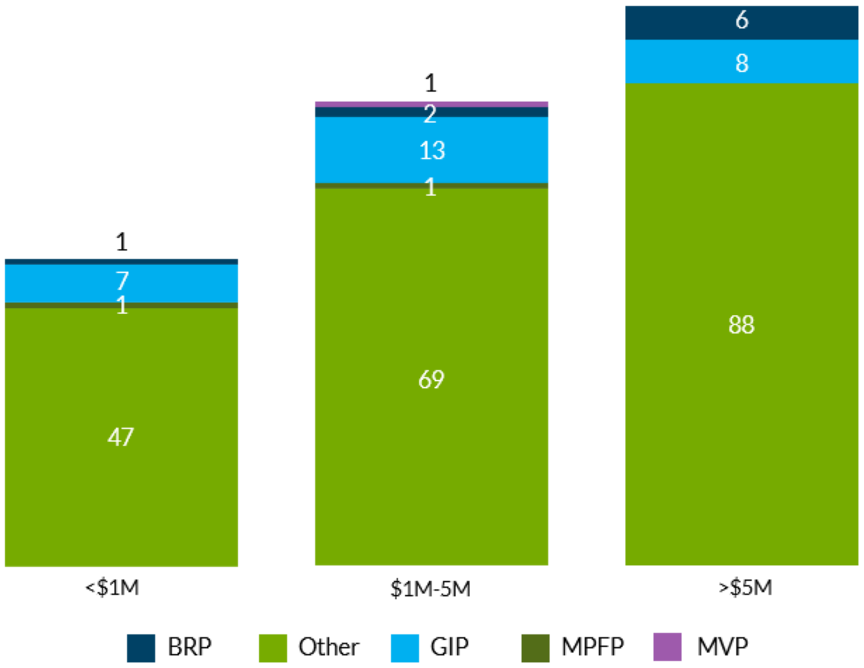


Figure 4.5-2: Project counts by cost category of MISO West region MTEP23 projects (data as of 9-29-2023)

The majority of the projects in the MISO West planning region are expected to go in service in the next three years (Figure 4.5-3). There are around 37 projects that have already went into service or are expected to be in-service by the end of 2023. A couple of projects were transmission network upgrades (GIP) correlated with generation projects that were justified by a separate Generator Interconnection process. Others fit into a bucket of timing or constructability considerations. Examples of these are the retirement of catastrophic failure devices, load additions which required short time frames to come online, or those that take advantage of outages already scheduled and planned the upgrade accordingly to meet the compliance.

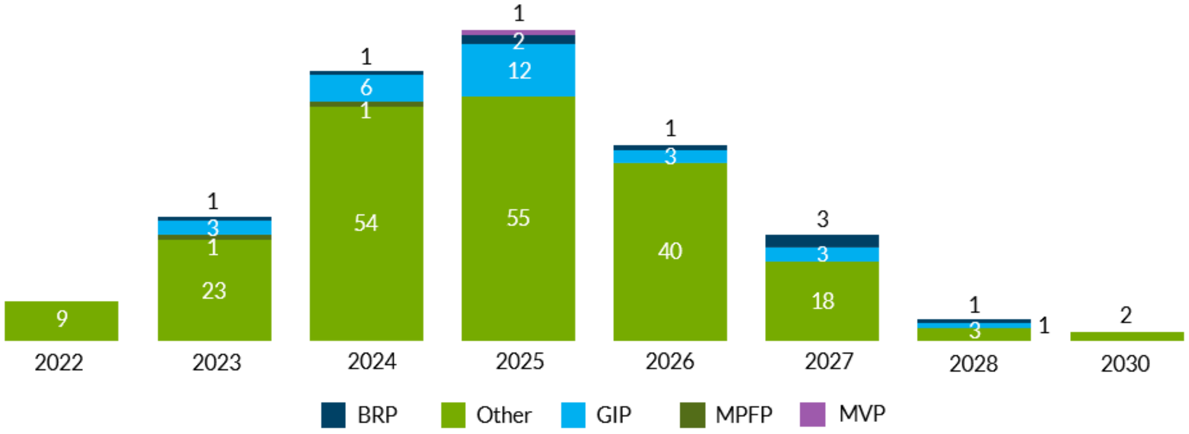


Figure 4.5-3: West region MTEP23 projects by in-service date (data as of 9-29-2023)

In accordance with Attachment FF of the tariff, in the event that a Transmission Owner determines that system conditions warrant the urgent development of system enhancements that would be jeopardized unless MISO performs an expedited review of the impacts of the project, MISO shall use a streamlined approval process for reviewing and approving projects proposed by the Transmission Owner(s) so that decisions will be provided to the Transmission Owner within 30 Days of the project's submittal to MISO unless a longer review period is mutually agreed upon. During the MTEP23 cycle, MISO received the following projects through the Expedited Project Review (EPR) process:

1. Project ID 23806, OTP Lake Preston, Load Addition
2. Project ID 23936, OTP Milbank, Load Addition
3. Project ID 25256 OTP Jamestown, ND Load Addition 115 kV
4. Project ID 24740, ITCM Commercial (JCE) 69 kV Substation
5. Project ID 24513, ITCM CIPCO Maquoketa 161 kV Sub Rebuild
6. Project ID 24464, ITCM Eagle to Tharp 69 kV Line Relocation
7. Project ID 24449, ITCM Nevada Area Load Interconnections
8. Project ID 25060, ITCM Grant Milford Interconnection
9. Project ID 23919, MRES Morris to Grant County to East Fergus Fall 115 kV Upgrade
10. Project ID 24978, MDU Tatanka Load Addition
11. Project ID 22871, GRE Cedar Lake Line Rebuild
12. Project ID 24999, MEC Southland Expansion & Upgrades

Also, in accordance with Attachment FF Section VIII.A.3, none of the projects were identified as an Immediate Need Reliability Project and excluded from the competitive developer selection process. The ten largest project investments in the MISO West region represent $400 million (22%) of the $1.8 billion total recommended projects for the West region in MTEP23, or 4% of the $9 billion total recommended in the MISO footprint. The locations of these projects can be seen in Figure 4.5-4 and the investment is spread across the West Planning region. Projects that are blanket expenditures (relays, physical security, etc.) are excluded from this list.

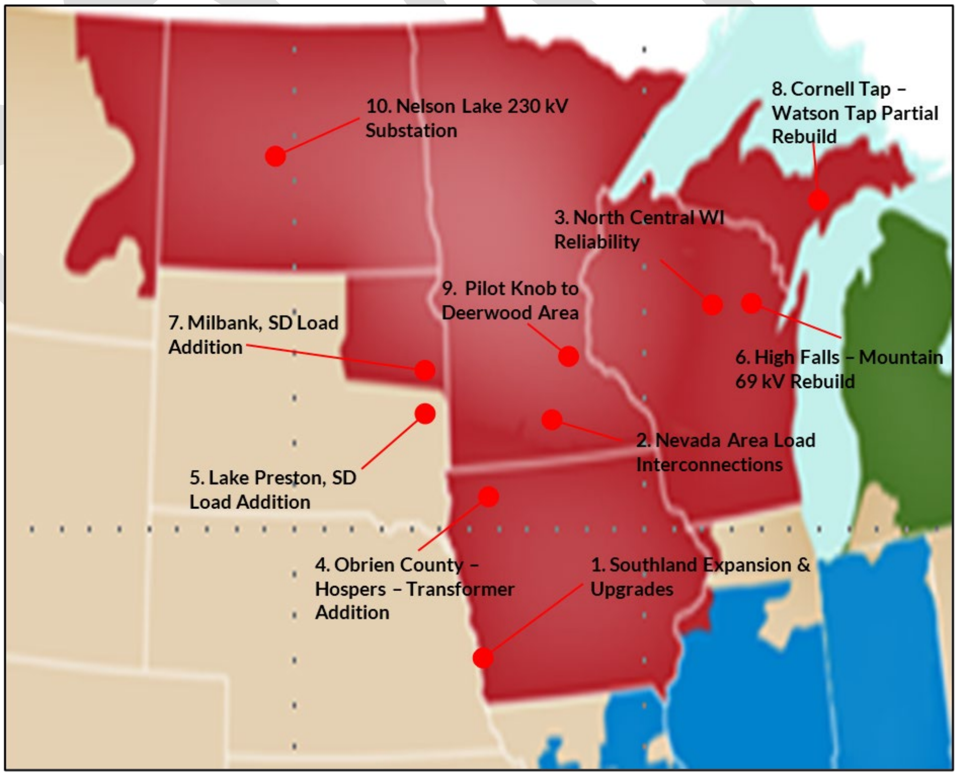


Figure 4.5-4: West region top ten projects by cost (data as of September 29, 2023)

4.5.1 American Transmission Company (ATC)

After MISO's independent reliability analysis, MISO and American Transmission Company recommend 55 projects at an estimated cost of $742 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, three are Baseline Reliability Projects, 39 are Other Projects, and 13 are Generator Interconnection Projects with signed Generator Interconnection Agreements. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Baseline Reliability Projects

Project 22587 North Central WI Reliability Project

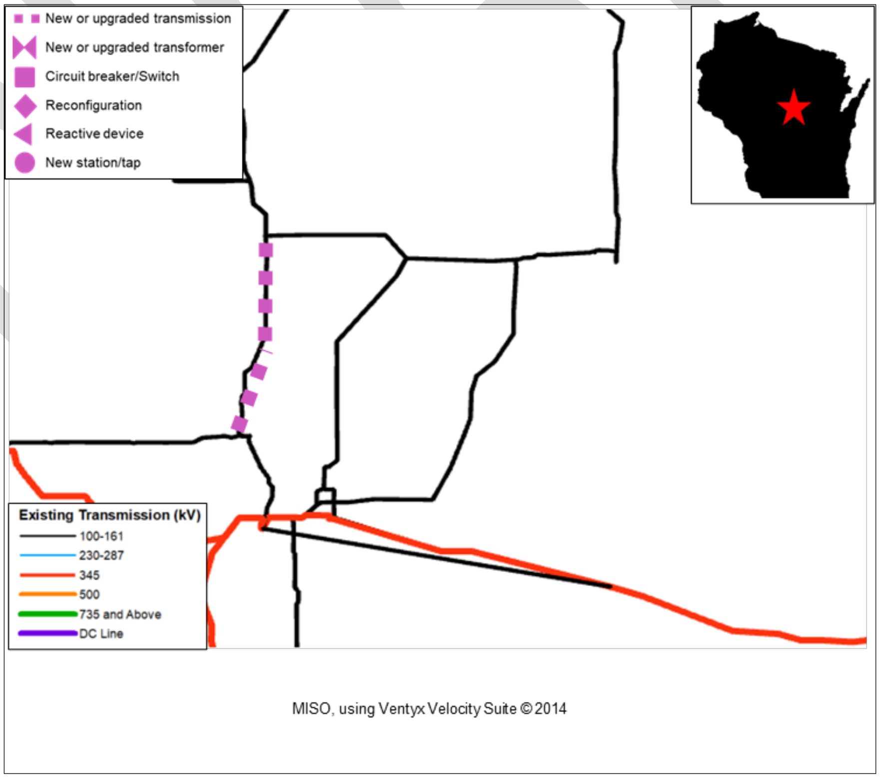
Project Description: Address reliability concerns in the 115 kV system in North Central Wisconsin for multiple P6 outage combinations. Scope includes the following:

- Construct new 115 kV source between Hilltop and Pine substations
- OPGW to be installed on new line
- Asset renewal work on relays at Hilltop, Maine, and Pine substation
- Upgrade Pine SS Bus #51 to match rating of new line

The total estimated cost of this project is $47.9 million and has an expected in-service date of June 1, 2028.

Project Need: NERC Category P6 Contingency causes overloads on the 115 kV system in Central WI. Bringing a second source into the area will prevent the need for system reconfiguration.

Alternatives Considered: No alternatives were considered.



MISO, using Ventyx Velocity Suite ©2014

Figure 4.5.1-1: P22587 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	'ACKLEY' 115 - 'KELLY' 115 1	173	104	56

Table 4.5.1-2: P22587 Thermal Loading drivers

Project 23912 East Krok SS Transformer Replacement

Project Description: This project will replace the existing East Krok Transformer 1 with a new 138/69 kV 100 MVA transformer. The total estimated cost of this project is $8.7 million and has an expected in-service date of December 31, 2027.

Project Need: Various outages cause the East Krok Transformer 1 to overload. Replacement of this transformer will minimize need for system reconfiguration.

Alternatives Considered: No alternatives were considered.

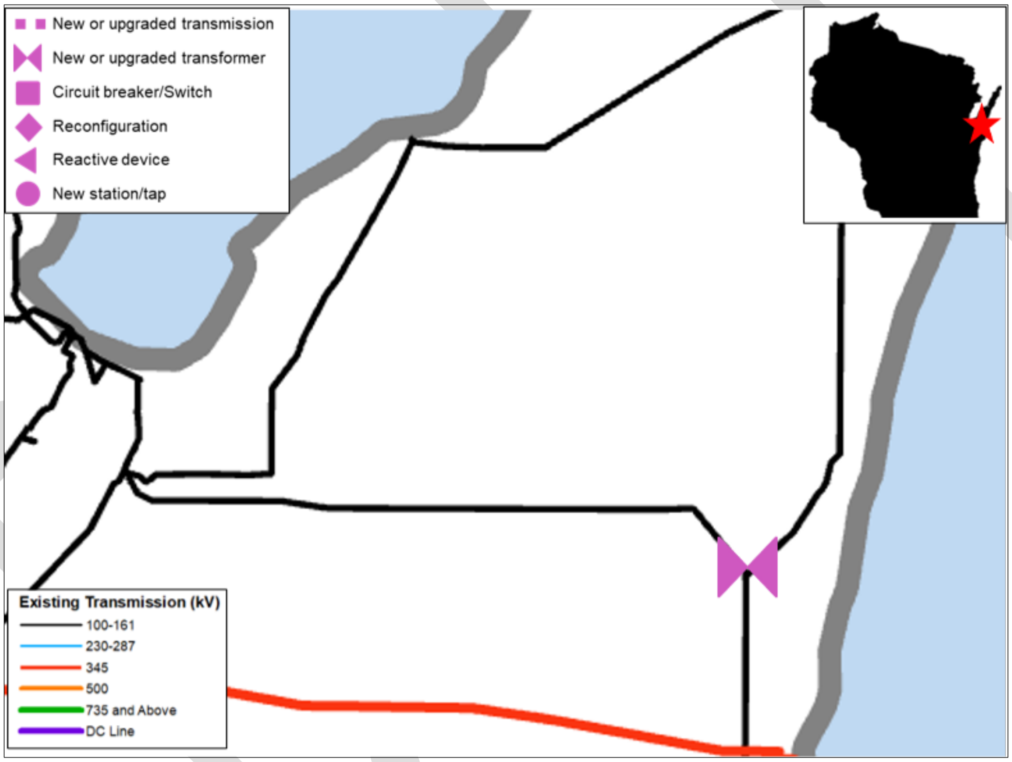


Figure 4.5.1-3: P23912 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	'EAST KRK' 69 - 'EAST KRK' 138 1	60	106	64
P6	'EAST KRK' 69 - 'EAST KRK' 138 1	60	105	63
P6	'EAST KRK' 69 - 'EAST KRK' 138 1	60	106	64

Table 4.5.1-4: P23912 Thermal Loading drivers

Project 24093 Rocky Run SS T2 and T4 Power Transformer Replacement

Project Description:

Planning Scope:

- Remove Rocky Run 345/115kV transformers T2 and T4. Replace with on-site spare 500MVA 345/115kV transformer in the T4 position.
- Upgrade two (2) 345kV bus switches and five (5) 115kV bus switches.
- Remove breaker 4-2 and shorten 345kV ring bus.
- Purchase new 500MVA 345/115kV system spare.

Asset Renewal Scope:

- Replace W-8 secondary relay SEL-321 (component replacement).
- Replace all physical security cameras.

The total estimated cost of this project is $17.6 million and has an expected in-service date of June 1, 2027.

Project Need: T4 loading exceeds the emergency rating for the NERC Category P6 contingency.

Alternatives Considered: No alternatives were considered.

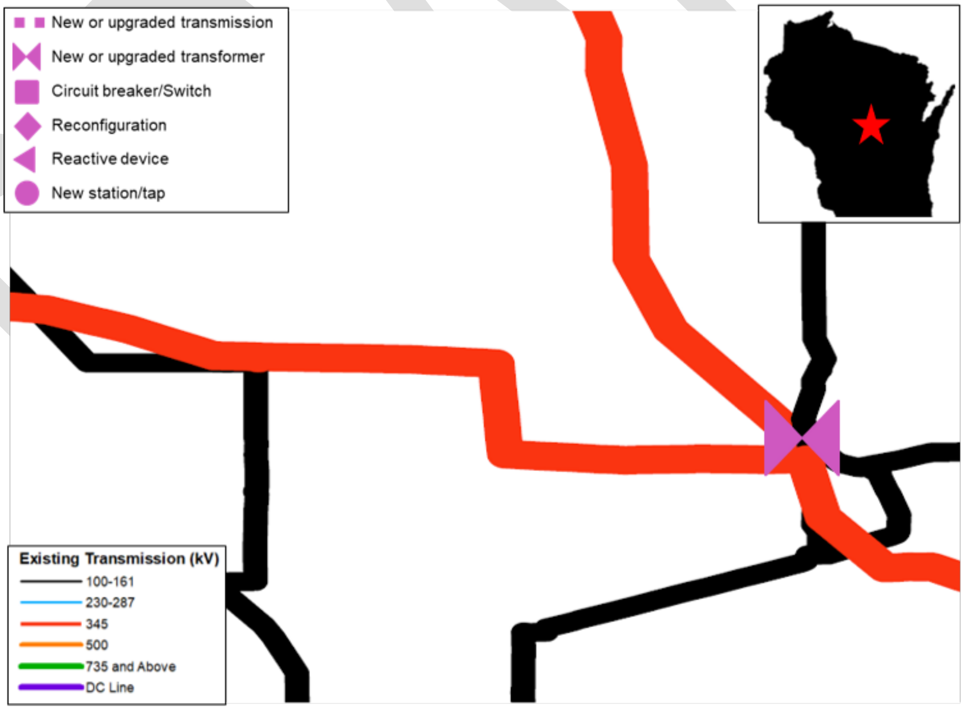


Figure 4.5.1-3: P24093 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	'ROCKY RN B4' 345 - 'ROCKY RN' 115 3	200	110	44

Table 4.5.1-5: P24093 Thermal Loading drivers

Other Projects

Projects Driven by Other Local Needs

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20202	Communication Reliability Program 2024	Communications network system upgrades typically require limited infrastructure modifications and additions with shorter project life cycles. Substation Communications Reliability Upgrade projects are typically (but not limited to): - OPGW additions, replacements, relocations, or removals. - Project drivers typically are communications support for SCADA, Relay protection, Security systems, Small communications network upgrades, and Telecom industry market transitions. These projects have limited scope and cost. Initial capital spend for this program expected in 2024.	6/30/2026	$11
23858	Wick Drive – Black Earth 69 kV, (Y-62), OPGW Addition & Partial Rebuild	Installation of 6 miles OPGW with (57) Structure Replacements and (2.2) miles of new (T2-477 HAWK) conductor added to scope between the Wick Drive to Mazomanie Tap substations. 55 replacements assumed due to engineering usage analysis of 1985 and earlier structures. Of the 55 replacements, 22 also are legacy with asset renewal condition need. 2 additional structures from WKS-MAZT to replace due to ground clearance for new T2-477. OPGW Termination from Wick Drive and Black Earth substation Dead-End structures into the control houses. Substation Router Configuration to route SCADA and Relay communications on to ATC's private fiber network infrastructure	12/31/2026	$7

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		Real Estate Easements Required to address gaps and areas of inadequate width. (~$500k)		
24465	Walworth - Brick Church (Y-159), OPGW Addition & Partial Rebuild	OPGW Addition on the Walworth - Brick Church (Y-159) line and partial transmission line rebuild.	6/30/2026	$4.6
25154	CRP Substation Ethernet Migration (Phase 2)	The telecommunication companies will construct fiber infrastructure to the substation locations. This fiber will extend from the road right of way to a telecommunications handhole located outside of the fence. When a handhole does not exist outside of the fence, a new ATC owned handhole will be installed. The telecommunication companies will install fiber from this handhole through existing conduit and into the control house. The telecommunication companies will install a network interface device (NID) and any other needed associated equipment on the telecommunications board to terminate their fiber. ATC will power the NID from at least one direct current (DC) circuit and will coordinate turn up of the new ethernet circuit with the telecommunication companies. ATC will coordinate with AT&T for the decommissioning of the existing T1 service. ATC will replace the substation router at 14 locations. Some of these locations will also require a cellular router and cell booster to be installed as the backup communications medium, replacing the existing plain old telephone service (POTS). ATC will install Voice over Internet Protocol (VoIP) phones at ATC owned control houses with existing analog phones.	6/30/2024	$5.5

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20203	Line Clearance Mitigation Program 2024	Line Clearance Mitigation projects have shorter project life cycles. Projects are driven by the ongoing assessment and analysis of field line	6/30/2026	$10.0

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		clearances using Light Detection and Ranging (LiDAR) technology. Clearance mitigation work immediately follows data assessments and issue identification to maintain safety and system reliability. Initial capital spend for this program expected in 2024.		
23836	Perch Lake - National 138 kV (468) Partial Retirement Project	Reconfigure 138 kV line 468, from Perch-Lake to Presque Isle, by terminating into National SS to establish a new Perch Lake – National line. The remaining 23 miles of line from National to Presque Isle will be retired.	11/1/2025	$10.4
24785	Pleasant Prairie 345 kV Capacitor Bank Addition	Install four 345 kV 75 MVAR capacitor banks at Pleasant Prairie substation.	6/30/2025	$7.6
24819	Racine 345 kV Capacitor Bank Addition	Install two 345 kV 75 MVAR capacitor banks at Racine substation.	6/30/2025	$8.4
24296	Valders SS, New 138/69 kV Substation	Construct a new 138/69 kV Valders Substation with 100 MVA transformer looping in Forest Junction - Howards Grove 138 kV (971K51) and Custer - St Nazianz - New Holstein 69 kV (P-68) lines.	07/31/2028	$24.2
25207	Forsyth-Empire (Forsyth) 138 kV, Rerate	Rerate Line Forsyth conductor for the Forsyth to Empire section to keep up with the system demand. The thermal study identified 18 clearance issues needed to be fixed to bring the rating up to meet Operations/Planning's needs.	10/20/2024	$5

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
19963	Kirkwood SS, Power Transformer and Breaker Asset Renewal	Replace T31, a 1974 vintage 138/69 kV 93 MVA power transformer with the onsite 138/69 kV 100 MVA system spare. Replace station service transformers of 100 kVA. Replace all relays, RTU, batteries and charger and install new DC panel in existing building.	12/31/2026	$14.1

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		Install battery monitoring solution instead of dual batteries to fit in existing building. Install new 138 kV and 69 kV bus tie breakers and associated disconnect switches. Replace two 69 kV and two 138 kV oil circuit breakers and replace with SF6 gas breakers. Remove and retire disconnect switches no longer in use and bypass switches. Replace one 69 kV disconnect switch due to condition. Replace capacitor cans and protection voltage transformers on existing 19.2 MVAR bank. Install new 138 kV 16.33 MVAR capacitor bank. Install new 138 kV bus PT's and new 69 kV bus PT's. Install new line side disconnects. Replace existing CCVT and wave trap. Replace brown glass insulation. Add corona rings to existing line dead-end polymer insulators.		
20201	Small Capital Project and Asset Renewal Program 2024	Asset replacements and upgrades typically require limited infrastructure modifications and additions with shorter project life cycles. Transmission Line Projects typically (but not limited to): - Structure, Cross-arm, Insulator, Surge-arrester, and Pole hardware replacements. Substation Projects typically (but not limited to): - Relays, Circuit breakers, Switches, Instrument Transformers (CTs & PTs etc.), Batteries, RTUs, and IT/OT/Communications hardware replacements. Project drivers may be Asset Renewal or small system limit upgrades. These projects have limited scope and cost. Initial capital spend for this program expected in 2024.	6/30/2026	$47

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
21921	Groenier – Rosholt (ALTE) Tap, 69 kV (Y-71), Partial Rebuild and Rerate	Sectionalize of tap near existing Rosholt (ALTE) Substation with 3-Way T-Line switch. Assumed rebuild section off center due to radial connection. Bury distribution to resolve rerate issues.	12/31/2025	$16.5
21985	Chandler-Delta 69 kV (Delta1), Rebuild and OPGW	Rebuild approximately 5.5 miles of 69 kV line Delta1 from Delta SS to Chandler SS and install OPGW.	6/30/2026	$11.6
23837	Northeast - Revere Dr. 69 kV (C-103), Uprate or Rebuild	Scope to include partial rebuild. Substation scope is for Revere Drive. Fiber optic installation.	1/31/2030	$8.6
23838	High Falls – Mountain 69 kV (Y-77), Rebuild & OPGW	Rebuild ~16.4 miles with new wire mesh wrapped wood pole structures and steel poles on foundation. - T2 4/0 Conductor and 48 Fiber OPGW. Conductor would meet and exceed planning needs. - Assumed to obtain Certificate of Authority (CA) application by rebuilding off center (30' shift) and obtaining new 80' easements typically. This is due to radial connection and uncertainty at this time if outage and distribution could be taken out for a period of time. This may not be necessary once project gets into details and could result in savings as listed under alternatives. Real Estate, Environmental, Vegetation - Majority of existing easements are 80' in width with vegetation management and access rights. 2 DNR parcels will require permit/easement. - Project assumes new easements at $800k due to shift in ROW, rest through NEPA permit. - Shifting centerline will require going through the NEPA process (schedule impacts), likely an Environmental Assessment (EA), with a resulting Special Use Permit from the Chequamegon-Nicolet National Forest. - Federal forest lands currently limit herbicide spray, resulting in brush growing up along the Rights-of-Way. Within two years of next cycle and in decent shape with prior aerial saw work.	12/31/2028	$33.0

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23856	Benson Lake SVC SCM Layer Asset Renewal	Replace hardware and software of the Benson Lake SVC plant System Control and Monitoring (SCM) Layer with supported hardware and software with a design life of 10 years.	12/1/2026	$4.5
23857	Pine Hy Tap – Pine Hy 69 kV (ASPY31-1), Rebuild & OPGW	Install 6.3 miles of new single circuit line on existing ROW.	12/31/2027	$11.5
23874	Harrison Tap – Iola 69 kV (Y-70), Rebuild & OPGW	Rebuild approximately 11 miles of 69 kV with new wood monopoles wrapped with mesh.	12/31/2026	$16.0
23875	Madison Area Relay Projects	Asset Renewal of Blount control building and contents. Retire the existing 69 kV control building at Sycamore. Install new relaying at Blackhawk (MGE), Blount, East Campus, Ruskin, Sycamore, Walnut GIS and Wingra SS.	12/1/2026	$21.9
23876	Cornell Tap – Watson Tap 69 kV (Chandler), Partial Rebuild	Rebuild approximately 18 miles of 69kV Chandler line between Cornell Tap and Watson Tap.	12/31/2026	$30.0
23895	McCue SS Control House and Relay Asset Renewal	Replace control building and contents. Install relay panels, no remote end work needed. Replace Siemens Station Manager RTU. Replace 69 kV OCB Westinghouse model 690-GS-2500. Replace existing 69 kV cap bank with 16.3 MVAR in the same bus position, replace zero crossing breaker. Retire or replace 796-A when reconductoring the 69 kV bus. Provisions to meet battery standard TPL-001-5 requirements with either dual battery or monitoring. Install 138 kV line side disconnects if practical. Install 138 kV line breaker and relaying for the section of 138 kV bus that leaves the McCue yard to feed Kennedy SS Replacement of 954.0 kcmil AAC 37 Magnolia bus and jumpers in MCU 69 kV Bus 1 and 2.	12/1/2026	$9.5
23897	Ohmstead SS Control House and Relay Asset Renewal	Replace control building and contents Install approximately five relay panels, no remote end work needed	12/1/2026	$5.7

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		Replace Siemens Station Manager RTU Replace one Bus power potential Transformer. Add four new 138 kV line side disconnects. Provisions to meet battery standard TPL-001-5 requirements with either dual battery or monitoring.		
23901	Shoto SS, Power Transformer Asset Renewal	Replace T1, a 1972 vintage 69/138 kV 84 MVA power transformer with a new 69/138 kV 100 MVA replacement. Install oil containment system for the new transformer. Install online monitoring to the new transformer and existing T2 transformer. Replace fuses and assemblies, capacitors, protection voltage transformers, and reactors on existing capacitor bank and rack for a life extension of the existing asset. Investigate and provide mitigation as needed to existing ground grid per current guidelines.	12/1/2026	$6.2
23902	SS Physical Security Switch and SS Asset Renewal Enhancement	Replace the existing Cisco 2520 switches at approximately 28 substation control house locations including dedicated firewall additions at the enhanced security sites. Replace the existing Cisco 3750/3850 physical security switches at approximately 56 control house locations. Install station wi-fi functionality at approximately 67 control house locations. Replace the existing network speakers and network door video stations at approximately 67 control house locations. Migrate mission critical equipment from AC inverted power to the station DC power at approximately 67 control house locations. Implement rogue device detection at approximately 67 control house locations.	12/1/2025	$10
23903	North Beaver Dam SS Asset Renewal	Reconfigure 138 kV bus layout. Install a fire wall between ATC and Alliant power transformers. Install online monitoring per approved 2020 program to T31 power transformer. Replace one 1980's vintage 138 kV circuit	12/1/2026	$16.1

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		switcher with a circuit breaker. Replace control building which will include relay replacements, RTU replacement, and battery replacement. Replace 69 kV 10.8 MVAR fused capacitor bank with a 12.25 MVAR fuseless bank. Install future 138 kV bus-tie disconnect switches and a set of 138 kV bus PTs to allow for bus sectionalizing. Install new line side disconnect switch on the X-47 terminal, does not currently exist. Upgrade jumpers per Planning requirements on the Y-59 line to meet future transmission line renewal needs. Upgrade strain bus in the 69 kV bus per Planning requirements to meet future needs.		
23904	South Beaver Dam – North Beaver Dam, 69 kV (Y-59) Line Rebuild & OPGW	Rebuild line and install OPGW on 4.1 miles and install 0.9 miles of OPGW on remaining section. Assumes newer legacy vintage structures can remain.	12/31/2026	$11.2
23905	Waupun - South Fond du Lac 69 kV, (Y-25) Partial Rebuild	Replace remaining legacy monopoles poles (~60%) as ~40% were replaced in 2011. Replace conductor and static with new material.	12/31/2026	$22.6
23906	South Fond du Lac SS, Power Transformer and Breaker Asset Renewal	South Fond du Lac: Replace two power transformers with new single larger voltage transformer. Install new bus for auxiliary station service. - Install new motor operated switches. - Relocate one gas circuit breaker to a new position to support new transformer location. - Retire three CCVTs and relocate one CCVT. - Install motor operators on two line disconnect switches. - Retire one oil circuit breaker and replace with gas breaker. - Replace portions of strain bus with rigid bus and replace bus PTs to support new transformer location. - Retire a portion of strain bus and replace bus PTs.	12/1/2026	$9.5

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		- Replace eight disconnect switches to support bus rebuilds and breaker replacement. - Replace four disconnect switches Columbia: - Purchase a new spare transformer.		
23911	Shoto – Northeast 69 kV (K-11), Rebuild	Line rebuild. Substation work at Northeast. Fiber optic installation.	10/31/2030	$5.4

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20204	Load Interconnection Program 2024	Load Interconnection Project life cycles are customer need driven and typically have shorter project life cycles. These Load Interconnections typically require limited infrastructure modifications and additions. These projects have limited scope and cost. Initial capital spend for this program expected in 2024.	6/30/2025	$16.0
23913	Northern Adams County Area Network Improvement Project	Construct 9.2 miles of 69 kV single circuit transmission line (5 miles between Badger West and Y-302, and 4.2 miles between Y-302 and Colburn). Expand Badger West substation with three 138 kV breakers, a 138/69 kV, 100/167/187 MVA base transformer, a new ATC control building and one 69 kV line breaker. Modify X-43 at Badger West to cross over the new 69 kV t-line.	5/1/2027	$39.9
23915	Delta County, DIC, Upgrades	ATC will construct a 138 kV, four-breaker ring configuration substation, with ultimate provisions for a six-position 138 kV ring bus. ATC will loop the existing Holmes-Old Mead Rd 138 kV line (OMDG81) into the new 138 kV substation, raising the OMDG81 line over the existing Old Mead Rd-Delta OMDY51 line.	1/31/2027	$21.0

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		ATC will retire a portion of the existing Old Mead Rd-Mead Paper 69 kV line (OMDY71), retire OMDY51/OMDY71 bypass equipment and retire the remaining portion of OMDY71 in place. ATC will remove a 69 kV breaker and OMDY71 line MOD at Old Mead Rd. ATC will replace 31 structures on the Arnold-Perkins 138 kV double circuit lines (ARNG81/29051). ATC will implement reverse power blocking and/or LTC tap limiting on the Chandler and Old Mead Rd 138/69 kV transformer LTC controls.		
24373	Manogue Rd SS DIC, New Substation	New tapped substation to serve 4.3 MVA motor load between the existing Edgerton Business Park and Russell substations on the 138 kV Line X-31. Line breakers will be installed at the Edgerton Business Park Substation on the Rockdale-Edgerton Business Park-ANR Manogue Rd-Russell 138 kV (X-31) line due to high network flow.	8/1/2025	$7.1
24473	Rock River SS, DIC, Additional Transformer	Expanding Rock River 138 kV Bus 3 to interconnect a distribution transformer.	7/1/2024	$3.0
24475	Tommy's Turnpike DIC, New Sub	ATC will construct an approximately 0.3 mile 115 kV double-circuit transmission line extension from the Whiting Ave – Okray 115kV line (B-106) to interconnect the proposed T-D substation. ATC will construct a 115 kV loop-through straight bus with line switches, bus-tie switches, and space reserved for potential line and bus-tie breakers. WPS to construct a new substation site, install two new 115/24.9 kV 33/38 MVA transformers with high side breaker protection for each and other supporting equipment.	12/31/2025	$7.7
24575	DPC Germantown Jct Tap, New T-T	New T-T interconnection to Council Creek-Hilltop 69 kV (Y-74), and constructing a new 69 kV loop-through substation near New Lisbon Tap with three line breakers to replace an existing three-way GOAB.	6/1/2026	$11.1

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24783	Hodag SS, DIC, Add Additional Transformer	Expand and reconfigure substation to a loop through straight bus configuration.	12/31/2024	$2.7
24784	Ellisville SS, DIC, New Substation	ATC will construct approximately 0.7 miles of 138 kV double-circuit transmission line extension from line M-39 to interconnect the proposed T-D substation. ATC will construct a 138 kV loop-through straight bus with two-line breakers and provisions for a future bus-tie breaker.	6/1/2025	$10.2

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24445	J1374 Ebenezer SS Network Upgrades and Interconnection Facilities	Wind Turbine generating Facility located in Grant County, Wisconsin.	8/1/2024	$1.6
24446	J1251 Summer Meadow Switching Station Network Upgrades and Interconnection Facilities	A 100 MW solar farm located in Marquette County, Michigan.	6/12/2025	$8.0
24447	J1483 Hill Valley SS Network Upgrades and Interconnection Facilities	Wind farm in Iowa County, Wisconsin.	9/1/2026	$2.3
24613	J1214 J1326 Rockdale SS Network Upgrades and Interconnection Facilities	Solar development with energy storage in Dane County, Wisconsin.	6/1/2025	$4.1
24758	J1410 J1411 North Arlington Swt St MPFCA & Network Upgrades	J1410 is a solar facility located in Dane County, Wisconsin. J1411 is an energy storage facility co-located in Dane County with J1410.	6/3/2026	$22.0
24782	J1304 J1305 J1460 MPFCA Network Upgrades	Transmission owner will reconductor one of the two segments of the line UNIG52.	12/31/2025	$4.9
24799	J1377 Blitz SS Network Upgrades and Interconnection Facilities	Solar generating facility in Rock County, WI.	11/12/2026	$14.6
24801	J1253 El Dorado SS Network Upgrades and Interconnection Facilities	Solar generating facility along with substation and network upgrades in Fond du Lac County, Wisconsin.	11/12/2027	$50.5

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24802	J1460 Sunrise SS Network Upgrades and Interconnection Facilities	Solar generating facility and substation upgrades in Rock County, WI.	12/27/2025	$4.5
24838	J1316 Paris SS Network Upgrades	J1316 is an energy storage facility interconnected at the same location as J878, a solar facility located in Kenosha County, WI.	12/29/2028	$22.4
24841	J1214 J1326 J1377 J1410 J1411 MPFCA Network Upgrades	Network upgrades to support new interconnections J1214 (solar), J1326 (storage), J1377 (solar), J1410 (solar), J1411 (storage).	5/30/2025	$1.3
24858	J1253 J1410 J1411 MPFCA Network Upgrades	Network upgrades to support new interconnections J1253 (solar), J1410 (solar), and J1411 (energy storage).	12/30/2025	$0.1
25262	J1305 Norwegian Creek SS Network Upgrades and Interconnection Facilities	Solar generating facility in Green County, Wisconsin.	11/08/2023	$8.1

4.5.2 Cedar Falls Utilities (CFU)

After MISO's independent reliability analysis, MISO and Cedar Falls Utilities recommend one Other Project at an estimated cost of $2 million to be approved for inclusion in MTEP23 Appendix A. The expected in-service date and estimated cost for this project is provided as of September 29, 2023.

Other Projects

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23993	Streeter-Wida Rebuild	Rebuild of the eastern half of CFU's part of the Streeter Switch Substation to MEC's WIDA substation. This will include reconductor and structures.	4/1/2024	$2.0

4.5.3 Central Minnesota Municipal Power Agency (CMMPA)

Central Minnesota Municipal Power Agency did not submit any new projects for MTEP23. MISO has not identified any issues in CMMPA's area.

4.5.4 City of Ames, IA (COA)

City of Ames, IA did not submit any new projects for MTEP23. MISO has not identified any issues in COA area.

4.5.5 Dairyland Power Cooperative (DPC)

Dairyland Power Cooperative did not submit any new projects for MTEP23. MISO has not identified any issues in DPC's area.

4.5.6 Great River Energy (GRE)

After MISO's independent reliability analysis, MISO and Great River Energy recommend 33 projects at an estimated cost of $105.5 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, two are Baseline Reliability Projects, 29 are Other Projects, and two are Generator Interconnection Projects with signed Generator Interconnection Agreements. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Baseline Reliability Projects

Project #23718: Rush City Ring Bus Upgrade

Project Description: This project will establish a 230 kV ring bus topology at Rush City. For GRE to address the rating exceedances experienced with the current shared breaker position, GRE will add breakers and associated equipment/relaying/etc. to the 230-kV Rush City bus between the Linwood, Red Rock, and Rock Creek lines. The total estimated cost of this project is $4.01 million and has an expected in-service date of March 27, 2025.

Project Need: Currently, both the Red Rock 230 kV and Rock Creek 230 kV lines share a common breaker position in the Rush City 230 kV bus and will both trip for any fault along the approximately 70 miles of exposure currently. Under prior outage of Blaine to Bunker Lake 230 kV, loss of both of these transmission lines simultaneously leaves the Blaine, Linwood, and Rush City substations without 230 kV system support, which can cause exceedances of ratings on the Blaine-Parkwood 69 kV path.

Alternatives Considered: No alternatives were considered.

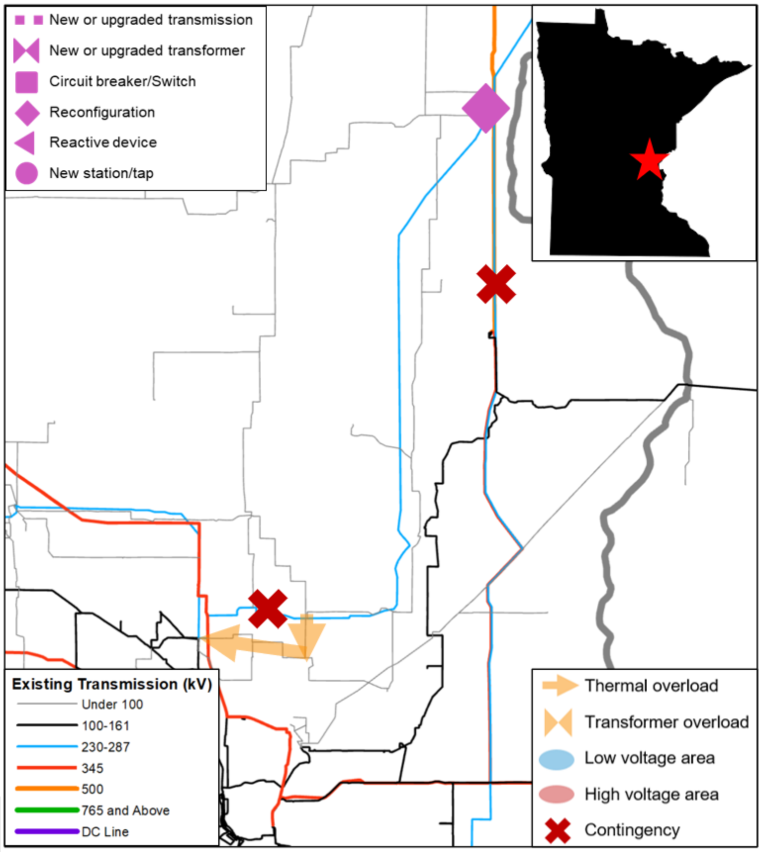


Figure 4.5.6-1: P23718 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	GRE-LXNGTN 8 - GRE-HWY65SW8 69 kV	58.8	106	64
P6	GRE-HWY65SW8 - GRE-SPRLKPK8 69 kV	58.8	107	64

Table 4.5.6-1: P23718 Thermal loading drivers

Project #23803: Big Swan Capacitor Bank Addition

Project Description: Add a new 40 MVAR capacitor on the extended 115 kV bus and replace 69 kV bus relaying, station power, and battery bank. The total estimated cost of this project is $2.63 million and has an expected in-service date of November 1, 2024.

Project Need: The Hutchinson area study identified low voltage concerns in the 115 kV system that is between Hutchinson, Wakefield, and Crow River. NERC category P6 contingencies involving prior outages, such as McLeod – Hutchinson 115 kV line, Crow River – Brooks Lake 115 kV line and Wakefield – Stockade 115 kV line causes low voltage problems at 115 kV side of GRE member substations. The Hutchinson area study also identified low voltage concerns in the 69 kV transmission system for the loss of the Hutchinson 115/69 kV transformer. Installation of a capacitor bank at Big Swan will improve the 115 kV system post contingent voltage.

Alternatives Considered: No alternatives were considered.

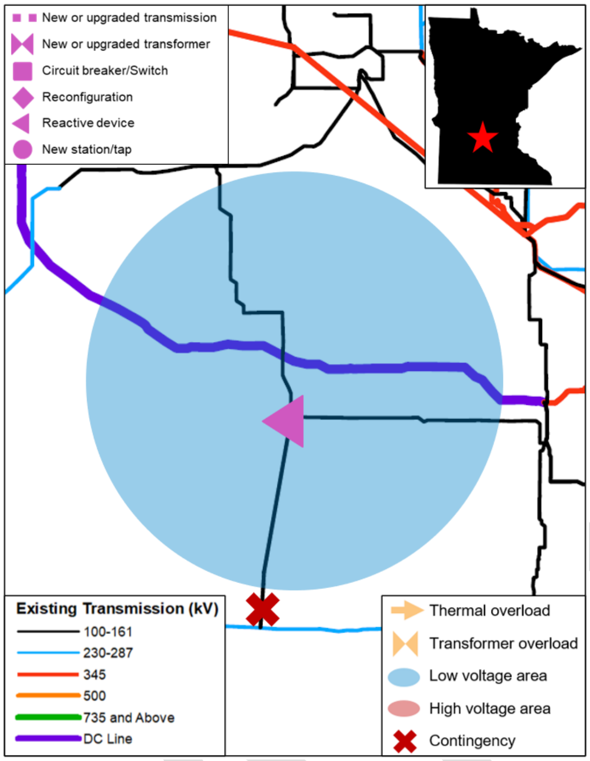


Figure 4.5.6-2: P23803 Geographic transmission map of project area

Cont. Type	Limiting Element	Voltage Limit (pu)	Pre-Project Voltage (pu)	Post-Project Voltage (pu)
P6	GRE-BIGSWAN7 115 kV	0.95	0.921	0.967
P6	GRE-SWAN LK7 115 kV	0.95	0.929	0.970
P6	GRE-BROOKSL7 115 kV	0.95	0.921	0.966
P6	HUC-HUTCHMN7 115 kV	0.95	0.915	0.956
P6	HUC-HUTCH3M7 115 kV	0.95	0.914	0.955

Table 4.5.6-2: P23803 Voltage performance drivers

Other Projects

Projects Driven by Other Local Needs

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
22871	Cedar Lake Line Rebuild	Relocate the existing Cedar Lake tap line to a new route to accommodate Hampton Corners - Helena 345 kV addition to the Hampton Corners - Chub Lake - Helena structures.	8/1/2025	$12.8

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23682	Princeton Breaker Addition	Add breaker and relaying to address incomplete topology and relaying load limit issue at Princeton. The plan to accommodate this work is to bring the OL line around to the west bay of the four structure and place breaker in PT occupied bay. Bus PT's will be replaced and relocated to a different location on site to accommodate the breaker addition in west bay. This project will also require that we rebuild to OL line tapping into the north by bringing it in to the west bay with the characteristics of the new line rebuild plan of the OL line.	6/21/2024	$0.76
23762	Trimont Substation Retirement	Retire GRE assets in the Trimont SMEC distribution substation.	4/30/2024	$0.24
23784	Blackberry Breaker Addition	Remove existing switch 20NSM1 from Blackberry and replace with a circuit breaker and disconnect. OR Retain existing switch 20NSM1 at Blackberry and add a circuit breaker between the 115/69 kV transformer and switch 20NSM1.	9/1/2025	$0.71
23805	Searles Capacitor Bank Retirement	Retire the 5.4 MVAR Searles Capacitor Bank and associated components.	8/31/2023	$0.12
23821	Penelope Capacitor Bank Retirement	Retire the 5.4 MVAR Penelope Capacitor Bank and associated components.	8/18/2023	$0.12
23823	Burnsville Capacitor Bank Retirement	Remove existing cap bank and 5M201. Relocate breaker 5M198 to 5M201 location. Leave A3 for future termination.	12/31/2025	$1.02

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23681	Riverton Breaker Replacement	This project will remove 69 kV bus differential relaying, replace GE-T60 with SEL-487E using existing panel 7, protect the 69 kV bus zone with the transformer relays, replace Riverton	6/30/2024	$0.85

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		IR8600 RTU with Cybectec RTU, replace Westinghouse 3-phase 115 kV PT with 3 single phase CCVTs on 115 kV bus, and replace the 115 kV 25WB1 oil breaker. In addition to this work, there will also be some 69 kV and 115 kV bus work and jumper modifications.		
23764	Stinson Breaker Addition	Add low side breaker and SEL-487E secondary transformer relay. Move 69 kV line relays to the 69 kV CTs. New panel will be installed with SEL-487E and breaker controls.	9/2/2025	$0.66
23781	Shannon Breaker Addition	Add low side breaker and SEL-487E secondary transformer relay. Move 69 kV line relays to the 69 kV CTs. New panel will be installed with SEL-487E and breaker controls. Replace RTU. Replace two (2) 69 kV Bus PTs (G.E. Superbute).	10/15/2024	$0.59
23800	Gilman - Milaca 69 kV Line Rebuild	Rebuild the JC line (18.93 miles) and switch SS2888 to 69 kV with 477 ACSS.	8/21/2026	$12.1
23801	Cotton Substation Tap Rebuild	LCP is rebuilding the existing Cotton Distribution site to the north, the 115 kV (TT Line) will need to adjust to terminate on LCP's new high side structure. The EEE from Goodland distribution substation will be placed at the new Cotton substation.	9/29/2023	$0.47
23804	Kimball Substation Tap	Install a 3-way 69 kV, 1200 A switch on Xcel Energy's Kimball – Watkins 69 kV line and construct about 2 miles of 69 kV line with 477 ACSR conductor to the high side of Meeker's new Kimball area distribution substation.	7/29/2025	$1.04
23824	Virginia Breaker Addition	Add low side breaker and SEL-487E secondary transformer relay. Move 69 kV line relays to the 69 kV CTs. New panel will be installed with SEL-487E and breaker controls. Replace RTU. Replace three (3) 69 kV Bus Pts (G.E. Superbute).	11/11/2024	$0.56
23849	Big Swan - Wakefield Storm Structures	Install (2) new storm structures every 5 miles along the ME-BW line between structures 306 and 415 as there are no	10/31/2024	$0.53

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		full stop dead ends in this section of line. Possible locations are structures 340 or 349 and 374 or 383.		
23920	Missouri River Line Crossing Relocation	Replace/relocate 5 towers and reconductor the river crossing to avoid structure/line segments from falling into Missouri river.	10/13/2023	$3.12

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23679	Cromwell Breaker Replacement	Replace 115 kV circuit breakers 13L and 26L.	11/1/2023	$1.36
23680	Frog Creek Breaker Replacement	Replace Circuit Switcher FC161-10 at Frog Creek substation with breaker and add disconnect switches. Replacement of Panel #2 relaying to also be included.	1/31/2025	$1.03
23717	Deer River Breaker Replacement	Replace breakers 21NB1,2 & 3. Oil containment and SSVT relocation project is be combined with this project to create more efficiencies with project execution. Replace bus PTs as well due to relay prioritization recommendation. Replace single phase 115 kV CCVT with 3 single-phase CCVTs. Move Zemple line relays to the 115 kV CTs (current transformers) and CCVTs. Replace EEE and internal equipment, address bus work and jumper issues, and fix wood high side dead-end.	4/9/2025	$3.82
23782	Dotson Corners Breaker Replacement	Replace 69 kV oil breakers 860, 861, and 862 and associated equipment.	7/18/2026	$0.78
23783	Maple Lake Breaker Replacement	Replace 69 kV relaying & Breakers 1NB4 & 5 at the Maple Lake sub and associated equipment.	2/28/2025	$1.16
23799	Benton County Breaker Replacement	Replace 115 kV breakers 5N52 and 5N53.	11/16/2023	$0.53
23822	Matawan - St. Olaf Lake 69 kV Rebuild	Rebuild SW-MB line segments 1 and 2 (11.01 miles) (Matawan switches to St. Olaf Lake switches) to 69 kV minimum conductor size 477 ACSR would meet	9/7/2026	$7.31

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		voltage and thermal considerations per planning.		
23869	Ramsey Breaker Replacement	Replace breaker 33RB1.	6/28/2024	$0.47
23921	Pilot Knob to Deerwood Area Projects	Rebuild the Pilot Knob Substation to a breaker and a half configuration due to age and condition of the current equipment. Upgrade the DA-PD line from Deerwood to Pilot Knob substation to increase the capacity. Upgrade to be built to 115 kV standards but operated at 69 kV. Retire the underground portion of the DA-PLX at Pilot Knob and replace with overhead. Retire the DA-RE line from Pilot Knob Road to Black Hawk Road. Retire the DA-PKX from Pilot Knob to Cliff Road. Retire SS-2820 and replace with a turning structure. Retire SS-2819.	5/21/2027	$29.6

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23761	NW Litchfield Substation Tap	Tap Xcel's Grove City – Litchfield Mun 69 kV line and Construct about 3 miles of 69 kV radial line to the high side of Meeker's new NW Litchfield distribution substation. Install metering and telecom at the new sub.	1/4/2027	$2.97
23763	Laketown Substation Tap	Install 3-way MOD 2000 A 115 kV switch on GRE's MV-VTT and construct about 3 miles of 115 kV transmission line from the three-way switch to the high side of MVEC's Laketown distribution substation.	9/26/2028	$6.31
23802	West Otsego Substation Tap	Install a 3-way 69 kV switch on GRE's Otsego to Albertville 69 kV line and construct about 0.5 miles of 69 kV tap line to the high side of Wright Hennepin's West of Otsego area substation.	10/31/2025	$1.28

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23819	Eidswold Substation Tap	New 115/12.47 kV substation for Dakota Electric Association (DEA) in the Elko New Market area.	11/22/2024	$0.21

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23883	Cedar Mountain Capacitor Bank Addition	Installation of two 75 MVAR capacitor banks, installation of three new 345 kV breakers to complete the breaker and a half.	5/31/2024	$4.03
24285	Benton County Solar Farm	The existing 115 kV Benton County substation is built as a two-row breaker-and-a-half breaker station. A new breaker and a half row would be built out to accommodate the interconnection of the 100 MW solar farm for J1426. The network upgrades at the substation will include the installation of a new 115 kV Breaker, Line arrestors, line CCVTs, Primary/Secondary Relay Panels, Metering, new metering CTs, and disconnects in the breaker-and-a-half row.	8/1/2025	$2.39

4.5.7 ITC Midwest (ITCM)

After MISO's independent reliability analysis, MISO and ITC Midwest recommend 19 projects at an estimated cost of $167.2 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, 12 are Other Projects and seven are Generator Interconnection Projects with signed Generator Interconnection Agreements. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23546	Jefferson County 161 kV Substation Rebuild	The relaying and SCADA equipment at the Jefferson County substation is nearing the end of its useful lifespan. In addition, the existing 161/69 kV	12/31/2025	$7.92

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		transformer does not have a high side protective device, there is not adequate space to add it, and the existing 161 kV bus configuration does not allow the flexibility needed. Due to this, ITC will rebuild the 161 kV bus at Jefferson to a 3-position ring bus configuration and will replace all existing relays at the station except on two 69 kV lines going towards NEMO. ITC will also replace and upgrade existing SCADA equipment and add 69 kV line PTs on all lines except those going towards NEMO.		
24513	Maquoketa (CIPCO) 161 kV Sub Rebuild	CIPCO has notified ITC that they will be rebuilding the 161 kV portion of their Maquoketa substation to a ring bus. ITC will need to relocate the Grand Mound – Maquoketa and Maquoketa – Sale 161 kV lines into new bus positions at Maquoketa to accommodate the new layout of the substation. T2-636 ACSR should be used for new conductor for the new line taps.	5/30/2024	$2.03
24464	Eagle to Tharp 69 kV Line Relocation	A 0.75 section of the Eagle - Tharp 69 kV line is required to be moved to a new permanent location by the Iowa DOT due to a project to rebuild the I-380 and Wright Bros Blvd interchange. Thirteen new wooden poles, three new steel poles, and new T2-477 ACSR cabling is to be constructed as shown in the sketched figures. PTS 1158 is to be retired and PTS 1114 is to have the jumpers remade to face towards Eagle. PTS 1114 will remain in this configuration until the switch is retired with the Kitty Hawk rebuild.	5/1/2024	$1.62
25060	Grant Milford Interconnection	Rebuild approximately 4 miles of existing 34.5 kV line to 69 kV construction standards to interconnect new IPL Grant Milford substation and facilitate future area conversion to 69 kV operation as part of CIPCO's SW IA 34.5 to 69 kV conversion plans.	06/30/2025	3.48

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23464	Abbott-Traer 161 kV 15 miles Rebuild	Due to aging condition, ITC will rebuild the Abbott – Traer 161 kV circuit with T2-Grosbeak. New control building as this is an IPL owned site.	12/31/2027	$16.84
23510	Rock Creek T3 Replacement	The existing Rock Creek T3 transformer is at the end of its useful life and in need of replacement. T3 will be replaced with a new 150 MVA 161/69 kV transformer with LTC. In addition, there is an 800-amp relay thermal limit on T3, so the existing relaying needs to be upgraded to remove the 800-amp thermal limit to allow full use of the 150 MVA transformer rating.	12/31/2025	$4.27
23677	ITC Midwest Asset Replacement Program 2025	Replace aging and outdated equipment on a cycle that will ensure each system is replaced near its expected end of life. Modern equipment can improve reliability, use state of the art technology, and will typically use longer maintenance intervals which reduces maintenance costs. Equipment is commonly equipped with better monitoring and alarming functionality giving improved remote supervision.	12/31/2025	$38.40

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23511	Grinnell South 69 kV Substation & 20 MVAR Cap	IPL has notified ITC that they will be rebuilding the Grinnell South substation in a new location directly south of the existing substation location which will replace the existing Grinnell South substation. ITC will construct the 69 kV portion of Grinnell South in the new location including two busses, two-line breakers, and a bus tie breaker. ITC will also install a new 69 kV capacitor bank at the new Grinnell South substation to provide improved area voltage support for existing and potential additional future load growth in the area.	12/31/2025	$5.64

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23636	ITCM Customer Interconnects (short lead time) 2025	These projects are being done at the request of an interconnection customer to facilitate new load, re-distribute existing load, improve the performance of the sub-transmission and distribution systems, or to accommodate a new Transmission-to-Transmission connection request.	12/31/2025	$3.60
23684	Kittyhawk 69 kV Substation Interconnection	IPL has notified ITC that they will be rebuilding the Kittyhawk substation in the existing location to allow the addition of a second IPL distribution transformer. ITC will construct the 69 kV portion of Kittyhawk which will include two busses/single box structures, two-line breakers, and a bus tie breaker.	12/31/2025	$3.90
24449	Nevada Area Load Interconnections	ITCM will construct new transmission substations and network them to the existing 161 kV transmission system at Ames, NE Ankeny, and Fernald. The project will support load interconnections in the Ames/Nevada and increase transmission reliability for the city of Ames, IA.	12/31/2024	$56.52
24740	Commercial (JCE) 69 kV Substation	For ITC's portion of the Commercial Substation ITC will install a new 69 kV substation with two 69 kV line breakers, one distribution transformer position, and one mobile transformer position. All the ITC equipment will be capable of 600A or greater.	6/1/2024	$3.80

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23483	J1175 GIA - Bluebill TOIF	A new Bluebill 345 kV switching station will be constructed to interconnect projects J1174 and J1175. The Bison – Colby 345 kV line will be tapped and re-routed to new positions in the Bluebill station. The TOIF will include dead-end,	6/30/2025	$0.86

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		disconnect switch, arresters, PT's, relay panel, and associated equipment.		
23485	J1174 & J1175 MPFCA - Network Upgrades	A new Bluebill 345 kV switching station will be constructed to interconnect projects J1174 and J1175. The Bison – Colby 345 kV line will be tapped and re-routed to new positions in the Bluebill station. ITC will TO self-fund the Network Upgrades and will earn a return of and return on investment under a FSA for 90% of the cost. 10% of the Network Upgrades costs will be recovered under Attachment GG.	6/30/2025	$16.22
23611	J982 Affected System Upgrades	MISO Facilities Study for Affected System upgrades for project J982, a 300 MW wind-powered generating facility with proposed interconnection on MEC's Obrien County – Kossuth 345 kV circuit. The system impact study has indicated the interconnection of project J982 will require sag mitigation on the Fox Lake to Rutland 161 kV circuit.	9/1/2023	$0.34
23693	J1132 GIA Network Upgrades	Expansion of the Creston Roundhouse 69 kV bus with an additional box structure.	6/1/2024	$0.32
23701	J1135 GIA TOIF	Install equipment dedicated to the J1135 generating facilities. The J1135 line will be connected to a new breaker position on the Hunt Woods 69 kV bus.	6/1/2024	$0.56
23722	J1132 GIA TOIF	TOIF includes facilities and equipment dedicated to the Generating Facility including 69 kV switch.	6/1/2024	$0.04
23484	J1175 GIA - Bluebill TOIF	A new Bluebill 345 kV switching station will be constructed to interconnect projects J1174 and J1175. The Bison – Colby 345 kV line will be tapped and re-routed to new positions in the Bluebill station. The TOIF will include dead-end, disconnect switch, arresters, PT's, relay panel, and associated equipment.	6/30/2025	$0.86

4.5.8 MidAmerican Energy Company (MEC)

After MISO's independent reliability analysis, MISO and MidAmerican Energy Company recommend 42 projects at an estimated cost of $269 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, three are Baseline Reliability Projects, 35 are Other Projects, and four are Generator Interconnection Projects with signed Generator Interconnection Agreements. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Baseline Reliability Projects

Project 23686 Obrien County 345-161 kV Transformer Addition & Hospers 161-69 kV Transformer Addition

Project Description: Construct new 161 kV line from Obrien County Substation to Hospers Substation, expand Obrien County Substation to install 345-161 kV, 560 MVA transformer and 161 kV bus and expand Hospers Substation to install 161-69 kV, 167 MVA transformer and 161 kV bus. The total estimated cost of this project is $45 million and has an expected in-service date of December 1, 2026.

Project Need: Thermal and voltage issues can occur following N-1-1 230 kV contingencies at Eagle Substation.

Alternatives Considered: No alternatives were considered.

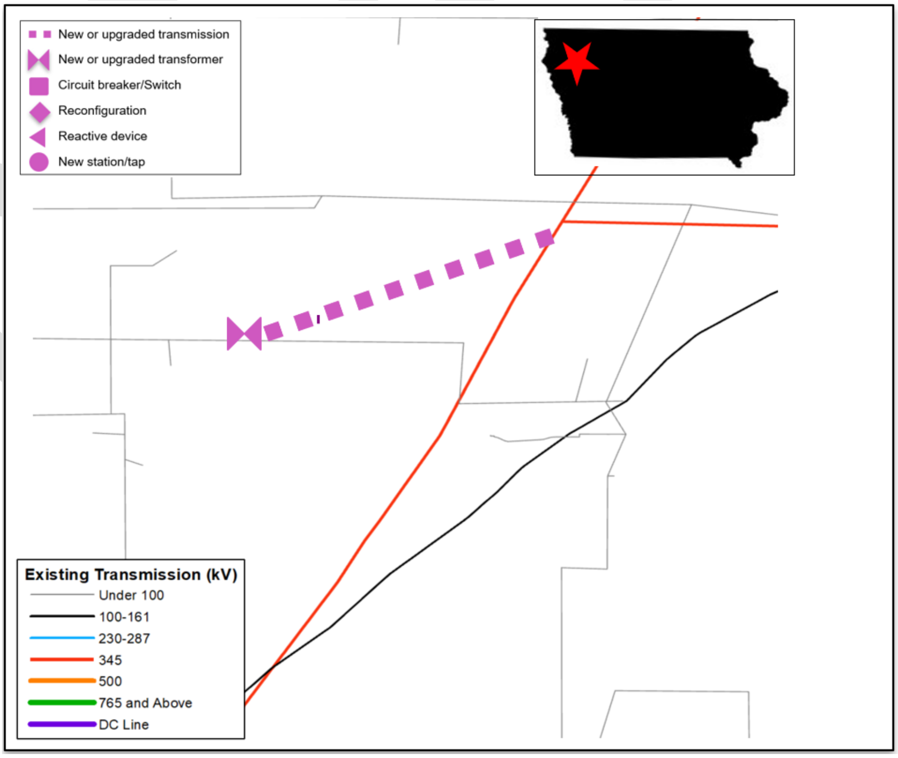


Figure 4.5.8-1: P23686 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (pu)	Pre-Project Voltage (pu)	Post-Project Voltage (pu)
P6	HOSPERS8' 69.000	0.95	0.6367	1.006
P6	MARCUS 8	0.95	0.7405	0.9715
P6	MERIDEN8	0.95	0.8260	0.9846
P6	SANBRN CRNR8	0.95	0.8061	0.9646
P6	K224MEAD-NI8	0.95	0.6899	0.999

Table 4.5.8-1: 23686 Voltage performance drivers

Project 23688 Macksburg - Winterset 161 kV Reconductor

Project Description: Reconductor the 161 kV line from Macksburg to Winterset. Line identified as a constraint in the MTEP22 generator deliverability analysis. The total estimated cost of this project is $12.5 million and has an expected in-service date of June 1, 2027.

Project Need: Line identified as a constraint in the MTEP22 generator deliverability analysis.

Alternatives Considered: No alternatives were considered.

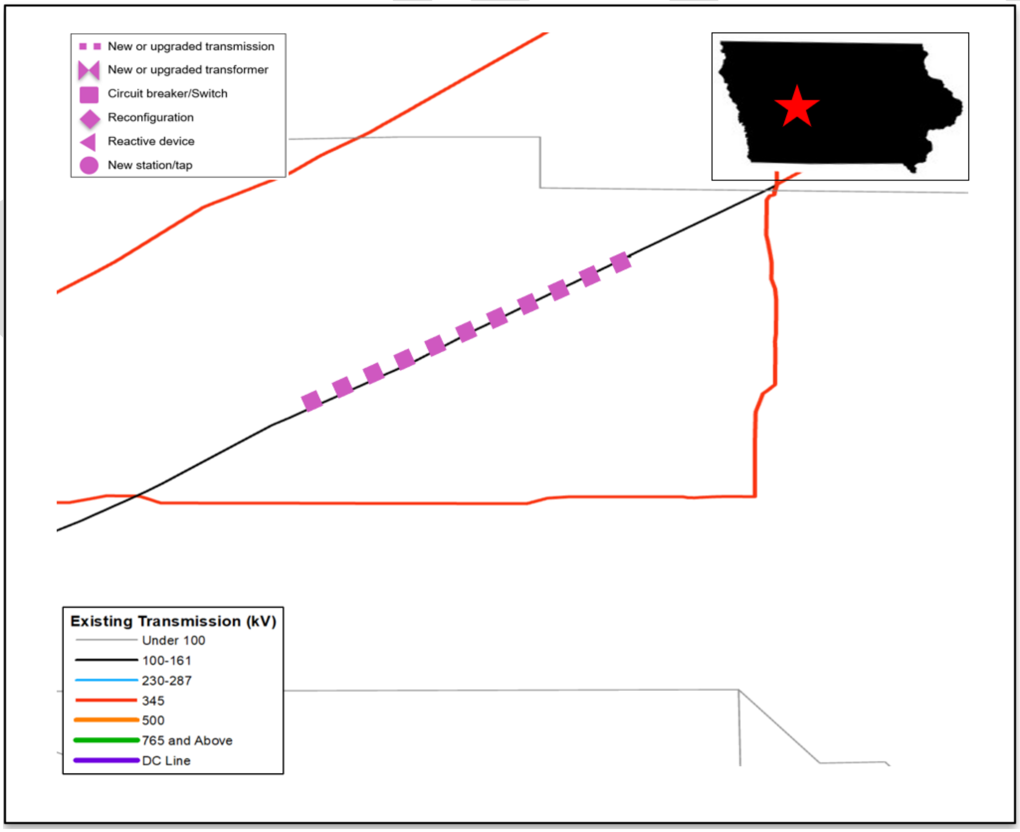


Figure 4.5.8-2: P23688 Geographic transmission map of project area

Project 23720 Hickory Avenue-Sioux Center 69 kV Line & Substation Line Terminals

Project Description: Construct new 69 kV line from Hickory Avenue Substation to Sioux Center Substation. Expand Hickory Avenue and Sioux Center Substations to install new 69 kV line terminals. The total estimated cost of this project is $12 million and has an expected in-service date of June 1, 2025.

Project Need: Mitigates thermal and voltage issues following N-1-1 69 kV contingencies at maintenance load levels.

Alternatives Considered: No alternatives were considered.

Figure 4.5.8-3: P23720 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	635370 SHELDON8 - 635372 SANBRN CRNR8	44	107	49
P6	635372 SANBRN CRNR8 - 635373 MAP SANBORN8	44	112	51
P6	635373 MAP SANBORN8 – 656573 WISDOM G	44	172	54

Table 4.5.8-2: P23720 Thermal loading drivers.

Cont. Type	Limiting Element	Rating (pu)	Pre-Project Voltage (pu)	Post-Project Voltage (pu)
P6	SANBRN CRNR8 69 kV	0.95	0.6482	0.9810
P6	MAP SANBORN8 69 kV	0.95	0.6623	0.9818
P6	DOON TAP8 69 kV	0.95	0.4585	0.9789
P6	BOYDEN 8 69 kV	0.95	0.4825	0.9865
P6	HICKORY AVE8 69 kV	0.95	0.4620	0.9894
P6	GEORGE 8 69 kV	0.95	0.4970	0.9777

Table 4.5.8-3: P23720 Voltage performance drivers

Other Projects

Projects Driven by Other Local Needs

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23572	Franklin: Replace 161 kV Breaker 9210	Franklin: Replace 161 kV Breaker 9210.	12/01/2023	$0.50
23694	Wall Lake 161 kV Terminal Equipment Upgrades	Replace limiting jumpers on Wright - Wall Lake and Wall Lake - Franklin 161 kV line terminals.	12/31/2026	$0.10
23740	Webster: Replace 161 kV Breaker 9250	Replace 161 kV breaker 9250 in Webster substation.	12/31/2026	$0.30
23741	Wright 161 kV Terminal Equipment Upgrades	Replace 1200A substation terminal equipment on Webster - Wright and Wall Lake- Wright 161 kV line terminals.	12/31/2026	$0.15
24212	Badger Creek Substation	Construct Badger Creek Substation that will bisect the existing Arbor Hill-Raccoon Trail 345 kV line. Construct a new 345 kV line from Badger Creek Substation to the Raccoon Trail Substation.	12/1/2025	$0.00

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23571	Humboldt 69 kV Reconfiguration	Network Humboldt Central Substation and establish tie with Corn Belt's Weaver Switching Station.	12/1/2026	$9.90

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23573	Black Hawk: 161-69 kV, 167 MVA Transformer	Replace existing 161-69 kV, 50 MVA Transformer.	12/1/2025	$9.0
23590	Granger Substation 161 kV Line Breakers	Install 161 kV line breakers and associated relaying.	12/1/2026	$2.10
23592	Floyd Substation: Add 69 kV Bus PTs, Remove Wave Trap, and Incorporate Fiber	Add 69 kV Bus PTs; remove wave trap and employ fiber for Floyd-Emery 161 kV line relaying.	12/31/2024	$0.35
23593	Charles City North add 69 kV Breakers	Charles City North Add 69 kV Breakers.	12/1/2027	$0.80
23608	E. 29th & Hubbell 69 kV Expansion and Line Tap	Expand substation steel for a second 69 kV line tap.	06/01/2024	$0.50

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23609	Delaware Substation 161 kV Line Breakers	Install 161 kV line breakers and associated relaying.	6/1/2025	$1.90
23610	Washburn: 161-69 kV, 125 MVA Transformer	Replace existing 161-69 kV, 50 MVA Transformer	12/1/2026	$7.50
23628	Waverly Junction: Reconfigure 69 kV Terminals	Reconfigure 69 kV line terminals to eliminate tapped substation transformer.	6/1/2024	$1.30
23675	Avoca: Install 69 kV Breaker on 161-69 kV Transformer 8T3 and 161 kV & 69 kV Breaker Replacements	Install a 69 kV breaker on the low-side of Avoca 161-69 kV Transformer 8T3, replace/relocate Avoca Breakers 622 and 623 to accommodate new 69 kV breaker and replace Breakers 801, 802 and 620 due to condition.	12/1/2025	$4.10
23690	Quad Cities Enron Substation: Install 161 kV Line Switches	Install new 161 kV line switches on both sides of the QEN Quad City Enron substation to increase switching flexibility.	12/31/2025	$0.50
23691	Riverdale 161-13.2 kV Substation	Construct new 161-13.2 kV substation and 161 kV line taps.	12/31/2026	$4.10

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23692	Sub 28 Add 161 kV Line Breakers and Install New Control Building	Install new 161 kV line breakers and new control building to replace existing control enclosure.	12/31/2027	$3.70
23719	Oakland: Add 69 kV, 12 MVAR Capacitor Bank and 69 kV Line Breakers	Install 69 kV, 12 MVAR capacitor bank and install 69 kV line breakers at Oakland Substation.	6/1/2026	$5.0
23721	Monona: Replace 161 kV Transformer	Replace the existing Monona 161-69 kV transformer with a 125 MVA unit. Convert Monona 161 kV bus to a ring bus configuration. Also, replace two 69 kV breakers and upgrade associated terminal equipment.	12/1/2025	$7.0
23723	Edgington 161-13.2 kV Substation	Construct new 161-13.2 kV sub and 161 kV line taps. Install fiber for communication and protective relaying.	12/31/2027	$10.50
23739	Sub 42: Install 69 kV Line Switches	Install new 69 kV line switches on both sides of the Sub 42 substation to increase switching flexibility.	12/31/2027	$0.80

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23570	Valley Trail 161 kV Substation	Construct Valley Trail 161-13.2 kV Sub and Line Taps.	6/1/2026	$9.50
23687	Storm Lake Industrial 69 kV Line Taps	Construct 69 kV line taps into new Storm Lake Industrial 69-13.8 kV Substation.	12/1/2026	$0.80
23699	Gifford Road 161-13.2 kV Substation and 161 kV Line Taps	Construct Gifford Road 161-13.2 kV Sub and Line Taps.	9/1/2026	$5.50
24999	Southland Expansion & Upgrades	Expand 345 kV bus at existing Southland Substation to serve new customer load. Construct new 345 kV line from Overland Trail to Pony Creek Substation, reroute the existing Pony Creek-Rolling Hills 345 kV line into Southland Substation and rebuild the existing CBEC-Pony Creek 345 kV line.	5/31/2024	$58.0

Projects Driven by Age and Conditions

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23591	Nashua Tap-Plainfield Junction 69 kV Rebuild	Replace conductor on section of Nashua Tap-Plainfield Junction 69 kV line using existing right of way.	12/31/2024	$2.50
23629	Charles City South-Nashua Tap 69 kV Rebuild	Charles City South-Nashua Tap 69 kV Rebuild.	12/1/2025	$7.70
23630	Wida-Streeter 69 kV Rebuild	Replace conductor on MidAmerican section of Wida-Streeter 69 kV line.	4/1/2024	$1.00
23655	Shenandoah: Replace 69 kV Breakers 601 & 602	Replace 69 kV breakers at Shenandoah Substation.	12/1/2024	$0.60
23683	Sheldon: 69 kV Breaker and Relay Replacements	Replace Sheldon 69 kV Breakers 7730, 7740, 7880 and 7890 and associated disconnect switches and relaying.	10/1/2024	$2.80
23685	Neal North-Southbridge Tap-Knox-State Steel Tap 69 kV Line Rebuild	Rebuild approximately 9 miles of line.	12/5/2024	$8.60
23689	Sub 93 Louisa: Replace 345 kV Breaker 934	Replace 345 kV breaker in Sub 93 (Louisa) ring.	4/7/2023	$0.39
23724	Pomeroy 161 kV Substation 69 kV Breaker Replacement and Addition	Replace 69 kV breaker 7290. Convert 34.5 kV system to 69 kV due to condition. Expand Pomeroy 69 kV bus to accommodate additional 69 kV line terminal and add 69 kV bus differential relaying.	12/31/2023	$0.60
24923	Sidney-Percival 69 kV Line Rebuild	Replace due to condition.	6/1/2025	$9.10

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23703	J982 POI New 345 kV Interconnection Substation and 345 kV Line Taps	Construct new 345 kV POI substation and 345 kV line taps for J982 wind farm.	6/1/2025	$15.25
23725	Palo Alto 345 kV Substation Expansion for J877	Add one new 345 kV line terminal at Palo Alto substation for J877 solar farm generator tie line.	7/1/2025	$3.80
23726	Raun - Remsen 345 kV Line Uprate for DPP 2018	Replace line structures to increase line rating.	12/01/2024	$1.20

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23727	Sub 56 161 kV Substation Expansion for J1131	Add one new 161 kV line terminal at Sub 56 for J1131 solar farm generator tie line.	9/1/2027	$2.03

4.5.9 Minnesota Municipal Power Agency (MMPA)

Minnesota Municipal Power Agency did not submit any new projects for MTEP23. MISO has not identified any issues in MMPA's area.

4.5.10 Minnesota Power (MP)

After MISO's independent reliability analysis, MISO and Minnesota Power recommend five Other Projects at an estimated cost of $51 million to be approved for inclusion in MTEP23 Appendix A. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Other Projects

Projects Driven by Other Local Needs

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23707	Maturi Expansion	The Maturi Expansion Project will add three circuit breakers to allow for the transmission line to be looped in and out of the Maturi Substation.	12/31/2025	$3.6

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23877	Nelson Lake 230 kV Substation	New 230 kV switching station tying together MP Square Butte East - Bison and GRE Square Butte - Stanton 230 kV lines.	6/1/2023	$25

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
22909	40 Line Rebuild	Rebuild Badoura - Dog Lake 115 kV Line, new 795 ACSR and OPGW will be installed.	12/31/2024	$17

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23708	Mahtowa Expansion	The Mahtowa Expansion project will add 3-115 kV circuit breakers to reconfigure the existing Mahtowa Substation into a 3-position ring bus.	12/31/2025	$2.5

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
22885	Brainerd Crypto	Mitigation solutions to accommodate a 70 MW Load addition at Brainerd 115 kV bus, including a second 20 MVAR capacitor bank and thermal upgrade of the Brainerd - Riverton 115 kV Line.	12/31/2024	$2.8

4.5.11 Missouri River Energy Services (MRES)

After MISO's independent reliability analysis, MISO and Missouri River Energy Services recommend three projects at an estimated cost of $3.5 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, one is a Market Participant Funded Project and two are Other Projects. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Market Participant Funded Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23919	Morris to Grant County to East Fergus Falls Upgrade	Increase the rating of 115 kV lines from Morris to Grant County to East Fergus Falls.	7/1/2024	$1.34

Other Projects

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23710	Atlantic 161 kV Breaker Replacement	Replace two 161 kV oil filled breakers with SF6.	1/1/2024	$0.8

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24232	ALP SE Substation	Alexandria Light & and Power (ALP) will build a new distribution substation on the southeast part of town. The substation will tap and existing 115 kV line with an in and out substation. The substation will have a 115 kV to distribution transformer.	12/31/2025	$1.36

4.5.12 Montana-Dakota Utilities Co. (MDU)

After MISO's independent reliability analysis, MISO and Montana-Dakota Utilities Co. recommend five projects at an estimated cost of $45.3 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, one is a Market Participant Funded Project and four are Other Projects. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Market Participant Funded Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24092	Baker upgrades MP funded	Market Funded project to upgrade terminal equipment at Baker.	12/31/2023	$0.05

Other Projects

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23596	Glenham Rebuild	Rebuilding the current Glenham substation 230/115/41.6 kV.	10/31/2025	$23.5
23634	Wishek Rebuild	Will be expanding the 230 kV to add new wind farm and rebuilding the 115 and 41.6 kV.	12/31/2025	$18.7

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23633	Ellendale Load Addition	MDU has new customer requesting service at Ellendale, ND for total demand of 180 MW. MDU will serve the customer from the existing Ellendale 2 transformer's 34.5 kV tertiary. An overhead line will be built from	2/15/2023	$3.06

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		the tertiary of the transformer to the customers sub.		
24978	Tatanka Load Addition	MDU will be signing an agreement to serve 100 MW of load at the Tatanka Wind Farm collector substation off the Tatanka South Substation. There will be no cost to MDU to serve the customer.	12/1/2023	$0

4.5.13 Muscatine Power and Water (MPW)

Muscatine Power and Water did not submit any new projects for MTEP23. MISO has not identified any issues in MPW area.

4.5.14 Northwestern Wisconsin Electric (NWEC)

Northwestern Wisconsin Electric did not submit any new projects for MTEP23. MISO has not identified any issues in NWEC area.

4.5.15 Otter Tail Power Company (OTP)

After MISO's independent reliability analysis, MISO and Otter Tail Power Company recommend 18 projects at an estimated cost of $100.6 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, 16 are Other Projects and two are Generator Interconnection Projects with signed Generator Interconnection Agreements. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23860	OTP Grenville - Veblen 41.6 kV	Rebuild of 41.6 kV line between Grenville 41.6 kV and Veblen 41.6 kV.	11/30/2025	$4.6
23943	OTP Pickert - McVille 41.6 kV	Rebuild portions of the 41.6 kV line between Pickert 41.6 kV and McVille 41.6 kV.	11/30/2024	$3.8
23917	OTP Fordville - Fordville Jct. 41.6 kV	Rebuild of 41.6 kV line between Fordville 41.6 kV and Fordville Jct. 41.6 kV.	11/30/2025	$1.5
23977	OTP Cooperstown 41.6 kV	Reroute and rebuild 5 miles of 41.6 kV line near Cooperstown 41.6 kV.	11/30/2024	$1.2
23842	OTP Wilmot - Peever Jct. 41.6 kV	Rebuild 4 miles of 41.6 kV line between Wilmot 41.6 kV and Peever Jct. 41.6 kV.	12/31/2024	$1.1

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23859	OTP Granville - Granville Station 41.6 kV	Rebuild of 41.6 kV line between Granville 41.6 kV and Granville Station 41.6 kV.	12/31/2023	$1
23918	OTP Michigan - Mapes 41.6 kV	Rebuild of the 41.6 kV line between Michigan 41.6 kV and Mapes 41.6 kV.	12/31/2023	$1
23942	OTP Gackle - Jamestown 41.6 kV	Reconductor and rebuild sections of the 41.6 kV line between Gackle 41.6 kV and Jamestown 41.6 kV.	11/30/2024	$1
23944	OTP Wabek - Parshall 41.6 kV	Rebuild and Reconductor the 41.6 kV line between Parshall 41.6 kV and Wabek 41.6 kV	12/31/2027	$0.9
23955	OTP Wilton 41.6 kV Breaker Addition	Install a new line sectionalizing 41.6 kV breaker at Wilton, ND.	12/31/2024	$0.3

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23866	OTP Veblen 41.6 kV Breaker Replacement	Replacement of Veblen 41.6 kV breaker.	12/31/2023	$0.5

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23896	OTP Devils Lake, ND 115 kV Delivery	OTP is converting the 4.16 kV distribution system in the town of Devils Lake, ND to a 12.5 kV system. With this conversion, the town will be removed from our 41.6 kV system and be served via the 115 kV system. In order to move the town to the 115 kV system, a new 115 kV delivery will be established by tapping the Devils Lake East to Sweetwater 115 kV line with a two-way switch. Two miles of 115 kV line will be constructed from the new switch over to the town of Devils Lake where a new 115/12.5 kV distribution substation will be established which will include a 115 kV	12/31/2026	$1.6

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		breaker on the high side of the 115/12.5 kV transformer.		
23129	OTP Casselton 115 kV Capacitor Addition	The project consists of expanding the existing 115 kV bus at OTP's Casselton, ND substation with two additional 115 kV breakers to allow for another position in the substation. A new 115 kV 15 MVAR capacitor and breaker will be added into the new position created in the Casselton 115 kV bus.	06/01/2024	$1.2
25256	OTP Jamestown Load Expansion	Add a 115/41.6 kV transformer to the 115 kV bus at OTP's Jamestown 345 kV substation to serve a 10 MW expansion of an existing customer's load. The new transformer will also be connected to OTP's existing 41.6 kV transmission system for backup service via a normally open breaker.	06/01/2024	$3.25
23806	OTP Lake Preston, Load Addition	OTP will serve a new customer load in SD by extending a 115 kV line from our Hetland 115 kV substation to a new Lake Preston 115/34.5 kV substation. A new 115 kV line will be extended from the new Lake Preston 115/34.5 kV substation to Xcel's Brookings County 345/115 kV substation to create a 115 kV looped network. Capacitors will be installed at the new Lake Preston 115/34.5 kV substation for additional voltage support. The Facilities will consist of Hetland 115 kV substation termination addition, a 9.5 mile 115 kV line from Hetland 115 kV substation to a new Lake Preston 115/34.5 kV substation, a new Lake Preston 115/34.5 kV substation with capacitors installed at the 115 kV level, and a 45 mile 115 kV line from the new Lake Preston 115/34.5 kV substation to Xcel's Brookings County 345/115 kV substation.	12/31/2024	$42.6
23936	OTP Milbank, Load Addition	OTP will serve a new 4.5 MW load at Milbank, SD and support the	12/31/2026	$32.3

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		conversion of a 9.5 MW electric boiler moving from non-firm service to firm service by expanding the Big Stone 115 kV bus to accommodate an additional 115 kV termination, create a new approximately 12.5 mile 115 kV line from Big Stone 115 kV substation to a new Milbank 115/12.5 kV substation, adding a new Milbank 115/12.5 kV substation, adding a new approximately 18.5 mile 115 kV line from the new Milbank 115/12.5 kV substation to a new 115 kV breaker station located on the Big Stone - Marietta 115 kV line, adding a new 115 kV breaker station on the Big Stone - Marietta 115 kV line, and adding a new 115 kV tap along the new 115 kV line from the new Milbank 115/12.5 kV substation to the new 115 kV breaker station to convert an existing distribution substation to the 115 kV system. The surrounding area is no longer reliably sufficient to serve the load.		

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23146	OTP Big Stone Network Upgrades - J722	J722, a 200 MW wind project, has requested to interconnect into OTP's Big Stone South 230 kV substation as part of the MISO August 2017 DPP study cycle. J722 has been assigned to complete the following network upgrades on OTP's transmission system to interconnect at Big Stone South 230 kV. 1. Increase capacity on the Big Stone South - Big Stone 230 kV circuits #1 and #2. 2. Increase capacity on the Big Stone - Blaire 230 kV circuit.	5/31/2023	$1.8
24457	OTP Bagley Jct. 115 kV Capacitor Addition	Expand the Bagley Jct. 115 kV switching station to allow for the installation of a single step 20 MVAR 115 kV capacitor	7/31/2024	$1.2

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		bank. The project will consist of the addition of two 115 kV breakers, three disconnect switches, a single 20 MVAR 115 kV capacitor bank, and other associated equipment to allow for the installation of a 20 MVAR 115 kV capacitor bank.		

4.5.16 Rochester Public Utilities (RPU)

Rochester Public Utilities did not submit any new projects for MTEP23. MISO has not identified any issues in RPU area.

4.5.17 Southern Minnesota Municipal Power Agency (SMMPA)

After MISO's independent reliability analysis, MISO and Southern Minnesota Municipal Power Agency recommend one Other Project at an estimated cost of $8.9 million to be approved for inclusion in MTEP23 Appendix A. The expected in-service date and estimated cost of this project is provided as of September 29, 2023.

Other Projects

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
25252	Fairmont, MN Area 69 kV Transmission Expansion	Building of a new 69/12.5 kV distribution substation "West Industrial Park" (WIP) west of Fairmont, construction of a new 69 kV SMMPA breaker station and construction of two 69 kV transmission lines, one from WIP to the SMMPA's Fairmont Energy Station (FES) substation (approx. 2 mi) and one from WIP which will tap Great River Energy's 69 kV line between Rutland substation and the Fairmont 10th Street Substation (0.5mi).	3/01/2024	$8.92

4.5.18 Wilmar Municipal Utilities (WMU)

Wilmar Municipal Utilities did not submit any new projects for MTEP23. MISO has not identified any issues in WMU area.

4.5.19 WPPI Energy (WPPI)

WPPI Energy did not submit any new projects for MTEP23. MISO has not identified any issues in WPPI area.

4.5.20 Xcel Energy (Northern States Power)

After MISO's independent reliability analysis, MISO and Xcel Energy recommend 62 projects at an estimated cost of $311.2 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, one is a Baseline Reliability Project, one is a Multi-Value Project, and 60 are Other Projects. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

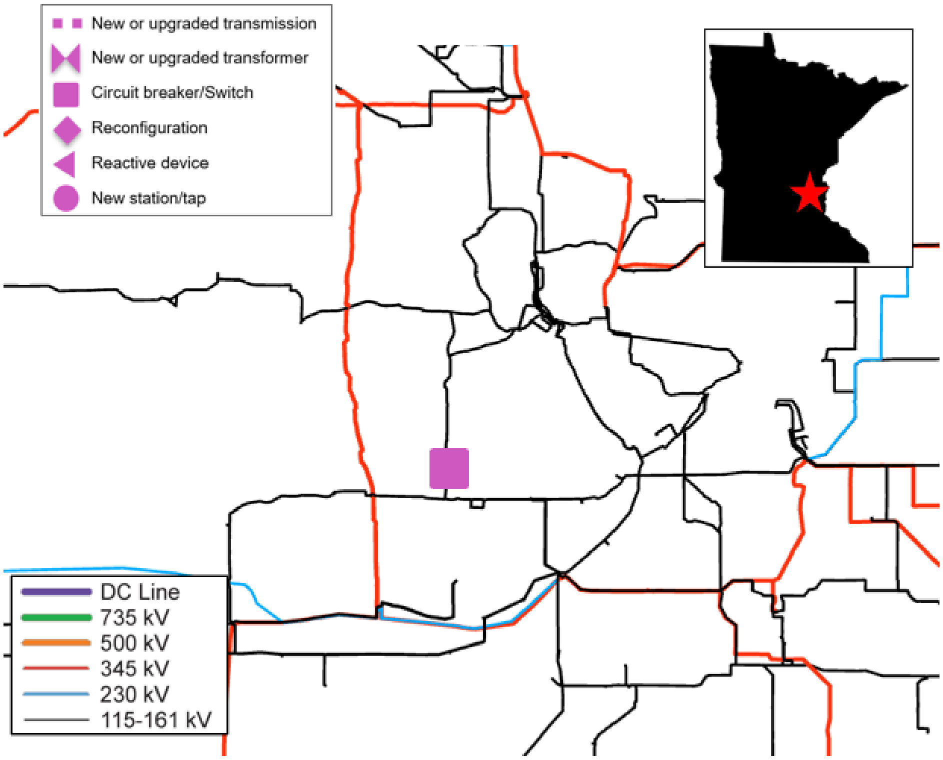
Baseline Reliability Projects

Project 24278 – Edina Switch Replacement

Project Description: Project will replace 115 kV switch at Edina, which is limiting the rating of the Edina - St. Louis Park 115 kV line. The total estimated cost of this project is $0.14 million and has an expected in-service date of December 31, 2023.

Project Need: This project remediates overloads on the Edina - St. Louis Park 115 kV line identified in MTEP22.

Alternatives Considered: No alternatives were considered.



MISO, using Ventyx Velocity Suite © 2014

Figure 4.5.20-1: P24278 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	Edina – St. Louis Park 115 kV	308.6	127	90
P7-1	Edina – St. Louis Park 115 kV	308.6	127	90

Table 4.5.20-1: P24278 Thermal loading drivers

Multi-Value Projects:

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24902	Brookings - Lyon, Hampton - Helena OPGW Replacement	This project will replace the aging OPGW on the Brookings - Lyon County and Hampton - Helena 345 kV lines. This project will be performed in tandem with the installation of the Brookings - Lyon County and Hampton - Helena 2nd circuit installation project.	9/1/2025	$4.0

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23347	Blue Lake Substation - FRM13	Replace ammeter on Blue Lake 345 kV breaker 8M33 to increase rating on the Blue Lake - Scott County 345 kV line.	9/2/2022	$0.1
23447	W3441 Extension to W3510	Extend the line from Birchwood substation to the east to connect to Xcel line W3510 in the vicinity of the town of Wieger, a distance of about 13 miles. Install motor operated switches at Birchwood to sectionalize the line. Install manual switches at the connection to W3510. The line would initially be operated as a normally open second source to Birchwood.	12/1/2025	$9.0
23450	STY Install TR3 & 115 kV Bus Tie	Install new 115 kV bus tie and associated disconnect switches and bus work and re-terminate 0818/5529 at Rogers Lake Sub.	12/15/2024	$5.3
23451	Pine Lake - Stanton 69 kV Rebuild	Rebuild 16.1 miles from Pine Lake - Stanton to 69 kV standard.	9/1/2023	$9.5

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23453	Line 0811 - Riverside Substation - FRM13	Replace switches 5M330B, 5M331B, 5M329A, 5M330A, 5M329B, 5M331A, aux current transformers on 5M304 and 5M305, and two sections of busbar.	12/31/2022	$0.9
23454	Line 0838 - Red Rock Substation - FRM13	Replace bushing current transformers on breaker K2, switches K2B1, 946B, K2B2, 946A, and meters on 946 and K2.	12/31/2022	$0.7
23463	Nighthawk Breaker Station	New 4-line terminal breaker station connecting to Minnesota Valley – Troy 69 kV transmission line (0724), Crook's substation, and the SMBSC plant.	6/1/2024	$5.0
23468	Chisago County Substation - FRM13	Replace primary and secondary 115 kV bus 1 differential relays for TR05 and TR06.	8/1/2022	$0.2
23469	Scott County Substation - FRM13	Replace busbar.	12/31/2022	$0.2
23486	Inver Hills Substation - FRM13	Replace busbar.	3/1/2023	$0.2
23487	Kohlman Lake Substation - FRM13	Replace meter on breaker 5P106.	12/31/2022	$0.1
23488	Prairie Substation - FRM13	Replace meter on breaker 5G8.	12/31/2022	$0.1
23489	Wilmarth Substation - FRM13	Replace bushing current transformer on breaker 5S11 as well as switches 8S26B1, 8S25B, 8S25A, 8S26B1.	12/31/2022	$0.6
23501	Line 0840 Elliot Park Pumping Plants	Upgrades to pumping station for HPFF.	6/1/2025	$5.0
23509	Junction Mill Substation	Build new Junction Mill substation near 3-terminal 115 kV connection with Glenmont, River Falls and Crystal Cave lines. In addition, this substation will install a new 115/69 kV transformer and change the operating voltage of the River Falls tap to 69 kV. The transformation at the River Falls substation will be removed as well as any 115 kV equipment.	6/1/2024	$12.0
23513	Emerald Substation	Line W3209 – Replace 3-way switch with new 161 kV to 115 kV substation. Rebuild 1 mile of double circuit 161-115 kV line to single circuit 115 kV line. Retire Pine Lake 161 kV to 115 kV yard.	6/15/2025	$12.0

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23515	Eau Claire TR09 Replacement	Upgrade Eau Claire TR09.	6/1/2025	$8.0
23712	Lyon County Substation - FRM13	Replace 5N130 actuator secondary current limitation to increase TR9 rating back up to its transformer limits.	9/1/2023	$0.3
23760	Nobles County Substation - FRM13	Upgrade flexible busbar to increase ratings of TR9 and TR10.	9/1/2023	$0.5
24374	Steep Bank Lake Line Swap	Move J460 Steep Bank Lake interconnection to new 34 5kV second circuit being built between Brookings County - Lyon County (MTEP ID 23452).	9/2/2025	$0.3

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23446	W3502 Rebuild and Connection to W3503	Construct a new line from the end of the existing line W3502 to Xcel's W3503 1.3 miles to the east. The new connection would be made with a group of one-way pole mounted switches. The new connection will allow the sections between the substations to be sequentially rebuilt. The existing line W3502 will be rebuilt to serve as a redundant connection.	6/15/2024	$3.0
23448	W3430 Rebuild	Rebuild 2 ¼ miles from Luck - Luck (DPC) to 69 kV standard.	6/1/2023	$1.0
23449	W3429 Clear Lake to STR 214 Rebuild	Rebuild 10 miles of line W3429 from Clear Lake to Structure 214 to 69 kV standard and add OPGW.	7/31/2024	$5.3
23455	Parkers Lake TR09 ELR	Replace Parkers Lake 345/115 kV TR09 (3 phases).	12/31/2025	$6.0
23456	Lake Yankton TR02 ELR	Replace Lake Yankton 115/69 kV TR02.	12/31/2026	$1.5
23457	Hydro Lane TR05 ELR	Replace Hydro Lane 115/69 kV TR05.	12/31/2026	$3.0
23458	Line 0893 NSS-BCK Rebuild	Rebuild 3.4 miles of 115 kV line between North Star Steel and Battle Creek substations. Portions of this line are double circuited with 0892, this project will separate the two circuits.	12/15/2023	$3.4

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23459	Line 0749 Waseca - ITC Tap Rebuild	Rebuild 6.7 miles of 69 kV line 0749 from Waseca - ITC Tap and add OPGW.	6/15/2024	$6.0
23460	Line 0714 Medelia - Watonwan Rebuild	Rebuild 22 miles of line 0714 69 kV from Medelia - Watonwan.	12/31/2024	$11.0
23461	Line 0708 STR 78 to 476 Rebuild	Rebuild 16 miles of line 0708 69 kV from Eagle Lake - Waterville and add OPGW.	12/31/2024	$9.0
23462	Line 0718 Arlington - Winthrop Rebuild	Rebuild 15 miles line 0718 69 kV from Arlington - Winthrop.	6/15/2024	$9.0
23466	W3351 88 kV Rebuild STR 336 to Saxton Pump	Rebuild line W3551 from structure 336 to Saxton Pump. Design the 88 kV circuit to be 115 kV capable. Include provision for a 34.5 kV under build circuit to connect to W3628 north of Saxton Pump.	12/31/2024	$8.0
23467	Line 0859 Str 16 to Chemolite rebuild	Rebuild 6.9 miles of line 0859 115 kV from Chemolite substation to structure 16.	12/31/2024	$9.0
23473	Line 0892 RRK-BCK Rebuild	Rebuild 3.4 miles of 115 kV line between Red Rock and Battle Creek substations. Portions of this line are double circuited with 0893, this project will separate the two circuits.	12/15/2023	$5.2
23474	Line 0736 Arden Hills - Lawrence Creek Rebuild	Rebuild 33 miles of line 0736 69 kV from Arden Hills - Lawrence Creek and add OPGW.	12/31/2025	$20.0
23475	Line 0721 STR 71 to 476 Rebuild	Rebuild 22 miles line 0721 69 kV from Structure 71 - Structure 476.	12/31/2025	$11.0
23476	Line 0822 Empire to STR 107 Rebuild	Rebuild 7 miles of line 0822 115 kV from Empire to Str 107 and add OPGW.	12/31/2024	$6.0
23477	Line 0772 Prairie to MNPC Connection Rebuild	Rebuild 12 miles of line 0772 69 kV from Prairie - Emerado.	12/31/2025	$6.0
23479	Iron River Substation Rebuild	Rebuild the existing Iron River substation to include a 115 kV ring bus and new 115/34.5 kV transformer.	6/1/2024	$7.0
23490	Crystal Cave TR01 ELR	Replace Crystal Cave 161/115 kV TR01.	12/31/2024	$3.5
23491	Parkers Lake TR10 ELR	Replace Parkers Lake 345/115 kV TR10 with a single 3 phase transformer.	12/31/2022	$3.5

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23492	Pine Lake TR03 ELR	Replace Pine Lake 161/115 kV TR03.	12/31/2027	$3.5
23493	Monticello TR06 & TR10 ELR	Replace Monticello 345/230 kV TR06 and 345/115 kV TR10.	9/16/2025	$7.0
23494	Prairie Island TR10 ELR	Replace Prairie Island 345/161 kV TR10	12/15/2024	$3.5
23495	Pipestone TR05 & TR06 ELR	Replace Pipestone TR05 and TR06 115/69 kV transformers.	12/31/2024	$3.0
23496	Inver Grove TR02 ELR	Replace Inver Grove 115/69 kV TR02.	12/31/2025	$2.5
23497	Lake Pulaski TR05 ELR	Replace Lake Pulaski 115/69 kV TR05.	12/31/2026	$2.5
23498	Minnesota Valley TR11 ELR	Replace Minnesota Valley 115/69 kV TR11.	12/31/2027	$2.5
23499	Osprey TR05 ELR	Replace Osprey 115/69 kV TR05.	12/31/2027	$3.5
23502	Line 0771 Rebuild	Rebuild 2 miles of line 0771 from Young America - Carver County 69 kV substations and add OPGW.	6/30/2024	$1.5
23503	Line 0719 Winthrop to STR 45 Rebuild	Rebuild 1.5 miles of line 0719 69 kV from Winthrop - Structure 45.	12/31/2025	$2.0
23506	Gingles TR05 ELR	Replace Gingles 115/69 kV TR05.	12/31/2025	$2.5
23508	Line 5503 Cherry Creek - Great Plains - West Sioux Falls Rebuild	Rebuild 2 miles 115 kV Cherry Creek - Great Plains. Rebuild 1 mile 115 kV Great Plains - West Sioux Falls (single circuit portion) as bifurcated double circuit. Rebuild 0.7 mile 115 kV Great Plains - West Sioux Falls (double circuit portion).	6/1/2024	$5.0
23512	Prairie View Substation	Rebuild the Wheaton Substation on a new location with a 4-row breaker and a half 161 kV configuration in order to separate it from the Generation facility.	6/1/2026	$17.0
23527	Line W3428 Clear Lake - New Richmond Rebuild	Rebuild 19.8 miles of line W3428 from Clear Lake - New Richmond.	3/15/2023	$10.0
23528	Gaiter Lake Substation	Build new Gaiter Lake substation in Waseca to pick up load off of Clarks Grove, Meridan, and Waseca substations. Retire Clarks Grove and Meridan substations.	10/15/2025	$7.8

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23514	Sauk Centre North Interconnection	Build three one-way switches on line 0794 to accommodate new Sauk Centre Municipal distribution substation.	12/31/2024	$0.8
23547	21829 - South Dayton Interconnection	New GRE interconnection (MTEP ID 21829). Xcel will own high side of new sub with an in-and-out configuration on the Elm Creek - Champlin Tap 115 kV line.	6/15/2023	$5.0
23728	Owen Area Substation	Install new Owen Area Substation and convert Owen Distribution to 23.9 kV.	10/15/2026	$7.9
24315	Dubay Lake Substation	Install new 115/34.5 kV substation in the Dayton area to meet area load growth.	6/16/2025	$12.4
