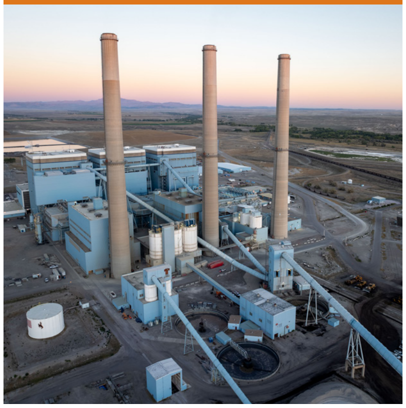
SUMMER

2026



RESILIENCE OF THE ELECTRIC GRID IN NORTH DAKOTA

NORTH DAKOTA
TRANSMISSION AUTHORITY

The North American Electric Reliability Corporation (NERC) produces a seasonal grid reliability assessment for winter and summer seasons. This reliability assessment covers the United States and Canada.

Similarly, the **Midwest Reliability Organization (MRO)** produces a seasonal grid reliability assessment for the Midwest region, covering the central states from northern Texas to Canada, including Saskatchewan and Manitoba. This region includes North Dakota. The MRO's Summer 2026 Reliability Assessment was released June 3, 2026. The full report is included in this document.

As part of Midwest Reliability Organization's annual summer assessment, staff engineers determined that operating reserves are expected to remain sufficient under normal summer weather conditions, assuming typical maintenance schedules and planned generation outages across the region.

However, periods of extreme heat that drive demand spikes, combined with forced generation outages, could result in insufficient electricity supply in SaskPower's service area. In those circumstances, SaskPower may need to implement demand response programs, arrange short-term power transfers, or issue energy emergency alerts to maintain required operating reserve levels.

This summer's outlook represents an improvement compared with previous years, reflecting the efforts of utilities across the region to add approximately 10 GW of new generation capacity, mostly from solar and hydro resources.

MRO's 2026 Regional Summer Assessment provides key stakeholders with critical insights into potential reliability challenges and recommends actions to mitigate risks. The report also highlights bulk power system performance trends specific to the MRO region to inform long-term system planning.

North Dakota generation and transmission owners & developers continue to build out transmission and generation assets. Both cooperative generation and transmission entities and investor-owned utilities see opportunities to develop natural gas generation in North Dakota to meet capacity requirements (dispatchable generation) and recognize that North Dakota also has rich wind resources that can be appropriately leveraged to meet energy requirements. Fortunately, the coal industry has received regulation reprieve, allowing coal generation facilities to plan for a more robust future. Solar projects offer valuable capacity attributes for summer peaks, with peak production aligning with summer peak consumption. Hydropower, though a small segment of the generation mix, is a dependable and flexible generation asset. Nuclear energy holds promise, particularly in the small modular reactor realm; however, like coal, the development and construction of a facility requires several years.

Claire Vigesaa, Executive Director
North Dakota Transmission Authority

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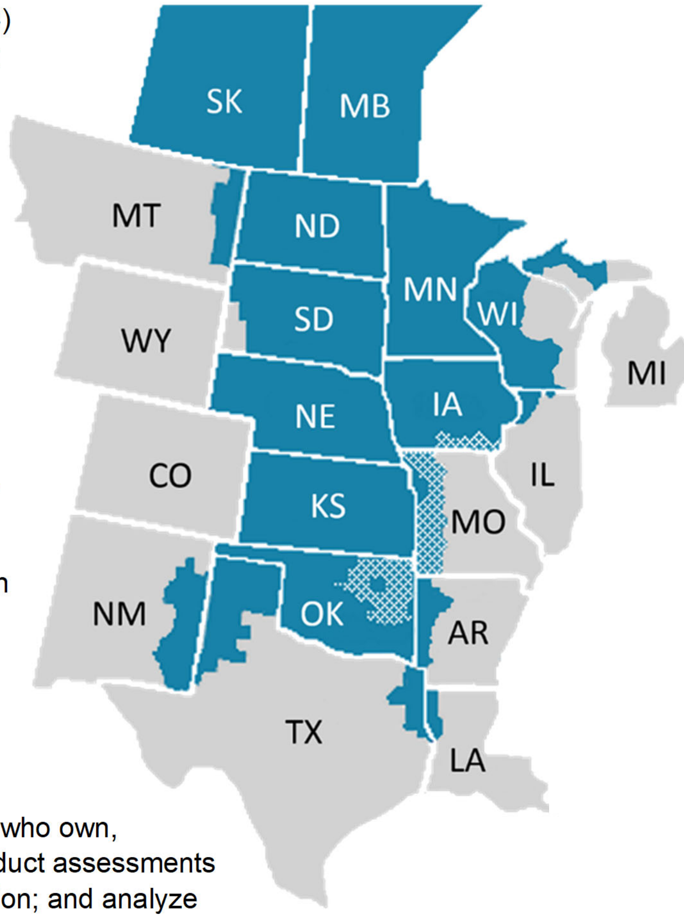
Preface

ABOUT THE ORGANIZATON

Midwest Reliability Organization (MRO) is dedicated to its vision of ***a highly reliable and secure North American bulk power system***. To ensure reliability of the bulk power system in the United States, Congress passed the Energy Policy Act of 2005, creating a new regulatory organization called the Electric Reliability Organization (ERO) to establish mandatory Reliability Standards and monitor and enforce compliance with those standards on those who own, operate or use the interconnected power grid.

In 2006, the Federal Energy Regulatory Commission (FERC) approved the North American Electric Reliability Corporation (NERC) as the ERO under section 215(e)(4) of the Federal Power Act. NERC delegates its authority to monitor and enforce compliance to six Regional Entities established across North America, of which MRO is one. Recognizing the international nature of the grid, NERC as the ERO, along with MRO, established similar arrangements with provincial authorities in Canada.



The MRO region spans the provinces of Saskatchewan and Manitoba, and all or parts of the states of Arkansas, Illinois, Iowa, Kansas, Louisiana, Michigan, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wisconsin. The region includes more than 290 organizations that are involved in the production and delivery of electric power, including Canadian utilities, cooperative and municipal utilities, investor-owned utilities, along with federal power marketing agencies, generator power marketers, and transmission system operators.

MRO's primary responsibilities are to monitor and enforce compliance with mandatory Reliability Standards by entities who own, operate, or use the North American bulk power system; conduct assessments of the grid's ability to meet electric power demand in the region; and analyze regional system events. Additionally, MRO creates an open forum for stakeholder experts and provides outreach across the region to discuss important topics related to addressing risk and improving reliable operations of the bulk power system.

Executive Summary

This annual assessment provides information and raises awareness of regional bulk power system challenges and trends, helping industry stakeholders and decision-makers reduce risk and maintain electric reliability during the summer season. The 2026 Regional Summer Assessment (RSA) provides critical insights for the upcoming summer season, specifically the months of June through September. In developing the 2026 RSA, MRO staff analyzed data from the four Planning Coordinators (PCs) operating in the region to determine if adequate electricity generation and transmission is available to meet projected peak summer demand. The four PCs in MRO's region are: Manitoba Hydro, Midcontinent Independent System Operator, SaskPower Corporation, and Southwest Power Pool.

Additionally, this report incorporates quarterly data from over 290 registered entities (users, owners, and operators of the bulk power system) to assess the regional grid's performance during previous summer seasons. This helps identify key trends and emerging risks. Information on the identification, registration, and certification of these entities is available in Appendix A.

This report complements NERC's North American Summer Reliability Assessment by providing a more detailed analysis of reliability concerns specific to MRO's geographic area.

KEY FINDINGS

- Anticipated resources are sufficient to meet operating reserve requirements under normal peak demand conditions with typical maintenance and forced outages in all PC areas.
- Sufficient resources are also anticipated to meet operating reserve requirements under extreme peak demand, even when coupled with extreme weather conditions, in the Manitoba Hydro, Midcontinent Independent System Operator, and Southwest Power Pool areas.
- Although SaskPower Corporation anticipates sufficient capacity and reserve margin to meet peak summer demand, there is an elevated risk of insufficient energy to serve load at all hours, according to the probabilistic energy analysis.
- Midcontinent Independent System Operator experienced a large increase in resource availability compared to the 2025 summer season, with a new record set for nameplate installations[1] in 2025.
- Capacity margins continue to tighten for Southwest Power Pool due to increasing load growth and a changing resource mix.
- Interruptions to fuel supply, combined with the growing share of variable energy resources, could create unique operational challenges. As variable resources become a larger part of the region's energy mix, their performance during periods of high demand becomes increasingly critical.

SUMMER SEASON TRENDS

- Eleven Bulk Electric System (BES) transmission events occurred on the regional system in 2025 - the lowest number since MRO began performing seasonal assessments.
- Summer generator performance improved compared to the previous year; however, ongoing outages from the spring maintenance cycle—particularly among fossil steam and simple cycle

[1] Nameplate capacity is the maximum sustained power output a generator or power plant can produce under ideal, manufacturer-specified conditions

units—led to higher event impacts and increased Weighted Equivalent Forced Outage Rate (WEFOR) percentages.

- The number of unknown momentary transmission line outages decreased by 53% compared to 2024, marking significant improvement following the 66% increase observed in 2024 relative to 2023.
- While total protection system misoperations increased by approximately 5% from 2024, the 2025 misoperations rate was well below the five-year average.

RECOMMENDATIONS

The following actions are recommended to mitigate risks of energy shortfalls on the regional bulk power system this summer:

- Reliability Coordinators (RCs), Balancing Authorities (BAs), Transmission Operators (TOPs), and Generator Operators (GOPs) should maintain heightened situational awareness during periods of unplanned generation or transmission outages, extreme weather conditions, and low wind forecasts.
- These organizations should also implement operating procedures as needed to ensure resource adequacy.
- RCs, BAs, and Generator Owners (GOs) should develop protocols to ensure sufficient generation resource availability before the summer season.
- State and provincial regulators should be prepared to support grid operators by approving environmental and transportation waivers and the issuance of public appeals to conserve electricity, both before and during the summer season.

Chapter 1: Assessment Overview

PROCESS

As part of the ERO Enterprise (collectively NERC and the Regional Entities) reliability assessment process, MRO staff independently evaluate and report on regional electricity supply and demand, transmission system adequacy, and emerging trends that could affect bulk power system stability.

This work is mandated by MRO's Regional Delegation Agreement, Section 800 of the NERC Rules of Procedure, and the ERO Enterprise Reliability Assessment Process.

The data MRO assesses each year is collected from regional RCs and PCs. The PCs are responsible for integrating transmission facilities, service plans, resource plans, and protection systems in their analyses to ensure reliable power within their specific footprints. These organizations collaborate with Transmission Planners (TPs) to assess the reliability impact of resource and transmission outages within interconnected areas. The RCs are responsible for the real-time reliable operation of the bulk power system and have a wide-area view of system operations. They hold the highest level of operational authority within their designated footprints.

In addition to the four PCs in MRO's region, there are three RCs: Midcontinent Independent System Operator (who also serves as the RC for Manitoba Hydro), SaskPower Corporation, and Southwest Power Pool.

NERC's 2026 Summer Reliability Assessment covers all of North America and is a coordinated evaluation between the NERC Reliability Assessment Subcommittee, NERC staff, and the six Regional Entities.[2] While MRO's RSA leverages some of the same data, historical information is also studied to offer a targeted, regional view of reliability concerns, trends, and emerging risks.

AREA STUDIED

MRO's region includes two Canadian provinces and all or parts of 16 U.S. states. Notably, the Midcontinent Independent System Operator footprint spans three Regional Entities: MRO, ReliabilityFirst (RF), and SERC Reliability Corporation (SERC). MRO is responsible for collecting resource and transmission system adequacy data for the entire Midcontinent Independent System Operator area and coordinates with RF and SERC for review and preparation of NERC reliability assessments. However, MRO's review of Midcontinent Independent System Operator's historical performance data is limited to the MRO region. Additionally, MRO gathers and analyzes performance data and NERC reliability assessment information for the entire Manitoba Hydro, SaskPower Corporation, and Southwest Power Pool footprints.

The sources used for this assessment include NERC's 2026 Summer Reliability Assessment and MRO's Performance Analysis data used in NERC's Generating Availability Data System (GADS), Transmission Availability Data System (TADS), Misoperation Information Data Analysis System (MIDAS), and Event Analysis (EA).

Figure 1.1 illustrates the North American assessment areas, and Figure 1.2 shows the boundaries of the North American Regional Entities, which do not align precisely with the assessment areas.

[2] https://www.nerc.com/AboutNERC/keyplayers/Pages/default.aspx

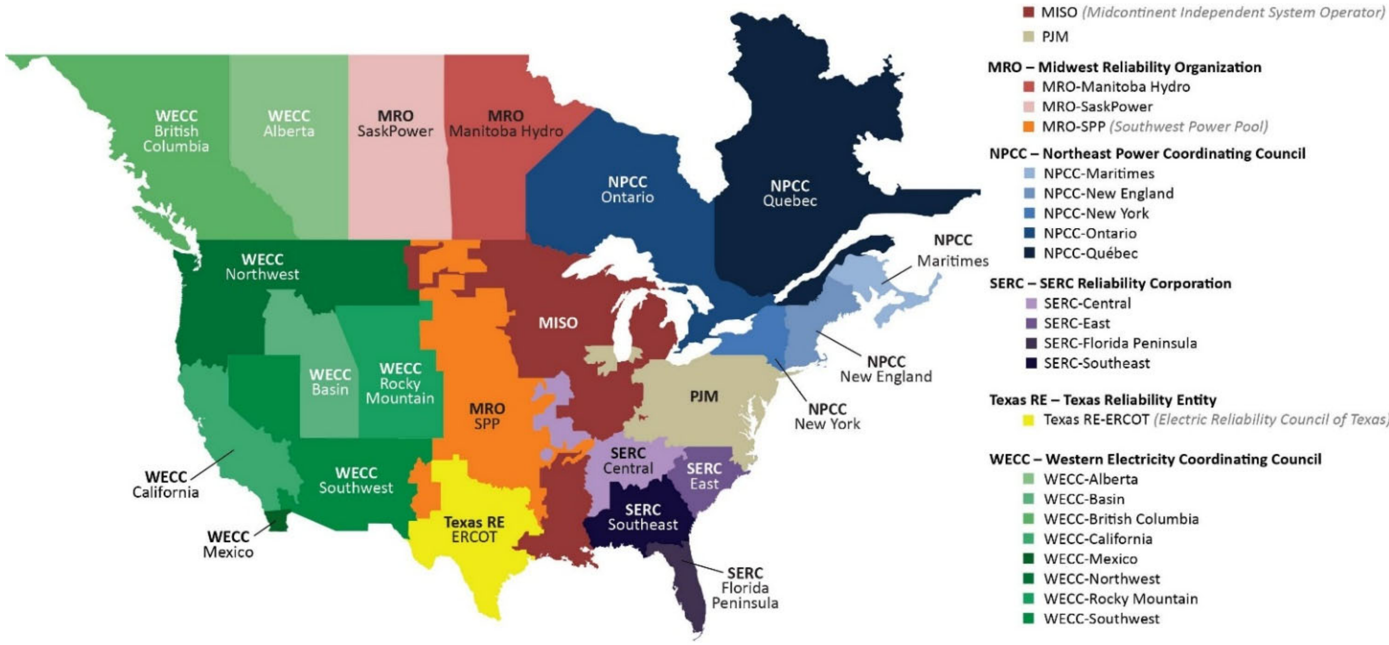


Figure 1.1: NERC Assessment Areas

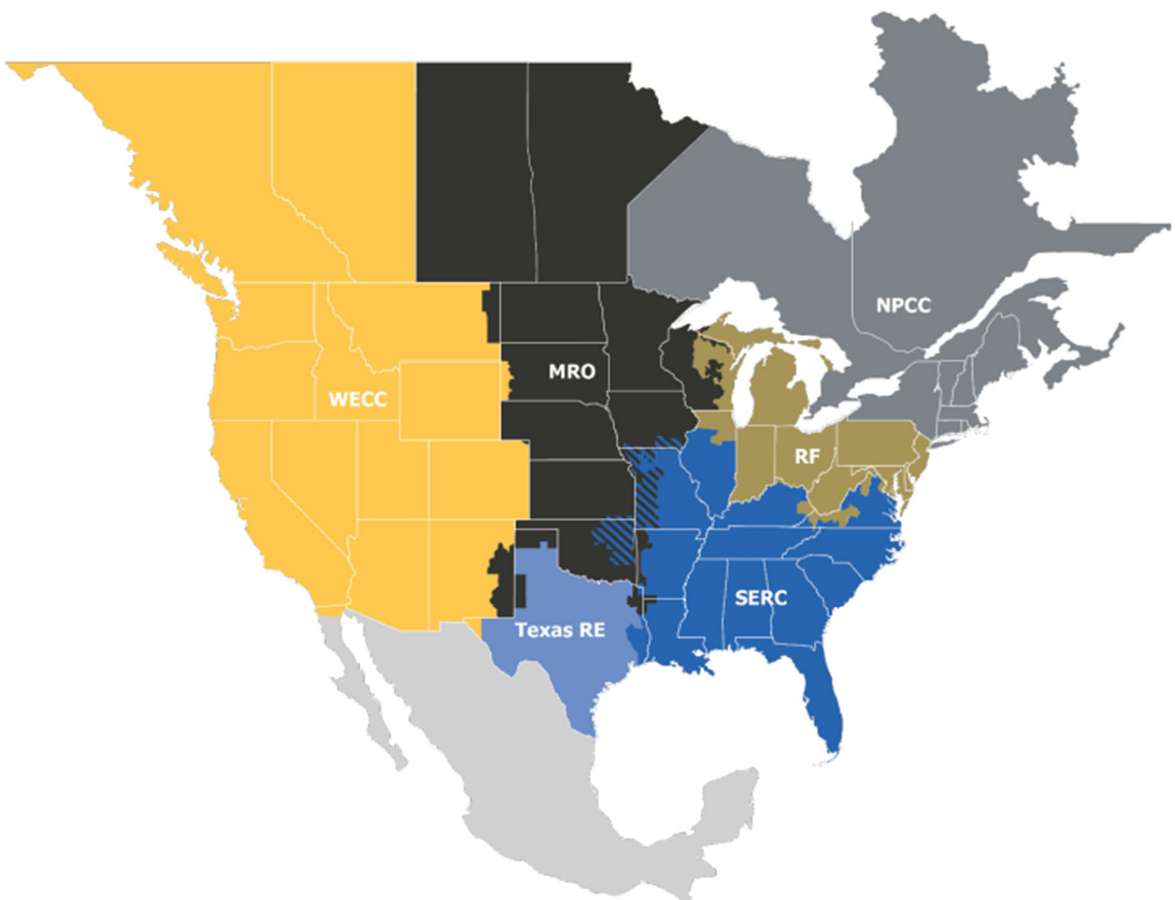


Figure 1.2: Regional Entity Boundaries

Chapter 2: 2026 Summer Outlook

Changing climate conditions have made seasonal load forecasting increasingly complex and difficult. The uncertainty associated with seasonal load forecasting has elevated summer reliability risks for the bulk power system. Extreme hot temperatures and severe weather can stress the grid and cause electricity demand to deviate significantly from historical forecasts. Underestimating demand may lead to ineffective operational planning and insufficient scheduling of resources, while overestimating demand can lead to adding excessive resources at consumers' expense. Additionally, generator performance and fuel supply issues are more likely to arise when generators are required to operate on short notice, exposing BAs to potential resource shortfalls.

In coordination with the ERO Enterprise and industry, MRO conducts seasonal generation and load forecasts to assess reliability risks. Details from the 2026 Seasonal Summer Forecast can be found in Appendix B. Based on this information, the projected reliability conditions for each assessment area in the MRO region for the 2026 summer season are outlined below.

BY ASSESSMENT AREA

Manitoba Hydro

Manitoba Hydro's Anticipated Reserve Margin (ARM) decreased from 14.6% last summer to 13.2% this summer due to a rise in demand and extended outages on some of its smaller units. The demand growth is driven primarily by overall population and economic growth, including electrification of a large industrial customer to reduce carbon emissions. Manitoba Hydro's Installed Capacity (ICAP) Planning Reserve Margin Requirement (PRMR) remains unchanged at 12%.

Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues in its assessment area for the upcoming 2026 summer season.

Manitoba Hydro reservoir storage conditions are below average, but winter snowfall has been above average, which will favorably impact spring runoff. The Manitoba Hydro system is designed and operated so that reliability can be maintained under extreme drought. Manitoba Hydro expects to reliably supply its internal demand and export obligations, even if extreme drought develops through 2026/27.

Midcontinent Independent System Operator

Midcontinent Independent System Operator's ARM increased from 24.7% last summer to 31.1% this summer, driven by anticipated resource additions, with a new record set for nameplate installations (primarily solar at 6.6 GW). Its ICAP PRMR decreased slightly from 15.7% percent last summer to 15% this summer, due to changes in resource capability under the summer 2026 seasonal capacity construct.

Demand forecasts and resource data indicate that Midcontinent Independent System Operator is likely to have adequate capacity to meet demand, as well as operating reserves, during periods of high demand.

Since the 2025 summer season, Midcontinent Independent System Operator has identified seven areas of focus to help address recent reliability and market concerns:

- Transmission system emergency response changes
- Operating reserve zone revisions
- Dynamic ramp requirements
- Elimination of dual registration for Emergency Demand Response (EDR) and Load Modifying Resources (LMR)

- Improvement on LMR / EDR / Demand Response Resource (DRR) type resources with the locational enrollment service
- Hybrid resource accreditation / participation
- Adoption of multiday gas purchase requirement

Saskatchewan Power Corporation

SaskPower Corporation's ARM decreased from 33.5% last summer to 29.2% this summer, mostly due to a rise in demand from residential and power class sectors. Contributing factors include population growth in the province, expansion projects, reduced self-generation in the industrial sector, and increased electrification across various customer groups. SaskPower Corporation's ICAP PRMR for the 2026 summer season remains unchanged at 15%.

Although Saskatchewan is mainly a winter-peaking region, summer can also bring high electricity demand due to extreme heat. Based on planned maintenance, typical forced outages from historical data, and expected renewable generation under normal and extreme demand conditions, SaskPower Corporation does not anticipate any reliability issues during the summer of 2026. However, during extreme summer conditions, there is risk for insufficient energy to serve load at peak hours, and SaskPower Corporation might need to utilize maintenance rescheduling, short-term power transfers from neighboring utilities, and/or available demand response programs.

Southwest Power Pool

The Southwest Power Pool East Assessment Area's ARM decreased from 28.5% last summer to 26.8% this summer due to increased demand. The Southwest Power Pool's East Assessment Area's accredited PRMR dropped to 10% compared to 19% coincident (15% non-coincident) peak demand last summer. This transition reflects the implementation of the new Southwest Power Pool East Assessment Area's Accredited Capacity (ACAP) PRMR.

Southwest Power Pool does not anticipate widespread reliability concerns under normal operating conditions for the 2026 summer season. However, operational challenges and emerging risks could impact system reliability under stressful conditions. Capacity margins continue to tighten due to increasing load growth and a changing resource mix, including greater reliance on variable energy resources. While planning reserve margins are expected to be met, energy adequacy risk remains during prolonged heat events aligned with low wind output. Additionally, the growing penetration of renewable resources introduces increased variability, ramping requirements, and challenges in maintaining essential reliability services like frequency response and voltage support.

Southwest Power Pool monitors transmission constraints and deliverability limitations, particularly during peak conditions when energy transfers may be restricted. Elevated forced outage rates across portions of the thermal fleet, combined with outage coordination challenges, increase operational uncertainty during high-demand periods. Extreme weather remains a key reliability driver, with the potential for regional conditions to increase demand, reduce generator performance, and limit imports due to the needs of the neighboring region. Emerging large load interconnections, including data centers and industrial facilities, further introduce forecasting and operational uncertainties. Overall, maintaining reliability will depend on proactive operational actions, enhanced outage coordination, and conservative operating practices during extreme or stressed scenarios.

Chapter 3: Historical Seasonal Trends

The following data was used to analyze system performance and identify seasonal trends:

- Bulk Electric System (BES) Event Analysis
- Energy Emergency Alerts (EEAs)
- Generation Availability Database System (GADS)
- Transmission Availability Database System (TADS)
- Misoperation Information Data Analysis System (MIDAS)
- Historical Summer Load Forecast

Performance data from GADS, TADS, MIDAS, and Event Analysis (EA) are collected and analyzed by MRO staff for the regional footprint. Resource and transmission system adequacy reviews are conducted by the Planning Coordinators (PCs) in the region within each respective area.

BULK ELECTRIC SYSTEM EVENT ANALYSIS

Mandated by Section 800 of the NERC Rules of Procedure, MRO staff studies events and system disturbances that include significant losses of load or generation, or other emergencies on the bulk power system. Using the Event Analysis Process established by the ERO Enterprise, MRO works with registered entities to perform a root cause analysis of the event, develop a brief report, and document recommendations or lessons learned that can be shared with electric power industry stakeholders.

Transmission System Events

Eleven Category 1a transmission events occurred on the system in MRO's region in 2025, with three during the 2025 summer season. Equipment failure and protection system misoperations were identified as contributing causes. A Category 1a event results in an unexpected outage, contrary to design, of three or more BES Facilities caused by a common disturbance. (The NERC Addendum for Determining Event Category can be found at NERC Addendum for Determining Event Category.)

MRO has published numerous lessons learned and two white papers addressing root causes identified through performance and event analysis to reduce misoperation risk. The Protective Relay Subgroup (PRS) updated and republished two white papers to consider more recent challenges and mitigation strategies. MRO staff continues to collaborate with industry experts on the PRS to reduce protection system misoperations.

Figure 3.1 illustrates MRO's Event Severity Index that includes all BES events and allows for comparison of the impact that each event had on the BES. Each section of the bar represents the calculated impact of the event using the number of elements lost, amount of generation lost, and amount of load lost. As an example, the event impact number for an event with 100 MW of load shed, 120 MW of generation lost, and eight BES elements taken out of service will be higher than the impact of an event with a low number in any of the named categories. The green bar is the average annual impact of all events, which MRO uses as a general indicator of how entities are limiting the impacts of events on the BES in the region.

MRO's primary focus is to limit large-impact events, especially those that may lead to a wide cascading event or outage. The total number of events over the five-year period shown on the chart has remained consistent year-over-year, while the average impact is trending downward.

A summary of BES events that occurred during the 2025 summer season in MRO's region, including the event category, number of BES facilities lost, MW of generation lost, and MW of load lost, is included in Appendix C.

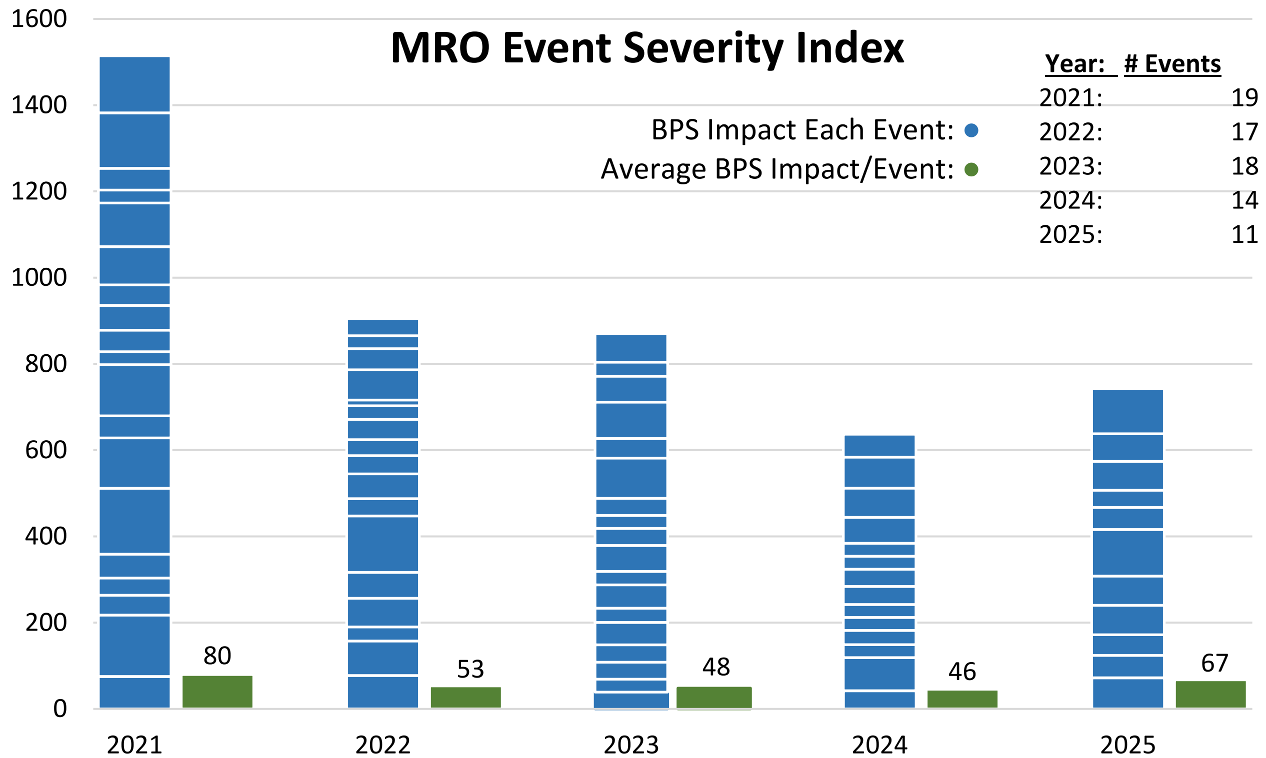


Figure 3.1: MRO Event Severity Index

Energy Management System Events

In 2025, four Category 1h Energy Management System (EMS) events occurred within the MRO region. One of these events took place during the 2025 summer season with a duration of 60 minutes. The average duration of the 2025 Category 1h events was 84 minutes. A Category 1h event results in the loss of monitoring or control at a control center such that it significantly affects the entity's ability to make operating decisions for 30 continuous minutes or more. (The NERC Reference Guideline for 1h events can be found at Reference Guideline for Category 1h Events.)

A common factor among these events is that they occurred either during or shortly after a routine maintenance procedure. The number of EMS related events has decreased over the last five years, possibly due to mitigation recommendations in NERC lessons learned, webinars, and other outreach efforts. NERC's Event Analysis Subcommittee (EAS) provides registered entities with the opportunity to engage in discussions around significant events impacting the BES, event causal factors, the event analysis process itself, as well as supporting the development of lessons learned.

MRO encourages entities to participate in these initiatives as they provide the opportunity for industry-wide information and knowledge sharing.

Figure 3.2 compares the loss of EMS events that took place during the last five years. Each section of the blue bar represents the duration of each event in minutes. The green bar is the average duration of all the events for each year.

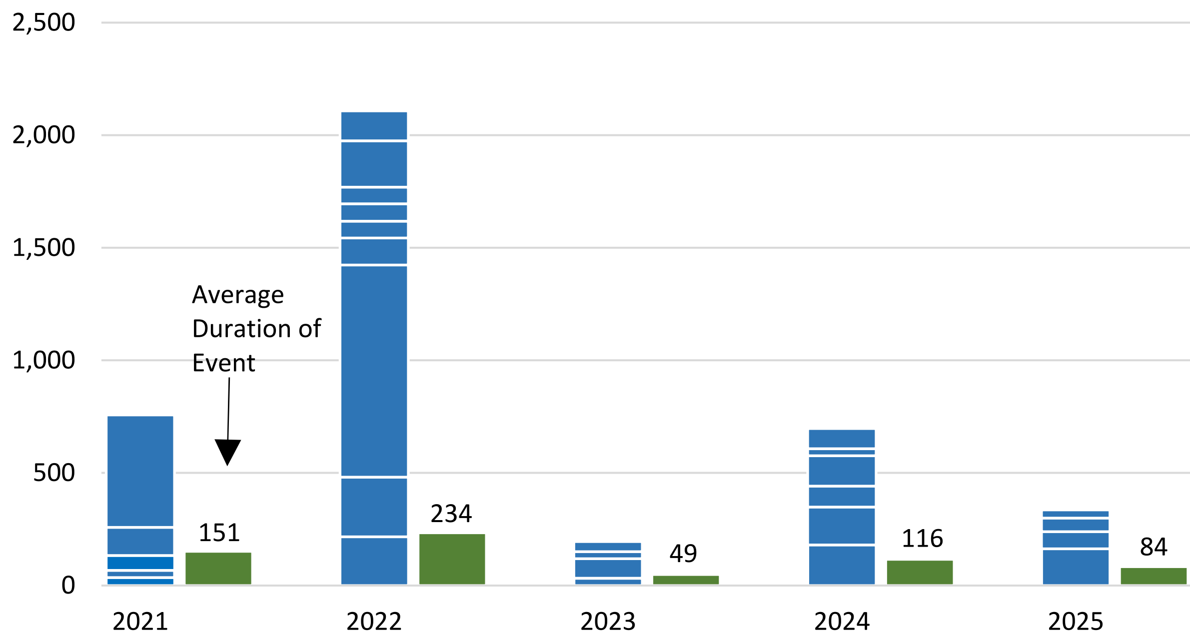


Figure 3.2: Loss of EMS Event Time Duration

ENERGY EMERGENCY ALERTS

An Energy Emergency Alert (EEA) occurs when a BA or load-serving entity exhausts all available resource options and cannot meet its expected load and operating reserves. EEAs are issued by RCs and are governed by NERC Reliability Standard EOP-011-4 to ensure that TOPs and BAs have coordinated operating plans to mitigate emergencies.

The MRO region experienced one EEA level 3 and two EEA level 1 events during the 2025 summer season. A summary of the events is included in Appendix C.

GENERATING AVAILABILITY

GADS is a program that collects information about the performance of electric generating equipment to assist with analyzing generation outages. GADS data has been reported since January 1, 2013, and includes information on more than 8,000 conventional generation units across North America. It is a valuable source of information on reliability, availability, and maintainability of generating units and includes unit design data, monthly performance data (including hours of availability and power produced), and event data. The ERO Enterprise has been capturing wind generation performance data in a separate GADS wind application since 2018, which has now been retired. GADS solar data was first collected in 2024, which was the first year for reporting events for GADS solar in the new data collection portal. This newly reported data is not included in this report but will be added once more information becomes available. Due to a change in GADS data reporting format in 2024, Manitoba Hydro data is not included in this report.

Generation unavailability can have a substantial impact on reliability. Useful metrics for generator unavailability are the equivalent forced outage rates (EFOR)[3] and megawatt Weighted EFOR or WEFOR. Long-term trends indicate increasing WEFOR rates due to component fatigue and an aging fleet. Given higher penetrations of intermittent resources, conventional generation is being cycled (ramping up and down / startup and shutdown) to follow load and operating at minimum output more often, increasing the number of forced outages due to component failures.

Key Findings

- MRO is seeing a continuing upward trend in WEFOR in the generation fleet driven largely by winter and maintenance season performance.
- Summer performance was improved over the previous year, but more heavily impacted by ongoing outages from the spring maintenance cycle.
- Fossil steam, simple cycle contributed to higher event impacts and increased WEFOR percentages.

Based on forced outage rates for fossil-steam and simple cycle gas turbines, MRO closely monitors the performance (and identifies the failure risk) of these types of resources. Higher forced outage rates of fossil-steam and simple cycle gas could impact generation resource availability during extreme summer peak demand and increase the number and duration of EEA events.

More details on generation impacts are provided in Appendix D.

TRANSMISSION AVAILABILITY

TADS is used to track the availability of AC/DC transmission circuits and transformers operating at 100kV and above. TADS data also includes detailed information about individual outage events, that when analyzed both regionally and North American-wide, provides useful data in reliability analyses. Momentary outages of less than one minute are only reported for elements at or above 200kV, while sustained outages of one minute or longer are reported for elements at 100kV and above.

Key Findings

- TADS-reportable outages were 5% lower than 2024 and 3% lower than the 5-year average.
- Lightning was the cause of 39% of the momentary outages reported in the 2025 summer season.
- The number of unknown momentary outages decreased by 53% compared to 2024. This is a considerable improvement from the 66% increase in 2024 over 2023.
- June 19 had the largest number of outages reported in a single day with 3.8% of the 2025 summer season.
- The three-day period of August 8-10 had 6.5% of the outages as two storms traveled across the southern portion of the MRO footprint.

Additional details on transmission outages are provided in Appendix E.

[3] The hours of unit failure (unplanned outage hours and equivalent unplanned derated hours) given as a percentage of the total hours of the availability of that unit (unplanned outage, unplanned derated, and service hours) - Alexander Eydeland and Krzysztof Wolyniec (2003). Energy and Power Risk Management. John Wiley and Sons. p. 109. ISBN 9780471455875

PROTECTION SYSTEM MISOPERATIONS

A properly functioning protection system is critical for maintaining reliability of the BES. Proper operation of protection systems is instrumental in preventing cascading events and large disturbances. A protection system misoperation is summarized as a failure of a composite protection system to operate as intended for protection purposes (the full definition can be found in the NERC Glossary).

Reporting of misoperations allows for causal analysis, overall trending across North America, and an opportunity to improve the effectiveness of mitigation measures. TOs, GOs, and Distribution Providers are required, per the NERC Rules of Procedure Section 1600 data request process, to report protection system operations and misoperations through MIDAS. A common measure using MIDAS data is a misoperation rate [misoperations) / (total operations)], which provides an industry measurement of protection system performance.

The annual ERO Enterprise misoperation rate is shown below in Figure 3.3 from the 2025 NERC State of Reliability report.

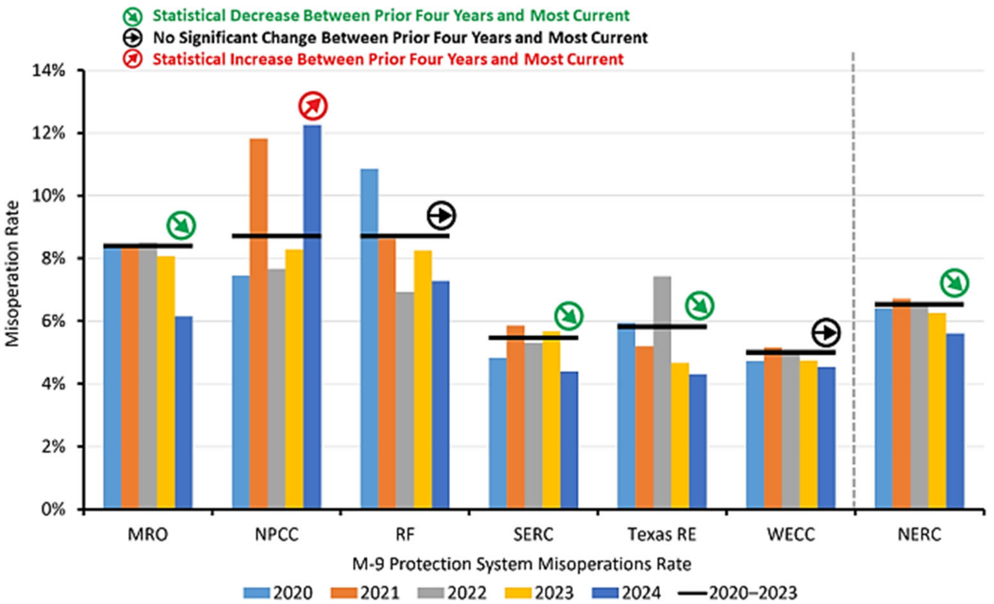


Figure 3.3: Changes and Trends in the Annual Misoperations Rate by Regional Entity

There were 3,127 operations and 198 misoperations reported in the MRO region in 2025 for a misoperation rate of 6.3%. Figure 3.4 shows the misoperation rate[4] had been trending nearly flat since 2020. 2024 showed a marked decrease in the misoperation rate, which was sustained in 2025.

[4] The misoperations rate data shown in Figure 3.4 was updated in 2024 to reflect final misoperation rates submitted through MIDAS for the five-year period. This resulted in nominal changes in the data reflected in this report compared to previously published seasonal assessments.

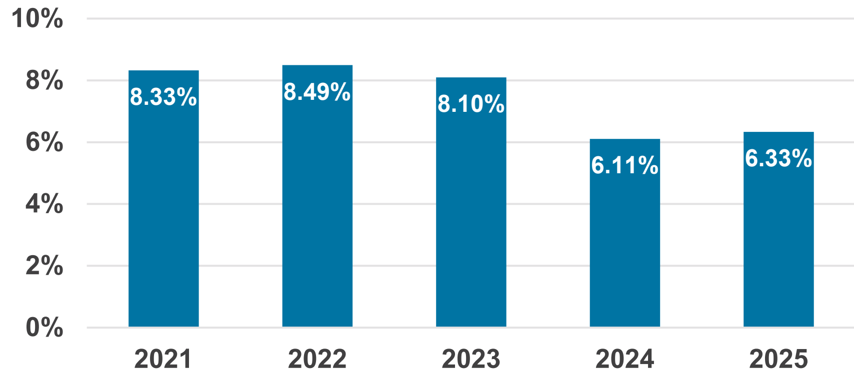
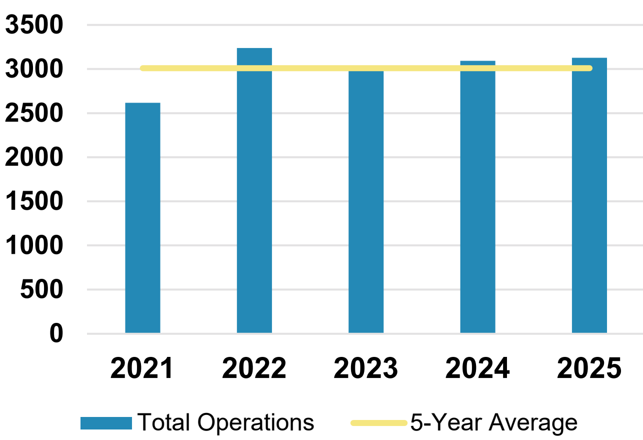


Figure 3.4: MRO Misoperation Rate by Year

Figures 3.5 and 3.6 provide context for the misoperation rate for 2025. Total protection system operations increased slightly, about 1%, in 2025 from the previous year, and total misoperations increased by approximately 5%, resulting in a slightly higher misoperations rate compared to 2024. Overall, Figures 3.4 and 3.5 show that 2025 was slightly above the five-year average for total operations and well below the five-year average for number of misoperations.



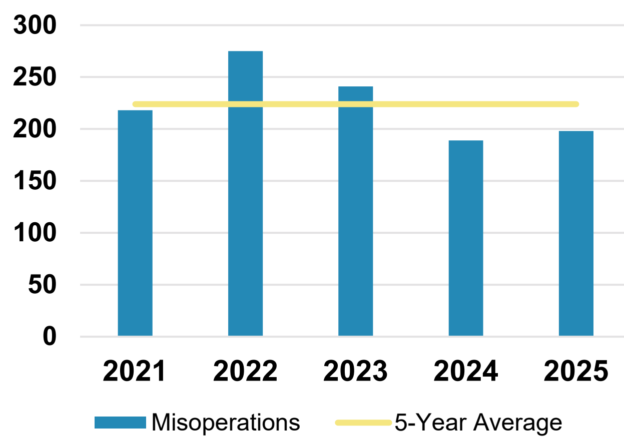


Figure 3.5: Yearly Protection System Operations **Figure 3.6: Yearly Protection System Misoperations**

MIDAS reports are completed and reported by entities quarterly. The second (April-June) and third (July-September) quarters of the year align closest to the summer season (June-September) for this assessment.

As shown in Figure 3.7, more relay system operations occur on the MRO system in the spring/summer vs. autumn/winter. MRO attributes this disparity to more BES faults caused by more frequent and impactful summer weather events when compared to winter weather.

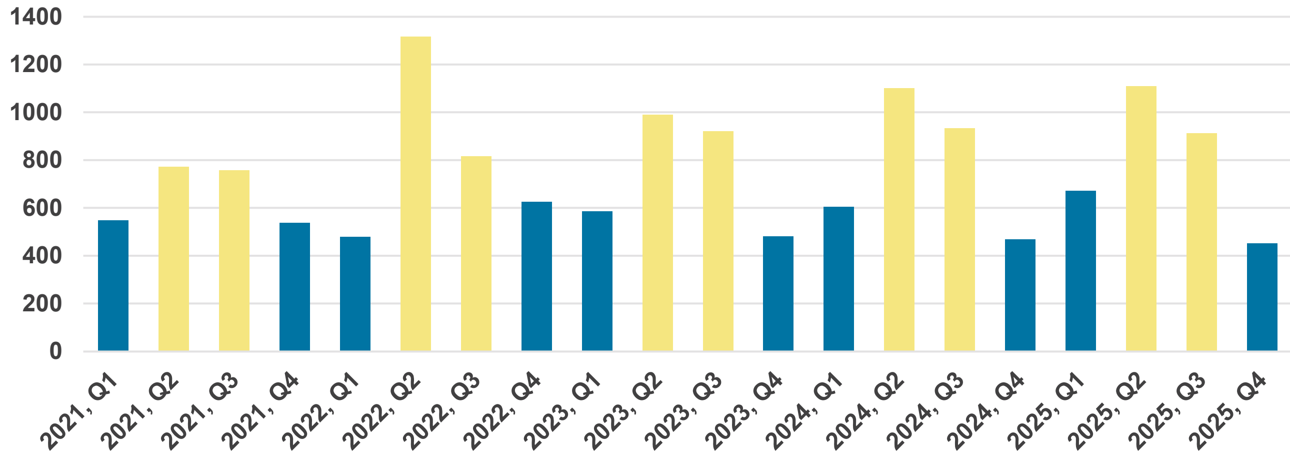


Figure 3.7: Total Operations (Spring/Summer vs. Autumn/Winter)

As shown in Figure 3.8, many misoperations are not associated with a fault. Non-fault-associated misoperations have a smaller annual variance than misoperations associated with a fault and do not vary from the number of correct protection system operations. Therefore, these misoperations would have a larger impact on the overall misoperation rate if the total number of protection system operations is low.

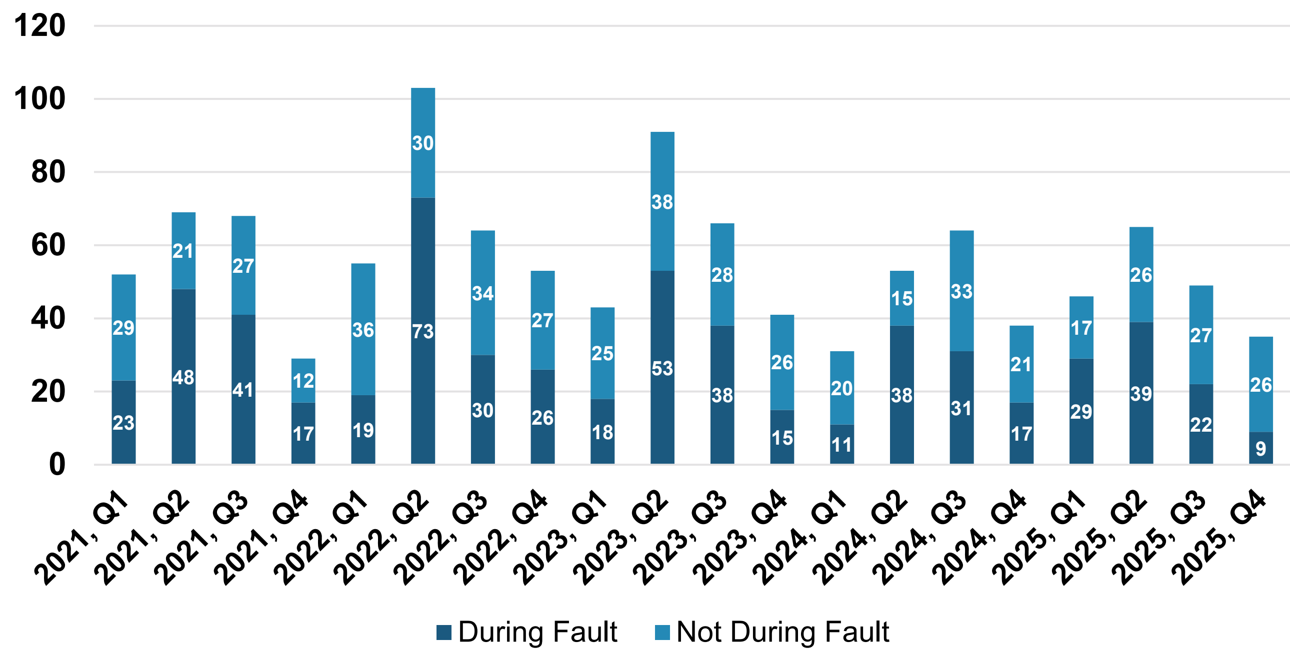


Figure 3.8: Fault Associated and Non-Fault Associated Misoperations

There were a total of 78 misoperations that occurred in the MRO region between June 1, 2025, and September 30, 2025. Examining these misoperations reveals several areas for improvement. As illustrated in Figure 3.9, of the 78 misoperations that occurred during this time, 49% were attributed to human errors (i.e., as-left personnel errors, design errors, incorrect settings, and logic errors) and 36% to equipment failures (i.e., relay failures/malfunctions, AC system, and DC system).

This trend underscores the importance of ongoing equipment maintenance and testing and reviewing obsolescence plans to ensure system reliability over time. With the higher number of protection system operations in spring/summer seasons, higher relay failure/malfunction rates during those seasons may coincide with the increased operational demand.

Although misoperations on the bulk power system stemming from human error have declined, a significant portion of misoperations in the MRO region remain attributed to human error causes. The following efforts help to reduce human error-related misoperations:

- Commissioning best practices and challenges are being discussed by MRO's Protective Relay Subgroup, which is an industry-led group comprised of utility companies and MRO staff.
- NERC hosted a third annual BES Protection System Misoperation Reduction Workshop at MRO's headquarters on October 7-8, 2025.

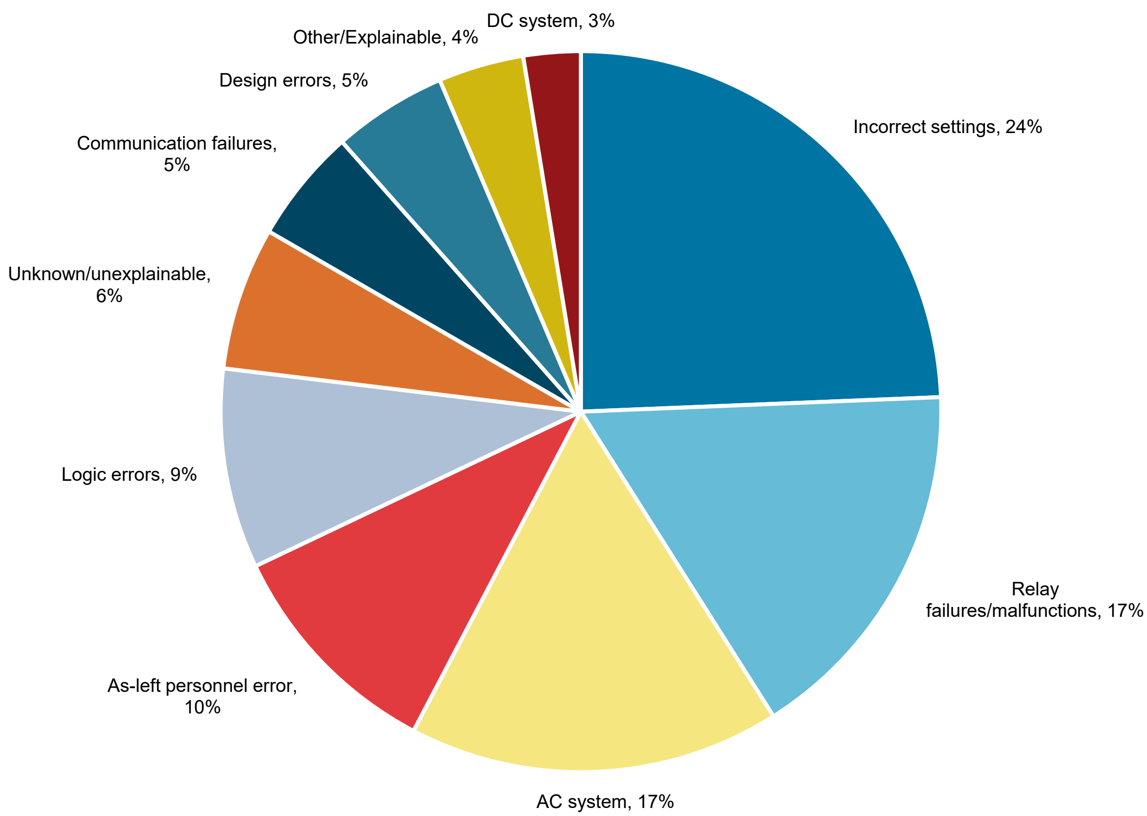


Figure 3.9: Summer 2025 Misoperations by Cause

HISTORICAL SUMMER LOAD FORECAST

To account for weather effects as accurately as possible, entities provide a forecast based on normal weather or assumed temperatures consistent with approximately the past 30 years of meteorological data. This is also referred to as the 50/50 forecast, which means that each year, the probability of the projected peak load being exceeded is 50%, while the probability that the actual peak load would be less than predicted is also 50%. A 90/10 forecast is a worst-case, extreme weather scenario that can be reasonably anticipated. It means there is only a 10% probability of the projected peak load being exceeded and there is a 90% chance that the actual peak load would be less than predicted. In other words, the forecast would exceed, on average, only once every ten years.

Figure 3.10 shows the five-year historical summer normal (50/50) and extreme (90/10) forecasts, actual and all-time summer peak load for each assessment area in the MRO region.

Figure 3.10: 5–Year Historical Summer Load Forecast

The extreme peak load forecast for the upcoming summer season is:

- Manitoba Hydro: 3,620 MW
- Midcontinent Independent System Operator: 122,714 MW
- SaskPower Corporation: 3,730 MW
- Southwest Power Pool: 58,118 MW

The highest historical summer hourly average demand recorded over the last five years is:

- Manitoba Hydro: 3,679 MW in June 2023
- Midcontinent Independent System Operator: 124,900 MW in August 2023
- SaskPower Corporation: 3,669 MW in July 2023
- Southwest Power Pool: 56,184 MW in August 2023

Actual weather conditions that occurred at the time of peak load can then be compared to the forecasted weather prediction to determine if any adjustments are warranted at the forecasted peak. This is particularly important for Midcontinent Independent System Operator and Southwest Power Pool, whose BA footprints span from the Canadian border to the Gulf of Mexico and can experience significant weather diversity on any given day.

Chapter 4: Emerging Risks

LARGE LOAD GROWTH

Growth in large load parcels like data centers and industrial facilities poses various challenges for system planners and operators. Large parcels of load on the system increases uncertainty in peak and hourly load forecasting. Moreover, determining how much of the current forecasted load will be installed further complicates planning efforts.

Large load development timelines are often much shorter than the timelines for building new power generation and transmission infrastructure. If data center and industrial facility growth rates surpass that of area resources, the risk of load loss increases.

GENERATION RESOURCE MIX

MRO's 2026 summer peak installed and accredited capacity reflects a diverse mix of fuel types, as shown in Figure 4.1. The largest single contributor by peak capacity in the region is natural gas, with approximately 54% of installed capacity located in the southern portion of the region. Coal plants and wind turbines make up the next largest portions of the generation mix. Battery energy storage systems (BESS) do not currently represent a significant share or portion of the regional generation resource mix.

Conventional generation, such as coal, steam, hydro, and combustion turbines, which have a large rotating mass capable of providing essential reliability services like frequency and voltage support, is gradually being retired.

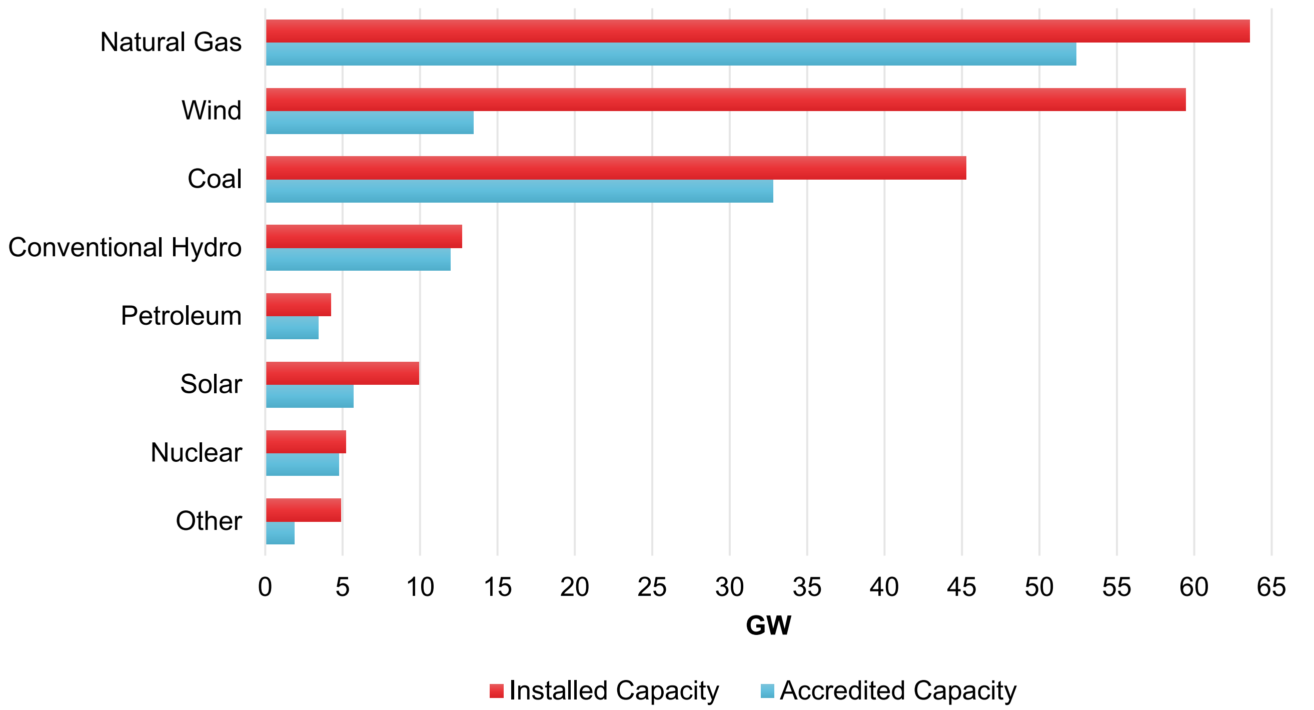


Figure 4.1: MRO 2026 Summer Peak Installed and Accredited Capacity by Fuel Types

The growing share of intermittent resources, such as wind and solar, is adding operational complexity in resource commitment and dispatch. Forecasting inaccuracies can lead to larger, unexpected energy shortfalls or excesses in real-time operations, making it difficult to predict ramping changes.

Wind

The MRO region has 59.4 GW of existing installed wind capacity, with 13.5 GW (23%) accredited for the 2026 summer peak season. Multiple proposed projects in the Midcontinent Independent System Operator and Southwest Power Pool generation interconnection queues could add approximately 23.8 GW of installed wind capacity by 2035. Operational challenges related to large amounts of wind power include difficulties in accurately forecasting wind output, impacts on conventional resource cycling, transmission capacity or voltage constraints, and limited inertia to provide voltage and frequency support compared to conventional generation.

Solar

Utility-scale solar photovoltaic (PV) installations are rapidly increasing in the MRO region and are projected to become the second most prominent renewable energy source after wind. The MRO region has 9.9 GW of existing installed solar capacity, with 5.7 GW (58%) accredited for the 2026 summer peak season. Approximately 22.6 GW of solar projects are being proposed in the Midcontinent Independent System Operator and Southwest Power Pool interconnection queues by 2035. Operational challenges related to large amounts of solar resources include forecasting and managing daily ramping changes at sunrise and sunset.

SUMMARY OF RISK

Not every project in the interconnection queue will be constructed, as some may be withdrawn after completion of system impact studies that determine transmission upgrades required for project integration. The transition from conventional generation to intermittent resources requires BAs to maintain flexible resources that can ramp quickly in response to fluctuations in output from intermittent sources and load variability. Conventional steam units, especially those designed for base load, generally have lower ramp rates, and were not built to handle frequent cycling, which can increase forced outage rates and maintenance needs.

These factors elevate the risk of insufficient resources to serve load during periods when renewable output falls short of forecasts. This challenges control room operators, especially when there is high uncertainty in intermittent resource output and significant ramping events. As a result, BAs are forced to carry additional operating reserves to manage forecast uncertainties for wind and solar, as well as load forecasting errors.

Moreover, with more intermittent resources in the mix and the retirement of conventional generation, it is becoming increasingly difficult to schedule planned outages for conventional generating units. The higher unpredictability of intermittent resource output means BAs rely more heavily on conventional resources during off-peak maintenance periods. This introduces scheduling complexities for planned maintenance that typically use the same labor resources, while at the same time need to ensure reliable load service. Additionally, increased ramping of conventional units due to intermittent resource challenges accelerates maintenance requirements, further complicating maintenance scheduling and labor resource utilization for these resources.

Chapter 5: Summary

FOCUS AREAS FOR 2026 SUMMER

MRO's independent evaluation of the generation and transmission systems for the 2026 summer season has identified the following key focus areas and potential operational concerns:

- **Electricity Supply Shortfalls:** SaskPower Corporation faces risk of electricity supply shortfalls during extreme summer conditions. SaskPower Corporation has sufficient capacity/reserve margin to meet peak summer demand however there are risk(s) for insufficient energy to serve load for all hours.
- **Variably Energy Resource Performance:** With the increased penetration of wind and solar in the MRO region, the performance of this generation during periods of high demand is crucial in determining whether the electricity supply will be sufficient to meet system demand.
- **Conventional Generation Outage Rates:** WEFOR for conventional generation in 2025 remained higher than the five-year moving average. Long-term trends show increasing forced outage rates, partly due to the cycling of conventional generation beyond its original design limits, driven by higher penetrations of intermittent resources. This cycling can lead to component failures.
- **Sustained Transmission Outages:** In four of the past five years, failed AC circuit equipment has continued to be the leading contributor to sustained transmission line outages during summer months.
- **Protection System Misoperations:** Protection system misoperations remain a leading cause of major events in the MRO region. Human error accounted for 49% of last summer's misoperations, with just under half of these resulting from incorrect settings.

Appendix A: Registration and Certification

REGISTRATION

There are 291 entities (NCR IDs) registered in the MRO region (NERC Compliance Registry (NCR)) as of the date of this publication. These users, owners and operators of the bulk power system are deemed material to reliability because they meet specific criteria or perform certain functions. The number of registered entities on the NCR fluctuates with the addition of new entities and/or changes to existing entities' operational structure and functions. Which mandatory NERC Reliability Standards and requirements are applicable depends on how an entity is registered and the functions it performs. Registration information is fundamental to reliability assessments in that certain functions pose greater risk to reliability of the bulk power system.

The functional relationships identified in the NERC Rules of Procedure, Reliability Standards, and important entity relationships are part of an entity's registration record. All BAs and TOPs are required to be under the responsibility of one RC. Transmission facilities must be the responsibility of one TP, PC, and TOP. Loads and generators shall be the responsibility of one BA. RCs, BAs, and TOPs, along with GOs and GOPs, have an important role in maintaining reliability during normal and complex weather operations. These entities provide accurate operational data for ERO Enterprise event analysis. Generator modeling data provided by GOs and GOPs is utilized by TOPs, BAs and RCs, and is critical for use in operations planning and real-time analysis of the bulk power system.

Registration growth over the past five years has predominantly been with the GO and GOP functions. The increase in entities registered as GOs and GOPs is due to the decline of vertically integrated utilities and the deregulation of the supply side of the industry, combined with an increase in renewable resources. With the increasing integration of Inverter Based Resources (IBRs), NERC's Category 2 GO/GOP registration criteria were established and implemented to register owners and operators of bulk power system-connected IBRs with a nameplate rating of 20 MVA or more connected at 60kV and above.

The registration of Category 2 GOs/GOPs began in August 2025. The NERC Inverter-Based Resources Work Plan (phase 3) required all candidates that met Category 2 criteria be registered by May 15, 2026. Of the more than 100 bulk power system-connected IBR assets initially identified by NERC as subject to registration in the MRO region, MRO staff found 60 to meet the Category 2 criteria. In the end, MRO added 88 Category 2 functional scopes to its registry under the responsibility of 50 different organizations (unique entity NCR IDs). While 21 of these entities added the Category 2 functional scope to an active NCR ID, 29 were registered under new NCR IDs and/or the entity added the MRO region to its functional scope responsibility.

Additional resources found to meet criteria through the IBR Registration Initiative (those with commercial operations dates after May 15, 2026) will process per the ERO Registration Procedure.

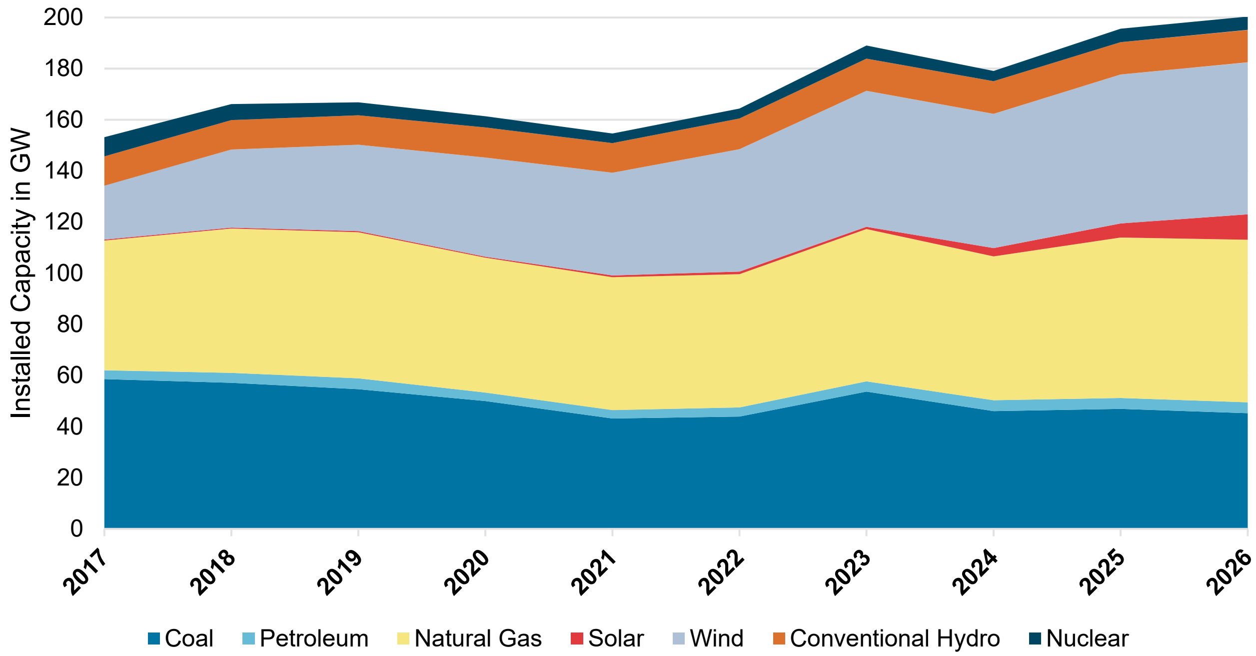


Figure AA1: MRO Historical Resource Mix by Fuel Types

CERTIFICATION

Real-time actions of RCs, TOPs, and BAs impact the reliable operation of the bulk power system. [ERO Enterprise Certification](#) activities provide regional assurance that the processes, procedures, tools, and training a registered entity applies in the performance of its functions meet the reliability obligations of registration. A registration candidate is required to complete the certification process for any new BA, RC, or TOP registered function. Material changes to already certified and operational registered entities require a review of conditions by the Regional Entity. The decision to certify changes to an already operating and certified registered entity is a collaborative decision between MRO and NERC.

During the first half of 2026, MRO completed one certification program activity. Currently, MRO has over 30 certification cases initiated and active. In addition to these active/in progress activities, MRO is evaluating one submission of change event and one TOP registration application. MRO anticipates more submissions before year end due to EMS modifications related to the industry changes required by FERC order 881 and the commission's approved extensions.

The Certification Program includes Certifications and Review of Conditions to identify issues that if not resolved, may lead to inadequate performance of duties and responsibilities applicable to the function. Fifty-seven functional registrations in the MRO region are applicable to the Certification Program.

This seasonal reliability assessment was developed based on data collected during performance analysis, event analysis, and situational awareness activities and directly focuses on RCs, TOPs, and BAs. The assessment provides reliability insight for the certification program and its activities. The roles fulfilled by the three functions (RC, BA, and TOP) are critical to the functional relationships within and between electric areas.

Appendix B: Summer Seasonal Forecast

The 2026 summer seasonal forecast includes the months of June 2026 through September 2026.

ANTICIPATED SUMMER RESOURCE AND PEAK DEMAND SCENARIO

Peak demand (or load) is the highest electrical power demand that occurs over a specific period and is typically characterized as daily, seasonal, or annual. The changes in demand levels are generally predictable and have daily, weekly, and seasonal patterns. The annual peak of hourly, daily, and monthly demand typically occurs during the summer or winter due to higher cooling or heating needs. Figure AB1 illustrates the 2026 anticipated, and the nine-year historical generation by fuel type at the time of summer peak for each of the PCs in the MRO region.

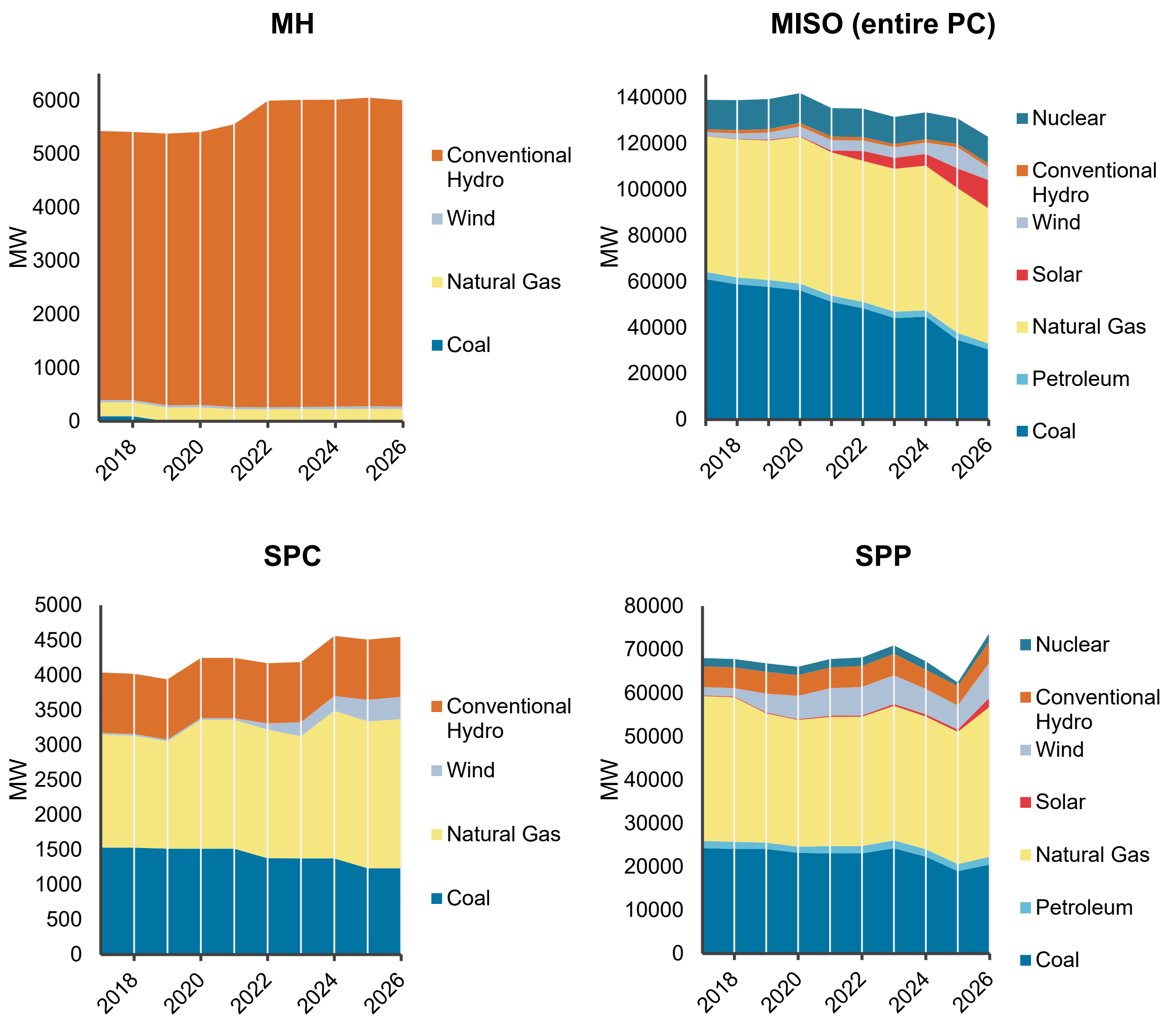


Figure AB1: Generation by Fuel Type at Time of Summer Peak

Each PC has a different resource mix. While Manitoba Hydro is predominantly conventional hydro, the resource mix in Midcontinent Independent System Operator, SaskPower Corporation, and Southwest Power Pool consist primarily of coal and natural gas with increasing amounts of wind in Southwest Power Pool. Because intermittent resources like wind and solar are weather dependent, forecasted on-peak wind and solar capacity contributions are based on historic average values and can be substantially less than ICAP.[5] Midcontinent Independent System Operator and Southwest Power Pool wind and solar capacity accreditation is significantly lower than the total existing ICAP values for this reason. As penetration of intermittent resources increases, forecast errors in the output of intermittent resources available in the short-term (hours or days) can have a greater impact. BAs may need to increase operating reserves to account for the uncertainty in short-term resource output.

Rooftop solar, battery storage, and other distributed, behind-the-meter generation resources are having a dramatic impact on the load shape and the ability to forecast net demand (total demand less behind the meter resource output). When coupled with the anticipated increase in demand (e.g., electric vehicle charging, cryptocurrency mining, data centers, hydrogen production, and other electrification efforts), future load forecasts and patterns will likely change dramatically from what they are today.

Fossil-steam, gas, and petroleum generating plant cooling systems are less effective when cooling water input temperatures are higher. This can lead to reduced output in the summer months. The increase in cooling water temperatures and low river water levels that can occur in summer may impact generators with once-through cooling, thereby reducing output capability. Environmental limitations on discharge temperatures can lead to similar restrictions. The extreme peak demand scenarios in Tables AB3 and AB4 examine how extreme or prolonged hot temperatures over a large area could impact the generation resource adequacy. Resources throughout the extreme scenarios are compared against expected reserve margin requirements based on peak load and normal weather. The effects from low-probability events are also factored in through additional resource derates. For example, maximum historical outages minus the average of both maintenance and forced outages for non-intermittent resources or low-output scenarios (such as a wind resource output adjustment due to low-wind), and additional load based on extreme weather conditions.

The [90/10 peak load] weather forecast methodology is used to model the reliability risk of the actual system peak exceeding the forecasted [50/50 peak load] due to load forecast uncertainty. The industry uses this traditional methodology and assumption to ensure energy availability through increased dispatchable resource capacity so that adequate resources are available during higher than anticipated peak demand. However, recent increases in extreme weather events and unavailability of energy during off-peak hours (e.g., low wind production) presents new challenges, in part due to the retirement of dispatchable resources and the rapid growth of fuel sources that are weather dependent and inherently less predictable (like wind and solar).

As a result, an ERO Enterprise cross-functional working group comprised of experts in multiple industries within the energy sector, including representatives from fuel supply and delivery chains (e.g., fuel oil and natural gas) and the electric grid will report to NERC's Reliability and Security Technical Committee. The [Energy Reliability Working Group (ERWG)] will serve as an informational stakeholder forum open to cross-sector organizations to facilitate ongoing assessment of energy-related risks to the balance of supply and demand on the North American bulk power system. This working group will also develop documents to

[5] The maximum amount of capacity a generator can produce. ICAP can be considered in two different ways: nameplate capacity rating in MW or seasonal net dependable capacity rating that accounts for ambient temperatures and humidity during the season.

clarify energy reliability issues and best practices for assessing energy risks and identify potential responsive measures associated with unassured energy supplies.

The electric power industry needs to develop new and enhanced forecasting methods and new metrics to evaluate energy availability required to support reliable and secure operations of the bulk power system at all times.

The following definitions are used for the risk scenario analysis:

- **Anticipated Resources**: Existing resources plus Net Firm Transfers plus Planned resources in MW.
- **Typical Maintenance Outages**: Historical average of generator maintenance outages in MW for specified period/conditions, (e.g., average of maintenance outages for December through February weekdays, over the past three years) or area-specific methodology for determining anticipated maintenance outages.
- **Typical Forced Outages**: Historical average of forced generator outages in MW for a specified period/conditions (e.g., average of forced outages for December through February weekdays, over the past three years), or area-specific methodology for determining anticipated forced outages for non-intermittent resources (e.g., thermal, hydro).
- **Normal Peak Load**: Peak hour demand forecast in MW based on normal weather. This is also referred to as the 50/50 peak load forecast.
- **Reserve Margin**: The amount of generation capacity in MW available above projected load to reliably meet expected demand.
- **Extreme Resource Derates**: Reduced capacity contribution in MW due to generator resource performance in extreme conditions (e.g., temperature-based derates; or based on severe historical events).
- **Extreme Peak Load**: Sum of Normal Peak Load and seasonal load adjustment in MW for extreme weather conditions (e.g., 90/10 peak load forecast; or based on severe historical events).
- **Extreme Low Generation**: Anticipated Resource minus Typical Forced Outages and Extreme Derates in MW.

Several risk factors and criteria are used when determining the risk levels (low, medium, and high) for an assessment area that is likely to issue Energy Emergency Alerts, or EEAs. This includes meeting the reference margin levels, the loss of load expectation and the availability of sufficient operating reserves under normal and extreme peak demand. The anticipated resources for conventional generators are based on ICAP or slightly lower accredited capacity, which represents physical generating capacity adjusted for ambient weather conditions. Intermittent renewables, such as wind and solar, capacity contributions are based on historic average values or Effective Load Carrying Capability (ELCC). Table AB2 displays anticipated reserve margins with normal peak load projections for each assessment area. The normal peak load projections are based on 50/50 weather forecasts and are provided on a coincident[6] basis for the assessment areas. Manitoba Hydro, Midcontinent Independent System Operator, SaskPower Corporation,

[6] Sum of two or more peak loads that occur in the same hour.

and Southwest Power Pool have sufficient resources to meet their PRMR under normal peak summer conditions.

Assessment Area	Anticipated Resources	Normal Peak Load	Anticipated Reserve Margin	PRMR	Likelihood to Issue EEAs
MH	3,917	3,460	**13.2%**	12.0%	**Low**
MISO	155,641	118,725	**31.1%**	15.0%	**Low**
SPC	4,699	3,638	**29.2%**	15.0%	**Low**
SPP	70,168	55,350	**26.8%**	10.0%	**Low**

Table AB2: Anticipated Reserve Margin Percentage with Normal Peak Load

Manitoba Hydro, Midcontinent Independent System Operator, SaskPower Corporation, and Southwest Power Pool anticipate reserve margins that reflect robust amounts of excess capacity, there is still potential risk of energy shortfall based on past performance during extreme weather events.

Based on the normal peak load forecast with typical maintenance and forced outage scenario shown in Table AB3, Manitoba Hydro, Midcontinent Independent System Operator, SaskPower Corporation, and Southwest Power Pool have sufficient resources to meet their operating reserve requirements under normal peak summer conditions with typical maintenance and forced outages.

Assessment Area	Anticipated Resources	Typical Maintenance and Forced Outages	Anticipated Resources with Typical Outages	Normal Peak Load	Anticipated Reserve Margin with Typical Outages	Likelihood to Issue EEAs
MH	3,917	130	3,787	3,460	**9.5%**	**Low**
MISO	155,641	11,272	144,369	118,725	**21.6%**	**Low**
SPC	4,699	217.3	4,482	3,638	**23.2%**	**Low**
SPP	70,168	2,977	67,191	55,350	**21.4%**	**Low**

Table AB3: Reserve Margin Percentage with Typical Outages and Normal Peak Load

The scenario shown in Table AB4 considers typical maintenance and forced outages combined with extreme summer peak load forecast. For this scenario, Manitoba Hydro, Midcontinent Independent System Operator, SaskPower Corporation, and Southwest Power Pool have sufficient resources to meet operating reserve requirements under extreme peak summer conditions with typical maintenance and forced outages.

Assessment Area	Anticipated Resources with Typical Outages	Extreme Peak Load	Reserve Margin Under Extreme Peak Load	Likelihood to Issue EEAs
MH	3,787	3,620	**4.6%**	**Low**
MISO	144,369	122,714	**17.6%**	**Low**
SPC	4,482	3,730	**20.2%**	**Low**
SPP	67,191	58,118	**15.6%**	**Low**

Table AB4: Reserve Margin Percentage with Typical Outages and Extreme Peak Load

The worst-case scenario for the 2026 summer season considers increased resource outages and derates combined with an extreme peak load forecast as shown in Table AB5.

Assessment Area	Anticipated Resources with Typical Outages	Extreme Resource Derates	Extreme Low Generation	Extreme Peak Load	Reserve Margin Under Extreme Resource Derates and Extreme Peak Load	Likelihood to Issue EEAs
MH	3,787	10	3,777	3,620	**4.3%**	**Low**
MISO	144,369	16,937	127,433	122,714	**3.8%**	**Low**
SPC	4,482	479.3	4,002	3,730	**7.3%**	**Medium**
SPP	67,191	6,850	60,341	58,118	**3.8%**	**Low**

Table AB5: Reserve Margin Percentage with Extreme Resource Derates and Extreme Peak Load

The extreme low generation in Table AB5 shows marked improvement in expected reserve margin compared to the 2025 summer season, with SaskPower Corporation being the only region with a medium risk profile. Even though SaskPower Corporation has a much higher reserve margin compared to other assessment areas, its probabilistic energy analysis indicates there is risk for insufficient energy to serve load for all hours for the 2026 summer season.

SaskPower Corporation experiences peak loads in winter months, however, the risk of operating reserve shortages or EEAs during extreme summer peak loads (like what was experienced during the 2023 and 2024 summer heatwaves) remain if a major unplanned generation outage coincides with large generation maintenance outages. SaskPower will activate demand response programs, implement short-term power imports from neighboring utilities, and, if necessary, implementing temporary load interruptions to maintain grid stability.

WIND AND SOLAR RESOURCES

Midcontinent Independent System Operator and Southwest Power Pool continue to see an increase in wind and utility-scale solar photovoltaic penetration in the region. Figure AB6 reflects the summer season wind and solar photovoltaic ICAP and peak capacity for each of the assessment areas. The peak capacity value is the accredited ELCC amount of wind or solar available during the period of peak demand. ELCC is defined as the amount of incremental load a particular type of resource, such as wind or solar, can dependably and reliably serve, while also considering the probabilistic nature of generation shortfalls and random forced outages.

The ELCC amount also varies with the resource mix of the system being evaluated. This results in decreasing ELCC values as renewable penetration becomes higher and conventional resources are retired, at times much lower than the ICAP value.

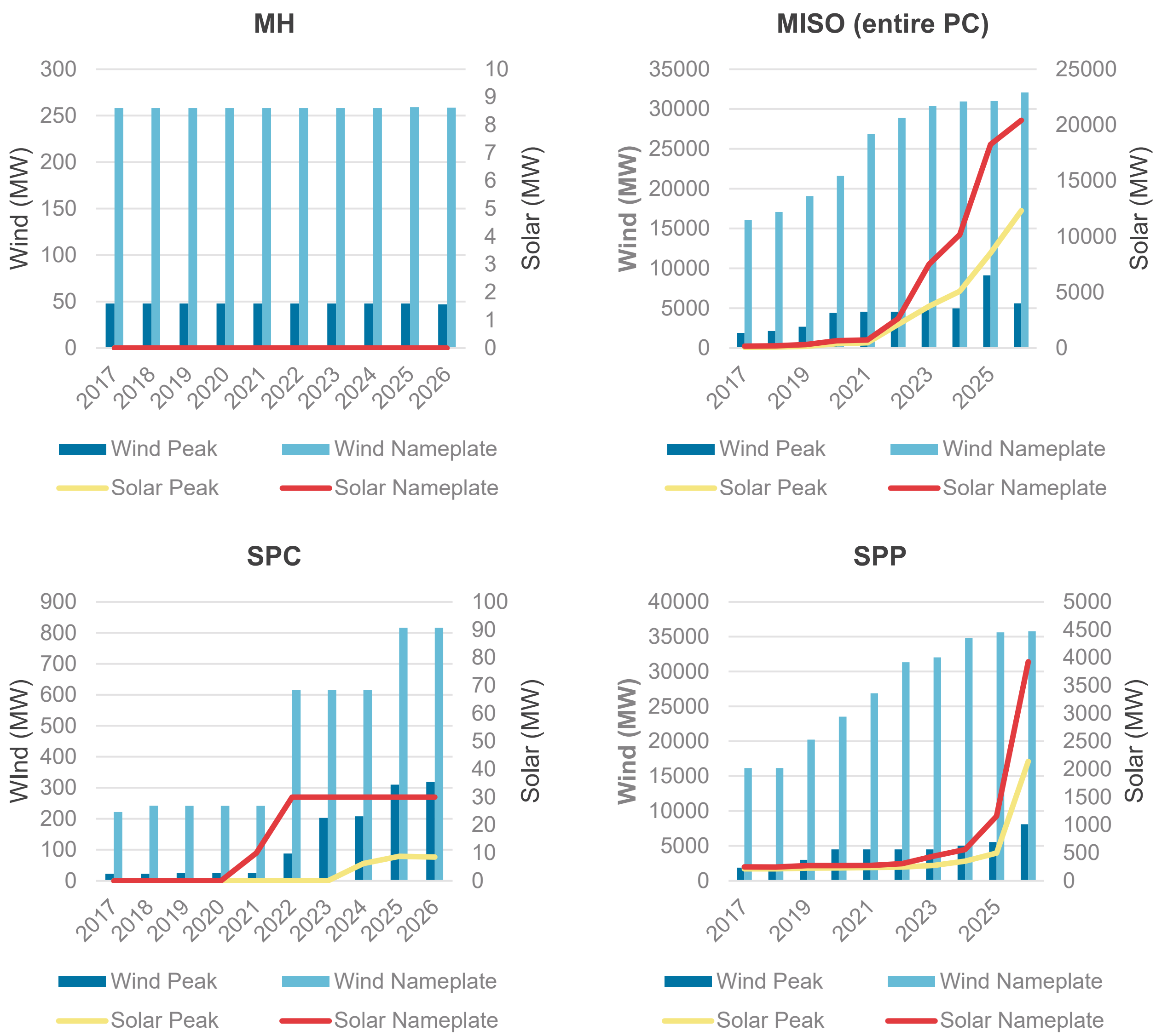


Figure AB6: Wind and Solar Photovoltaic Summer ICAP and Peak Capacity

The rapid growth of inverter-based resources (IBRs) is the most significant driver of grid transformation and poses a high risk to bulk power system reliability. The new NERC registration criteria for Category 2 IBRs will result in an increase in existing and future wind and solar capacity in the MRO region. Bulk power system-connected wind and solar power resources are growing in the MRO region and combined, could reach as much as 115.7 GW by 2035.

When implemented correctly, inverter technology can provide significant benefits for reliability of the power grid. However, it can introduce significant challenges for power grid planners and operators if not integrated properly. Performance issues, such as wind plants shutting down under high winds during storms and solar panels losing efficiency from high ambient temperatures, or storms and cloud cover, can have a significant impact on reliability of the bulk power system.

Appendix C: BES Event and EEA Details

August 1, 2025 - Transmission Event

Event Category: 1.a

- 5 BES Facilities interrupted
- 5 MW of generation lost
- 0 MW of load lost

At 17:31 on August 1, 2025, a lightning strike resulted in the operation of a 138kV transmission line. Following that correct operation, a misoperation occurred at one of the 138kV terminals resulting in multiple breakers operating due to a breaker failure lockout operation.

It was determined that the cause was incorrect settings.

The entity queried their database to identify any reoccurrence of the error identified as the cause of this event. One instance was found in a relay at the same site and corrected.

August 21, 2025 - Transmission Event

Event Category: 1.a

- 4 BES Facilities interrupted
- 0 MW of generation lost
- 0 MW of load lost

On August 21, 2025, at 13:17, while performing switching to return a 115kV line breaker to service following a relay replacement, the C phase bus differential relay operated and tripped the 115kV main bus lockout relay, tripping three 115kV lines and opened the 115kV terminal of a 230/115kV transformer. Hydraulic system problems were identified on one of the breakers as the cause of the event.

There was no customer load lost during this incident.

September 3, 2025 - Transmission Event

Event Category: 1.a

- 3 BES Facilities interrupted
- 172 MW of generation lost
- 0 MW of load lost

On September 3, 2025, at 10:27:00 AM, the entity was undergoing a monthly inspection on a 230/13.8kV unit transformer for one of their 86 MW generators. The transformer fan control was set to manual, as part of the routine maintenance steps. The vibration from the fan control switch movement tripped the fast gas relay which then tripped a 138kV transmission line and two 86 MW generators.

The fast gas relays were mounted on anti-vibration mounts and were found to have dried out and broken.

The entity has added a warning card on the fan controls and has a repair scheduled for the degraded fast gas relay cards.

June 24, 2025 - EEA Level 1 Event

The BA had several energy imports (purchases) curtailed by the RC. The BA had a total loss of schedule(s) of 195 MW for HE 1800.

Outages included 344 MW (long term 138 MW due to equipment failure(s), short term 206 MW due to routine maintenance and/or flooding conditions).

Derates included 88 MW (long term 32 MW due to equipment failure(s), short term 56 MW due to an ongoing real-time contingency).

All the stated outages and derates were hydro generation.

The BA attempted to make a real-time purchase to no avail. They were told that purchase would be curtailed also. Exports from a local BA were curtailed, which helped to recover Area Control Error (ACE) and maintain reserves.

August 20, 2025 - EEA Level 3 Event

High humidity greatly reduced cooling tower(s) capacity and high temperatures reduced gas turbine outputs at several of the BA's gas plants. The wind forecast was forecasting more wind power at this time, but it did not show up. A 150 MW converter station was not in commercial service and was only available for emergency use.

The BA cut export sales which immediately restored required operating reserves. There was no load shed during this event.

August 27, 2025 - EEA Level 1 Event

High ambient temperature and wind generation coming in lower than forecast led to the entity declaring an EEA level 1. A transmission outage was limiting imports and there were forced outages on two generating units. A 75 MW generator unit was brought online to help improve conditions. No load was shed during this event.

Appendix D: Generating Availability Details

Generator unavailability can have a substantial impact on power grid reliability. Useful metrics for generator unavailability are EFOR and WEFOR, which measure unavailability of generators as a percentage of all calendar hours.

For the MRO region, the historical annual conventional generator WEFOR for all seasons is shown in Figure AD1 and solidifies the upward trend in WEFOR for the region. However, summers continue to be a point of low outage rates and stable performance in the region, as detailed in the sections below. The steep increase in 2022 WEFOR was driven in part by extreme outage events at the beginning (January and February) and end (December - Winter Storm Elliott) of the winter season as shown in figure AD2. This was also driven by high levels of outages in the fall due to simple cycle gas turbines and a small, but heavily MW weighted increase in WEFOR of fossil steam plants. Summers have been marked by low outage rates, with some marked decreases from the spring outage season. This effect is notable in 2025 due to the scale of WEFOR increases in spring and their continuation into June. This elevated rate is indeed driven largely by ongoing outages that started in the spring months.

Beginning with a slightly elevated WEFOR from a difficult 2022 fall maintenance season, performance throughout 2023 was poor due to a challenging winter with high unavailability among simple cycle gas turbines and poor fossil steam performance over the summer. WEFOR in 2024 and 2025 does not currently include any data from Canadian entities, making the data somewhat incomparable. However, 2024 data was largely in line with 2023, suggesting that issues around maintenance outage seasons and elevated forced outage rates are a continuing concern.

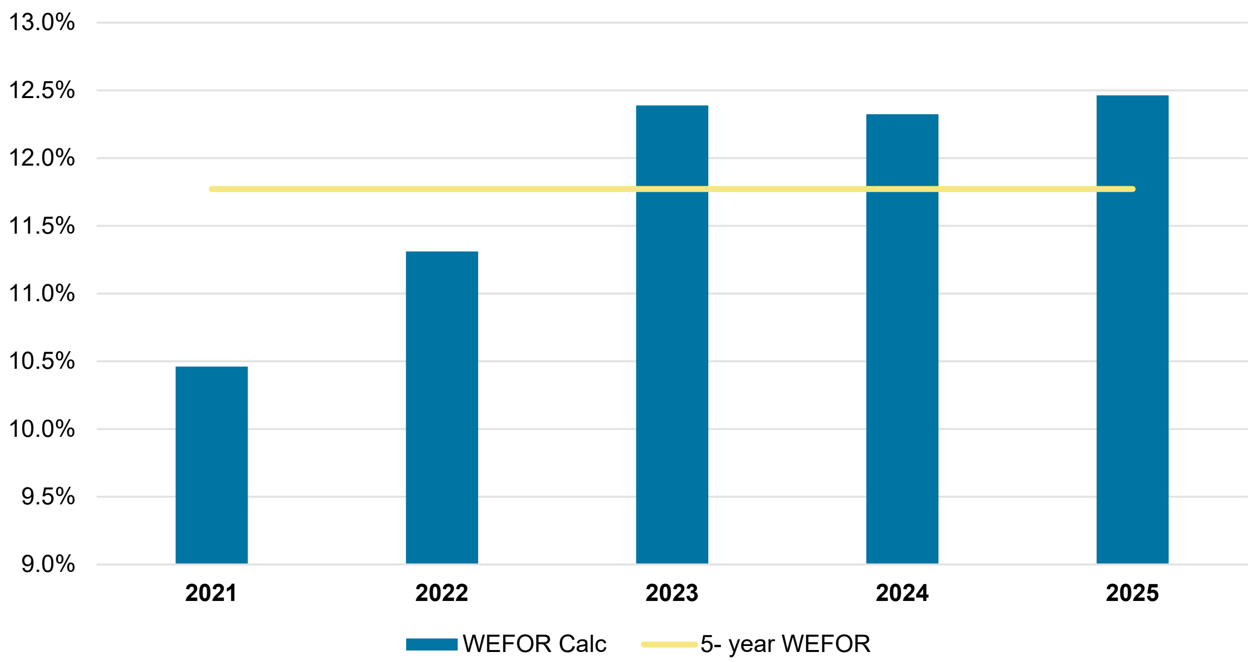


Figure AD1: MRO Annual Generator MW-Weighted EFOR

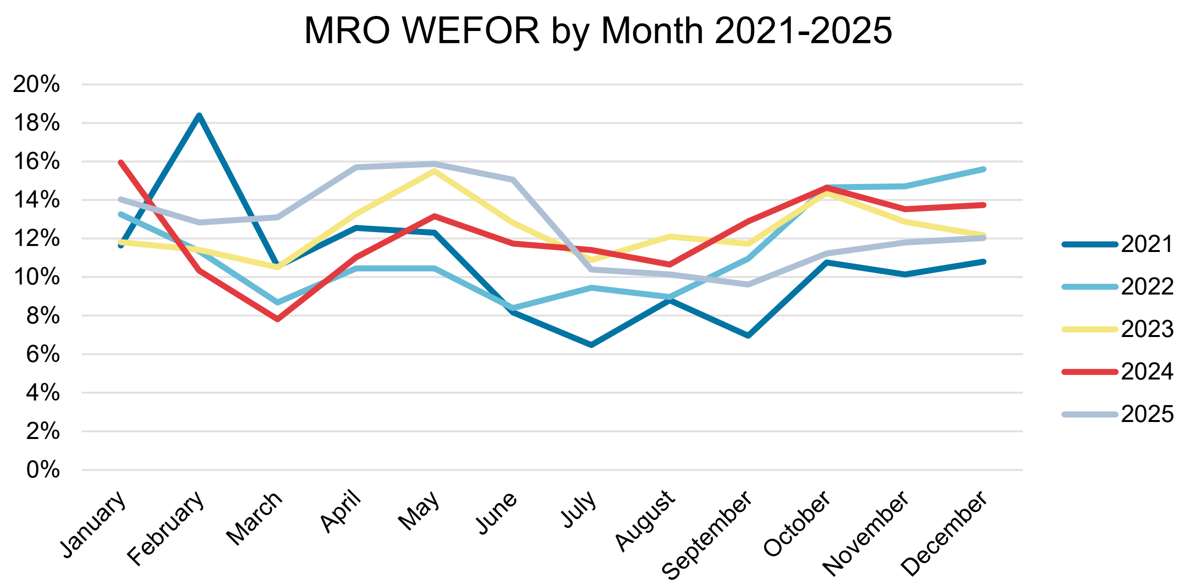


Figure AD2: MW-Weighted EFOR By Month

Table AD3 shows the top five causes for the 2025 summer season forced outages, forced derates, and startup failures by MWh loss for fossil-steam plants. Table AD4 shows the top outages in calendar year 2025 and Table AD5 shows this data for the previous five summer seasons.

Cause Type	Portion of Lost MWh
Generator Rotor – 2 events	7.4%
Waterwall – 30 events	7.3%
Operating Procedure Error – 5 events	7.0%
Generator Hydrogen Seals – 11 events	5.4%
Generator Vibration – 24 events	4.2%

Table AD3: Fossil-Steam 2025 Summer Outages

Cause Type	Portion of Lost MWh
Circulating Water Pipes – 3 events	6.6%
Generator Hydrogen Seals – 14 events	5.1%
Waterwall – 55 events	4.8%
Main Transformer – 56 events	3.6%
Tornados – 1 event	3.3%

Table AD4: Fossil-Steam 2025 Calendar Year Outage Causes

Cause Type	Portion of Lost MWh
Generator Rotor – General – 3 events	4.5%
Waterwall (Furnace wall) – 103 events	4.3%
Main Transformer – 46 events	4.2%
LP Turbine Buckets or Blades – 18 events	2.8%
First Reheater Leaks – 52 events	2.7%

Table AD5: Fossil-Steam 2021-2025 Summer Outage Causes

Fossil-steam outage causes for the 2025 summer season skew the five-year trends with extremely high impact events lingering from other seasons, namely generator rotor issues. Waterwall is historically the most impactful and well-distributed outage amongst fossil-steam units and acts as a barometer of relative impact of cause codes. Operating procedure error's megawatt hours are attributable to two events of very high duration, while the remaining three were relatively small impact. While not significant in the scope of the five-year or annual analysis, it does draw attention to the need to continually invest in human performance efforts. Hydrogen seals and generator vibration are both prone to reasonably well-distributed outages across the fleet but are outliers in severity due to the sometimes catastrophic nature of the failure modes. While consequential for the season in which it occurred, it does not imply systemic risk outside of well-known operational concerns.

In the annual scope, fossil steam units are not dominated by any one cause code or grouping of cause codes. Rather, the increased WEFOR over fleet average is mostly defined by a wide variety of outage causes. Those that make up the top five are waterwall, which is a widespread and well-understood operation issue, and cause codes that are largely defined by high-duration, high-impact events for singular units. The generator category does amplify the outage rate issues endemic in the spring season, but dramatically improved summer performance in 2025.

Table AD6 shows the top five causes for the 2025 summer season forced outages, forced derates, and startup failures by MWh lost for simple cycle gas turbines. Table AD7 shows the same information for calendar year 2025 and AD8 shows the same for five-year historical summer period.

Cause Type	Portion of Lost MWh
GT Starting System – 19 events	9.6%
Expander Turbine Bearings – 3 events	7.6%
Other Jet Engine Low Pressure Turbine Problems – 4 events	5.9%
JE Engine Vibration – 4 events	4.8%
GT Boroscope Inspection – 4 events	4.4%

Table AD6: Simple Cycle Gas Turbine 2025 Summer Outages

Cause Type	Portion of Lost MWh
Lack of fuel: Contract or Tariff allows for interruption – 277 events	11.4%
GT Starting System – 51 events	8.1%
Expander Turbine Bearings – 1 event	5.9%
Other Jet Engine Low Pressure Turbine Problems – 5 events	3.8%
JE Engine Vibration – 5 events	3.5%

Table AD7: Simple Cycle Gas Turbine 2025 Calendar Year Outage Causes

Cause Type	Portion of Lost MWh
JE Engine Vibration – 25 events	11.4%
Main Transformer – 22 events	8.1%
Other Misc. Generator Problems – 36 events	5.9%
GT Boroscope Inspection – 7 events	3.8%
JE Hydraulic Oil System – 12 events	3.4%

Table AD8: Simple Cycle Gas Turbine 2021-2025 Summer Outage Causes

Simple-cycle gas turbines have struggled with substantially higher than fleet proportionality of both event impact and WEFOR in the MRO region, even in the summer. This is, in part, due to maintenance issues as evidenced by the generator class's large contribution to increased WEFOR in the spring and fall maintenance periods. The relatively low run times and somewhat frequent cycling contribute to their outage rates. However, it is somewhat expected from the economics of peaking simple cycle gas turbines. In the 2025 summer season, gas turbines performed consistently with five-year averages and lost most megawatt hours due to generator stator issues predating the summer season. Stator events were limited to two units, not broadly impacting the forced outage rate of the generator category. However, the category's WEFOR for 2025 was higher than the fleet average WEFOR for the year.

From an annual perspective, gas turbines' major concern continues to be fuel availability. For 2025, fuel availability no longer makes the top five causes in either the summer seasonal or five season horizons. However, it remains the top cause of unavailability for the generator category. Other top causes do not have a strong seasonal correlation. Additional historical five-year and five-year summer season forced outage, forced derate, and startup failure causes for other types of generation is provided below.

Cause Type	Portion of Lost MWh
Generator Stator – 2 events	60%
GT Load Shaft and Bearings – 2 events	8.1%
Station Service Startup Transformer – 2 events	6.8%
Other Circulating Water System Problems – 4 events	3.8%
Other Gas Turbine Inlet Air Problems – 8 events	2.7%

Table AD9: Combined Cycle Gas Turbine 2025 Summer Outages

Cause Type	Portion of Lost MWh
Generator Stator – 2 events	52.4%
HP Desuperheater – 2 events	4.8%
GT Load shaft and Bearings – 1 event	3.1%
Other Gas Turbine Inlet Air Problems – 4 events	3.0%
Inlet Air Vanes / Nozzles – 4 events	2.9%

Table AD10: Combined Cycle Gas Turbine 2025 Calendar Year Outage Causes

Cause Type	Portion of Lost MWh
Generator Stator – 3 events	17.9%
Main Transformer – 10 events	8.2%
Gas Turbine Vibration – 5 events	7.7%
Cold Reheat Steam Piping up to Boiler – 1 event	7.5%
GT Fuel Piping and Valves – 19 events	5.7%

Table AD11: Combined Cycle Gas Turbine 2021-2025 Summer Outage Causes

Cause Type	Portion of Lost MWh
Retaining Rings – 1 event	53.2%
Station Service Startup Transformer – 1 event	10%
Turbine Lube Oil Pump – 6 events	7.6%
Other Feedwater System Problems – 2 events	3.1%
Other Circulating Water System Problems – 2 events	3.1%

Table AD12: Combined Cycle Steam 2025 Summer Outages

Cause Type	Portion of Lost MWh
Retaining Rings – 1 event	42.1%
HP Desuperheater/Attemperator Piping – 2 events	5.3%
Turbine Lube Oil Pumps – 3 events	5.2%
Station Service Startup Transformer – 1 event	3.5%
Open Cooling Water Heat Exchangers – 1 event	3.4%

Table AD13: Combined Cycle Steam 2025 Calendar Year Outage Causes

Cause Type	Portion of Lost MWh
Generator Stator – 2 events	11.7%
Boiler, Misc. – 16 events	8.0%
Main Transformer – 7 events	5.3%
Gas Turbine Vibration – 3 events	5.0%
Exciter Commutator and Brushes – 7 events	4.7%

Table AD14: Combined Cycle Steam 2021-2025 Summer Outage Cause

Appendix E: Transmission Availability Details

Table AE1 shows the number of circuits and circuit miles for overhead 100-599kV AC transmission lines within the MRO region. AC circuits in the voltage range of 100-399kV accounted for 90% of the outages during the latest summer season and will be the elements analyzed in the section below.

100-199kV		200-299kV		300-399kV		400-599kV	
Circuits	Miles	Circuits	Miles	Circuits	Miles	Circuits	Miles
3,557	48,322	429	14,359	535	18,878	9	1,001

Table AE1: AC Transmission Circuit Miles

Figure AE2 shows the number of 100kV and above automatic AC circuit outages that include both momentary (for 200kV and above) and sustained outages for the 2021 through 2025 summer seasons. There were a total of 502 outages reported for the 2025 summer season for the 100-399kV voltage classes. There were no 400-599kV outages reported for the summer of 2025.

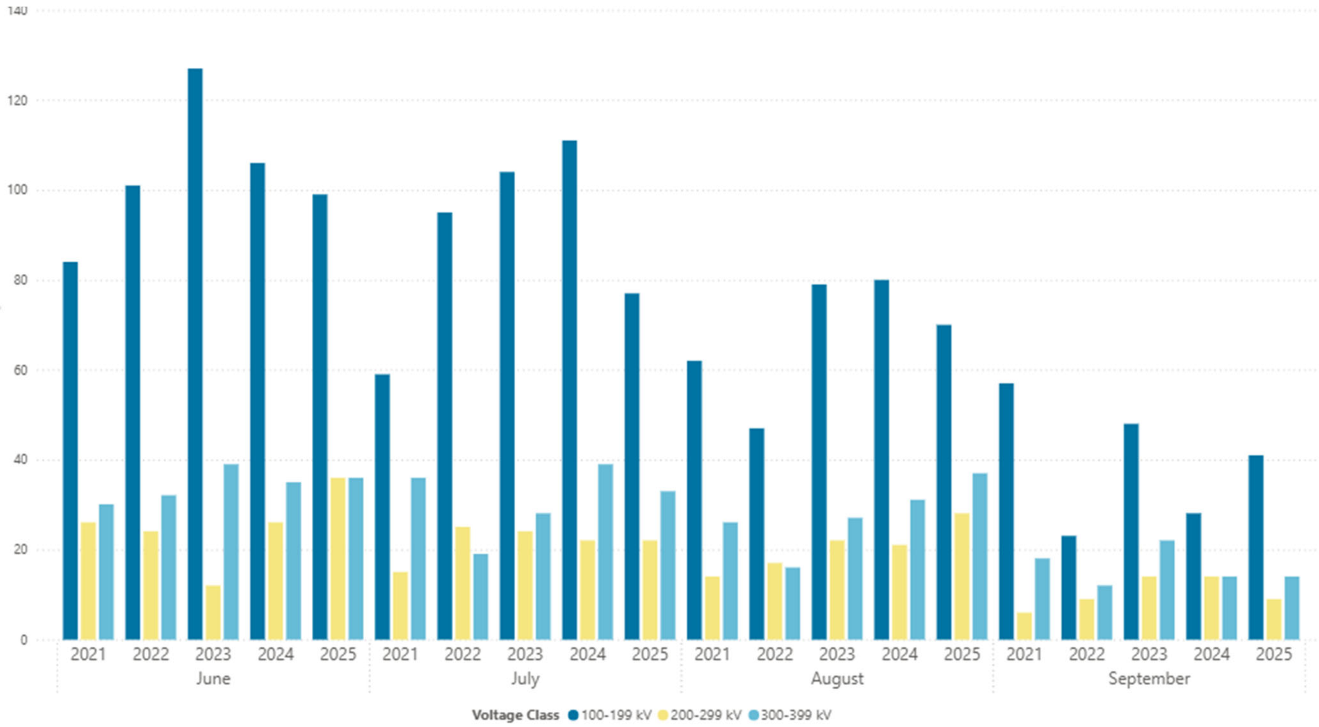


Figure AE2: Summer Automatic Outages by Month

Figure AE3 shows the causes of momentary outages for the past five summer seasons. The causes are in descending order for the total number of momentary outages over the five-year period. The chart does not include momentary automatic outages for circuits 100-199kV because causes are not reported for momentary outages on circuits less than 200kV. Lightning was the leading cause of momentary outages for the summer season of 2025 with 30, followed by unknown with 21 and weather, excluding lightning with 15 reported outages.

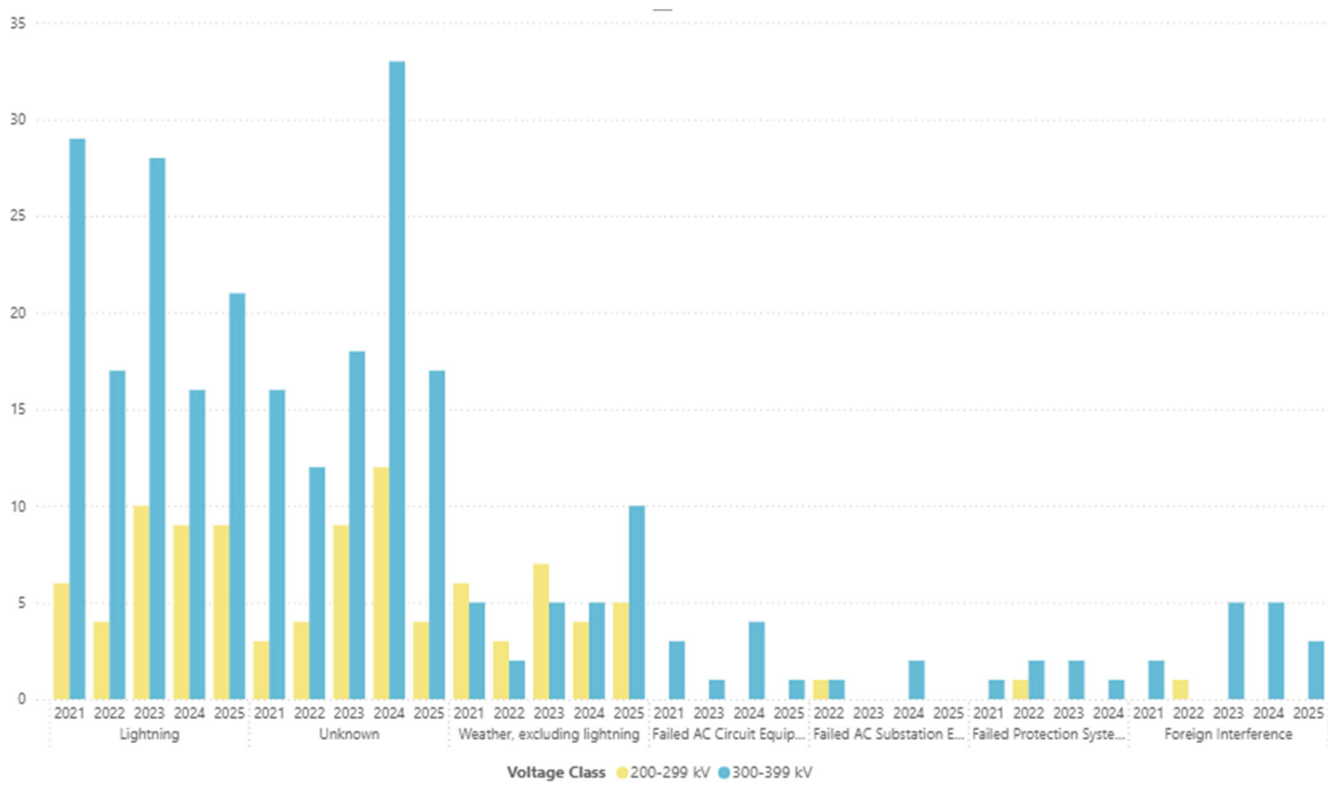


Figure AE3: Summer Momentary Outages by Cause

Figure AE4 shows the causes of sustained outages (automatic outages with an outage duration of a minute or greater) for the 2021 through 2025 summer seasons. The causes are in descending order for the total number of sustained outages over the five-year period. The chart shows that failed AC circuit equipment, other, and failed AC substation equipment continue to be major contributors to sustained outages during the summer seasons. For the most recent period, failed AC circuit equipment was the largest contributor to sustained outages with 102. Followed by other with 99, and failed AC substation equipment with 77.

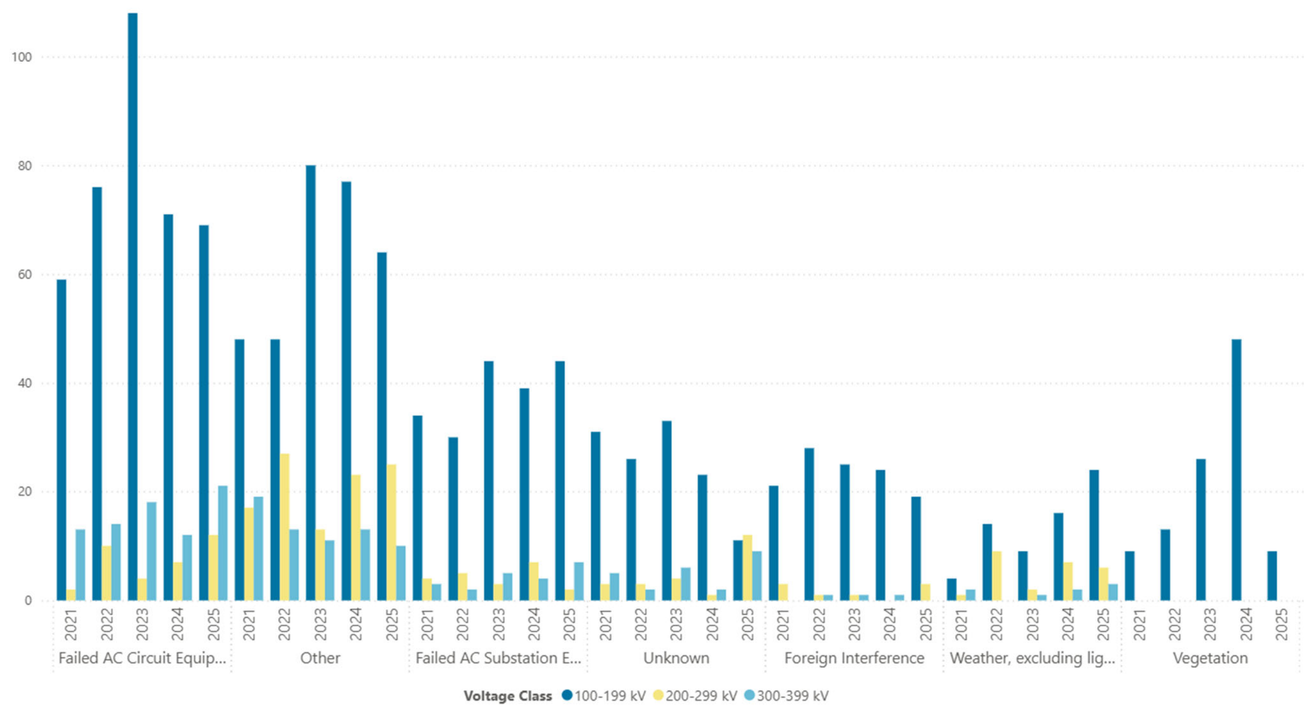


Figure AE4: Summer Sustained Outages by Cause

Figure AE5 reflects the yearly summer total outages per 100 circuit miles for 100-399kV circuits. The chart shows the outages per 100 circuit miles for the 100-199kV voltage class continue to decrease while the 200-299 and 300-399kV voltage class outages continue to increase (since 2023).

June 19, 2025, had the largest number of outages reported in a single day with 3.8% of the 2025 summer season. The three-day period of August 8-10, 2025, had 6.5% of the outages as two storms travel across the southern portion of the MRO footprint.

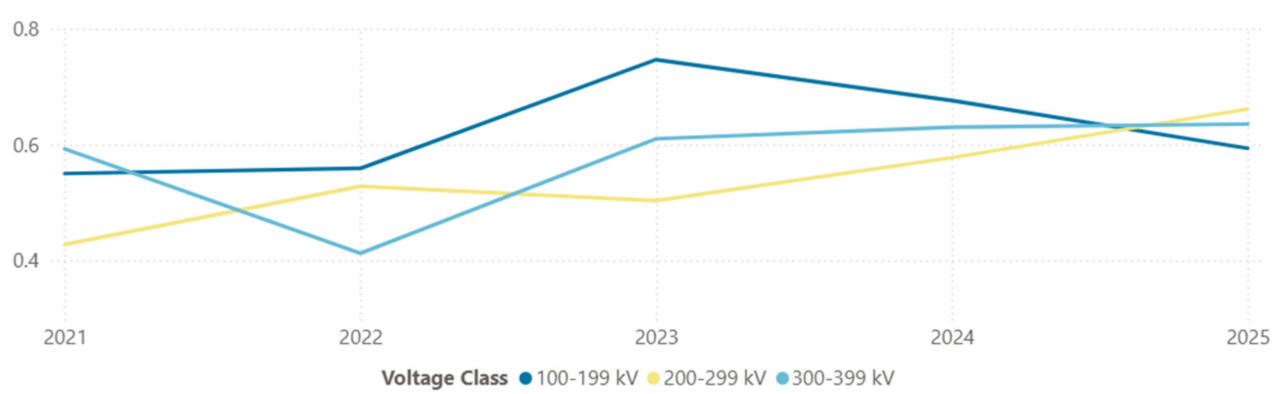


Figure AE5: Total Transmission Outages per 100 Circuit Miles

GLOSSARY

Compliance	Compliance by industry is conforming to Reliability Standards. Strategies by MRO to achieve industry compliance range from education to enforcement and/or sanctions
Bulk Power System	Facilities and control systems necessary for operating an interconnected electric generation and transmission network (or any portion thereof); and electric power needed to maintain transmission system reliability and serve load. The term does not include facilities used in the local distribution of electric energy.
CMEP	The rules governing compliance and enforcement oversight are included in the Compliance Monitoring and Enforcement Program.
Eastern Interconnection	The Eastern Interconnection is a major bulk power system grid in North America. All the electric utilities in the Eastern Interconnection are electrically tied together during normal system conditions and operate at a synchronized frequency that averages 60 Hz. The Eastern Interconnection reaches from central Canada eastward to the Atlantic coast (excluding Quebec) south to Florida and back west to the foot of the Rockies (excluding most of Texas).
Highly Reliable Organization	An organization that avoids sudden, uncontrolled cascading events despite operating in a highly complex environment by adopting a constant state of vigilance resulting in the fewest number of operating errors. These organizations have the following characteristics: Preoccupation with failure • Attention on “close calls” and “near misses” Reluctance to simplify interpretations • Solid “root cause” analysis practices Sensitivity to operations • Situational awareness and carefully designed change management processes Commitment to resilience • Resources are continually devoted to corrective action plans and training Deference to expertise • Listens to experts on the front lines (ex. authorities follows expertise) Refer to Managing the Unexpected-Assuring High Performance in an Age of Complexity by Karl E. Weick and Kathleen M. Sutcliffe
Industry	Those regulated by MRO include: Investor-owned utilities MRO’s Regulatory Philosophy Cooperative and municipal utilities Canadian utilities Transmission operators • Generator operators

	U.S. federal power agencies Other users. owners, and operators, of the bulk power system For more information, please refer to the MRO registry (known as “Registered Entities”)
Industry Stakeholders	A person, group or organization that has interest or concern in the industry and MRO
Intelligence-Led	Using intelligence products based on analytics, root cause analysis, and other mechanisms to inform program areas, such as compliance, around risks.
Registered Entity	An owner, user, or operator who has a material impact on the bulk power system and is on the registry
Reliable Operations	Operating the elements of the bulk power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.
Responsive Regulation	Responsive regulation is an approach that varies the compliance oversight and enforcement response depending on the registered entity’s individual circumstances. Circumstances that are considered include the participant’s compliance history, function, location, cooperation, and other factors. The aim of the responsive regulators is to return the registered entity to full voluntary compliance. The response is therefore proportional to the risks and consistent for the same type of registered entity in similar circumstances.
Risk	The chance of something happening has the potential to have an adverse impact on bulk power system reliability. All risks are considered in the context of the potential adverse outcome.