Public

2023-2024 REGIONAL WINTER ASSESSMENT

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MIDWEST RELIABILITY ORGANIZATION

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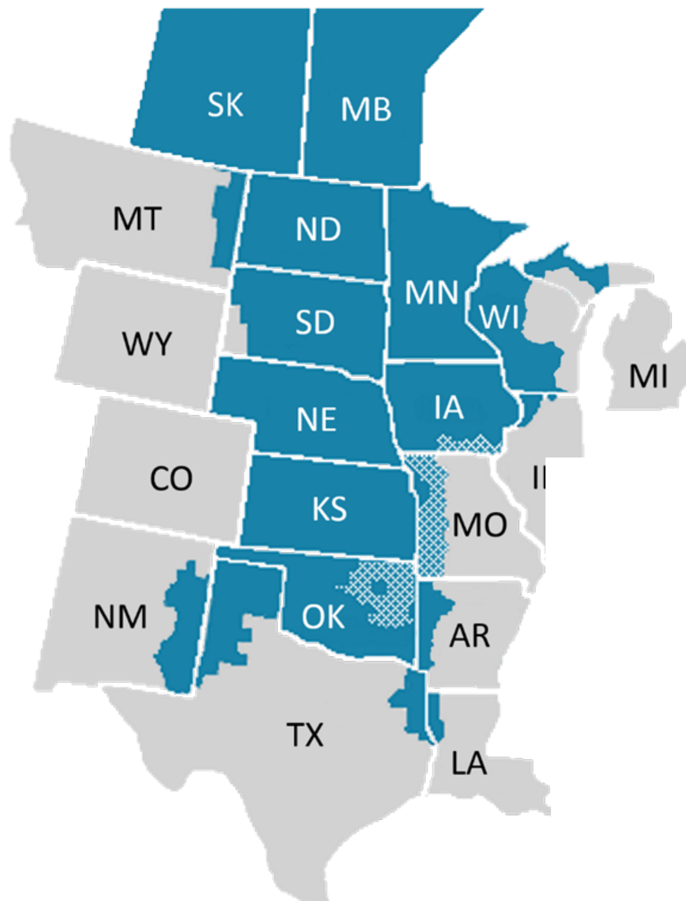
PREFACE

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 225 organizations that are involved in the production and delivery of electric power, including municipal utilities, cooperatives, investor-owned utilities, transmission system operators, federal power marketing agencies, Canadian Crown Corporations, and independent power producers.

MRO's primary responsibilities are to ensure 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 in the region to discuss important topics related to addressing risk and improving reliable operations of the bulk power system.

EXECUTIVE SUMMARY

This 2023-2024 Regional Winter Assessment (RWA) helps inform key stakeholders of projected reliability challenges for the bulk power system in MRO's region for the upcoming winter season. This assessment complements NERC's Winter Reliability Assessment by taking a more granular look at continent-wide reliability concerns that present a greater risk within MRO's regional footprint. MRO's RWA is unique in that it includes a review of regional bulk power system performance during the 2022 winter season to identify trends that might impact future system reliability.

This assessment focuses on the winter months of December through February and provides an evaluation of resource and transmission system adequacy needed to meet projected winter peak demands. The data collected and assessed by MRO staff on resource and transmission system adequacy is provided by the four Planning Coordinators (PCs) that operate within MRO's regional footprint: Manitoba Hydro (MH), Midcontinent Independent System Operator (MISO), Saskatchewan Power Corporation (SPC), and Southwest Power Pool (SPP).

The data used to assess historical performance of the regional bulk power system is collected from more than 240 registered entities (users, owners and operators of the bulk power system) within MRO's regional footprint each quarter. More information on the registration and certification of companies whose data is used in this report can be found in Appendix A.

Key Findings

- SPC projects insufficient capacity to meet operating reserve requirements under normal peak-demand with typical maintenance and forced outages. Under extreme winter conditions, combined with large generation forced outages, SPC may need to use available demand response programs, short-term power transfers from neighboring utilities, maintenance rescheduling, Energy Emergency Alerts (EEAs), and/or short-term load interruptions. SPC's reserve margins are lower for the 2023-2024 winter season when compared to the 2022-2023 winter. This is primarily due to generation retirement, increased peak demand projections, and planned maintenance outages.
- MISO anticipates sufficient capacity to meet forecasted seasonal peak load with typical maintenance and forced outages for the 2023-2024 winter season. The organization postponed certain generation retirements, reducing its risk from last winter when coupled with lower peak demand forecasts for the coming season. MISO also implemented a new seasonal resource adequacy construct that resulted in increased seasonal unit accreditation, and subsequently higher reserve margins. Extreme winter conditions may result in insufficient energy to cover anticipated winter peak demands and could require the implementation of load modifying resources, non-firm imports, and EEAs to meet operating reserve requirements.
- SPP anticipates resources will be sufficient to meet reserve margin requirements under normal demand for the 2023-2024 winter season. Extreme weather may result in insufficient energy to meet anticipated winter peak demands and could require implementing conservative operations and EEAs.
- Interruptions to fuel supply could create unique operational challenges in MISO and SPP for the upcoming winter. MISO and SPP continue to work with neighboring regions to address potential natural gas deliverability issues associated with extreme weather conditions. Efforts at enhancing communications and operator preparedness are also ongoing.
- Conventional generation Weighted Equivalent Forced Outage Rates (WEFOR) for 2022 were higher than the five-year moving average.

- Relay failure/malfunction-related misoperations accounted for nearly a quarter of last winter's total misoperations, but human error-related misoperations saw significant improvement over previous seasons.

Recommendations

To reduce risks of energy shortfalls on the bulk power system this winter, MRO recommends the following:

- Reliability Coordinators (RCs), Balancing Authorities (BAs), Transmission Operators (TOPs) and Generator Operators (GOPs) should maintain situational awareness of fuel risk, unplanned generation and transmission outages, abnormal and extreme weather conditions, and low wind forecast periods. These organizations should employ operating procedures as needed to ensure adequate resource availability.

- RCs, BAs, and Generator Owners (GOs) should have safeguard protocols to ensure adequate generation resource availability prior to the winter season.

- State and provincial regulators should be prepared to assist grid operators prior to, and during, the winter season by supporting requested environmental and transportation waivers, as well as public appeals for electric load and natural gas conservation.

- Review NERC Alerts and guidelines related to cold weather preparedness, lessons learned from Winter Storm Elliott, and participate in MRO's voluntary Generator Winterization Program.

- Assess and develop new and better methods to evaluate supply adequacy, especially when a significant amount of generation capacity has an intermittent fuel source that is difficult to forecast.

CHAPTER 1: ASSESSMENT OVERVIEW

Purpose

The purpose of this report is to provide information on, and raise awareness of, reliability challenges, and trends to assist industry stakeholders and key decision-makers with reducing risk to the regional bulk power system.

Process

MRO staff annually assesses the regional Reliability Coordinator (RC) and Planning Coordinator (PC) areas to identify key reliability issues and the risks and uncertainties affecting adequacy of the bulk power system in the region. PCs are responsible for integrating transmission facilities, service plans, resource plans, and protection systems to ensure reliable power within their respective footprints. These entities collaborate with Transmission Planners to assess resource and transmission impacts within an interconnected area. RCs—the entities responsible for real-time, reliable operation of the bulk power system—have a wide-area view of the system and are the highest level of operating authority within a designated footprint. In addition to the four PCs in MRO (MH, MISO, SPC, and SPP), there are three RCs: MISO (who is also the RC for MH), SPC, and SPP.

NERC's reliability assessment process, which covers all of North America, is a coordinated reliability evaluation effort between the NERC Reliability Assessment Subcommittee (RAS), NERC staff, and the six Regional Entities.[1] MRO's 2023 RWA is an independent staff assessment that utilizes some of the same data as NERC's 2023-2024 Winter Reliability Assessment (WRA), with a more targeted focus on MRO's regional footprint. The evaluation of previous seasonal performance helps to identify reliability concerns, trends and emerging risks that are region-specific.

Area Studied

MRO's 2023 RWA covers MRO's regional footprint, which includes two Canadian provinces and all or parts of 16 states. It is important to note that the MISO footprint spans three Regional Entities: Midwest Reliability Organization (MRO), Reliability First (RF), and SERC Reliability Corporation (SERC). MRO is responsible for collecting resource and transmission system adequacy data for the entire MISO area and reviews it jointly with RF and SERC when performing NERC reliability assessments. In contrast, the review of MISO's historical performance data includes only the portion of the MISO footprint within the MRO region. MRO collects and reviews both performance data and NERC reliability assessment information for the entire MH, SPC, and SPP Planning Coordinator footprints.

Sources of information used in this assessment include NERC's 2023-2024 WRA, as well as MRO Performance Analysis (PA) data from the ERO 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 North American Regional Entity footprints, which are separate from, and do not precisely align with, the assessment areas.

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

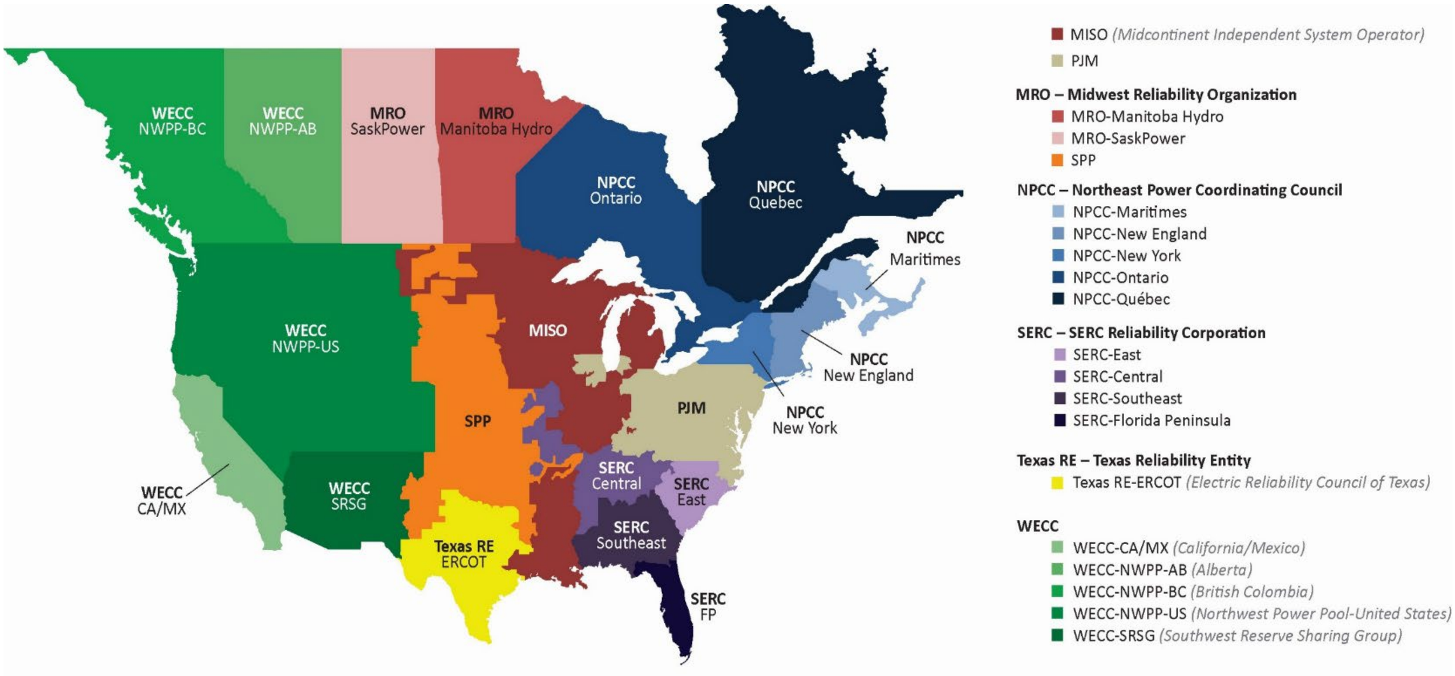


Figure 1.1: NERC Assessment Areas

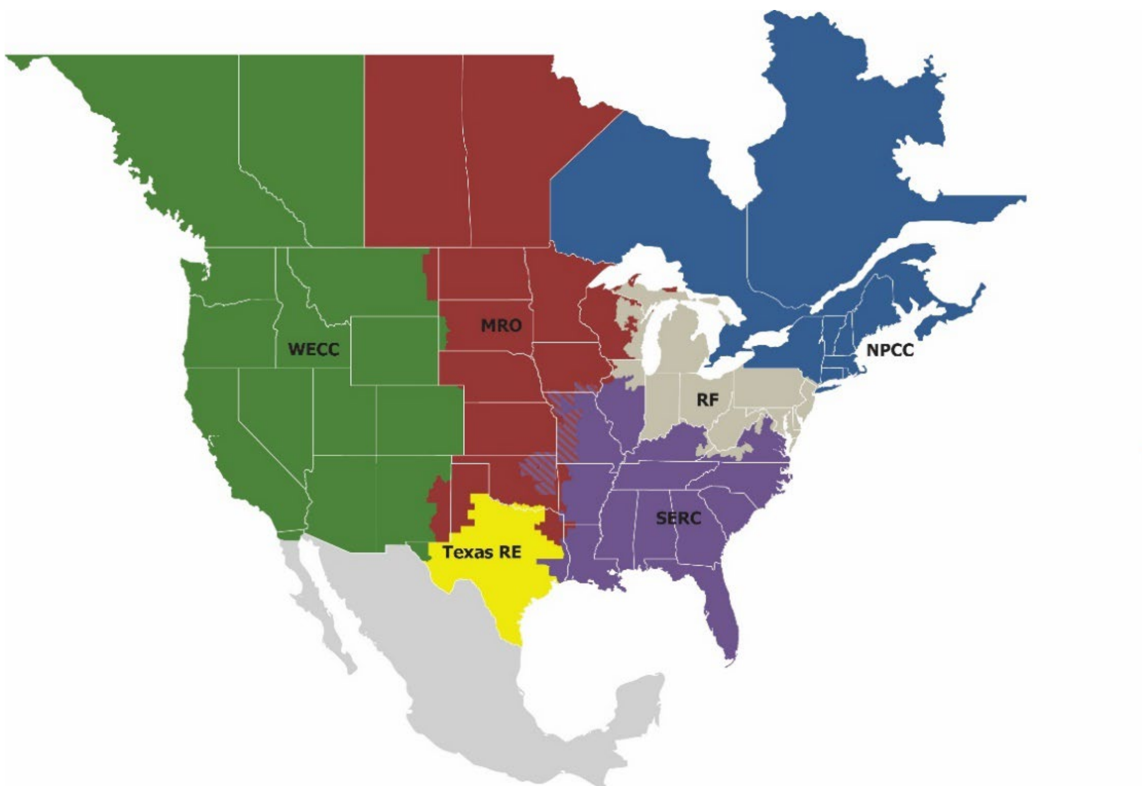


Figure 1.2: Regional Entity Boundaries

CHAPTER 2: 2023-2024 WINTER OUTLOOK

The growing complexity and increasing uncertainty in seasonal load forecasting adds to winter reliability risks. Extreme cold temperatures and severe weather can cause demand for electricity to deviate significantly from historical forecasts. Underestimating electricity demand can lead to ineffective operations planning and insufficient resources being scheduled. Relatedly, generator performance and fuel supply issues are more likely to occur when generators are called upon with short notice, exposing Balancing Authorities to potential resource shortfalls.

In coordination with the ERO Enterprise and industry, MRO performs seasonal generation and load forecasts to determine reliability risk as part of this assessment. Details from the 2023 Seasonal Winter Forecast can be found in Appendix B.

Based on this information, MRO's independent analysis of projected reliability conditions for each assessment area in the MRO region for the 2023-2024 winter season is described below.

Manitoba Hydro

MH does not anticipate any emerging reliability issues for the 2023-2024 winter season. Although MH has experienced unanticipated higher than normal winter load conditions in the past, no changes are required to operating plans/procedures or seasonal resource planning for the upcoming winter season because anticipated reserve margins exceed the reference margin level. Manitoba Hydro continues to monitor several issues such as extreme weather events, drought, decarbonization-driven changes to supply and demand, and asset health. Although water conditions are below normal for this time of year, the system was planned for extreme drought conditions and MH's operations plans ensure reliability can be maintained should drought conditions continue.

Midcontinent Independent System Operator

MISO has identified some risk for the 2023-2024 winter season in a high generation outage and high winter load scenario. However, reliability is expected to be maintained through mitigation measures that include Load Modifying Resources (LMR), non-firm energy transfers into the system, energy-only resources that do not have a must-offer requirement but may still offer into the energy markets, or internal transfers that exceed the Sub-Regional Import/Export Constraint (SRIC/SREC) between the MISO North/Central and South regions. MISO continues to coordinate extensively with neighboring Reliability Coordinators and Balancing Authorities to improve situational awareness and assess any needs for firm or non-firm transfers to address extreme system conditions.

MISO is a summer peaking region. The extreme cold weather experienced during the 2022 winter season is a reminder of how critical resource adequacy and proper planning are for all seasons of the year, not just for summer peak season. To that end, MISO continues to survey and coordinate with its members on winter preparedness and fuel sufficiency. In addition, acknowledging that resource adequacy risk is not limited to the summer peak season, MISO has filed and implemented a seasonal resource adequacy construct and seasonal unit accreditation to plan for adequate supply in all seasons.

Saskatchewan Power Corporation

SPC typically experiences peak load in winter given its geographic location and extreme cold weather. No impactful fuel supply or transportation issues with coal or natural gas facilities are expected for the upcoming winter season. The risk of an operating reserve shortage or Energy Emergency Alert (EEA) during peak load times exists if a large generation forced outage occurs during peak load times combined with transmission tie-line maintenance work or generation maintenance work scheduled during winter months. SPC may have to rely on demand response programs, short-term power transfers from neighboring utilities, and potential load interruptions during extreme peak loads.

In case of extreme winter conditions combined with large generation forced outages, SaskPower would utilize available demand response programs, short-term power transfers from neighboring utilities, maintenance rescheduling and/or short-term load interruptions.

Southwest Power Pool

SPP does not anticipate any emerging reliability issues impacting the area and forecasts adequate planning reserves for the upcoming winter season. However, interruptions to fuel supply could create unique operational challenges. SPP continues to work with neighboring regions to address potential electric deliverability issues associated with extreme weather events. Efforts are aimed at enhancing communications and operator preparedness. SPP has historically maintained reliability despite experiencing weather extremes during each peak season. SPP has comprehensive procedures that help mitigate the reliability impact of such extreme weather events and associated weather forecast errors.

To minimize the need for conservative operations and/or EEAs, and to respond to mid-range errors and uncertainty in wind forecasts, SPP created new mitigation processes to address high-impact areas of concern. SPP has developed operational mitigation teams, processes, and procedures to address a variety of situations to ensure real time reliability.

SPP formed the Resource and Energy Adequacy Leadership Team to address SPP's current resource adequacy construct and anticipated challenges resulting from resource mix changes, extreme weather impacts, increased demand, and evolving consumer behaviors.

CHAPTER 3: SEASONAL TRENDS

The following data was used to analyze system performance during the 2022-2023 winter season to identify seasonal trends:

- Bulk Electric System (BES) Event Analysis
- Energy Emergency Alerts
- Generation Availability Database System
- Transmission Availability Database System
- Misoperation Information Data Analysis System
- Historical Winter Load Forecast

Performance analysis information (GADS, TADS, MIDAS) and Event Analysis (EA) data is collected and analyzed by staff for MRO's regional footprint, while the resource and transmission system adequacy reviews are conducted by the Planning Coordinators within each respective area.

BES Event Analysis

MRO staff analyzes major events and system disturbances per the NERC Rules of Procedure Section 800. Using the Event Analysis Process established by the ERO Enterprise (collectively NERC and the Regional Entities), 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

Twenty-seven transmission events occurred on the system in MRO's region from January 2022 through September 2023, with one occurring during the 2022 winter months. Equipment failure and protection system misoperations were identified as contributing causes for this event. Protection system misoperations is a leading cause of events across the ERO Enterprise.

To mitigate this risk, MRO has published lessons learned and two white papers that address issues related to protection system misoperations identified through the performance analysis and EA programs. MRO staff continue to collaborate with subject matter experts that serve on the Protective Relay Subgroup to reduce protection system misoperations.

Energy Management System Events

There were two Category 1h (loss of monitoring or control at a control center) Energy Management System (EMS) related system events within the MRO region during the 2022 winter season, with an average duration of 83 minutes. A Category 1h event is described as: An event that 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 identified among the two EMS events is that they occurred either during or shortly after a routine maintenance procedure.

Figure 3.1 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 individual event in minutes. The green bar is the average duration of all the events for each year.

Figure 3.2 illustrates MRO's Event Severity Index, which 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. 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. MRO's primary focus is to limit large impact events, especially those that may lead to a cascading event.

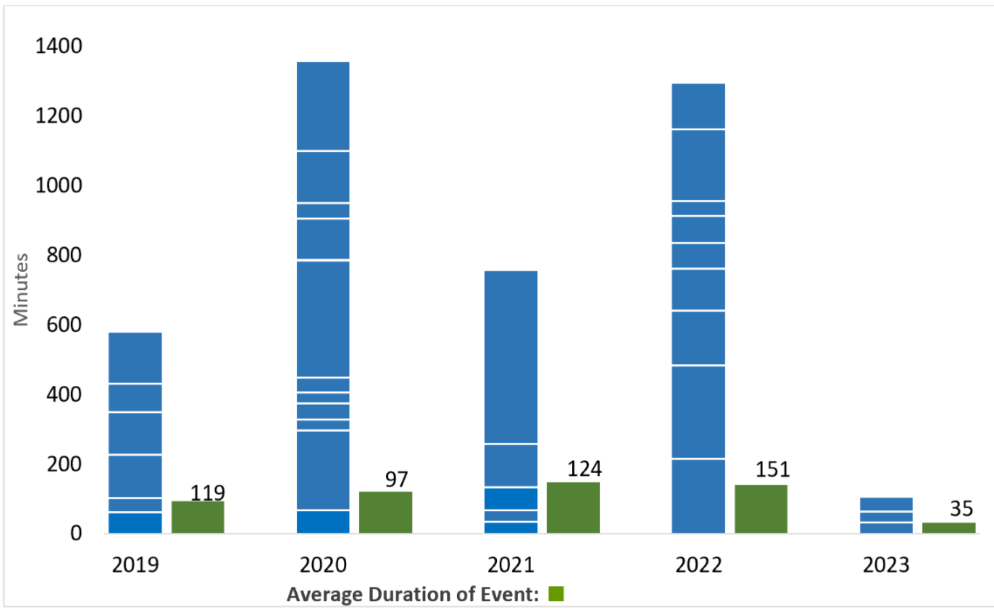


Figure 3.1: Loss of EMS Event Time Duration

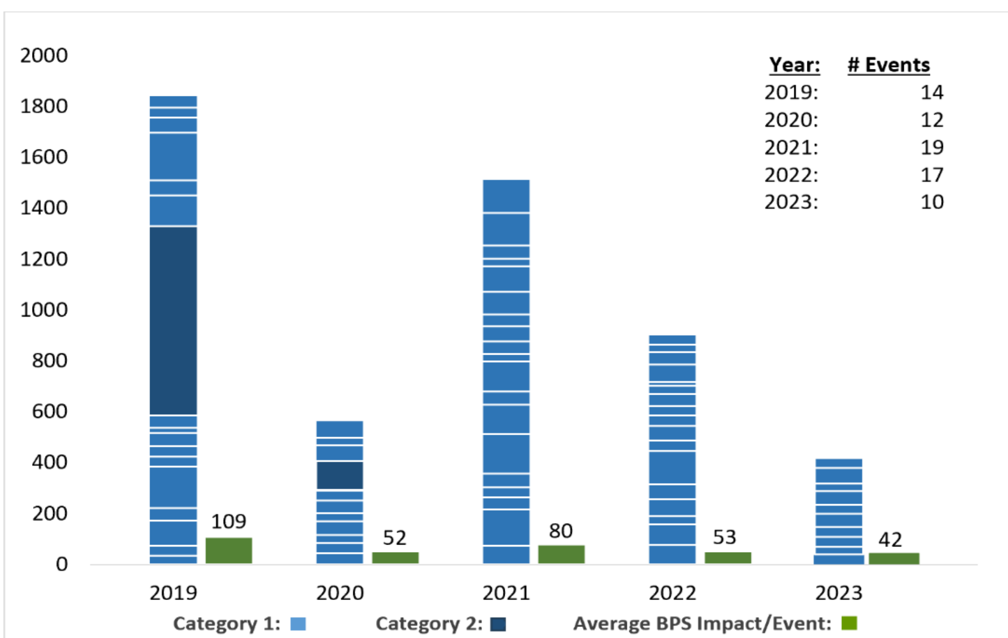


Figure 3.2: MRO Event Severity Index as of September 2022

Below are the event categories included in the Event Severity Index (note the NERC Addendum for Determining Event Categories is on NERC's website):

- **Category 1a**: An event that results in an unexpected outage, contrary to design, of three or more BES Facilities caused by a common disturbance.
- **Category 2d:** An event that results in complete loss of off-site power (LOOP) to a nuclear generating station per the Nuclear Plant Interface Requirement.
- **Category 2f**: An event that results in an unintended loss of 300 MW or more of firm load for more than 15 minutes.

A summary of 2022 BES events that occurred during the 2022 winter 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.

Historical Event Causes

Figure 3.3 shows the top 15 event causes from January 2017 through March 2023 for the MRO region. These causes include event characteristics and attributes associated with BES events, as well as EMS events. This chart indicates that Transmission Outage and Loss of Firm Load continue to drive major events in the MRO region.

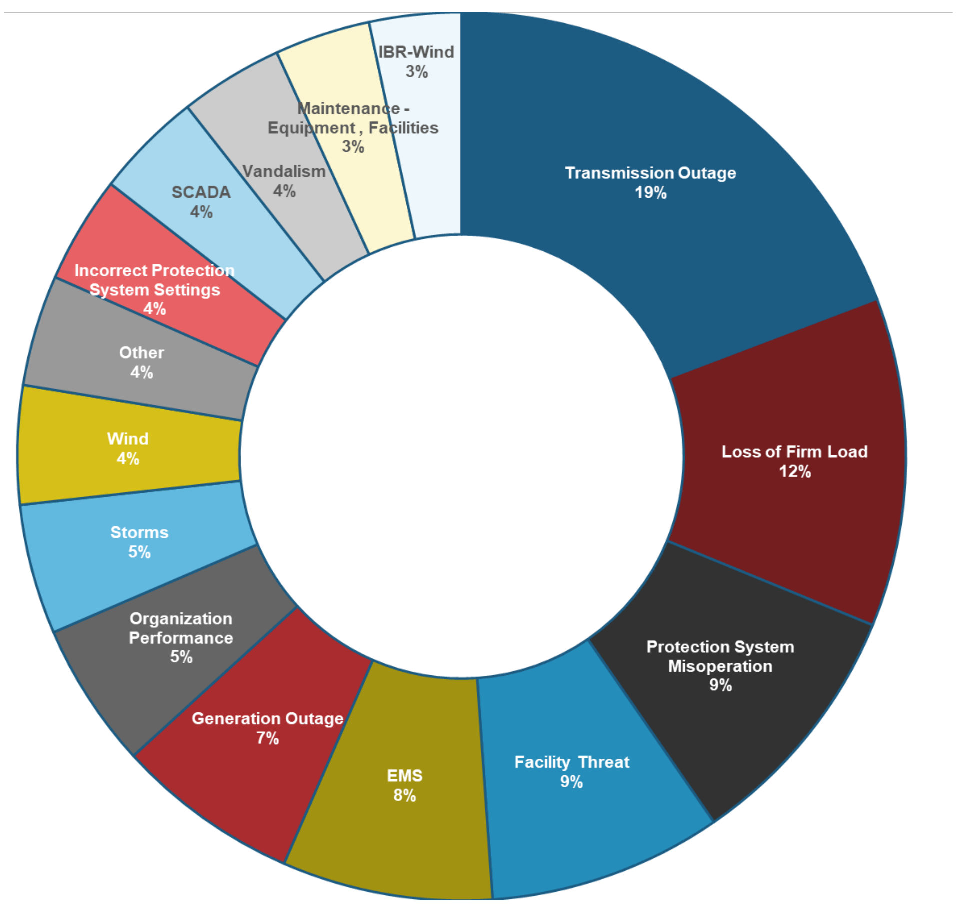


Figure 3.3: Top Event Causes since 2017

Energy Emergency Alerts

An energy emergency occurs when a load serving entity or Balancing Authority (BA) has exhausted all the resource options and can no longer meet its expected load and operating reserves. Energy Emergency Alerts (EEAs) are issued by the Reliability Coordinator (RC). The current enforceable version of NERC Reliability Standard EOP-011-2 addresses the effects of operating emergencies by ensuring each Transmission Operator (TOP) and BA has developed an operating plan(s) to mitigate operating emergencies, and those plans are coordinated within an RC area. NERC has established three levels of EEAs. to ensure all RCs clearly understand potential and actual energy emergencies. More information on EEAs and energy emergency response can be found in the current NERC Reliability Standard EOP-011-2 Emergency Preparedness and Operations.

The MRO region experienced five energy emergencies during the winter of 2022. More detail on these EEA events is included in Appendix C.

Generator Availability

Generating Availability Data System (GADS) is a program that collects information about the performance of electric generating equipment to assist with analyzing generation outages. GADS reporting became mandatory on January 1, 2013, and includes data on more than 8,000 conventional generation units across North America. It is a valuable source of information related to reliability, availability, and maintainability and includes unit design data, monthly performance data (including hours of availability and power produced), and events data. Wind generation performance data is currently captured in a separate GADS Wind application that became mandatory on January 1, 2018. Beginning in 2024, wind performance will move to a new OATI platform that will also capture wind events as well as solar events and performance data. This reporting becomes mandatory January 1, 2024. However, data will not be collected until the second quarter submission date in 2024. Wind turbine outage information and solar data will be included in this report when mandatory and representative data sets are available. Generation unavailability can have a substantial impact on reliability. Useful metrics for generator unavailability are the equivalent forced outage rates (EFOR)[2] and megawatt Weighted EFOR or (WEFOR)[3].

Long-term trends continue to indicate increasing EFOR rates due to component fatigue and an aging fleet. Given higher penetrations of intermittent resources, conventional generation is being cycled (ramping up and down) to follow load and operating at minimum output more often, increasing the number of forced outages due to component failures. Additional findings:

- Increase in 2022 WEFOR was driven in part by extreme outage events during winter storm Elliott.
- 2022 winter season saw sizable decrease in event impact from the 2021 winter season.
- Fossil Steam and Simple Cycle GT contributed to higher event impacts and increased WEFOR percentages for 2022 winter season but overall have lower impact to the BES.

Based on forced outage rates for fossil-steam and simple cycle gas turbines, MRO is closely monitoring the

[2] 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

[3] WEFOR measures the probability that a group of units will not meet their generating requirements because of forced outages or forced derates. The weighting gives larger units more impact to the metric than smaller units.

performance and identifying the failure risk of these types of resources. MRO is also monitoring system improvements being implemented by generator owners to reduce forced outages through the MRO Generator Winterization Program. Higher forced outage rates of fossil-steam and simple cycle gas could impact the generation resource availability during extreme winter peak demand and increase the number and duration of EEA events. Maintaining a robust and reliable fleet of balancing resources is critical to meet energy needs at all hours and integrating renewable resources.

More details on generation event impacts and winter season forced outage, forced derate, and startup failure causes for certain types of generation are provided in Appendix D.

Transmission Availability

Transmission Availability Data System (TADS) is a program that collects information regarding the availability of AC and DC transmission circuits and transmission transformers operating at 100kV and above. TADS also collects detailed information about individual outage events, that when analyzed both regionally and North American-wide, provides useful data in reliability analyses. An automatic outage results from the automatic operation of a switching device, such as a circuit breaker, causing an element to change from being in-service to not being in-service. Sustained outages for one minute or greater are reported for outages to elements that are operated at 100kV and above. Momentary outages of less than one minute are only reported for elements operated at or above 200kV.

The following summarizes the transmission outages experienced during the winter of 2022.

- A significant number of momentary outages have an unknown cause, suggesting that thorough line inspections after transient faults are not typically performed after clear weather operations or an inspection is performed, but a definitive cause for the transient faults cannot be determined.
- Galloping due to weather is most likely the second leading cause of momentary automatic outages.
- Failed AC circuit equipment, weather (excluding lightning), other, and failed AC substation equipment continue to be major contributors to sustained outages during the winter seasons.
- Several winter storms, including winter Storm Elliot, resulted in 166 transmission outages in the MRO region during the 2022-2023 winter season.

Additional information on winter seasonal automatic outages, momentary outages, sustained outages and historical winter transmission outages per 100 circuit miles are provided in Appendix E.

Protection System Misoperations

A properly functioning protection system is critical for maintaining reliability of the Bulk Electric System (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). The 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. Reporting is accomplished through the Misoperation Information Data Analysis System (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 3.4 from the 2023 NERC State of Reliability report.

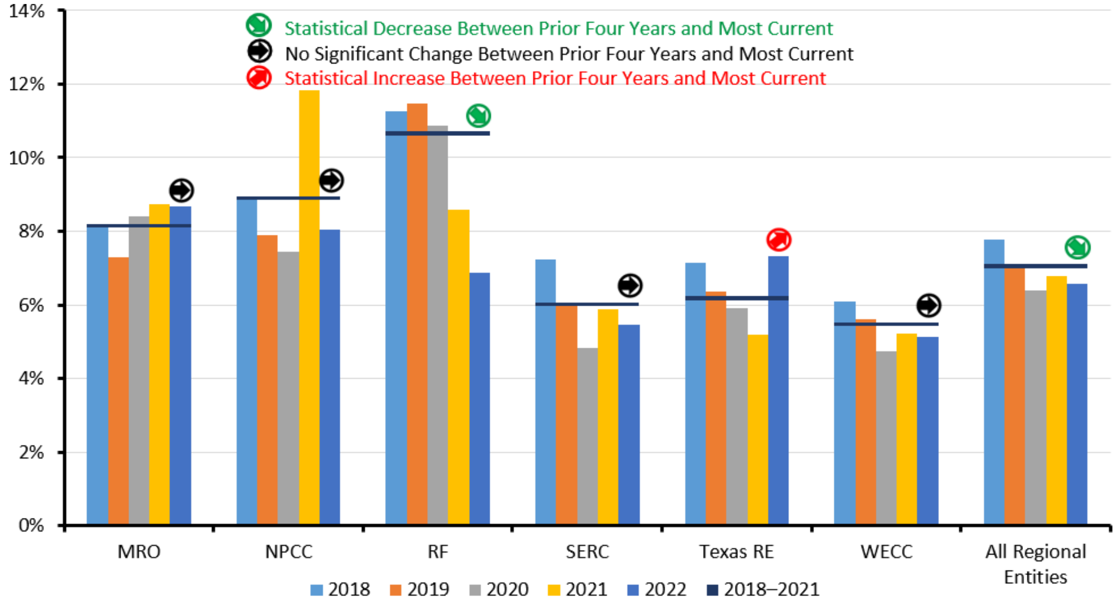


Figure 3.4: Changes and Trends in the Annual Misoperations Rate by Regional Entity

There were 3,299 operations and 281 misoperations reported within the MRO region in 2022 for a misoperation rate of 8.51 percent. Figure 3.5 shows the misoperation rate in MRO's region had been trending downward until 2020. The upward trend seen in 2020 and 2021 leveled off in 2022.

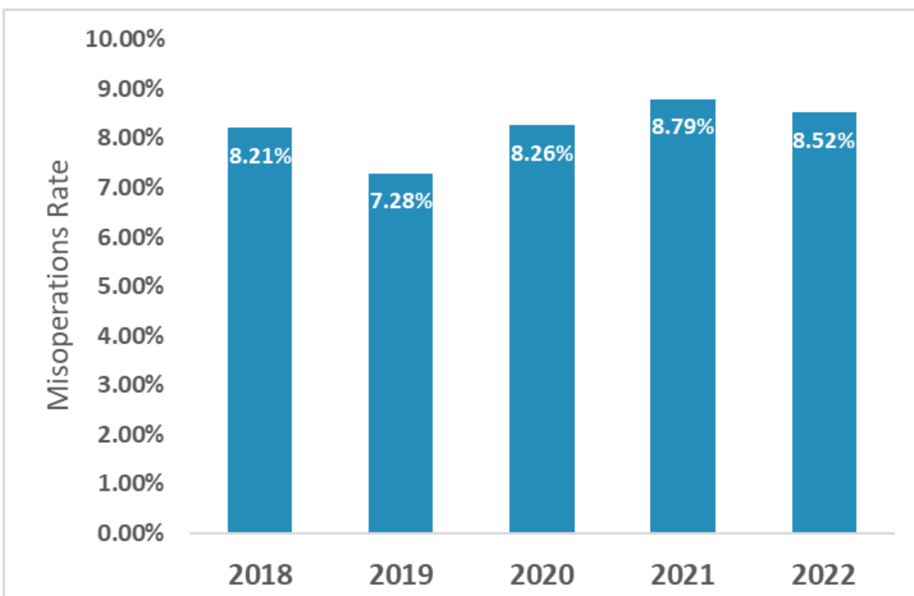


Figure 3.5: MRO Misoperation Rates by Year

Figure 3.6 provides context for the misoperation rate in 2022. Total protection system operations were up about 25 percent in 2022 from the previous year. Total misoperations were up about 18 percent.

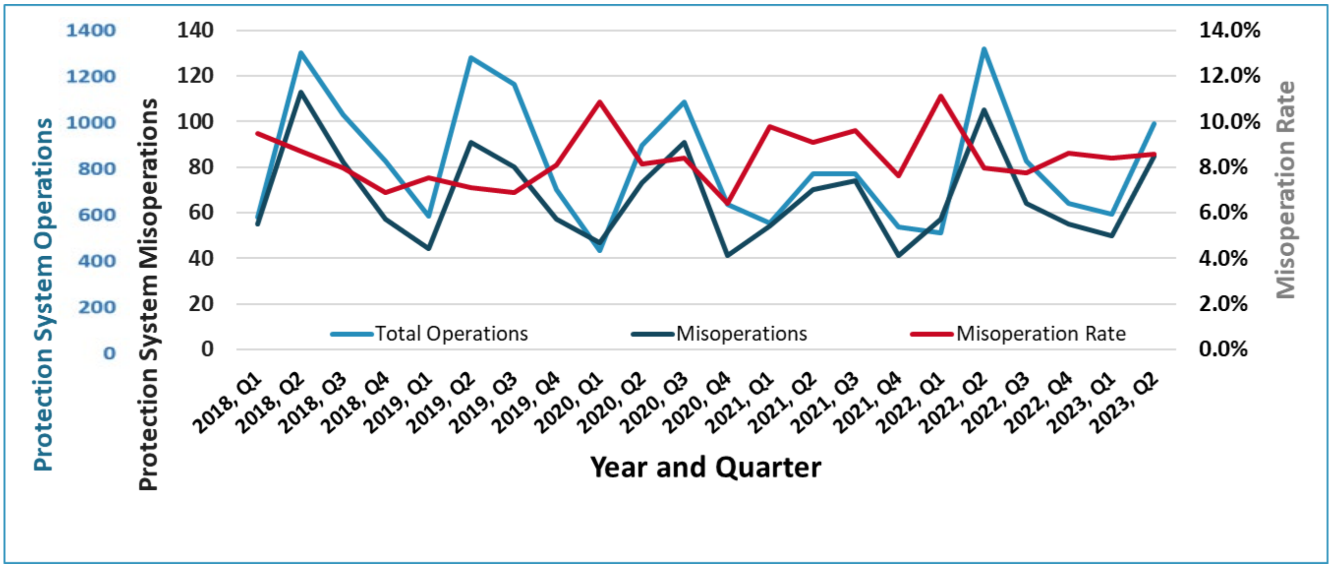


Figure 3.6: Protection System Operations and Misoperations Rate

The cause for the significant increase in total operations from previous years is difficult to ascertain. Of the 3,299 total operations that were reported in MIDAS for 2022, 2,291 occurred at voltages less than 200kV. Of those 2,291 outages, only 800 were sustained outages, the other 1491 were momentary automatic outages. As neither TADS nor MIDAS collects outage cause data on momentary automatic outages at voltages less than 200kV, the causes of those outages remain unknown to MRO. As those outages made up approximately 45 percent of the reported outages that occurred in 2022, and similar percentages were seen in previous years, MRO cannot definitively attribute the increase in outages to any specific cause(s).

Summer weather events typically cause more BES faults and relay system operations than winter weather events. An increased number of total protection system operations reported in MIDAS and an increased number of summer weather-related transmission outages reported in TADS indicate that the 2022 summer storms were more frequent and severe on the BES than previous years. This is likely a major contributing factor to the increase in total overall operations in 2022. It is worth noting that there was a significant spike in operations in the second quarter, which is historically when the highest number of operations are seen, likely due to spring and early summer storms.

MIDAS reports are completed and reported by entities quarterly. The fourth and first quarters of the year (October 1 through March 31) align closest to the winter season (designated December 1 through February 28) for this assessment. As shown in Figure 3.7, many misoperations are not associated with a fault. Non-fault associated misoperations have a smaller variance than fault associated misoperations and do not vary with the number of correct protection system operations. Therefore, these misoperations have a larger impact on the overall misoperation rate when the total number of protection system operations is low. It is reasonable to expect the misoperation rate would be higher than average when the total number of correct operations (associated with faults) is lower.

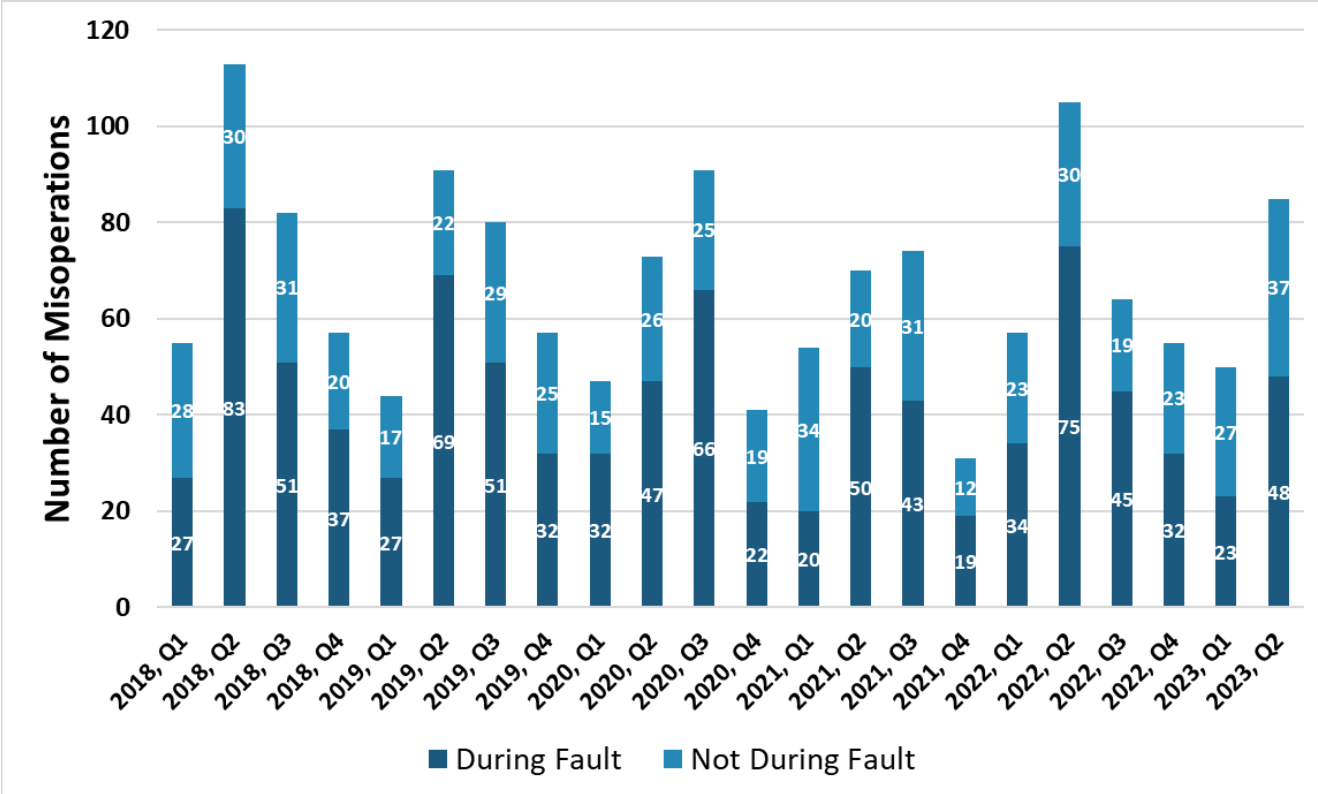


Figure 3.7: Fault Associated and Non-Fault Associated Misoperations

A total of 41 misoperations occurred in the MRO region between December 1, 2022, and February 28, 2023. Examining these misoperations revealed that relay failure/malfunction-related misoperations accounted for nearly a quarter of last winter's total misoperations (see Figure 3.8). It is worth noting that human error-related misoperations, or those attributed to as-left personnel errors, design errors, incorrect settings, and logic errors, accounted for less than a quarter of the total misoperations last winter. This is a significant improvement from previous periods.

However, a single season improvement does not constitute a trend and human error continues to be the leading cause of misoperations both in MRO as well as ERO-wide. This highlights the importance of utilizing a robust system of controls throughout a project lifecycle (design, production, construction, commissioning, and maintenance) to ensure that any human errors are mitigated as thoroughly as possible through human performance tools.

To address the concern that human error-related misoperations continue to present, the following actions have been taken or continue to take place:

- Commissioning best practices and challenges are being discussed by MRO's Protective Relay Subgroup, which is an industry-led group comprised of utility company and MRO staff.
- NERC hosted a BES Protection System Misoperation Reduction Workshop in Atlanta on October 25-26, 2023.

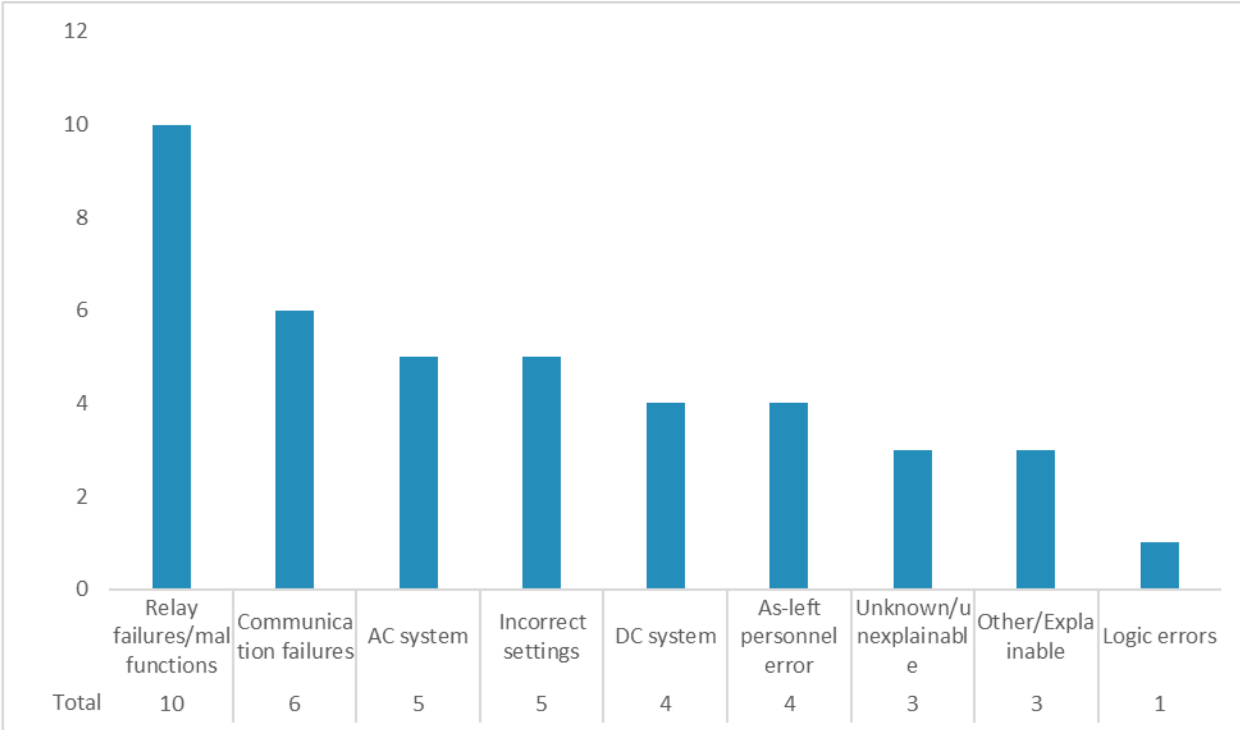


Figure 3.8: Winter 2022 Misoperations by Cause

Historical Winter 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 percent, while the probability that the actual peak load would be less than predicted is also 50 percent. A 90/10 forecast is a worst-case, extreme weather scenario that can be reasonably anticipated. It means there is only a 10 percent probability of the projected peak load being exceeded and there is a 90 percent chance that the actual peak load would be less than predicted. In other words, the forecast would be exceeded, on average, only once every ten years.

Figure 3.9 shows the five-year historical winter normal (50/50) and extreme (90/10) forecasts, along with actual and all-time winter peak load for each assessment area in the MRO region. SPP actual peak demand exceeded the normal and extreme forecast last winter. SPP recorded a new all-time winter peak load in December 2022 and is forecasting 46,718 MW extreme peak load for the upcoming winter season. The historical five-year all-time highest winter hourly average demand recorded for each of the MRO assessment areas are as follows:

- MH: 4,911 MW in January 2019
- MISO: 108,637 MW in January 2017
- SPC: 3,910 MW in December 2021
- SPP: 47,157 MW in December 2022

Actual weather conditions that occurred at the time of peak load can then be compared to the forecast weather prediction to determine if any adjustments may be warranted in the forecast peak. This is particularly important for MISO and SPP, whose single BA footprints span from the Canadian border to the Gulf of Mexico and can result in significant weather diversity on any given day.

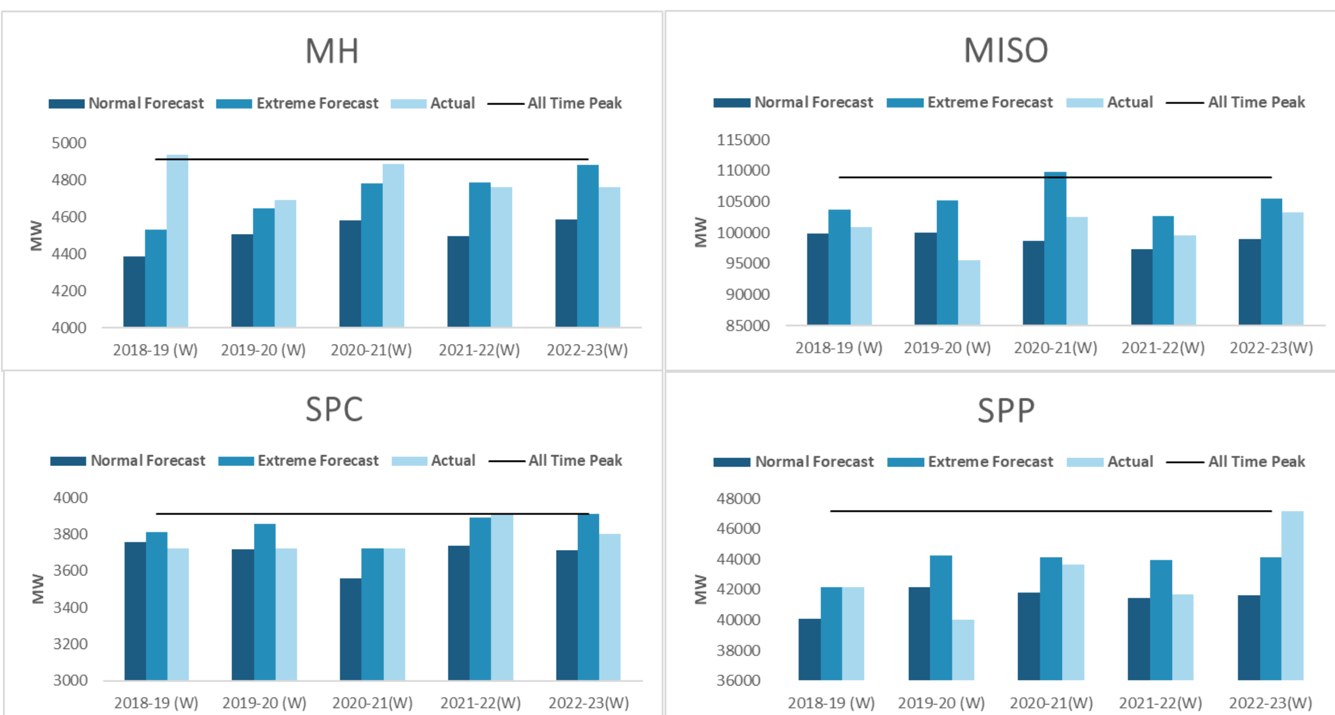


Figure 3.9: 5-Year Historical Winter Load Forecast

CHAPTER 4: EMERGING RISKS

Generation Resource Mix

A diverse mix of fuel types is reflected in MRO's 2023 winter peak accredited capacity as shown in Figure 4.1. The largest single contributor of generation by peak capacity in the region is natural gas. Approximately 70 percent of gas plants are in the southern portion of the region. Coal plants and wind turbine generators make up the next largest portions of the generation mix. Conventional generation with large rotating mass (i.e., steam, hydro, and combustion turbine technologies) capable of providing essential reliability services like frequency and voltage support continues to be retired and replaced with renewable generation that either cannot, or has limited capability, to provide these essential reliability services because of design constraints.

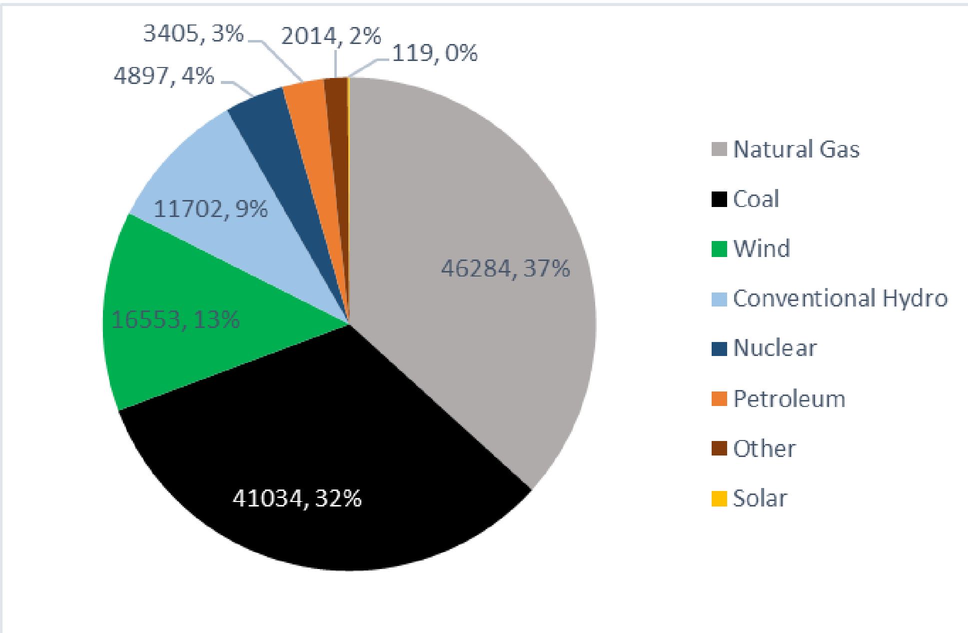


Figure 4.1: MRO 2023 Winter Peak Capacity (MW) by Fuel Types

Increases in intermittent resources, such as wind and solar, are also contributing to operational complexity in terms of resource commitment and dispatch. Forecasting inaccuracy can result in larger, unanticipated shortfalls or exceedances in real-time operations and ramping changes are also hard to accurately predict.

Wind

There are approximately 61 GW of installed wind capacity in the MRO region, of which 17 GW (28%) is accredited for the 2023 winter peak. Multiple proposed projects in the MISO and SPP generation interconnection queue will add approximately 38 GW of installed wind capacity by winter 2033. Operational challenges associated with large amounts of wind include accurately forecasting the output of wind resources, maintenance impacts of conventional resource cycling, and in some older wind turbines, less reactive support capability than comparable conventional generation resources.

Solar

The installation of utility scale solar photovoltaics (PV) generation is accelerating in the MRO region and is projected to become the second most prominent renewable source after wind. Approximately 34 GW of proposed solar projects exist in the MISO and SPP generation interconnection queue for installation by winter

2033. Solar resources create additional operational challenges while preparing for daily ramping changes at sunrise and sunset. It is important to note that not every wind and solar project in the interconnection queue will be built, as some requests may be withdrawn after a system impact study. A system impact study establishes necessary transmission upgrades that may be needed before a project can connect to the bulk power system.

Summary of Risk

The move away from conventional generation to intermittent resources requires BAs to have capacity available that can ramp quickly and respond to change in output from intermittent resources. Existing steam units do not typically have high ramp rates, especially those that were designed as base load units. Furthermore, the units were not designed to be cycled to the extent they are today, which can lead to higher forced outage rates and additional maintenance requirements. These factors increase the risk of having insufficient resources to serve load during periods when the actual output of renewables is significantly less than forecasted. This creates a challenge for control room operator awareness and decision-making processes, especially during periods of high uncertainty in intermittent resource output and significant ramping. It also forces BAs to carry additional operating reserves to account for forecast uncertainty associated with wind and solar resources and load forecasting errors.

With increased penetration of intermittent resources and retirement of conventional resources, planned outages of conventional generating units are more difficult to schedule. With the higher uncertainty of output of intermittent resources, a BA is more dependent upon conventional resources to be available to respond during more of the off-peak periods. This reduces the number of resources that can perform planned outage work while at the same time reliably serving load. This, coupled with the increased maintenance requirements driven by more frequent ramping of conventional units, makes it more challenging to serve load during non-peak load periods.

CHAPTER 5: MITIGATING ACTIVITIES

MRO Generator Winterization Program

After action analyses of extreme cold weather events reflect major interruptions to resources, transmission paths, and ultimately end-use customers. MRO's Generator Winterization Program (GWP) mitigates the impact of such events by annually assessing industry operating practices and identifying recommended improvements related to resource/generator cold weather preparedness. The GWP is outside of any compliance or enforcement activity and is meant to promote cold weather reliability by sharing knowledge, identifying best practices, and offering recommendations to help entities reduce weather-related risks. The program is a technical engagement aimed at enhancing outreach and generator performance to mitigate large-scale, unplanned outages due to cold weather. The recent NERC Alert Essential Actions to Industry (Cold Weather Preparations for Extreme Weather Events III) provides specific actions that MRO registered RC, BA, TOP, and GO entities should implement to ensure reliable operation of the bulk power system when preparing for extreme cold weather.

MRO produced its first Generator Winterization Program General Findings Report in April 2023, highlighting key findings from the first two years of the program. The report offers recommendations to help reduce weather-related risks and improve generator performance during the winter season. The goal of this report (and the GWP) is to reduce the likelihood of a large-scale, unplanned outage due to extreme cold weather.

MRO's annual generator data review includes geographic location, plant configuration, technology, quarterly generating unit performance data (GADS), and functional registration data, to determine the annual GWP preparedness survey approach and site visit selections. The 2023 GWP will include six generator site visits and corresponding surveys. The surveys allow for additional generator owners or operators to participate in the GWP by providing data to MRO as a benchmarking tool. The 2023 focus expands beyond conventional generation as cold weather impacts are applicable to all types of generation resources, regardless of location and design.

Cold weather continues to have an impact on generation reliability and is recognized as a high risk across the industry. MRO's GWP encourages the use of the seven key components described in NERC's guideline on generating unit winter weather rediness. Raising awareness of, and helping industry prepare for, extreme cold weather continues to be a focus area for both MRO and the ERO Enterprise. Winterization outreach resources are available on the MRO GWP web page.

CHAPTER 6: SUMMARY

Focus Areas for 2023-2024 Winter

The following focus areas represent MRO's independent evaluation of the generation and transmission system for the 2023 winter season, as well as potential operational concerns that should be considered during this same timeframe:

- SPC projects insufficient firm generation available to meet forecasted seasonal normal winter peak load with typical maintenance and forced outages. Based on extreme winter conditions, SPC would likely need to use available demand response programs, short-term power transfers from neighboring utilities, and Energy Emergency Alerts (EEAs).

- Forced outages during the upcoming winter season could increase the risk of operating reserve shortages in MISO and SPP during extreme peak load times, depending on the amount of generation lost due to such forced events.

- Potential gas delivery or supply issues in MISO and SPP could be an emerging reliability risk for the upcoming winter.

- Conventional generation Weighted Equivalent Forced Outage Rates (WEFOR) for 2022 were higher than the five-year moving average. Causal identification of these long-term trends during peak load periods are crucial and essential to bulk power system reliability.

APPENDIX A: REGISTRATION AND CERTIFICATION

Registration

There are approximately 240 registered entities in the MRO region on the NERC Compliance Registry (NCR). 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. This information is also fundamental to reliability assessments in that certain functions pose greater risk to reliability of the bulk power system.

Reliability Coordinators (RCs), Balancing Authorities (BAs), Transmission Operators (TOPs), Generator Owners (GOs) and Generator Operators (GOPs), have an important role in maintaining reliability during winter weather operations. These entities also provide accurate operational data for ERO event analysis. There has been little registration growth over the past five years in all functions except GO and GOP. 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. Generator modeling data provided by GOs and GOPs to TOPs, BAs and RCs is critical for use in operations planning and real-time analysis of the bulk power system.

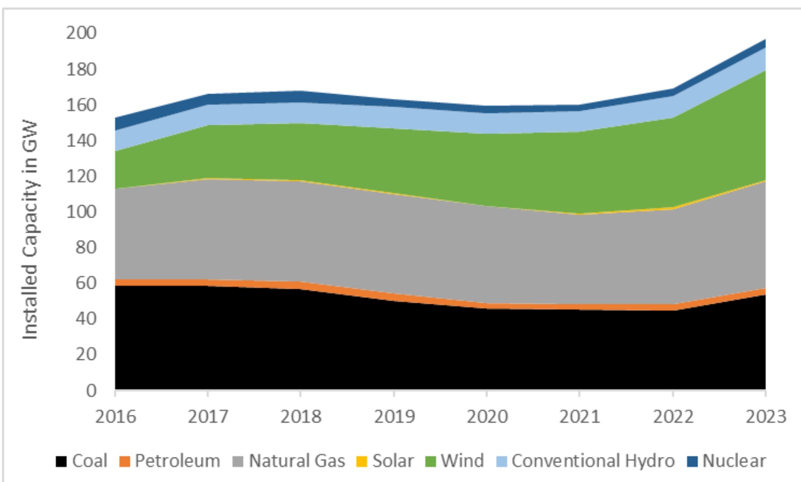


Figure AA1: MRO Historical Resource Mix by Fuel Types

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 uses to perform its functions have the capacity to meet the reliability obligations of its registration. Material changes to already certified and operational Registered Entities require a Certification review 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. MRO has completed one Certification in the last six-year period and averages five Certification Review activities per year. This seasonal reliability assessment directly focuses on RCs, TOPs, and BAs, and was developed based on data collected during performance analysis, event analysis, and situational awareness activities, providing insights on the performance of Bulk Electric System (BES)[4] elements.

[4] BES_Reference_Doc_08_08_2018_Clean_for_Posting.pdf (nerc.com)

APPENDIX B: 2023-2024 WINTER SEASONAL FORECAST

The 2023 winter seasonal forecast includes the months of December 2023 through February 2024.

Anticipated Winter 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 2023 anticipated, and the seven-year historical, generation by fuel type at the time of winter peak for each of the PCs in the MRO region:

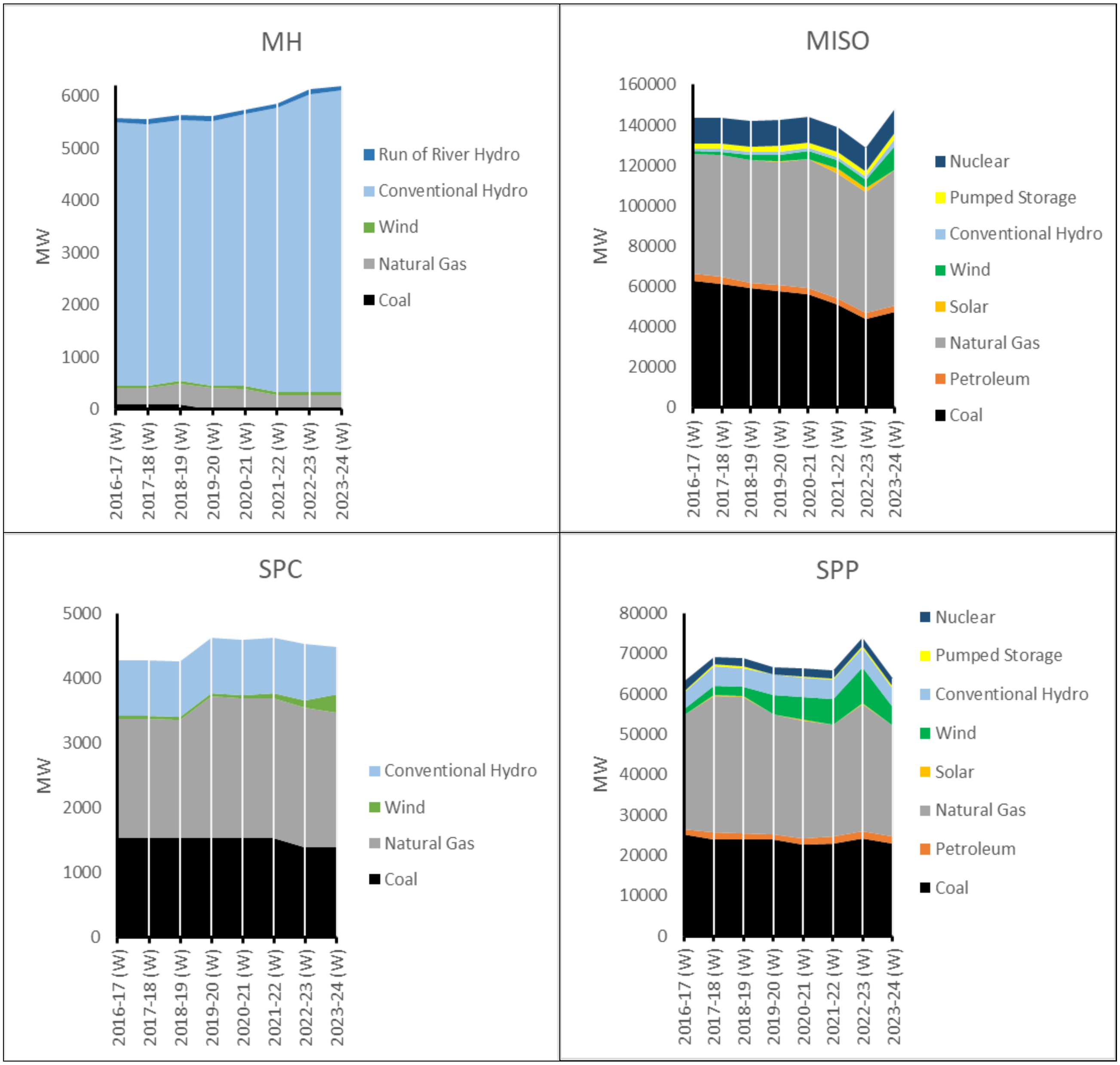


Figure AB1: Generation by Fuel Type at Time of Winter Peak

Each PC has a different resource mix. While MH is predominantly conventional hydro, the resource mix in MISO, SPC, and SPP consists primarily of coal and natural gas with increasing amounts of wind in MISO and SPP. 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 Installed Capacity[5] (ICAP). MISO and SPP 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 greater impact. Balancing Authorities 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, hydrogen production, and other electrification efforts), future load forecasts and patterns will likely change dramatically from what they are today.

Fossil-steam, combined/simple cycle gas power plants and wind turbines are susceptible to extreme cold temperatures if not properly winterized to account for these conditions. Wind turbines may also go offline due to ice buildup on blades which require the ice to melt before the turbines are brought back on-line. The extreme peak demand scenarios in Tables AB3 and AB4 examine how extreme or prolonged cold 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. This traditional methodology and assumption are used by the industry to ensure energy availability through increased dispatchable resources capacity, and to assure adequate resources 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) present 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, a new ERO Enterprise energy availability initiative is underway to review existing forecast methodology and assumptions and identify metrics and criteria for adequate energy assessments. The [Energy Reliability Assessment Task Force (ERATF)] is tasked with assessing the risks associated with unassured energy supplies, including the timing and inconsistent output from intermittent resources, fuel location, and volatility in forecasted load that can result in insufficient amounts of energy on the system to serve electrical demand. The power industry needs to develop new and enhanced forecasting methods and new metrics to evaluate energy availability that provides reliable and secure operations of the bulk power system at all times.

MH's anticipated reserve margins have reduced moderately to 15.3 percent for this winter compared to the prior winter of 18.1 percent due to increased peak demand projections and capacity exports and decreased accredited capacity. There were no changes to MH's ICAP Planning Reserve Margin Requirements (PRMR).

[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.

MISO's ICAP PRMR increased from 17.9 percent last winter to 25.5 percent for this winter based on the newly implemented seasonal capacity construct and associated modeling improvements. MISO's seasonal construct, accepted by FERC in September 2022, introduces seasonal requirements to the Planning Resource Auction (PRA) to account for the unique risk profile of each season. MISO incorporated several study improvements due to the approved seasonal construct, including updated transfer limits due to improved redispatch, seasonal outage rates, correlated hot/cold-weather outages, probabilistic distribution of non-firm support, and hourly wind and solar profiles. Additionally, newly added resources, delayed generation retirements, and lower peak demand forecast contributed to the increase in reserve margin for the 2023 winter when compared to the 2022 winter.

In 2022, SPP increased its ICAP PRMR from 12 percent to 15 percent non-coincident peak starting with the 2023 summer season. The 15 percent non-coincident peak is equivalent to a 19 percent coincident peak PRMR for the SPP assessment area. The increase is mainly attributed to the following drivers and risks:

- Influx of renewables and resulting volatility
- Generation retirements
- Increased probability of outages due to extreme temperatures and fuel supply issues
- Changing load shapes and volatility
- Persistent operational issues and capacity shortfalls in recent years

SPP reserve margins have fallen this winter because of increased peak demand projections and declining anticipated resources. Moreover, some of the resources that were available during the summer season are unavailable for the upcoming winter season based on fuel availability requirements.

SPC's 2023 winter PRMR increased to 15 percent from 11 percent in 2022 to adequately address energy risks due to changing resource mix. SPC's reserve margins have fallen this winter by about 8 percent when compared to the previous winter due to retirement of a natural gas unit (95 MW), increased peak demand projections, and planned maintenance outages.

The winter seasonal risk, which includes the cumulative impact resulting from the occurrence of multiple low-probability events, is higher than the summer season due to poor predictability of load and generation available during the winter season. The following definitions is used for the risk scenario analysis:

- **Anticipated Resources**: Existing resources plus Net Firm Transfers plus Planned resources.
- **Typical Maintenance Outages:** Historical average of generator maintenance outages 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 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 based on normal weather. This is also referred to as the 50/50 peak load forecast.
- **Reserve Margin**: The amount of generation capacity available above projected load to reliably meet expected demand.
- **Extreme Resource Derates:** Reduced capacity contribution 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 on 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
- **Operational Mitigations:** Emergency procedures that would be employed in extreme conditions (e.g., additional imports, voluntary load curtailment, voltage reductions, public appeals, and foregoing reserve requirements).

Several risk factors and criteria are used when determining the risk levels (low, medium and high) if an assessment area is likely to issue EEAs. This includes meeting the reference margin levels, the loss of load expectation and the availability of sufficient operating reserve under normal and extreme peak demand.

The anticipated resources for conventional generators are based on the ICAP, which represents physical generating capacity adjusted for ambient weather conditions while intermittent renewables, such as wind and solar, capacity contributions are based on historic average values. 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. MH, MISO, SPP and SPC have sufficient resources to meet their PRMR under normal peak winter conditions.

Assessment Area	Anticipated Resources	Normal Peak Load	Anticipated Reserve Margin	PRMR	Likelihood to issue EEAs
MH	5,332	4,623	**15.3%**	12.0%	**Low**
MISO	147,097	94,394	**55.8%**	25.5%	**Low**
SPC	4,570	3,789	**20.6%**	15.0%	**Low**
SPP	60,676	43,718	**38.8%**	16.0%	**Low**

Table AB2: Anticipated Reserve Margin Percentage with Normal Peak Load

While MISO and SPP's anticipated reserve margin shows a robust amount of excess capacity, there is still potential risk of energy shortfall based on past performance during extreme weather events as shown in Table AB4 and AB5. Based on the normal peak load forecast with typical maintenance and forced outage scenario shown in Table AB3, SPC is projecting insufficient firm generation available to meet forecasted winter peak load with typical maintenance and generator forced outages. The operating conditions indicate that SPC is at high risk for insufficient operating reserves for the normal weather forecast and would likely need to issue EEAs to implement demand response programs and/or short-term power transfers from neighboring utilities. The retirement of a natural gas unit and the increased in peak demand projections and planned maintenance outages have contributed to lower firm generation available for this winter. MH, MISO, and SPP have sufficient resources to meet their operating reserve requirements under normal peak winter 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	5,332	100	5,232	4,623	**13.2%**	**Low**
MISO	147,097	27,676	119,421	94,394	**26.5%**	**Low**
SPC	4,570	519	4,051	3,789	**6.9%**	**High**
SPP	60,676	10,600	50,076	43,718	**14.5%**	**Low**

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

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

The scenario shown in Table AB4 considers typical maintenance and forced outages combined with extreme winter peak load forecast. For this scenario, SPC is at high risk of operating below the required operating reserve requirement and would need to utilize available demand response programs, short-term power transfers from neighboring utilities, maintenance rescheduling and/or short-term load interruptions. MISO and SPP are at elevated risk for potential insufficient operating reserves in above-normal peak load conditions and would need to employ operational mitigations such as load modifying resource deployment and declaring conservative operations.

MH is at low risk of issuing EEAs since its resource mix portfolio is made of over 90 percent of conventional hydro generation which leads to low loss of load expectation when compared to other assessment areas that consists of resource with higher probability of generation forced outages.

Assessment Area	Anticipated Resources with Typical Outages	Extreme Peak Load	Reserve Margin Under Extreme Peak Load	Likelihood to issue EEAs
MH	5,232	4,909	**6.6%**	**Low**
MISO	119,421	110,278	**8.3%**	**Medium**
SPC	4,051	3,952	**2.5%**	**High**
SPP	50,076	46,718	**7.2%**	**Medium**

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

The worst-case scenario for winter 2023 considers increased resource outages and derates combined with an extreme peak load forecast as shown in Table AB5. The extreme low generation in Table AB5 shows that MISO, SPC and SPP resources fall significantly below the extreme peak load, due to extreme cold weather-related generation outages and derates. Under the extreme winter peak demand and high generation outage scenario studied, MISO, SPC and SPP would likely need to issue EEAs for operational procedures and/or emergency procedures, which may include demand response, non-firm purchases, and/or short-term load interruption.

Assessment Area	Anticipated Resources with Typical Outages + Operational Mitigations	Extreme Resource Derates	Extreme Low Generation	Extreme Peak Load	Reserve Margin Under Extreme Resource Derates and Extreme Peak Load	Likelihood to issue EEAs
MH	5,232	0	5,232	4,909	**6.6%**	**Low**
MISO	119,421	18,067	101,354	110,278	**-8.1%**	**High**
SPC	4,051	275	3,776	3,952	**-4.5%**	**High**
SPP	50,076	11,940	38,136	46,718	**-18.4%**	**High**

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

This worst-case scenario has much higher than expected generation outages and derates when combined with prolonged cold weather. These scenarios can occur as witnessed in the February 2021 winter weather event that affected the Electric Reliability Council of Texas (ERCOT), SPP and MISO areas. The extreme cold weather events of 2011, 2014, 2018 and 2021, indicate that prolonged low temperatures are happening more frequently and can jeopardize the reliable operation of the BPS. Added to this risk is an interruption in fuel supply during extreme cold weather events. Potential natural gas delivery issues in MISO and SPP could be a reliability issue for the upcoming winter. MISO and SPP continue to work with stakeholders to address fuel deliverability issues associated with extreme weather events.

Wind and Solar Resources

MISO and SPP continue to see an increase in wind and utility scale solar photovoltaic penetration in the region. Figure AB6 reflects the winter season wind and solar photovoltaic ICAP and peak capacity for each of the assessment areas. The peak capacity value is the accredited [Effective Load Carrying Capability (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.

SPP is calculating wind and solar based on historical availability during peaks and is assuming 4,500 MW wind and 90 MW solar availability for the 2023 winter.

MISO's newly implemented seasonal capacity construct, renewable resource accreditation and associated modeling improvements resulted in higher wind availability and lower solar peak capacity for the upcoming winter peak season. With all solar units having a seasonal Generator Verification Test Capacity (GVTC), the individual ICAP values are also much lower than in years past.

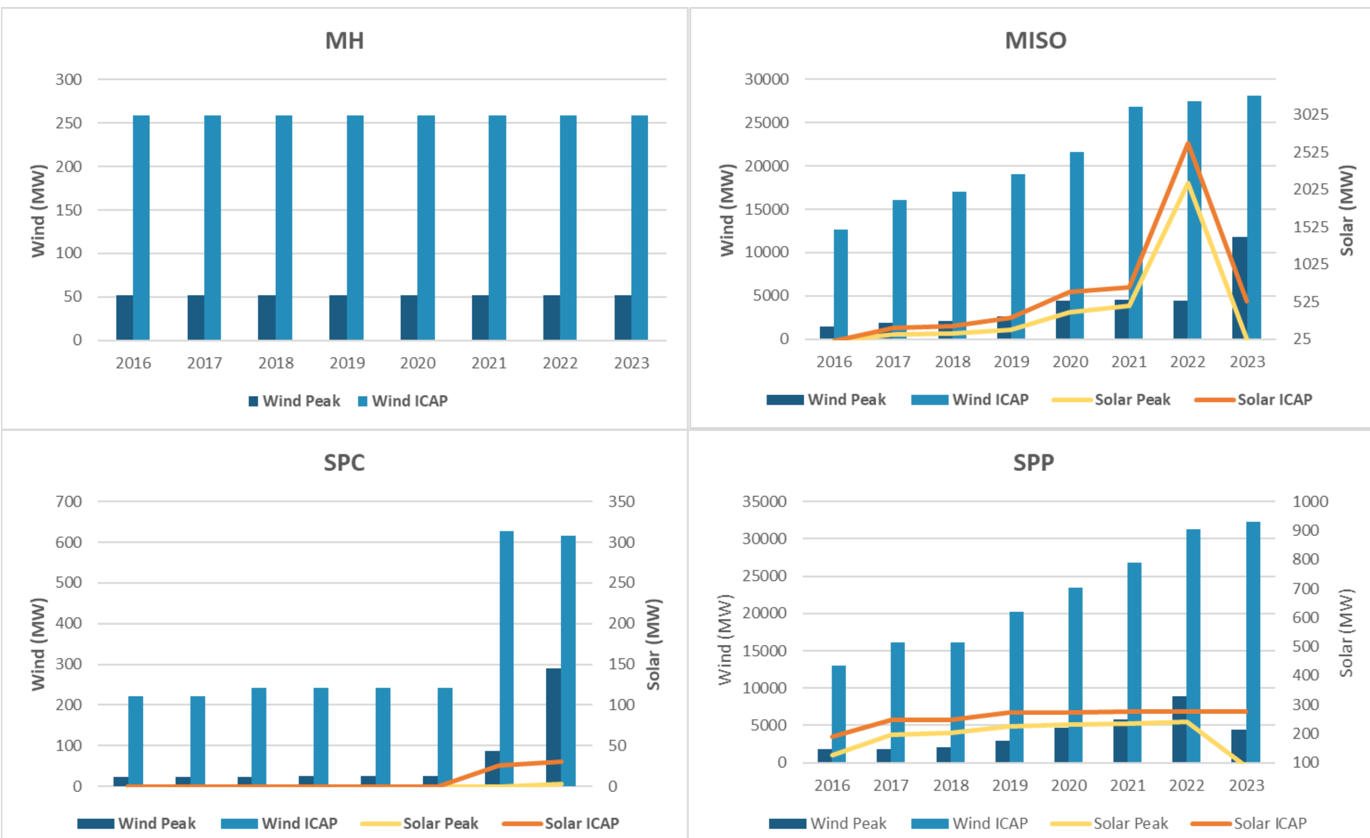


Figure AB6: Wind and Solar Photovoltaic Winter ICAP and Peak Capacity

APPENDIX C: 2022-2023 BES EVENT AND EEA DETAILS

December 30, 2022, Transmission Event

Event Category: 1.a

- # of BES facilities Interrupted: 4
- MW of Generation Lost: None
- MW of Load Lost: None

On December 30, 2022, at 11:04 a.m. CST, a B-phase to ground fault occurred within overlapping protection zones for the 345kV bus and a transmission line at the station. The transmission line protection was associated with the compromised current transformer (CT) stack responsible for the fault and thus the fault clearing time was delayed.

At a remote station, 345kV line protection for a transmission line adjacent to the faulted line overtripped due to an incorrect pilot relaying signal.

About 30 cycles later, smoke from the failed CT stack caused a phase-to-phase fault on another adjacent 345kV line. This line protection operated correctly.

The same remote station protection that had previously overreached, operated again for the second fault after a reclose from the initial overreach.

The cause of the initial fault was undetermined at the time of this publication. A similar unit was found to have experienced failed insulation in a previous event based on analysis from the manufacturer.

Three 345kV transmission lines and a 345/115kV transformer were outaged during this event.

The entity performed corrective maintenance on the pilot equipment and retested the equipment to verify correct operation after the event.

December 21, 2022 - EEA Level 2 Event

On December 21, 2022, at 3:20 p.m. CST, an RC declared an EEA2 after the loss of approximately 250 MW of generation at two different locations. The actual system load was around 3,757 MW while forecasted load was 3,722 MW for the day. The temperature was close to -22 degrees Fahrenheit.

The actual operating reserve was 292 MW of the required 300 MW for the BA.

445 MW of generation was offline/unavailable due to maintenance or derates.

150 MW of exports were curtailed.

Wind generation was also low at this time at approximately 20 MW.

At 9:20 p.m. CST, the RC was able to declare an EEA0 as loads dropped, imported 50 MW and one unit that had tripped came back online.

No firm load was shed during this EEA event.

December 23, 2022 – Two EEA Level 1 Events

On December 23, 2022, an RC issued two EEA1s due to insufficient capacity concerns. The EEA1 alerts were issued for two short periods in which the capacity declined to a level requiring notification of the interconnect.

At 8:27 a.m. CST, the RC declared the first EEA1 due to operating reserve shortages. which was terminated at 10:00 a.m. CST as load decreased.

The second EEA1 was issued at 5:20 p.m. CST and terminated at 8:20 p.m. CST.

During the first EEA1 event, the RC curtailed approximately 600 MW of non-firm exports and during the second EEA1 event, the RC curtailed approximately 1,100 MW of non-firm exports.

No firm load was shed during these two EEA1 events.

December 23, 2022 - EEA Level 2 Event

On December 23, 2022, another RC issued an EEA2 due to system conditions resulting from the extreme cold weather. Tightened system conditions with real-time transmission congestion and diminishing generation deliverability led to an EEA1 declaration at 4:22 p.m. CST to allow the entity access to emergency only generation and maximum generation from online generators. At 4:40 p.m. CST, EEA2 was declared allowing access to demand response, which reduced the peak demand. At 7:36 p.m. CST, the RC terminated the EEA2 as system conditions improved. No firm load was shed during this event.

January 11, 2023 - EEA Level 2 Event

On January 11, 2023, at 6:00 p.m. CST, an EEA2 was declared when the RC lost approximately 350 MW of generation. The loss of generation was due to an issue that tripped the units offline at one of their power plants. The actual system load was 3,409 MW while the forecasted load was 3,450 MW. The temperature was moderate for this day and wind generation was only 18 MW.

The required operating reserves were 201 MW with a requirement of 292 MW.

Approximately 741 MW of generation was offline or unavailable due to generation maintenance and derates and transmission line work when the forced outage occurred which impacted generation resource availability the BA receive.

The RC curtailed exports to 150 MW.

At 9:17 CST, the RC declared an EEA0 as generation was restored.

No firm load was shed during this EEA event.

APPENDIX D: GENERATION AVAILABILITY DETAILS

Generation unavailability can have a substantial impact on reliability. Useful metrics for generator unavailability are the EFOR and WEFOR. For the MRO region, the historical annual conventional generator WEFOR for all seasons is shown in Figure AD1 and is on an upward trend over the five-year span. 2020 had the lowest rate due to a reduction in both total demand and reductions in forced outages and derates in simple cycle generation and internal combustion engines. The increase in 2021 was partially attributed to a cold weather event that occurred in February 2021.

The steep increase in 2022 WEFOR was driven in part by extreme outage events in the winter season at the beginning (January and February) and end of the year (December - Winter Storm Elliott). This was also driven by high levels of outages in the fall primarily led by simple cycle gas turbines and a small, but heavily MW weighted increase in WEFOR of fossil steam plants. WEFOR has held relatively steady until 2022, which saw a notable increase in the last year along with event impact, attributable almost entirely to fossil steam and simple cycle gas turbines. The details of the 5-year monthly outage changes are explored below in Figure AD2.

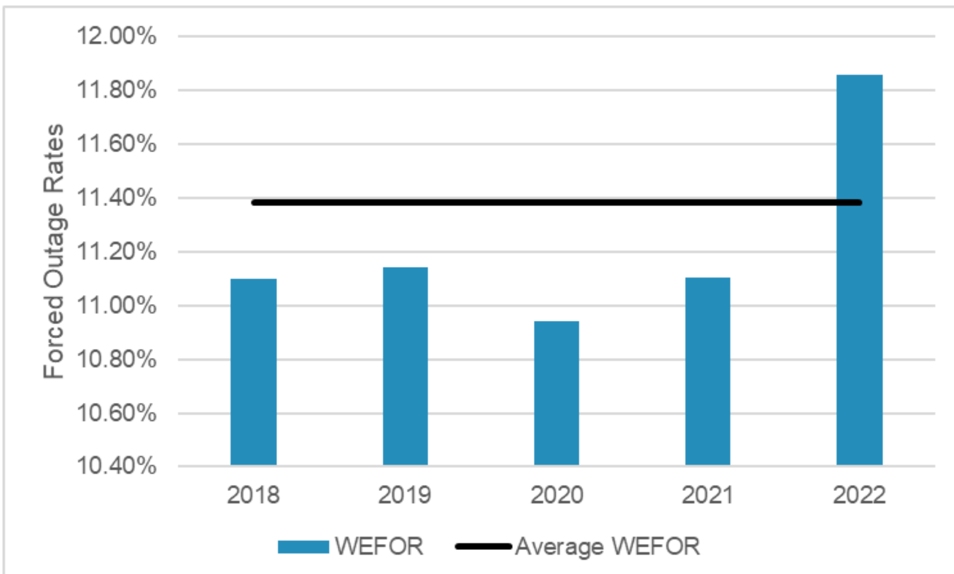


Figure AD1: MRO Annual Generator MW-Weighted EFOR

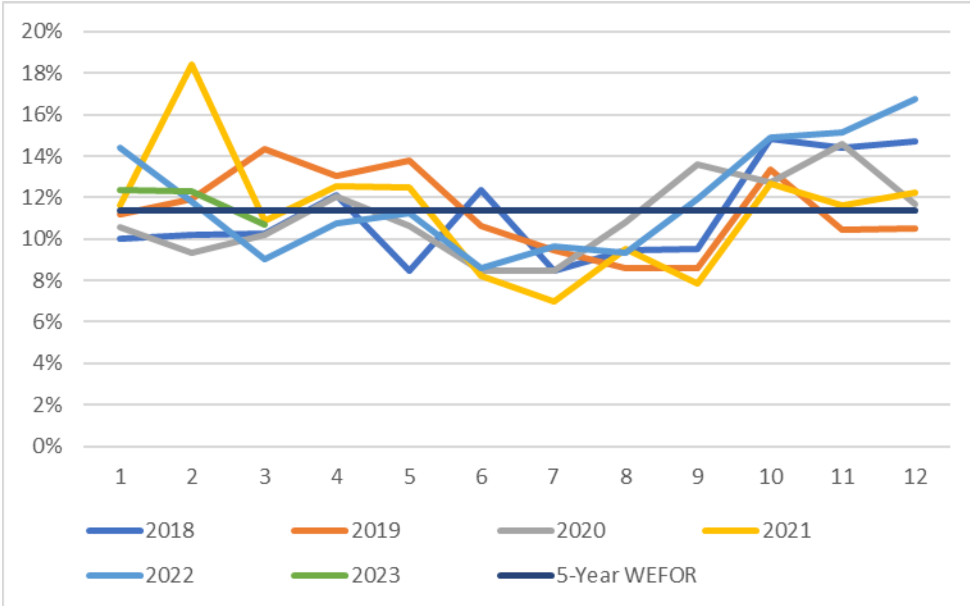


Figure AD2: MW-Weighted EFOR By Month

Figure AD3 shows the total event impact in gigawatt hours (GWh) and the number of impactful events due to forced outage, forced derate, or startup failure for each conventional unit type. The total event impact is a measure of total energy unavailable or lost due to a forced outage, forced derate, or start-up failure. The number of event impact is the unit's GWh lost per unavailability due to an event.

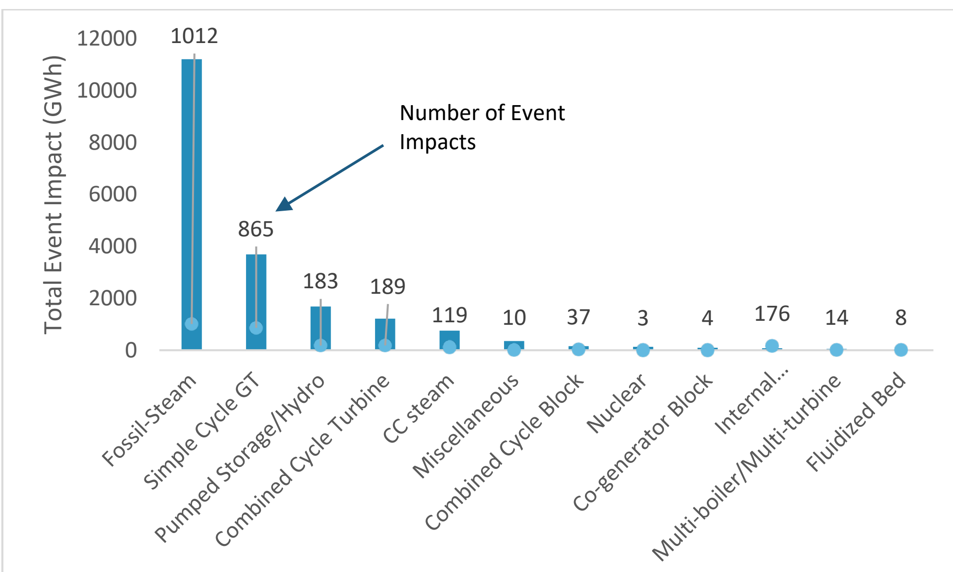


Figure AD3: Total Event Impact (GWh) and Number of Event Impact for Winter 2022

The GADS data presented in Figure AD3 is a summary of 2022 winter season and five-year historical event impact in the MRO footprint over the winter months. In this chart, even though fossil-steam generation shows a high event impact of 11,209 GWh, the total event impact of 19,451 GWh for all generation types had less impact on the BES. There was a sizable decrease in event impact in 2022 from the 2021 winter season, despite the impacts of winter storm Elliot. This is due to the previous winter's event impacts being driven by multiple high duration events, particularly among gas turbines.

Table AD4 shows the top causes of forced outages, forced derates, and startup failures by MWh lost for fossil-steam plants in winter 2022. Table AD5 shows the same information for the five-year historical winter season period.

Cause Type	Portion of MWh lost
Other high pressure turbine problems – 2 events	9.12%
Pulverizer mills – 37 events	8.65%
Rotor; General – 2 events	5.95%
Buckets or Blades C – 2 events	5.66%
Waterwall (Furnace wall) – 30 events	5.58%

Table AD4: Fossil-Steam 2022 Winter Outage Causes

Cause Type	Portion of MWh lost
Waterwall (furnace wall) – 130 events	7.44%
Plant Modifications Strictly for Compliance with new or changed regulatory requirements – 9 events	3.39%
Buckets or blades C – 3 events	3.04%
Pulverizer mills – 186 events	3.03%
Hydrogen Seals – 4 events	2.47%
Storms (ice; snow; etc.) – 71 events	2.44%

Table AD5: Fossil-Steam 2018-2022 Winter Outage Causes

Fossil steam outages were more concentrated than usual during the 2022 winter period. Other high pressure turbine problems were accounted for in two events, of which, one high duration event accounts for over 90 percent of the lost MWh. Pulverizer problems were more numerous and were not concentrated in a handful of plants. However, a high duration outage accounted for 80 percent of the MWh lost due to pulverizers. The concern of this cause being higher than the five-year average is mitigated by the fact that all but two of these events were derates that left the plant capable of producing 50 percent or more of its rated capacity. However, it also reflects issues associated with fossil-steam's high duration events. Notably in the months leading up to the winter season, fossil-steam WEFOR rose substantially above the average for those months in the five-year span, leaving the fleet diminished at the beginning of December.

General rotor outages are a cause type that do not occur frequently but have a high impact when they do. The presence of these outages is not cold-related, and the effect is concentrated in a very small number of events. These events are largely outage events and are long duration events. This explains the deviations in 2022 data from the expected largest cause code in the five-year data, Waterwall. This cause is common and expected and is well distributed across both the fleet and geographically. Five-year data indicates that storms were a small portion of cause codes and top cause codes over the span were not closely related to cold.

This is borne out by the relative stability of EFOR and WEFOR over the course of the year. Fossil-Steam plants do still experience an increase in WEFOR and event impact in the winter months, with marked increases in WEFOR and event impact in the 2022 winter season. However, this issue is distributed, suggesting that events during the winter months are increased not due to specific cause codes. The ambient stresses of cold and winter weather seem to exacerbate the existing behavior of high event impact being driven by both the plants' large size and diverse, abstract problems like age.

Table AD6 shows the top causes of forced outage, forced derate, and startup failure by MWh lost for simple cycle gas turbines in the 2022 Winter. Table AD7 shows the same data for the five-year historical winter period.

Cause Type	Portion of MWh lost
Lack of fuel: Contract of Tariff allows for interruption – 238 events	27.05%
Engine vibration – 4 events	11.42%
Lack of fuel: Physical failures of fuel supply or delivery/transportation of fuel – 45 events	4.49%
High Pressure blades/buckets C – 1 event	4.08%
12kV generator circuit breakers – 4 events	4.02%

Table AD6: Simple Cycle Gas Turbine 2022 Winter Outage Causes

Cause Type	Portion of MWh lost
Lack of fuel: Contract or tariff allows for interruption – 1075 events	19.98%
Other miscellaneous gas turbine problems – 66 events	7.29%
Lack of fuel: Physical failures of fuel supply or delivery/transportation of fuel – 197 events	6.12%
Main transformer – 17 events	6.05%
Engine vibration – 25 events	5.77%

Table AD7: Simple Cycle Gas Turbine 2018-2022 Winter Outage Causes

The 2022 winter had substantially less impactful events than during the previous 2021 season. However, like fossil-steam, there were ongoing events that lead to high WEFOR in the months prior. This effect was more substantial among simple cycle gas turbines. Outages due to engine vibration have longer outage duration resulting in higher MW lost hours, even though there were only four events. This cause also does not seem to correlate well with seasonal effects and was contained to a single plant in the 2022 season. Similarly, outages due to high pressure blades/buckets have high outage duration. Outages caused by 12kV generator circuit breaker issues are not historically a high duration event, but in the 2022 season a single extreme duration event accounted for over 99 percent of MWh lost due to this cause. Outages with fuel cause codes on the other hand are consistent with the top causes of portion of MWh lost over the five-year winter season.

There was a sizable increase in WEFOR in December largely due to the spike in lack of fuel. December 2022 was only the third highest WEFOR for simple cycle gas turbines over the span, but still greatly elevated over the fleet average and the generator class average for both the year and the five-year winter season. Lack of fuel continues to be the largest concern for this generation class, especially during extreme weather events like what was experienced during Winter Storm Elliot.

Winter season forced outage, forced derate, and startup failure causes for other types of generation is provided below.

Cause Type	Portion of MWh lost
Circulating water valves – 2 events	69.16%
Fuel piping and valves A – 5 events	7.77%
Lack of fuel: Physical failures of fuel supply or delivery/transportation of fuel – 17 events	3.26%
Other HRSG tube problems – 1 event	3.20%
Chamber A – 2 events	2.31%

Table AD8: Combined Cycle Gas Turbine 2022 Winter Outage Causes

Cause Type	Portion of MWh lost
Stator windings; bushings; and terminals – 3 events	23.21%
Fuel piping and valves A – 25 events	15.15%
Circulating water valves – 2 events	12.85%
Lack of fuel: Contract or Tariff allows for interruption – 40 events	4.11%
Storms (ice; snow; etc.) – 46 events	3.29%

Table AD9: Combined Cycle Gas Turbine 2018-2022 Winter Outage Causes

Cause Type	Portion of MWh lost
Circulating water valves – 1 event	51.33%
Other auxiliary steam problems – 2 events	7.76%
Gas burner piping and valves – 4 events	6.99%
Fuel piping and valves A – 3 events	3.42%
Hot end inspection B – 2 events	3.41%

Table AD10: Combined Cycle Steam 2022 Winter Outage Causes

Cause Type	Portion of MWh lost
Stator windings; bushings; and terminals – 3 events	21.14%
Fuel piping and valves A – 12 events	9.95%
Circulating water valves – 1 event	8.90%
Lack of fuel: Contract or Tariff allows for interruption – 22 events	2.96%
Storms (ice; snow; etc.) – 26 events	2.84%

Table AD11: Combined Cycle Steam 2018-2022 Winter Outage Causes

Cause Type	Portion of MWh lost
Power Station switchyard (non-generating unit equipment) – 7 events	25.31%
Stator windings; bushings; and terminals – 2 events	23.75%
Emergency generator trip devices – 1 event	9.04%
Other runner problems – 2 events	8.77%
Other miscellaneous hydro turbine/pump problems – 2 events	6.00%

Table AD12: Hydro 2022 Winter Outage Causes

Cause Type	Portion of MWh lost
Stator windings; bushings; and terminals – 17 events	10.51%
Emergency generator trip devices – 11 events	8.52%
Rotor windings (including damper windings and fan blades on hydro units) – 8 events	4.20%
Power Station switchyard (non-generating unit equipment) – 9 events	3.66%
Other runner problems – 5 events	3.58%

Table AD13: Hydro 2018-2022 Winter Outage Causes

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. DC transmission circuit miles were not included since there are so few outages.

100-199-kV		200-299-kV		300-399-kV		400-599-kV	
Circuits	Miles	Circuits	Miles	Circuits	Miles	Circuits	Miles
3372	47077	419	14210	516	18826	9	1001

Table AE1: AC Transmission Circuit Miles

Figure AE2 shows the number of 100kV and above automatic outages that include both momentary (for 200kV and above) and sustained outages for the 2018-2019 through 2022-2023 winter seasons. There were very few 400-599kV outages during the 2018-2023 winter seasons.

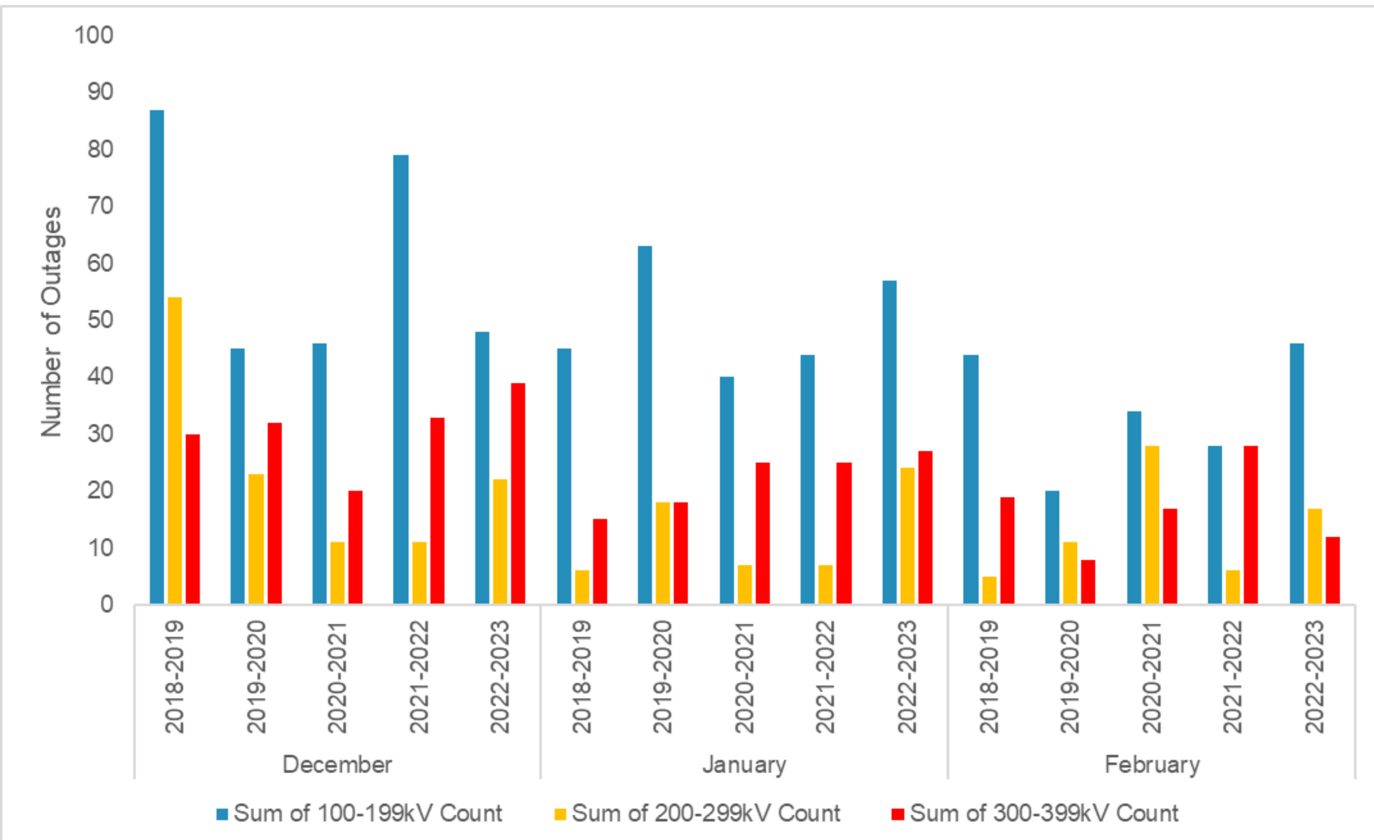


Figure AE2: Winter Automatic Outages by Month

Figure AE3 shows the causes of momentary outages for the past five winter seasons. 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. The chart illustrates a significant number of momentary outages have an unknown cause. This suggests that thorough line inspections after transient faults are not typically performed after clear weather operations. It may also suggest that even if an inspection is performed, a definitive cause for many transient faults cannot be determined. The chart shows that for the current period the number of momentary outages with a unknown cause is significantly lower than the previous period. The chart also shows that the second leading cause of momentary automatic outages is weather-related and most likely due to galloping.

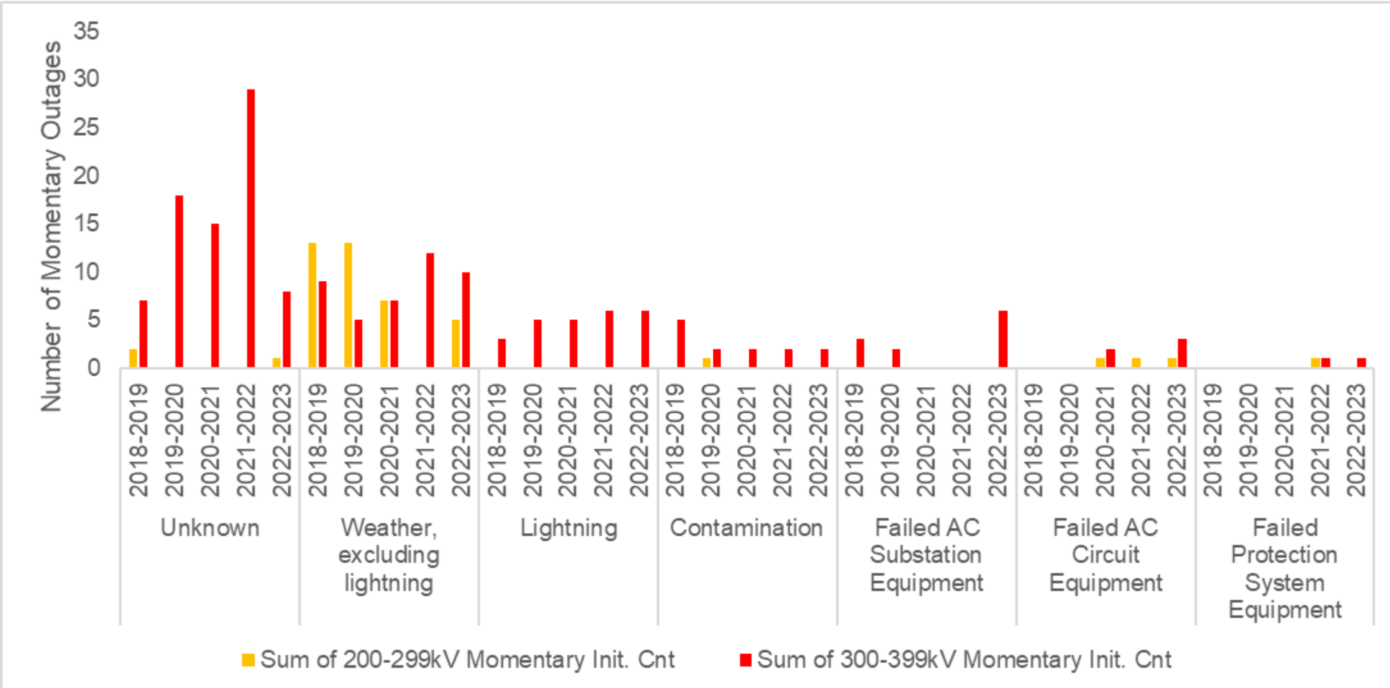


Figure AE3: Winter Momentary Outages by Cause

Figure AE4 shows the causes of sustained outages for the 2018-2019 through 2022-2023 winter seasons. The chart shows that failed AC circuit equipment, weather (excluding lightning), other, and failed AC substation equipment continue to be major contributors to sustained outages during the winter seasons. The graph shows that for the 2022-2023 period, weather, excluding lightning, is higher than any of the other previous winter periods.

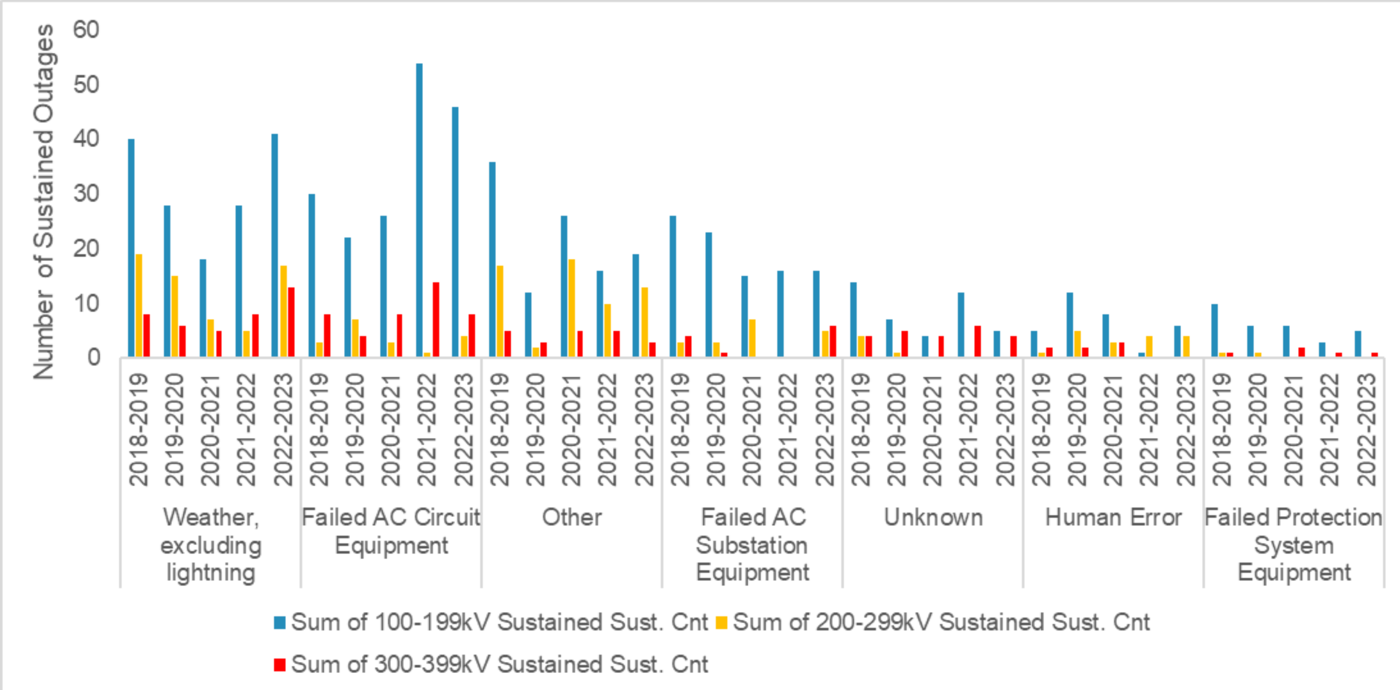


Figure AE4: Winter Sustained Outages by Cause

Figure AE5 reflects the yearly winter total outages per 100 circuit miles for 100-399kV circuits. The chart clearly shows an increase in outages during the 2021-2022 winter season in the 100-199kV and 300-399kV voltages. This is largely due to the derecho that swept through the MRO region on December 15-16, 2021. Those two days attributed to fifty-seven (57) 100-199kV outages, which is 35 percent of the outages reported for that voltage range, and twenty (20) 300-399kV outages, which is 22 percent of the outages reported for that voltage range.

There were several winter storms that impacted the number of outages in the MRO region for the 2022-2023 winter season. On December 13-15, 2022, a blizzard swept through the northern and north central region of MRO. There were 48 outages during that period, which accounts for 44 percent of all outages for the month of December. During winter Storm Elliot (December 21-26) there were 23 outages reported in the MRO region.

In addition, 23 outages were reported between January 1-4, 2023, as a winter storm traveled through the central portion of the MRO region. Again, 46 outages were reported between January 18-23 from 2 storms that traveled through the MRO region. The first one began in the southern portion of the region and traveled northeast and the second one traveled across the southern portion. Finally, a storm on February 26-27 resulted in 26 outages as it traveled across the central and northern parts of the region.

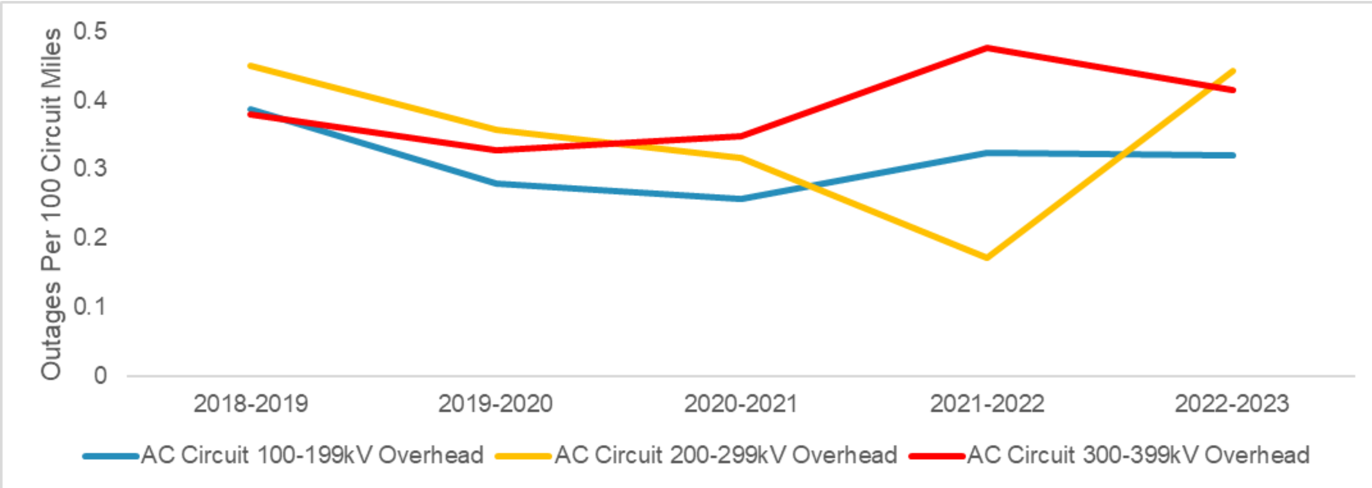


Figure AE5: Total Transmission Outages per 100 Circuit Miles