# 2022 MRO REGIONAL WINTER ASSESSMENT

**December 5, 2022**

MIDWEST RELIABILITY ORGANIZATION

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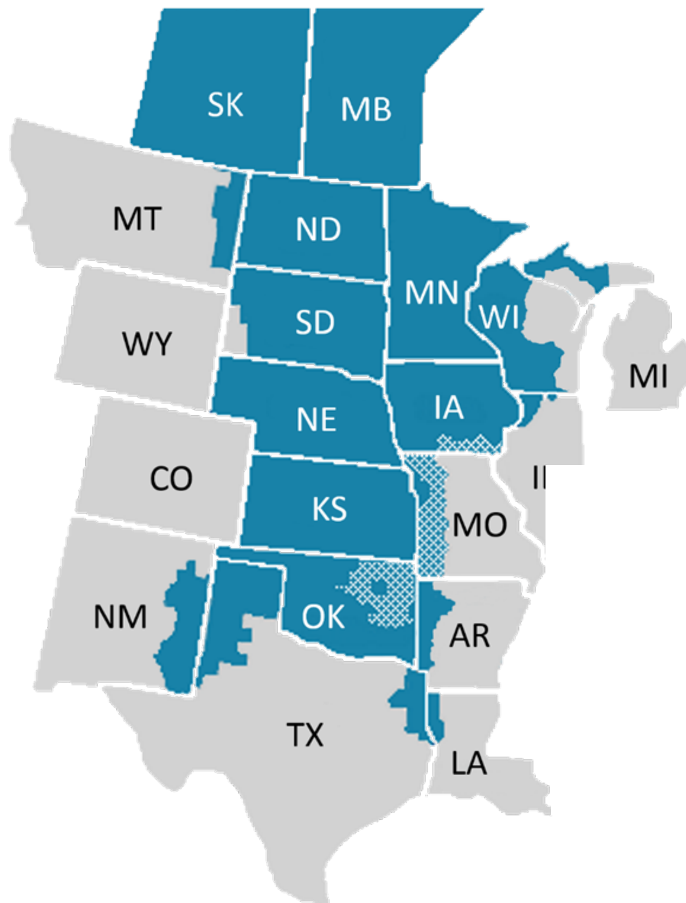
# PREFACE

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

MRO's 2022 Regional Winter Assessment (RWA) helps to inform key stakeholders of projected reliability concerns 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 reliability challenges that present a greater risk within MRO's regional footprint. MRO's RWA is unique in that it also includes a review of historical regional bulk power system performance during the 2021 winter season to identify trends that might impact system reliability during future winter seasons.

The 2022 RWA focuses on the winter months and provides an evaluation of resource and transmission system adequacy needed to meet projected winter peak demands during this timeframe. The historical performance data used in this assessment is collected from registered entities in MRO's regional footprint each quarter and analyzed by staff. The resource and transmission system adequacy information is collected and assessed for the respective footprints of 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).

## Key Findings

- MISO is projecting insufficient capacity available to meet forecasted seasonal peak load with typical maintenance and forced outages this winter and could require implementation of operating mitigations such as load modifying resources or non-firm imports to meet reserve requirements. Extreme winter conditions may result in insufficient capacity to cover anticipated extreme winter peak demands, placing MISO at high risk of implementing Energy Emergency Alerts (EEAs).
- Generation lost during forced outages could increase the risk of operating reserve shortages in SPC during peak load times. Extreme winter conditions, combined with large generation forced outages, would likely require SPC to use available demand response programs, short-term power transfers from neighboring utilities, maintenance rescheduling, and/or short-term load interruptions.
- MH and SPP anticipate resources are sufficient to meet reserve margin requirements under normal and extreme demand for the 2022 winter season. While SPP's reserve margin shows a robust amount of excess capacity, there is still potential risk of capacity shortfall in SPP based on past performance during extreme weather events.
- Potential coal delivery issues in MISO and SPP could be an emerging reliability concern for the upcoming winter. Conservation efforts are underway for plants experiencing lower coal stock during abnormal fuel supply or transportation limitations.
- Conventional generation MW-Weighted Equivalent Forced Outage Rates (WEFOR) for 2019 and 2021 were higher than the four-year moving average.
    - Long-term trends continue to indicate increasing generation forced outage rates due to component fatigue and an aging fleet. This is due in part to higher penetrations of intermittent resources that cause conventional generation to cycle more, causing component failures.
    - Continuing to monitor these long-term trends more closely during peak load periods is crucial and essential to reliability of the power grid.

## Recommendations

To reduce the risks of energy shortfalls on the bulk-power system (BPS)[1] this winter, MRO recommends the following:

- **Industry:** Review NERC level 2 alert related to cold weather preparedness and participate in MRO's voluntary Generator Winterization Program.
- **Industry:** Maintain situational awareness of unplanned generation outages and low wind forecasts and employ operating mitigations when needed during extreme weather conditions.
- **Industry:** 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.
- **Regulators:** Preserve critical generation resources at risk of retirement ahead of the winter season to maintain reliability.
- **Regulators:** Understand requests for environmental and transportation waivers that place fuel at risk.
- **Regulators:** Support electric load and natural gas distribution company conservations and public appeals during emergencies.

[1] Bulk-power system means (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability.

# PURPOSE

The purpose of this report is to provide information on, and raise awareness of, reliability challenges, concerns, and trends in an effort to assist industry stakeholders and key decision-makers with reducing risk to the regional BPS.

MRO staff annually assesses the Reliability Coordinator (RC) and Planning Coordinator (PC) areas within the region to determine reliability and resource adequacy of the BPS. PCs are the entities responsible for integrating transmission facilities, service plans, resource plans, and protection systems to ensure reliability needs are met. PCs collaborate with Transmission Planners to assess resource and transmission impacts within an interconnected area. RCs are responsible for the real-time reliable operation of the BPS and have a wide area view of the system. RCs are the highest level of real-time operating authority within a designated footprint. The four PCs within the MRO region are MH, MISO, SPC, and SPP. The three RCs within the MRO region are 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.[2] MRO's 2022 RWA is an independent staff assessment that utilizes some of the same data as NERC's 2022 Winter Reliability Assessment (WRA) and NERC's Long-Term Reliability Assessment (LTRA), with a more targeted focus on MRO's regional footprint. In addition to providing an evaluation of previous seasonal performance, this assessment also identifies reliability concerns for the upcoming 2022 winter season.

Sources of information for this assessment include MRO Performance Analysis (PA) data from the ERO Generating Availability Data System (GADS), Transmission Availability Data System (TADS), Misoperation Information Data Analysis System (MIDAS), Event Analysis (EA), and the NERC Reliability Assessments. It is important to note that MISO 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 MISO area and reviews it jointly with RF and SERC for NERC reliability assessments.

In contrast, the review of PA data for MISO includes only the MRO portion of the MISO footprint. MRO is responsible for collecting and reviewing both PA data and NERC reliability assessment information for the entire MH, SPC, and SPP PC footprints.

Figure C1 illustrates the North American assessment areas and Figure C2 shows the North American Regional Entity footprints that are separate from the assessment areas.

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

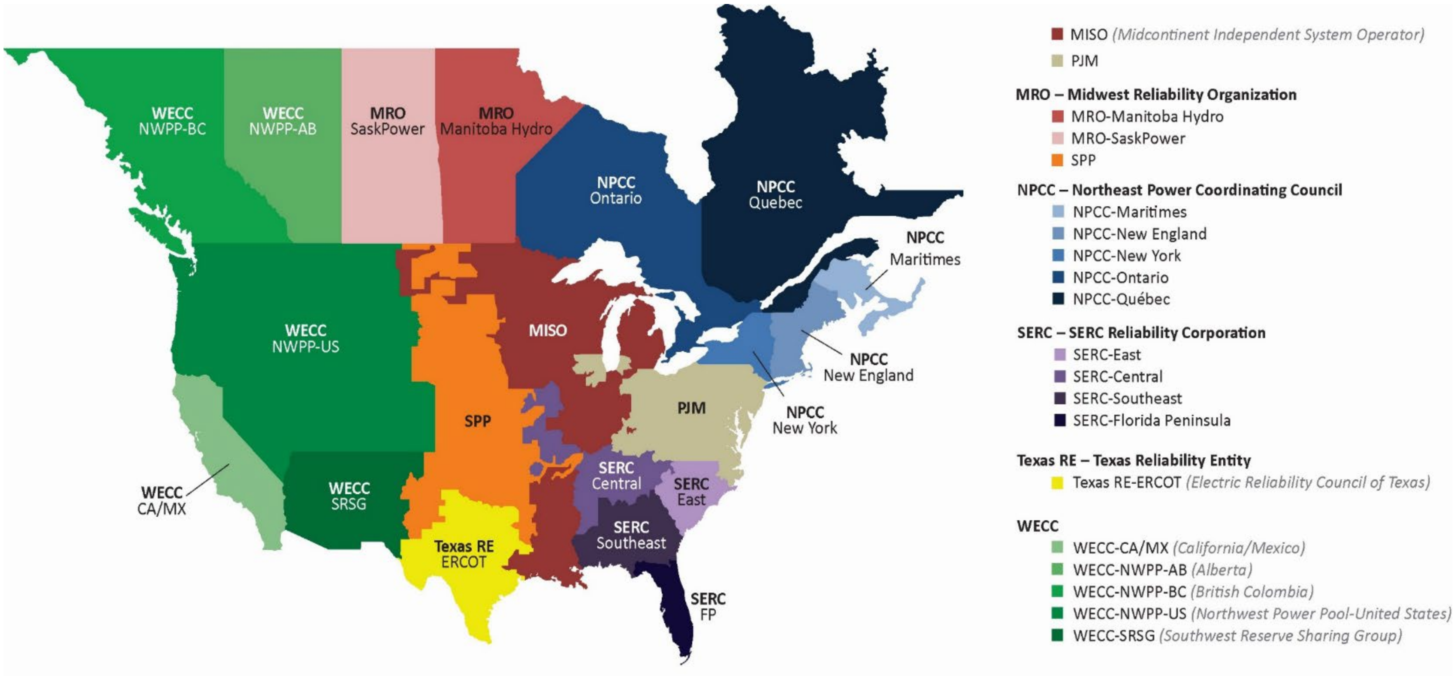



**Figure C1: NERC Assessment Areas**

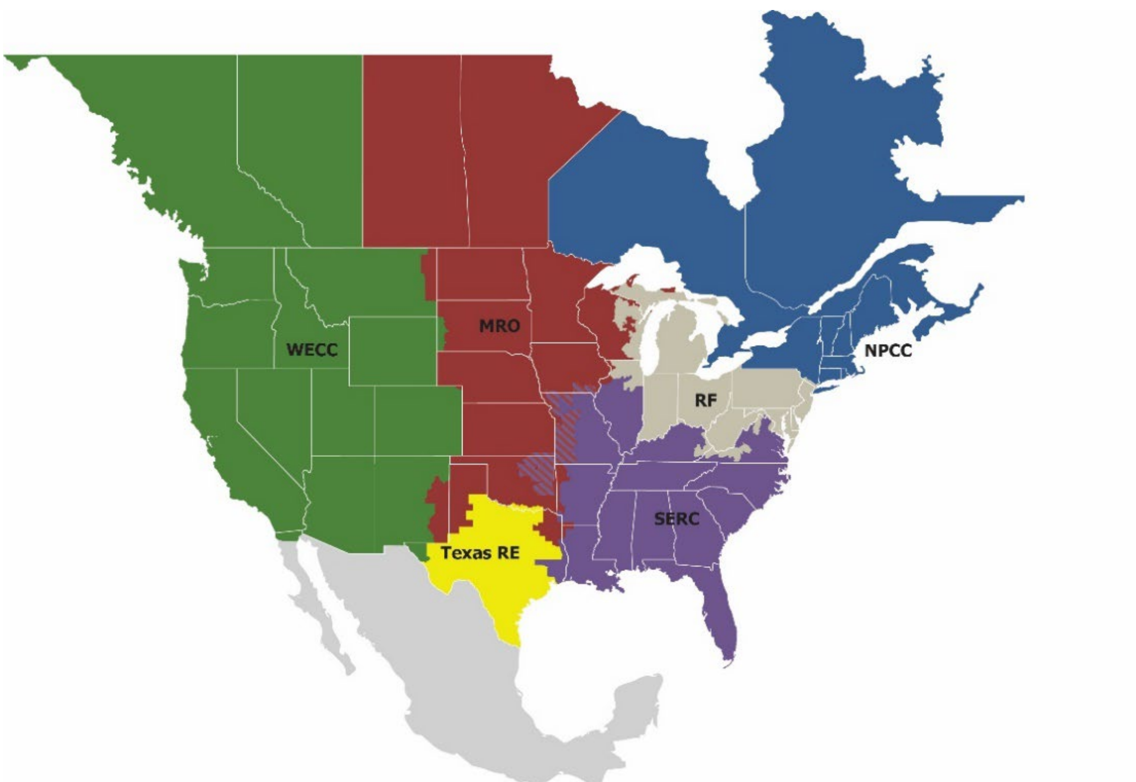



**Figure C2: Regional Entity Boundaries**

# MRO REGISTRATION AND CERTIFICATION

## Registration

There are 232 registered entities on the NERC Compliance Registry (NCR) in the MRO region. These entities have been deemed material to the reliability of the BPS. Functional types/scopes define the criteria each function performs, as owners, operators and users of the BPS. The number of registered entities on the NCR ebbs and flows with the addition of new entities and changes to the operational structure and function of existing entities. The registration process is fundamental to both enforcement of mandatory reliability standards and the performance of reliability assessments as it determines the entities that pose a material risk to the BPS and which entities MRO will be working closely with.

Reliability Coordinators (RC), Balancing Authorities (BA), Transmission Operators (TOP), Generator Owners (GO) and Generator Operators (GOP), play an important role during winter weather operations by providing accurate operational data for analysis. The trend over the past five years demonstrates minimal growth in all functions except GO/GOP. Over this period, MRO has registered approximately 60 additional (roughly 30 each) GOs and GOPs related to new facility and/or ownership changes. The increase in registered GOs and GOPs can be attributed to the changing resource mix. Generation data provided by GOs and GOPs is crucial to the accuracy in the TOP, BA and RC's planning and real-time operations models and critical to reliability.

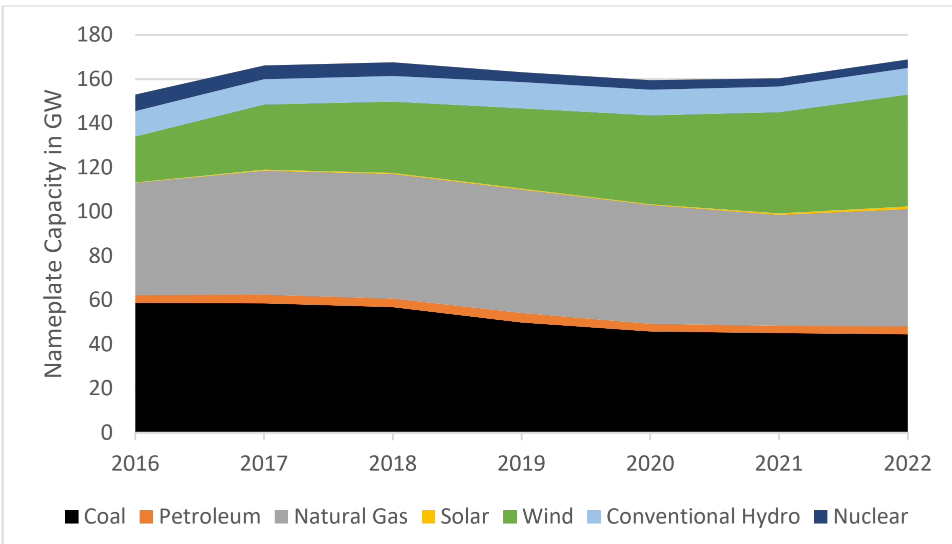



**Figure D1: MRO Historical Resource Mix by Fuel Types**

## Certification

Real-time actions of RCs, TOPs, and BAs impact the reliable operation of the bulk power system. Certification activities provide regional assurance that the processes, procedures, tools, and training an 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. 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 five-year period and has averaged five Certification review activities per year. This seasonal reliability assessment directly focuses on RCs, TOPs and BAs, specifically as it relates to data collected during performance analysis, event analysis, and situational awareness activities, which focus on the performance of Bulk Electric System (BES) elements, which is all Transmission Elements operated at 100kV or higher and real power and reactive power resources connected at 100kV or higher.

## MRO GENERATOR WINTERIZATION PROGRAM

Major interruptions to resources, transmission paths and ultimately, end-use customers were results of the most recent extreme cold weather events. Assessing operating practices and identifying recommended improvements for resource/generator cold weather preparedness is foundational to MRO's Generator Winterization Program (GWP). 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 reduce weather-related risks. The program is categorized as a technical engagement/activity aimed to enhance outreach and actions to incent reliable generator performance to help prevent a reoccurrence of large scale unplanned outages due to cold weather. The NERC Alert R-2022-09-12-01 Cold Weather Events II provides specific actions that MRO registered entities should consider when preparing for extreme cold weather.

MRO introduced its GWP in 2021, and at that time focused on identifying preparations an entity was taking to winterize its facilities and confirm whether or not participating entities had an established winterization program/plan. Due to COVID travel restrictions, MRO selected ten northern facilities with ten different owners to survey. In addition, completed a site visit for four of the ten sites local to the St. Paul, Minnesota area. MRO found not all of the entities had an established program/plan. Regardless, some winter preparation activities were taking place. All of the entities with incomplete winterization programs/plans indicated they were working to formalize and/or finalize these programs /plan. Survey results revealed the prevention of critical components from freezing was the highest priority. Heat tracing and insulation were identified as the most popular preventative measures.

The focus of MRO's GWP this year moved beyond identifying winter weather programs/plans to evaluating the level of readiness and the program/plan's effectiveness. The joint inquiry issued on the January 17$^{th}$, 2018 Cold Weather Event was a call to action for many entities based on the large amount of generation capacity that was lost due to below average temperatures. Four years later it is imperative that an entity has taken actions to improve its cold weather reliability and is prepared for the Project 2019-06 cold weather standards that become effective Q2 of 2023. MRO surveyed and conducted on-site visits with six different entities in 2022. With COVID travel restrictions lifted, this allowed MRO to expand the site visits in terms of number of visits and geographic area based on the GADS data and the entities willingness to participate. All six entities were found to have established actions of readiness to prepare for the cold weather season and reliability impacts. In addition, all six were able to provide a documented program/plan. The level of effectiveness varied when focusing on the seven key components described in NERC's Reliability Guideline: Generating Unit Winter Weather Readiness – Current Industry Practices – Version 3.

Regardless of the location and design of the facility, cold weather can have an impact on the reliability of a generator. The entities surveyed expressed similar concerns related to original equipment manufacturer (OEM) minimum designed or operating temperatures that are difficult to determined, answering what constitutes an actionable and/or severe temperature versus extreme temperatures and how to gauge what will be sufficient for the upcoming effective standards. Winterization outreach resources are available on the MRO Generator Winterization Program (GWP) web page. A summary report of MRO's GWP 2021-2022 findings is planned to be published in 2023.

# 2022 WINTER SEASONAL FORECAST

The 2022 winter seasonal forecast focuses on the months of December 2022 through February 2023.

## Anticipated Winter Resource and Peak Demand Scenario

Peak demand (or load) is the highest electrical power demand that has occurred over a specified 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 winter or summer due to higher heating or cooling usage. Figure F1 below illustrates the 2022-2023 anticipated and six-year historical generation by fuel type at the time of winter peak for each of the PCs in the MRO region:

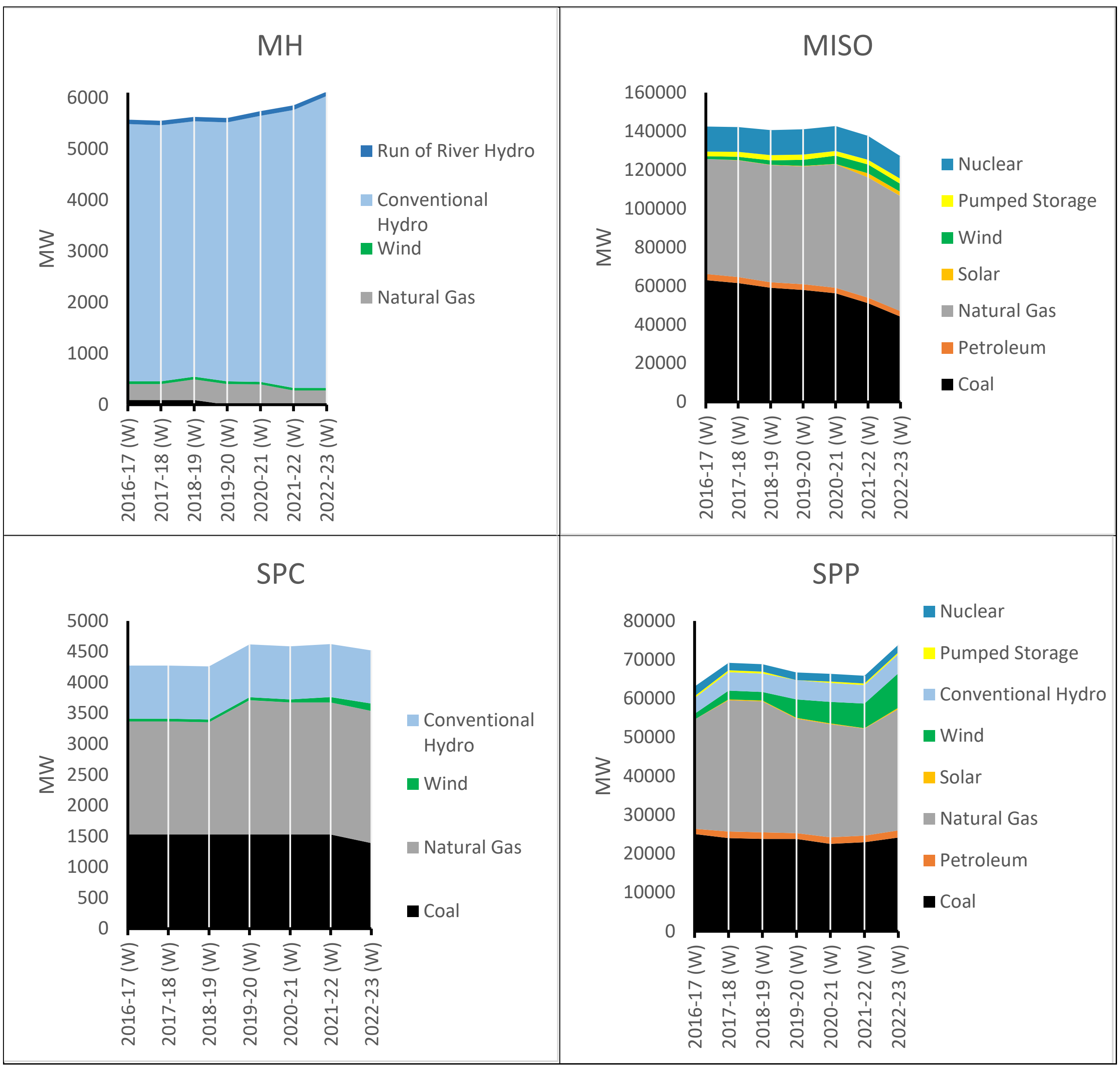



**Figure F1: Generation by Fuel Type at Time of Winter Peak**

Each PC has a slightly 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 the electric capacity output of wind depends on weather conditions, on-peak wind capacity contributions are average values and can be substantially less than nameplate capacity. For this reason, MISO and SPP wind capacity contribution is accredited at much lower values than the total existing nameplate capacity.

Impacts from new technology and resource types could create reliability challenges in the near future for the MRO region. Rooftop solar, demand response, and other distributed behind the meter generation resources will have a dramatic impact on the load shape. When coupled with the anticipated increase in demand (e.g., electric vehicle charging), future load patterns will likely be dramatically different from what they are today.

Fossil-steam, combined cycle gas power plants and wind turbines are susceptible to extreme cold temperatures when not properly winterized and without cold weather packages installed. Wind turbines are also susceptible to ice buildup on blades that needs to melt off before the turbines are available for use. The extreme peak demand scenarios in Table F2 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 that are 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 outage 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 extreme peak load weather forecast methodology is used to model the reliability risk of the actual system peak exceeding the 50/50 forecasted value due to load forecast uncertainty. This traditional methodology and assumption is used by the industry to ensure energy availability through increasing capacity and reserve margins to assure adequate resources during higher than anticipated peak demand. However, recent increases in extreme weather events 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 secure (like wind and solar). As a result, a new energy availability initiative is currently 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 variable renewable energy resources, fuel location, and volatility in forecasted load, which can result in insufficient amounts of energy on the system to serve electrical demand. The power industry needs to develop new and enhanced methods to evaluate energy availability that will provide reliable and secure operations of the BPS at all times throughout the year.

The winter seasonal risk scenario, 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. Tables F1 and F2 show the risk scenarios if peak demand exceeds forecast using the following NERC reliability assessment definitions:

- **Anticipated Resources**: Existing resources plus Net Firm Transfers plus Planned resources.
- **Typical Maintenance Outages:** Historical average of 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 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).
- **Net Internal Demand**: Total of all end-use customer demand and electric system losses within specified metered boundaries, reduced by the projected impacts of Controllable and Dispatchable Demand Response programs.
- **Reserve Margin**: The amount of generation capacity available above projected load to reliably meet expected demand.
- **Extreme Derates:** Reduced capacity contribution due to generator resource performance in extreme conditions (e.g., 90/10 or Polar Vortex forecasted load; or based on severe historical events).
- **Extreme Peak Load:** Sum of Net Internal Demand and seasonal load adjustment on extreme weather conditions (e.g., 90/10 or Polar Vortex forecasted load; or based on severe historical events).
- **Extreme Low Generation**: Anticipated Resource minus Outages/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).

The anticipated resources are based on the Installed Capacity (ICAP), which represents physical generating capacity adjusted for ambient weather conditions. Table F1 displays anticipated reserve margins with typical maintenance and forced outages and normal forecast for each assessment area. The net internal demand projections are based on normal 50/50 weather forecasts and are provided on a coincident[3] basis for the assessment areas.

Based on the normal weather forecast with typical maintenance and forced outages as shown in Table F1, MISO is projecting insufficient firm generation available to meet forecasted winter peak load. The operating conditions indicate that MISO is at increased risk to implement operating mitigations such as load modifying resources or non-firm imports to meet the 17.9 percent of planning reserve requirements under normal peak winter conditions. Supply conditions in MISO have tightened since last winter as a result of a decrease in peak generation capacity when compared to the 2021 winter season. This is primarily due to the retirement of approximately 4.2 GW of coal and nuclear generation resources. Projected shortfalls will continue without an increase in reliable generation supply.

Having a mechanism in place to prevent or delay retirement of generators needed to maintain reliability, including the management of energy shortfall, would temporarily mitigate potential risks of insufficient energy supplies during peak winter conditions until new reliable resources are available. Maintaining a higher reserve margin requirement will also compensate for declining energy margins.

MH, SPC, and SPP have sufficient resources to meet their reserve requirements under normal peak winter conditions.

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

| Assessment Area | Anticipated Resources | Typical Maintenance and Forced Outages | Anticipated Resources with Typical Outages | Net Internal Demand | Anticipated Reserve Margin with Typical Outages | Reserve Margin Requirements |
|---|---|---|---|---|---|---|
| MH | 5,418 | 85 | 5,333 | 4,588 | **16.2%** | 12.0% |
| MISO | 141,565 | 28,818 | 112,747 | 98,939 | **14.0%** | 17.9% |
| SPC | 4,779 | 249 | 4,530 | 3,714 | **22.0%** | 15.0% |
| SPP | 70,772 | 10,600 | 60,172 | 41,637 | **44.5%** | 16.0% |

**Table F1: Anticipated Reserve Margin with Typical Outages and Normal Forecast**

Forced outages during the winter season could increase the risk of operating reserve shortages in SPC during peak load times depending on the amount of generation lost. During extreme winter weather conditions, combined with large generation forced outages, SPC would utilize available demand response programs, short-term power transfers from neighboring utilities, maintenance rescheduling and/or short-term load interruptions. While SPP's reserve margin shows a robust amount of excess capacity from added generation (natural gas and wind) since last winter, there is still potential risk of capacity shortfall in SPP based on past performance during extreme weather events.

The worst-case scenario for winter 2022 considers increased resource outages and derates combined with an extreme peak load forecast as noted in Table F2.

The reserve margin percentage in Table F3 determines the likelihood to issue EEAs and is calculated using the difference between extreme low generation plus operational mitigations and extreme peak load.

| Assessment Area | Anticipated Resources with Typical Outages | Extreme Derates | Extreme Low Generation | Operational Mitigations | Extreme Low Generation + Operational Mitigations | Extreme Peak Load |
|---|---|---|---|---|---|---|
| MH | 5,333 | 0 | 5,333 | 0 | 5,333 | 4,882 |
| MISO | 112,747 | 17,624 | 95,123 | 2,400 | 97,523 | 105,513 |
| SPC | 4,530 | 123 | 4,407 | 0 | 4,407 | 3,914 |
| SPP | 60,172 | 11,940 | 48,232 | 0 | 48,232 | 44,137 |

**Table F2: Extreme Winter Resource and Peak Demand Scenario (in MWs)**

| Assessment Area | Extreme Low Generation + Operational Mitigations | Extreme Peak Load | Reserve Margin Under Extreme Conditions | Likelihood to issue EEAs |
|---|---|---|---|---|
| MH | 5,333 | 4,882 | **+9.2%** | Low |
| MISO | 97,523 | 105,513 | **-7.6%** | **High** |
| SPC | 4,407 | 3,914 | **+12.6%** | Low |
| SPP | 48,232 | 44,137 | **+9.3%** | Low |

**Table F3: Reserve Margin Percentage under Extreme Winter Conditions**

The extreme low generation plus operational mitigation scenario in Table F3 above shows that MISO resources fall significantly below the extreme peak load, due to extreme outages and derates. Under the extreme winter peak demand and high generation outage scenario studied, MISO would likely need to issue EEAs or max-gen alerts, as well as employ operating mitigations such as demand response, non-firm purchases, and short-term load interruption.

This worst-case scenario has much higher than expected generation outages and derates (partial outage with an associated reduction in capacity) when combined with prolonged cold weather. These types of outages can occur at the same time as witnessed in the February 2021 winter weather event. The extreme cold weather events of 2011, 2014, 2018 and 2021 indicate that prolonged low temperatures are happening more frequently in places where reliable operation of the BPS may be jeopardized.

Added to this risk is an interruption in fuel supply during cold weather events. The potential coal delivery issues in MISO and SPP and the impacts of supply chain disruptions could be an emerging reliability issue for the upcoming winter in MRO's region. Efforts are underway to conserve coal at plants experiencing lower coal stock during abnormal fuel supply or transportation limitations.

## Wind and Solar Resources

MISO and SPP continue to see an increase in wind and utility scale solar photovoltaic penetration in the region. Figure F2 reflects the winter installed wind and solar photovoltaic nameplate 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[4] 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, at times much lower than the nameplate value.


**Figure F2: Wind and Solar Photovoltaic Nameplate and Peak Capacity**

[4] Garver, L. L. (1966) “Effective Load-Carrying Capability of Generating Units.” IEEE Transactions on Power Apparatus and Systems. Vol PAS-85.

## Distributed Energy Resources

The NERC DER Report defines Distributed Energy Resources (DER) as any resource on the distribution system that produces electricity and is not included in the NERC definition of the BES. Inverter-based DERs, such as rooftop solar photovoltaic (PV), are having a major impact on generation, transmission, and distribution systems in some areas of the country. This is particularly true for those resources that are connected to the BPS, but not defined as BES resources. MH, MISO, SPC, and SPP do not anticipate any reliability issues related to DERs given the capacity of DER resources in the respective assessment areas is very low compared to overall system load during the 2022 winter assessment period. Figure F3 shows the winter peak installed nameplate and peak capacity DERs (rooftop solar PVs, small wind turbines, gas-powered generators, etc.), for each of the assessment areas. Peak capacity is the amount of DER projected to be available during the period of peak demand.

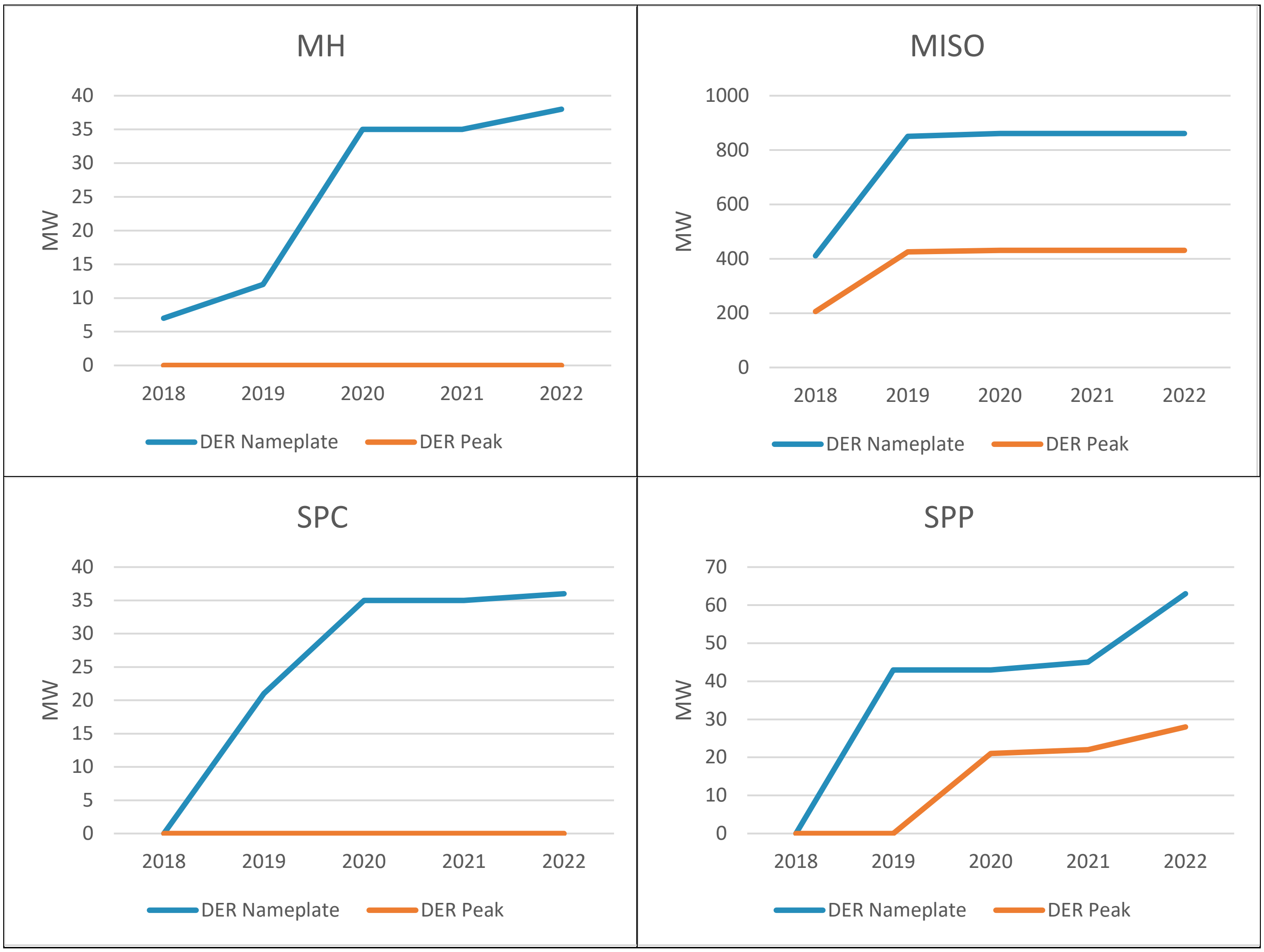



**Figure F3: DERs Nameplate and Peak Capacity**

## 2022 Winter Outlook

The following sections describe the projected reliability conditions for each assessment area in the MRO region.

**MH**

Manitoba Hydro (MH) does not anticipate any emerging reliability issues for the 2022 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. All seven units at the Keeyask Hydro Station (630 MW net addition) are anticipated to be in commercial operation for winter 2022-23.

**MISO**

Midcontinent ISO (MISO) projects a capacity shortfall for the upcoming 2022 winter season as tighter than normal operating conditions may be observed in MISO areas. MISO may need to utilize load modifying resources (LMRs) during peak periods as LMRs become an increasingly important segment of MISO's resource mix. Previous enhancements have enabled MISO to access LMRs more efficiently, resulting in faster response times. The operating conditions also indicate that MISO has a slightly increased risk to implement temporary, controlled load sheds.

### Regional Directional Transfer (RDT)

The Regional Directional Transfer (RDT) Settlement Agreement provides MISO with 3,000 MW of power transfer capability (limit) from MISO Midwest to MISO South and 2,500 MW of power transfer capability (limit) from MISO south to MISO Midwest. Of the 3,000/2,500 MW transfer rights, 1,000 MW is a firm transmission transfer right and the remaining 2,000/1,500 MW transmission right is "non-firm, as-available" service. These "non-firm, as-available" transfers can be curtailed down to 0 MW under system emergencies or to prevent load shed conditions. The RDT limit may also be temporarily increased or decreased to avoid a system emergency or during an emergency, as long as the changed flow limit does not cause an emergency on the system of another party to the Settlement Agreement. Figure F4 shows the defined MISO Midwest and MISO South Intra-Market RDT flow directions and limits.


**Figure F4: MISO Midwest and MISO South Intra-Market RDT**

The resource mix is rapidly shifting away from dispatchable thermal units and increasing towards variable resources. MISO experiences tight supply and demand conditions with increasing frequency across all seasons. Weather events, especially extreme and prolonged cold weather events, have been and continue to be a reliability risk for MISO. MISO relies on its contractually-available transmission capacity under the RDT to schedule power to help cover the electrical demand plus reserves during weather events.

The RDT limit has been an effective tool for managing resource reserve margins, market pricing, and system reliability. The ability of the RDT to shift the quantity and direction of flows by 5,500 MW provides tremendous reliability benefits, especially under system emergency conditions. The RDT played a critical role during the January 2018 and the February 2021 severe cold weather events. During these events, the RTOs were facing critical operation challenges due to extremely high demand and excessive forced generator outages, especially in the southern region. The RDT north to south transfer greatly alleviated potential load interruptions caused by generation shortage in the south. In order to provide replacement for MISO's generator outages and derates in the southern region, the RDT was delivering power close to the 3000 MW north to south limit, and the flow even exceeded the 3,000 MW limit many times.

On December 10, 2021, a 4-mile section of the RDT firm Contract Path (Dell - New Madrid 500kV line) was torn down by a tornado which resulted in the RDT firm transfer capacity decreasing to 0 MW. The Dell–New Madrid line returned to service on June 30, 2022, the RDT firm transfer capacity was 0 MW throughout the 500kV line outage period. MISO could operate the RDT to the full 3,000 or 2,500 MW transfer level during the outages, but all transmission services were "non-firm, as-available" services. The 2021 winter was a relatively mild winter, and there was no wide-spread extreme cold event that occurred during the outage period. According to the MISO RDT flow data, there were 10 hours that the north to south flow was above 2450 MW over the 3-month winter period. 7 out of the 10 hours were before or on the day of December 10, 2021. Transmission is vital to delivering electricity from the source to where it is needed most. In some extreme events, the MISO region had adequate supply but could not deliver the energy to the areas where it was needed due to the transmission constraints, including overloaded lines or forced transmission outages. The 2021 Dell - New Madrid 500kV line outage reminds us that the Dell - New Madrid 500kV line outage is a credible contingency, advanced preparation and planning for the loss of Dell - New Madrid 500kV line under energy emergency conditions should be developed and RC training exercises should be implemented.

Though risk has been identified for this upcoming winter season, MISO operators anticipate that system reliability can be maintained using Load Modifying Resources (LMRs) and when necessary and available, non-firm transfers into the system. MISO continues to coordinate extensively with neighboring RCs and BAs to improve situational awareness and assess any needs for firm or non-firm transfers to address extreme system conditions.

## SPC

Saskatchewan Power Corporation (SPC) typically experiences peak load in winter due to 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 operating reserve shortages during peak load times could increase if large generation forced outages occur and are combined with planned 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.

## SPP

Southwest Power Pool (SPP) recognizes that coal transport could be an emerging reliability risk. SPP has issued a memo to GOPs detailing reporting thresholds and a minimum coal supply to maintain. The Market Monitoring Unit (MMU) has been involved in coal conservation discussions and allows for coal conservation during abnormal fuel supply and transportation limitations. To this point, SPP has experienced lower coal stock at a number of plants because of a variety of issues related to railroad system and supply chain.

SPP does not anticipate any other 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 as experienced during the extreme cold weather event in February 2021. SPP is working with neighboring regions to address potential electric deliverability issues associated with extreme weather events. These efforts are aimed at enhancing communications and operator preparedness. SPP has historically maintained reliability despite experiencing weather extremes during each peak season. Although reliability issues, such as extreme weather events and weather forecast errors, disrupt planned real-time operations, SPP has comprehensive procedures that help mitigate the impact of such events.

To minimize implementation of conservative operations and Energy Emergency Alerts and to respond to mid-range forecast error 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 created the Improved Resource Availability Task Force (IRATF), that has primary responsibility for addressing Tier 1 recommendations related to fuel assurance (FA) and resource planning and availability (RPA) identified in the Comprehensive Review of SPP's Response to the February 2021 Winter Storm report.

# 2021 WINTER SEASONAL REVIEW

The 2021 winter seasonal review provides a historical analysis of the following areas:

- 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 for MRO's regional footprint, while the resource and transmission system adequacy reviews are conducted within the PC's footprints.

## BES Event Analysis

Analysis of large-scale outages and system disturbances is a responsibility of MRO. Details can be found in the NERC ROP Section 800. MRO follows the ERO Event Analysis Process that works with the registered entity to develop a brief report, perform a root cause analysis of the event, and document recommendations or lessons learned that can be shared with electric power industry stakeholders.

The MRO region saw a total of twenty-nine transmission events on the system from January 2021 through September 2022, with four occurring during the 2021 winter months. Equipment failure and protection system misoperations were identified as contributing causes in these events. MRO has published lessons learned and white papers to address issues related to protection system misoperations identified through trend analysis in the performance analysis and EA programs. MRO also recently held a webinar discussing protection system commissioning best practices and lessons learned. MRO continues to collaborate with entities through the Protective Relay Subgroup (PRS) on efforts to reduce protection system misoperations.

Figure G1 illustrates MRO's Event Severity Index, which includes all BES events and allows for comparison of the impact 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.

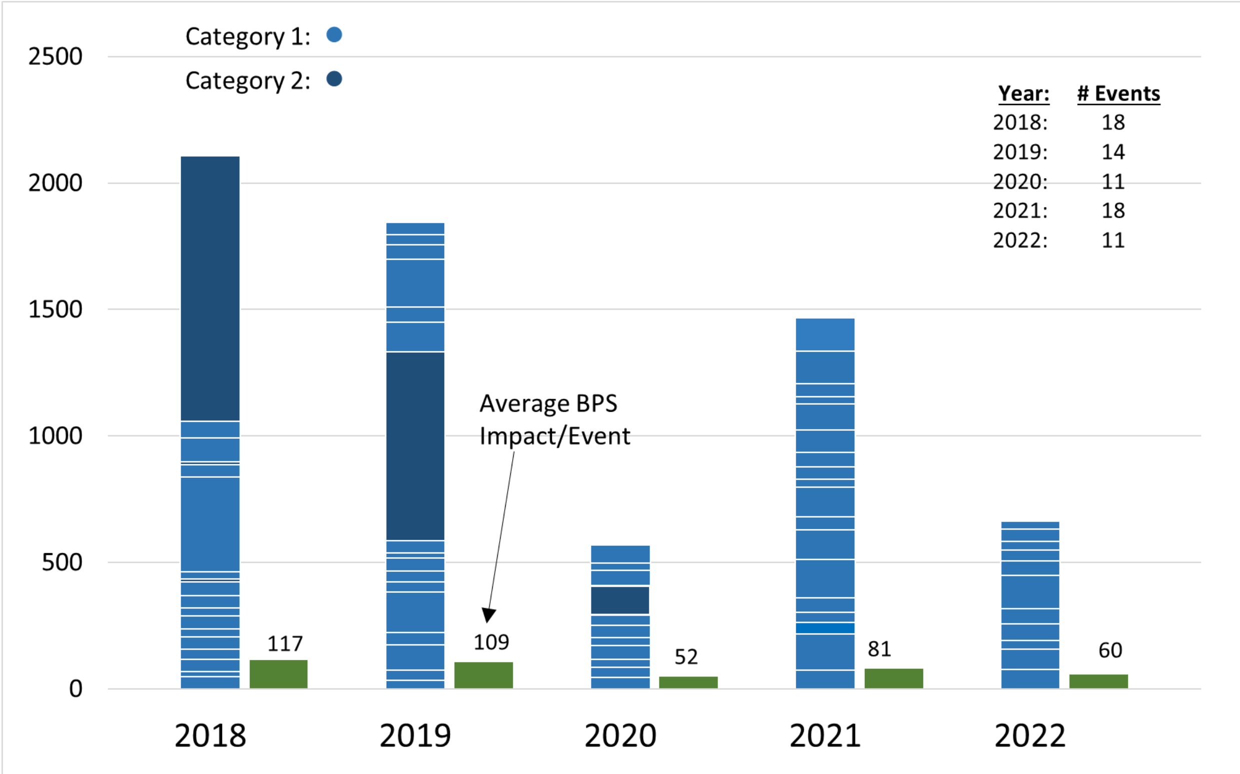



**Figure G1: MRO Event Severity Index as of September 2022**

Described below are the event categories in the Event Severity Index chart:

**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.

The NERC Addendum for determining event categories can be found at [Addendum for Determining Event Category.]

The following section contains a summary of each of the four BES events that occurred during the 2021 winter season, including the event category, number of BES facilities lost, MW of generation lost, and MW of load lost.

**December 15, 2021 Transmission Event**

Event Category: 1.a

- # of BES facilities Interrupted: 7
- MW of Generation Lost: 0 MW
- MW of Load Lost: 5 MW

On December 15, 2021, at 3:56 p.m. Central Standard Time (CST), a 115kV transmission line tripped on a phase to ground (A-G) fault. The transmission line relays at both terminals initiated to clear the fault at the same time. While terminal A breaker was opening, the fault on the line transitioned to a phase to phase to ground (A-B-G) fault. The terminal A breaker had a restrike (B-G) 112 milliseconds after the fault initiation and faulted internally to ground. The restrike and internal breaker fault caused the 115kV bus differential relay at terminal A to operate, clearing the bus. The relays operated correctly as did the communications. The transmission line had been heavily damaged, including several downed structures due to severe weather.

A known issue with the make/model of the failed breaker was identified as a contributing cause for this BES event. The entity has an existing plan to replace all the breakers of the same make/model on the portion of their system susceptible to phase to phase faults caused by galloping conductors. They have also modified their breaker testing procedures for this make/model in an attempt to identify this type of failure before it occurs.

**January 14, 2022 Transmission Event**

Event Category: 1.a

- # of BES facilities Interrupted: 4
- MW of Generation Lost: 274 MW
- MW of Load Lost: None

On January 14, 2022, at 8:34 a.m. CST, while working on a scheduled maintenance clearance, a breaker failure lockout relay initiated and tripped a 230kV bus, two 230kV transmission lines and a generator unit.

The cause of the trip was determined to be induced current on a line relay while work was performed on a CT circuit to reconfigure the 230kV bus.

The entity has identified a need to modify the procedure for completing this work and plans to implement changes on protection relay isolation moving forward.

**March 10, 2022 Transmission Event**

Event Category: 1.a

- # of BES facilities Interrupted: 8
- MW of Generation Lost: None
- MW of Load Lost: None

On March 10, 2022, at 9:51 a.m. CST, a failed insulator assembly caused a fault on a 230kV bus at an entity substation. Delayed clearing of this fault due to incorrect protection relay settings caused the 230kV bus, four 230kV transmission lines, one 345kV transmission line, a 345/230kV transformer and a 230/115kV transformer to trip offline.

Relay settings were corrected and similar protection schemes on the entity's system were reviewed to prevent a similar occurrence.

**March 22, 2022 Transmission Event**

Event Category: 1.a

- # of BES facilities Interrupted: 3
- MW of Generation Lost: None
- MW of Load Lost: 5.2 MW

On March 22, 2022, at 12:06 a.m. CST, a Bus Differential Lockout Relay operated due to an animal contact on a 115/13.8kV transformer, removing two 115kV transmission lines and a 115kV bus from service. The 115kV interrupter on the transformer operated too slow, resulting in the over-trip. The entity identified rust and corrosion on the tripping mechanisms of the interrupter as the reason for the delayed trip and ordered repairs on this equipment.

**Loss of Energy Management System Events**

Described below are the event categories in the Loss of EMS Event Time Duration chart:

**Category 1h**: 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.

Loss of Energy Management System (EMS) events have the potential to reduce situational awareness on the BES. There was one Category 1h (loss of monitoring or control at a control center) EMS-related system event within the MRO region in 2021 winter season, with a duration of 216 minutes.

A common factor identified among the EMS events has been that a malfunction occurred either during or shortly after a routine maintenance procedure. This was the case with the 2021 winter event where the cause of the event was directly related to configuration error during a maintenance activity.

The NERC Reference Guideline for 1h events can be found at Reference Guideline for Category 1h Events.

Figure G2 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.

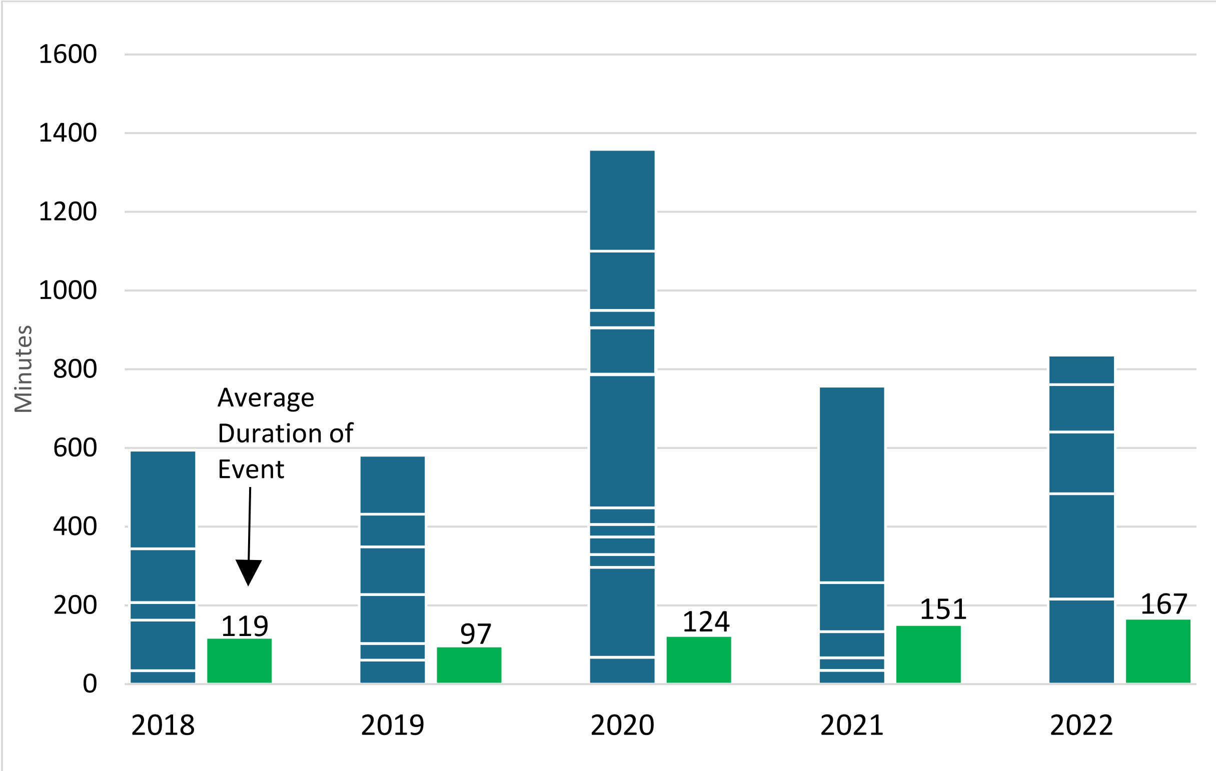



**Figure G2: Loss of EMS Event Time Duration**

## Energy Emergency Alerts

An energy emergency occurs when a load serving entity or 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). NERC Reliability Standard EOP-011-1 Emergency Operations addresses the effects of operating emergencies by ensuring each TOP and BA has developed an Operating Plan(s) to mitigate operating emergencies, and those plans are coordinated within an RC area. To ensure all RCs clearly understand potential and actual energy emergencies, NERC has established three levels of EEAs. More information on EEAs can be found in the NERC Reliability Standard EOP-011-1.

The MRO region experienced three EEAs during the winter of 2021. More detail is provided below.

**December 30, 2021 - EEA Level 1 Event**

The RC was experiencing -31°F temperatures and had just set a new all-time winter peak of 3,910 MW on December 29. They had 370 MW of conventional generation offline or unavailable plus very low wind generation.

The RC declared an EEA1 at 5:14 a.m. CST anticipating being below their minimum required operating reserves of 332 MW at the time of the forecasted peak, which was approximately 3,900 MW.

The RC was able to import 85 MW at the peak hour, the operating reserves were maintained and an EEA0 was declared at 9:00 p.m. CST.

**January 6, 2022 – EEA Level 2 Event**

The RC was experiencing -27°F temperatures with a forecasted peak load of 3,793 MW.

Issues with coal deliveries at a generator station led to 285 MW in derates at that plant.

The RC had an additional 387 MW of offline or unavailable generation resulting in a total of 672 MW of conventional generation that was unavailable.

Wind generation was between 225 MW and 250 MW out of 275 MW installed capacity.

At 7:45 p.m. CST, the RC declared an EEA2 due to the sudden loss of a 350 MW unit.

The RC was able to import emergency power from neighboring RCs and declared an EEA0 at 11:00 p.m. CST, when a 180 MW gas turbine was returned to service and loads decreased.

**February 21, 2022 – EEA Level 2 Event**

The RC was experiencing -13°F temperatures with a forecasted peak load of 3,548 MW. Approximately 828 MW of generation was offline or unavailable due to planned and unplanned outages.

Available wind generation was approximately 20 MW of the 275 MW installed capacity.

A sudden loss of 280 MW of generation resulted in a declaration of an EEA2 at 7:10 p.m. CST.

The RC was able to quick start available generation and the load came in lower than the expected peak load for the day. An EEA0 was declared at 10:05 p.m. CST.

## Generator Availability

Generating Availability Data System (GADS) is a data collection tool used by the ERO Enterprise to collect information about the performance of electric generating equipment to analyze generation outages. This 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. GADS reporting became mandatory on January 1, 2013, and currently holds data on more than 8,000 generation units across North America, with the exclusion of wind turbines. Wind generation data is captured in a separate GADS wind application that became mandatory on January 1, 2018. GADS data is also used to conduct assessments of generation resource adequacy. Wind turbine component outage information will not be included in this report until mandatory and representative data sets are available. A mandatory reporting requirement is currently under development.

## Resource Mix

The MRO region has a diverse mix of 2022 winter peak accredited capacity as shown in Figure G3. Conventional generation with large rotating mass (steam, hydro, and combustion turbine technologies) that traditionally provided essential reliability services like frequency and voltage support continues to be retired and replaced with renewable generation that either cannot provide these essential reliability services or has limited capability per design constraints. The MRO region currently has approximately 53,000 MW of installed nameplate wind capacity. However, only about 12,000 MW of wind is accredited capacity for 2022 winter peak demand. Multiple proposed projects exist in the MISO and SPP generation interconnection queue that would add approximately 84,000 MW of nameplate wind capacity to the MRO region by winter 2031. Operational challenges associated with a large amount of wind include accurately forecasting the output of wind resources, and in some older wind turbines, less reactive support than conventional generation typically provides. Increases in renewable generation also adds operational complexity to resource commitment and dispatch. With large amounts of wind resources, forecasting inaccuracy can result in larger, unanticipated shortfalls in real-time operations. Similarly, 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. It is estimated about 52,000 MW of proposed solar projects exist in the MISO and SPP generation interconnection queue by winter 2031. It is important to note that not every wind and solar project on the interconnection queue will be built, as some entities may withdraw after a system impact study, which establishes necessary transmission upgrades that may be needed before a project can connect to the BPS.

The move away from conventional generation requires BAs to have unloaded capacity that can respond quickly to the deviation in resource output of variable 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 the forecast. This creates a challenge for control room operators' awareness and decision-making processes, especially during periods of high overall load and significant ramping. It also forces BAs to carry additional operating reserve to account for forecast uncertainty associated with wind and solar resources and load forecasting errors.

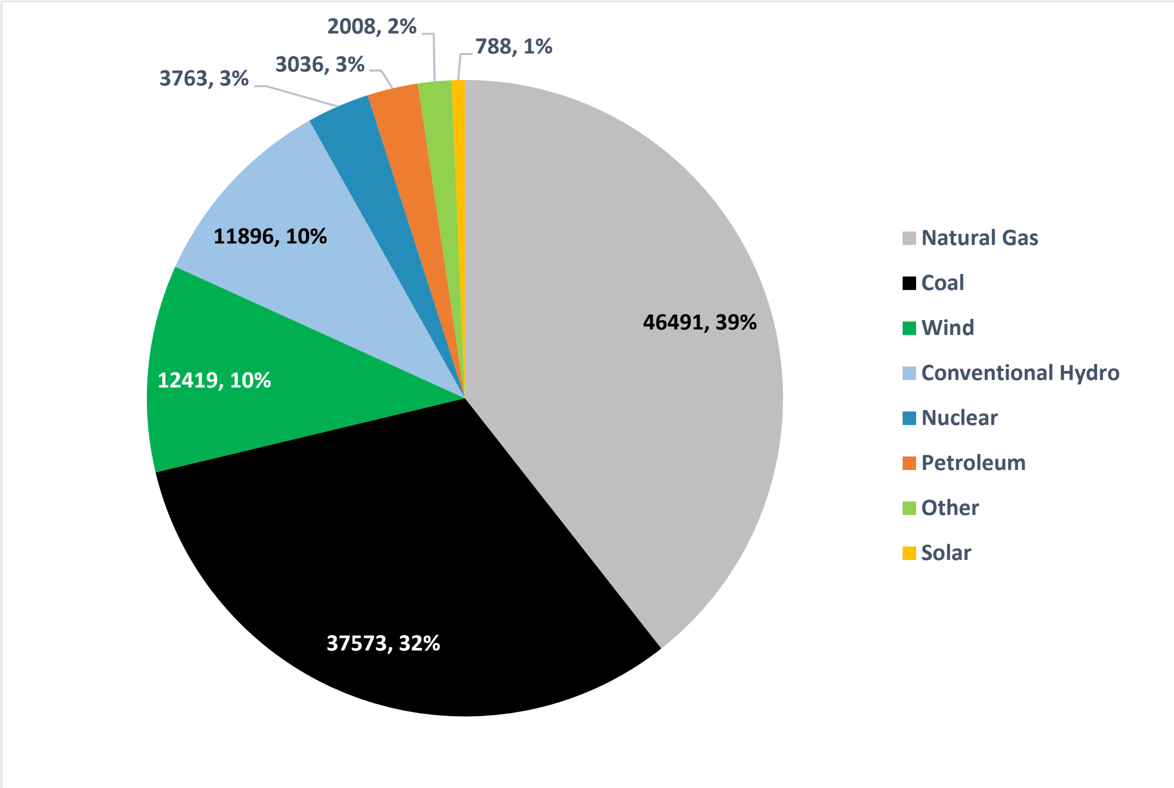



**Figure G3: MRO 2022 Winter Peak Capacity by Fuel Types**

The largest single contributor of generation by peak capacity in the MRO region is natural gas plants. Coal plants and wind turbine generators make up large portions of the generation mix as well. Generation unavailability can have a substantial impact on reliability. Useful metrics for generator unavailability are the equivalent forced outage rates (EFOR)[5] and Megawatt weighted EFOR or (WEFOR)[6]. For the MRO region, the annual conventional generator forced outage rates for all seasons as shown in Figure G4 is on an upward trend in the four-year span. 2020 had a lower rate due to a reduction in both total demand from the previous year and reductions in forced outages and derates in simple cycle generation and internal combustion engines. The increase in 2021 was attributed to the cold weather event in February 2021. The WEFOR for 2019 and 2021 were higher than the four-year moving average. Long-term trends also continue to indicate increasing EFOR rates due to component fatigue and an aging fleet. Given higher penetrations of intermittent resources, conventional generation is being turned off and on, following load, and operating at minimum load more often, which increases the number of forced outages due to component failures.

[5] 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

[6] 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.

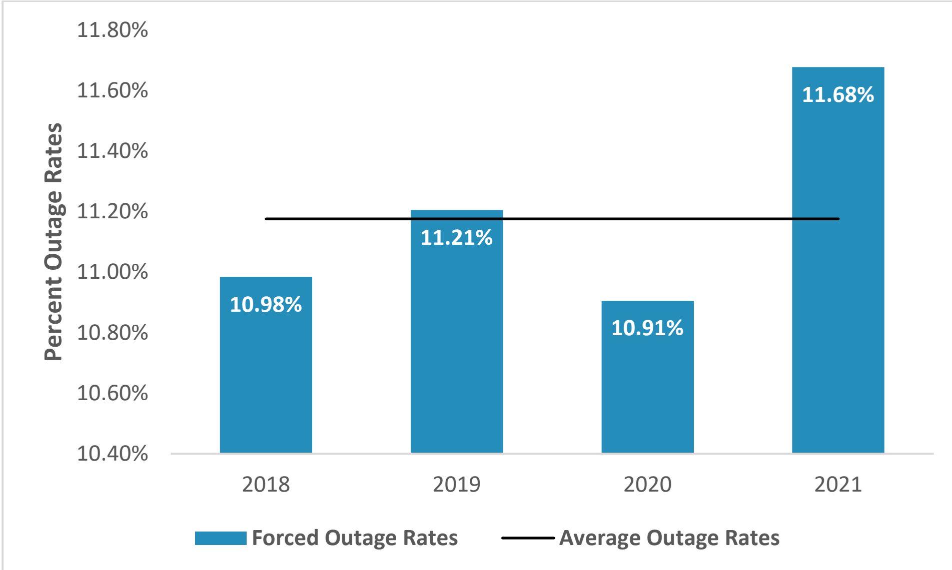



**Figure G4: MRO Annual Generator MW-Weighted EFOR**

Event impact serves to concisely indicate the megawatt hours (MWh) unavailable due to a forced outage, forced derate, or start-up failure. The GADS data presented below is a summary of 2021 and five-year historical event impact in the MRO footprint over the winter months.

Figure G5 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 event impact is the unit's GWh lost per unavailability due to an event. In the chart below, even though fossil-steam generation shows a high event impact of 8,168 GWh, the total event impact of 15,986 GWh for all generation types have less impact to the BES. Due to aging, fatigue and component failure from frequent cycling, fossil steam plants had the most event impact on the BES during the winter of 2021. The total impact of the winter season was substantially larger than the preceding summer season. Fossil-steam plants performed better in the winter with the other largest generation types (simple cycle gas turbines, combined cycle units, and hydro) performing notably worse.

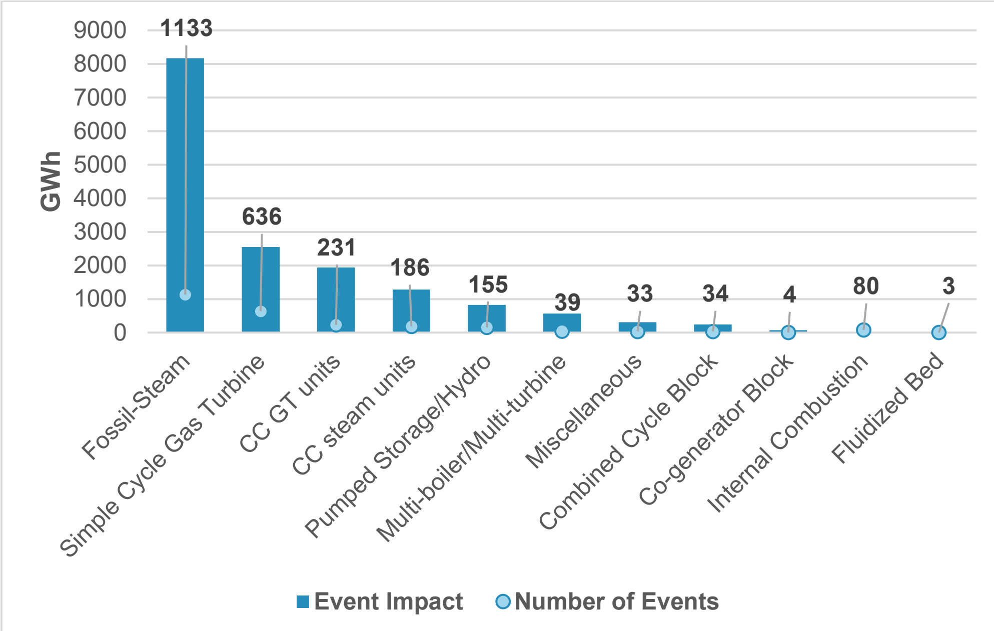



**Figure G5: Total Event Impact and Number of Event Impact for Winter 2021**

Table G1 shows the top causes of forced outages, forced derates, and startup failures by event impact for fossil-steam plants in winter 2021. Table G2 shows the same information for the five-year historical winter season period.

| Cause Type | Portion of MWh lost |
|---|---|
| Waterwall (furnace wall) | 7.63% |
| Stator windings; bushings; and terminals | 6.16% |
| Feed water pump | 5.88% |
| Feed water pump drive – steam turbine | 4.83% |
| High pressure heater tube leaks | 4.06% |

**Table G1: Fossil-Steam 2021 Winter Outage Causes**

| Cause Type | Portion of MWh lost |
|---|---|
| Major overhaul (forced outage) | 8.70% |
| Waterwall (furnace wall) | 6.23% |
| Plant modifications strictly for compliance with new or changed regulatory requirements | 5.51% |
| Differential expansion | 3.33% |
| Storms (ice; snow; etc.) | 3.27% |

**Table G2: Fossil-Steam 2017-2021 Winter Outage Causes**

Fossil steam outages were driven by a wide variety of causes over the 2021 winter period and were seen consistently across the fleet, except for stator windings, bushings, and terminals. This stator cause code outage portion was driven by a few isolated high duration events, most of which were attributable to routine failures of a variety of causes, suggesting no underlying cause. Waterwall was the primary outage cause for winter 2021. Notably over the 2017-2021 winter time period, causes for fossil steam are dominated by outlier cases of extreme length, and thus impact, over the duration, with waterwall being the only cause code that was consistently applied across the fossil steam fleet in each year. The large event impact reflects not only fossil-steam's large portion of generation, but the amount of lost megawatt hours. This, together with the relatively well distributed event impact across cause codes, suggests that fossil-steam units forced outage or derates across the region are not due to a single failure mechanism, but possibly suffer large outage numbers due to aging, fatigue, or component failure from frequent cycling. The unique winter concerns for these plants largely seems to be found in winter storms, causing various freezes and fuel supply issues both within and outside management control.

Table G3 show the top causes of forced outage, forced derate and startup failure by event impact for simple cycle gas turbines in winter 2021. Table G4 shows the same data for the five-year historical winter period.

| Cause Type | Portion of MWh lost |
|---|---|
| Lack of fuel: Contract or Tariff allows for interruption | 41.09% |
| Main transformer | 15.24% |
| Other fuel system problems | 4.73% |
| Gas turbine control systems | 4.60% |
| Lube oil pumps | 3.40% |

**Table G3: Simple Cycle Gas Turbine 2021 Winter Outage Causes**

| Cause Type | Portion of MWh lost |
|---|---|
| Lack of fuel: Contract or Tariff allows for interruption | 32.38% |
| Lack of fuel: Physical failures of fuel supply or delivery/transportation of fuel | 10.69% |
| Main transformer | 4.93% |
| Other miscellaneous gas turbine problems | 4.84% |
| Other controls and instrumentation problems A | 4.48% |

**Table G4: Simple Cycle Gas Turbine 2017-2021 Winter Outage Causes**

Simple cycle gas turbine outages are clustered in the 2021 winter season, with over 69 percent of megawatt hours lost is attributable to the top five causes and over 55 percent attributable to the top 2. While "Lack of fuel: Contract or Tariff allows for interruption" has been the top cause code for winter months for four of the last five years, this season had a substantially larger portion of events attributed to it. However, this increase does not correspond to an increase in the total event impact attributed to this cause over other winter seasons. This cause accounted for only 7 percent of all MWh's lost in the 2021 winter season, the second lowest in the five-year span. While the second largest cause of event impact for the 2021 season maps to long-term concerns. This shows the impact of relatively few, highly impactful events in the past two years. There are no obvious underlying causes. This data along with the rash of occurrences may suggest age related failures.

Winter season forced outage, forced derate, and startup failure causes for other types of generation are provided in Appendix A.

## Wind Generator Availability

In previous years, GADS Wind data was presented as preliminary data. However, since component outage data is voluntarily submitted, less than two percent of installed wind capacity in the MRO region was reported for the 2021 winter season. The proposed mandatory GADS wind component outage data reporting will go into effect beginning on January 1, 2024.

## Summary of Generator Availability

Based on forced outage rates for fossil-steam and simple cycle gas turbines, MRO is closely monitoring the 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 needed to serve energy and integrating renewable resources.

## 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 at the regional and NERC levels, provide useful data in reliability analyses. This section summarizes the transmission outages experienced during the winter of 2021.

An automatic outage results from the automatic operation of a switching device, such as a circuit breaker, causing an element to change from an in-service state to a not in-service state. Momentary outages are automatic outages, with a duration of less than one minute. If the circuit recloses and trips again in less than a minute of the initial outage it is only considered one outage. Sustained outages are automatic outages with a duration of one minute or greater. Sustained outages are reported for elements operated at 100kV and above. Momentary automatic outages are only reported for elements operated at or above 200kV.

Table G5 shows the number of circuits and circuit miles for overhead 100-599kV AC transmission lines.

| 100-199-kV | | 200-299-kV | | 300-399-kV | | 400-599-kV | |
|---|---|---|---|---|---|---|---|
| Circuits | Miles | Circuits | Circuits | Circuits | Miles | Circuits | Miles |
| 3363 | 46774 | 415 | 14117 | 400 | 18400 | 8 | 901 |

**Table G5: AC Transmission Circuit Miles**

Figure G6 shows the number of 100kV and above automatic outages that include both momentary (for 200kV and above) and sustained outages for December 2017 through February 2022. There were no 400-599kV reported outages during the winter of 2021.

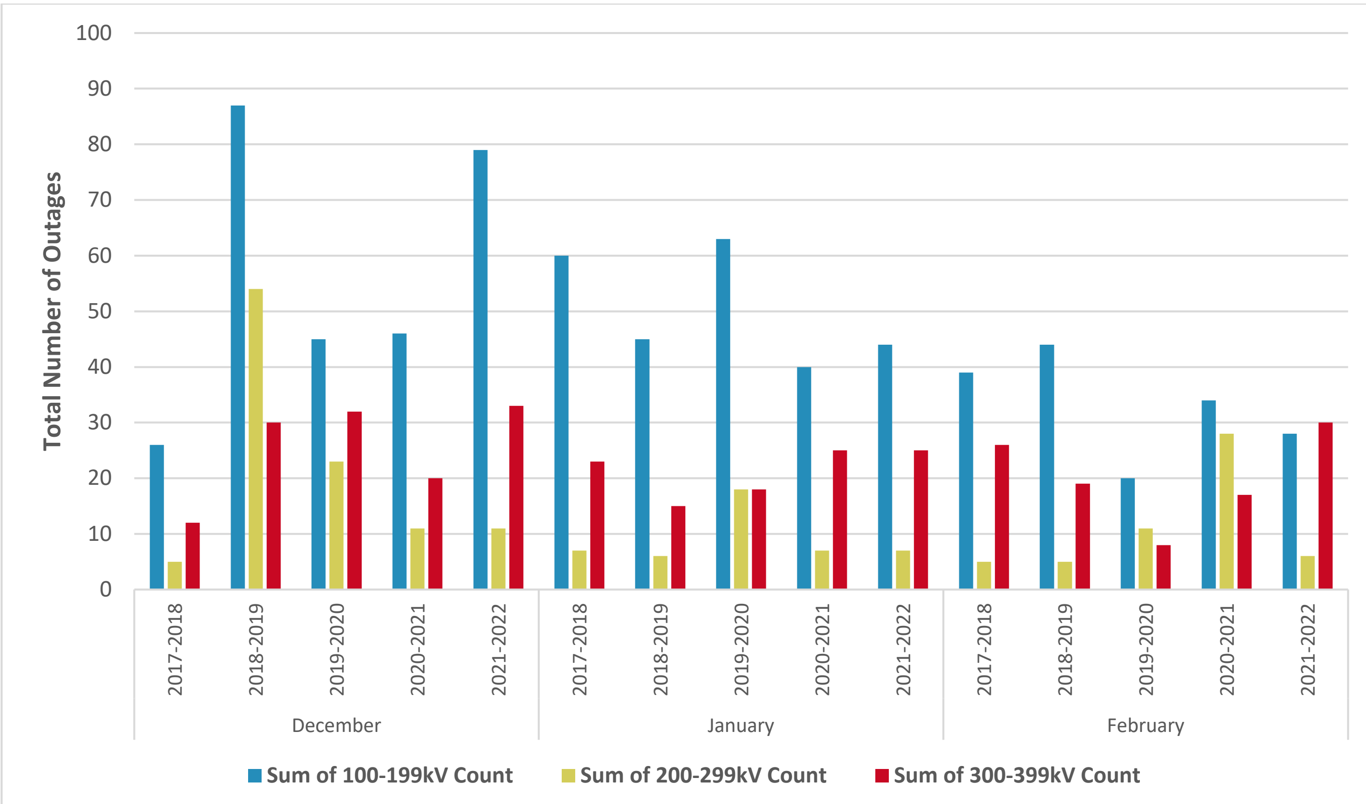



**Figure G6: Winter Automatic Outages by Month**

Figure G7 shows the causes of momentary outages for the winter seasons between December 2017 and February 2022. The chart does not show the cause of momentary automatic outages for 100-199kV because causes are not reported for momentary outages less than 200 kV. Figure G7 also illustrates a significant number of momentary outages have an unknown cause, which increase dramatically for the most recent period. This may indicate that thorough line inspections after transient faults are typically not performed after clear weather operations. It may also indicate that even if an inspection is performed, a definitive cause for many transient faults cannot be determined. The chart also shows that the second leading cause of momentary automatic outages is weather-related and most likely due to galloping.

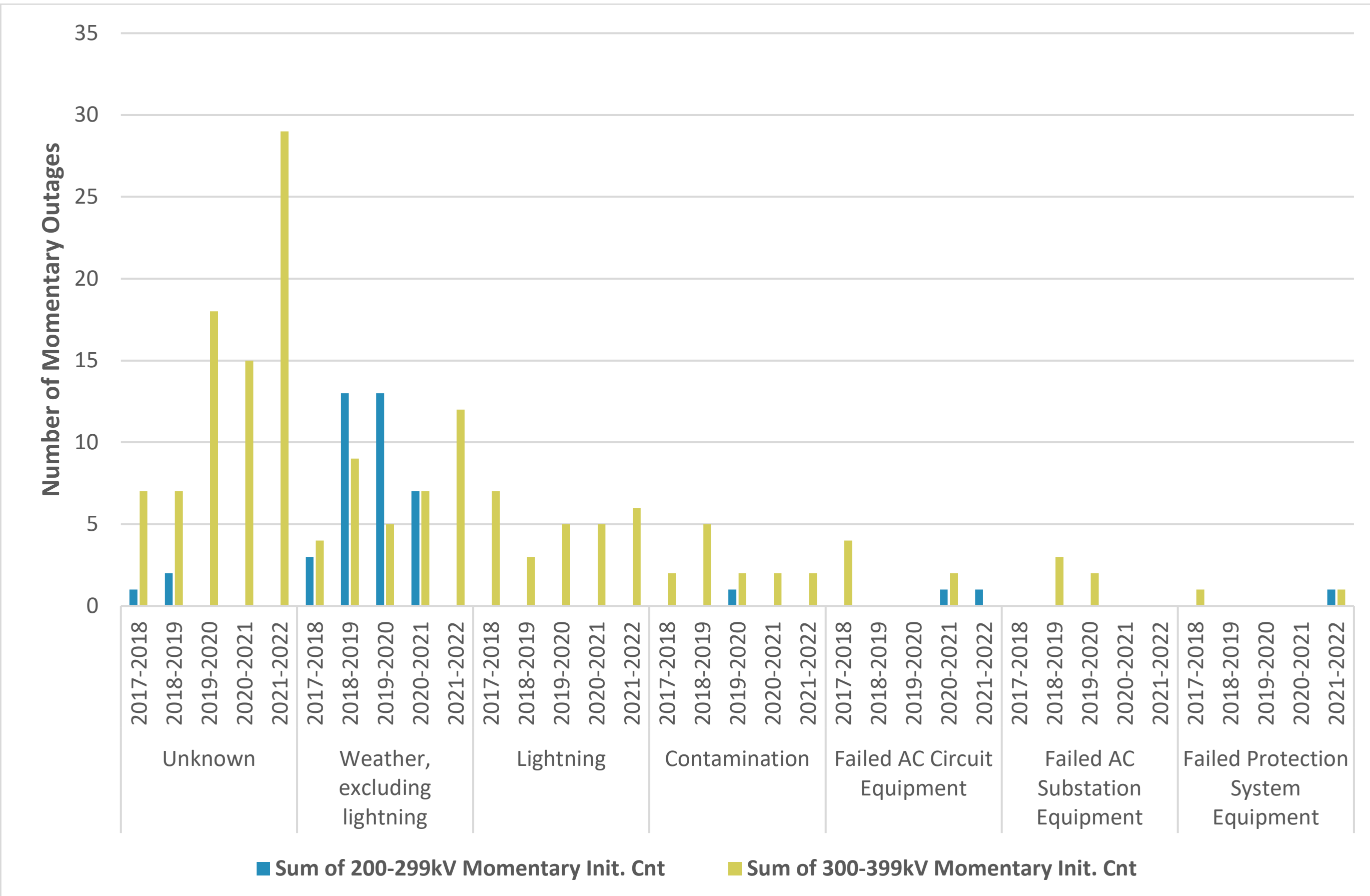



**Figure G7: Winter Momentary Outages by Cause**

Figure G8 shows the causes of sustained outages for the winter seasons between December 2017 and February 2022. Figure G8 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 failed AC circuit equipment for the 100-199kV and 300-399kV voltages was higher than any of the other winter periods shown.

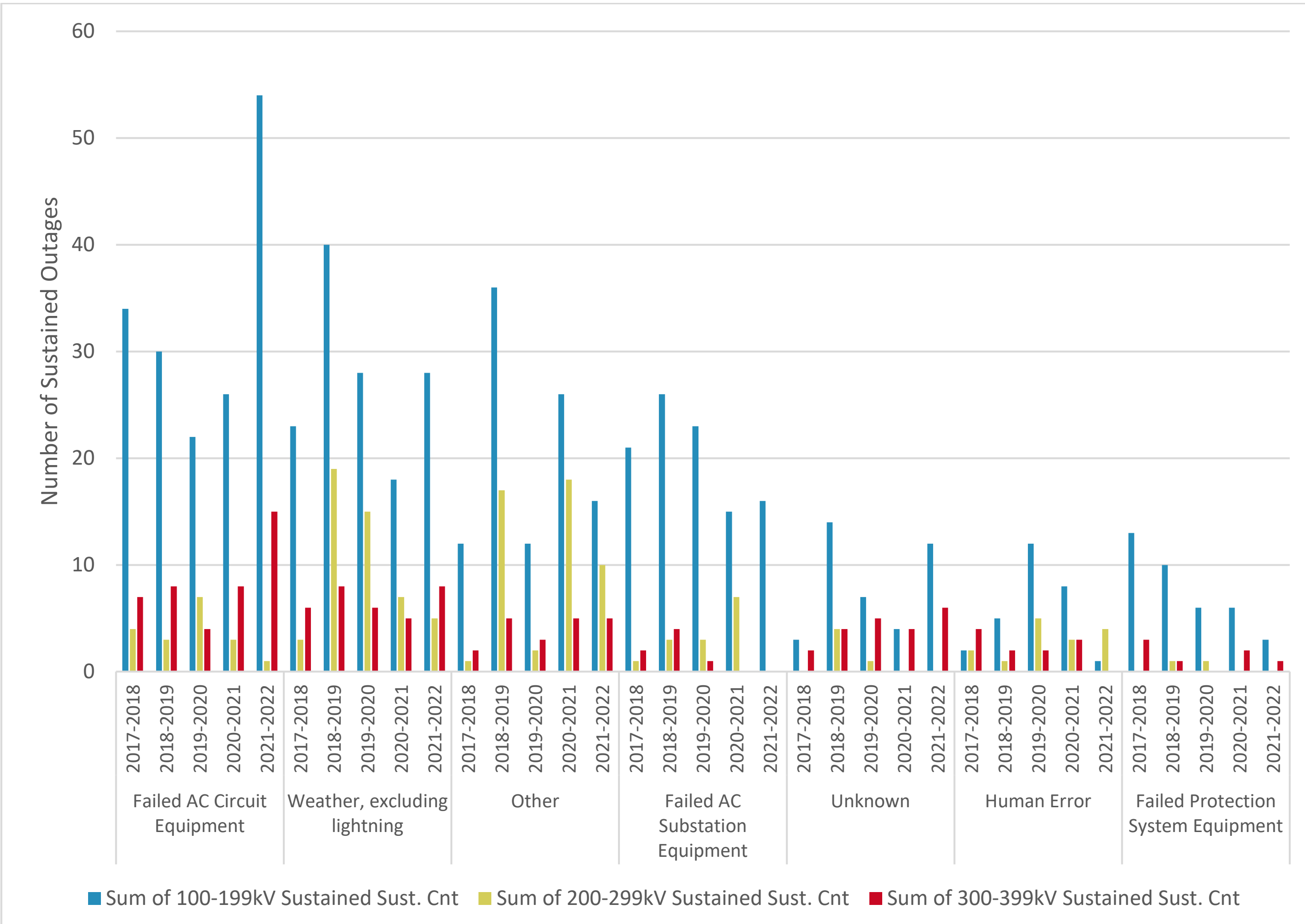



**Figure G8: Winter Sustained Outages by Cause**

Figure G9 reflects the yearly winter total outages per 100 circuit miles for 100-399kV circuits. The chart clearly shows an increase in outages for 2021-2022 in the 100-199kV and 300-399kV voltages. This is largely due to the derecho that swept through the MRO region December 15 and 16, 2021. Those two days attributed to 57 100-199kV outages, which is 35 percent of the outages reported for that voltage range, and 20 300-399kV outages, which is 22 percent of the outages reported for that voltage range.

The derecho also had a significant effect on the 200-299kV circuits. There were 11 200-299kV outages, which is 46 percent of the total outages for the winter season. These were also the only outages reported on 200-299kV circuits for December 2021. The 11 outages reported is well below the average five-year outage rate of 23 for the month of December. Overall, the number of outages for 200-299kV circuits were lower for the winter of 2021-2022 than the previous five winter seasons. The reason for this is not known at this time.

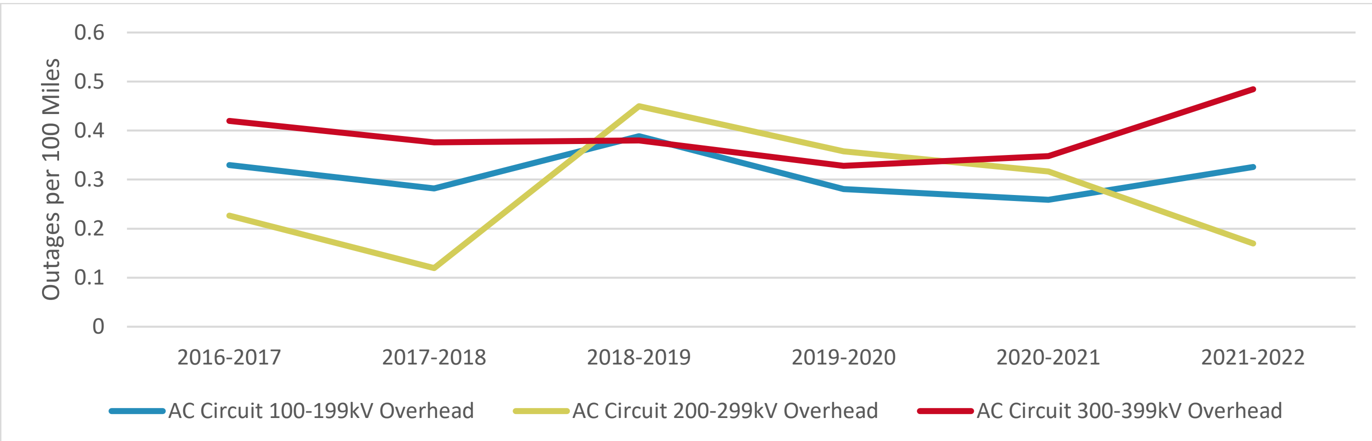



**Figure G9: Total Transmission Outages per 100 Circuit Miles**

## 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). 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 DPs 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 G10 from the 2022 NERC State of Reliability report.

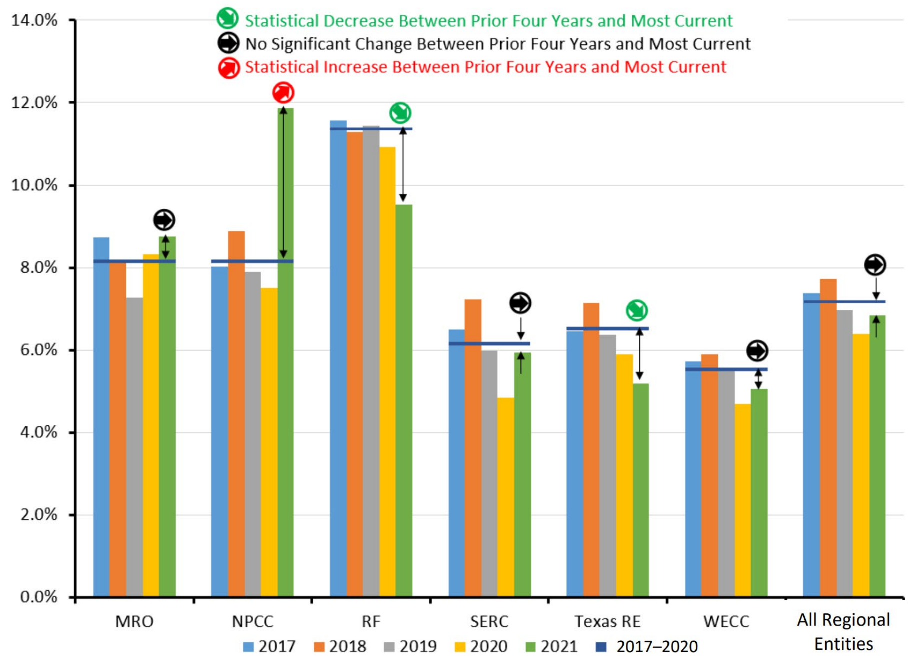



**Figure G10: Year-Over-Year Changes and Trends in the Annual Misoperations Rate by Region**

There were 2,628 operations and 231 misoperations reported within the MRO region in 2021 for a misoperation rate of 8.79 percent. Figure G11 shows the misoperation rate had been trending downward until 2020. The upward trend seen in 2020 continued in 2021.

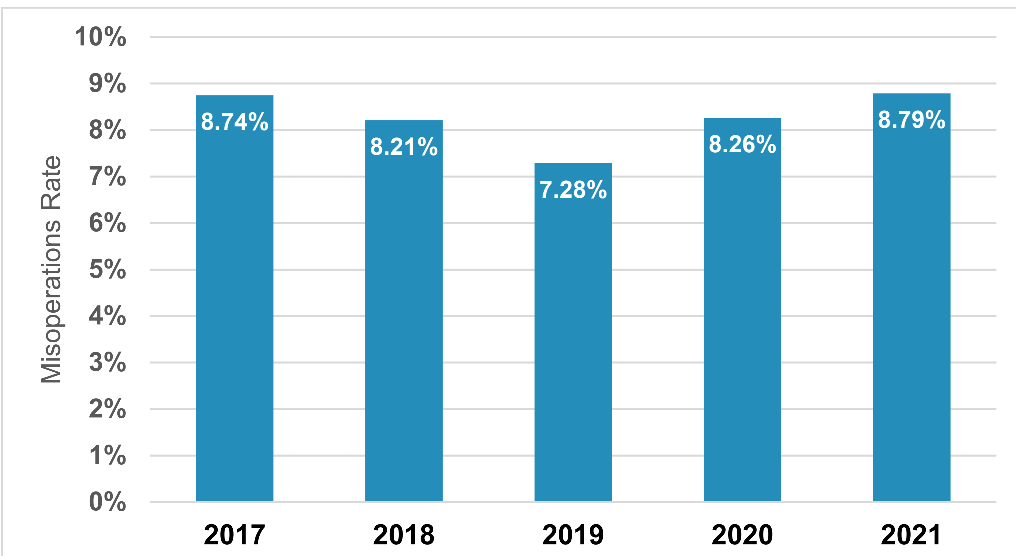



**Figure G11: MRO Misoperation Rates by Year**

Figure G12 provides context for the misoperation rate increase in 2021. While total protection system operations were down about 26 percent in 2021 from the previous three-year average, total misoperations did not experience the same proportional decrease, dropping only 17 percent during the same time, resulting in a higher misoperation rate.

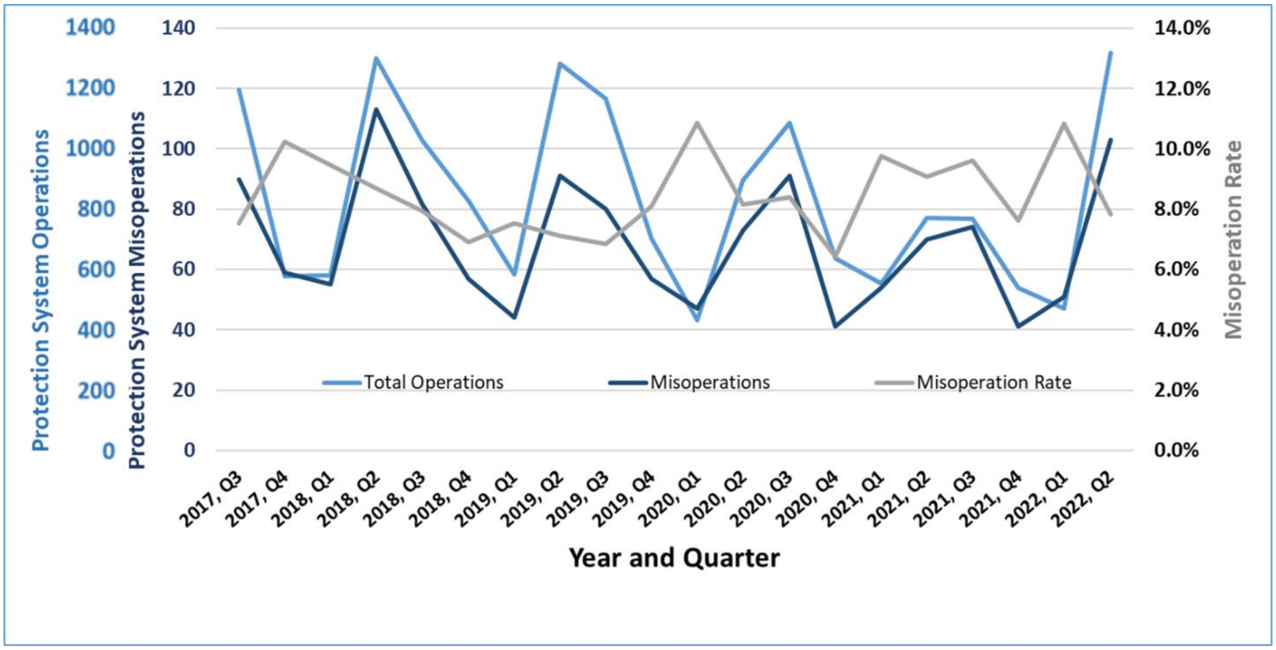



**Figure G12: Protection System Operations and Misoperations Rate**

The cause for the significant drop in total operations from previous years is difficult to ascertain. Of the 2,628 total operations that were reported in MIDAS for 2021, 1,850 of them occurred at voltages less than 200kV. Of those 1,850 outages, only 656 of them were sustained outages, the other 1,194 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 2021, and similar percentages were seen in previous years, MRO cannot definitively attribute the drop in outages to any specific cause(s).

However, it is generally true that summer weather events typically cause more BES faults and relay system operations than winter weather events. A reduced number of total protection system operations reported in MIDAS and a reduced number of summer weather-related transmission outages reported in TADS indicate that the 2021 summer storms were not as frequent and severe on the BES as previous years. This is likely a major contributing factor to the reduction in total overall operations in 2021.

MIDAS reports are completed and reported by entities on a quarterly basis. The fourth and first quarters of the year (October 1 through March 31) aligns closest to the winter season (designated December 1 through February 28) for this assessment. As shown in Figure G13, 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.

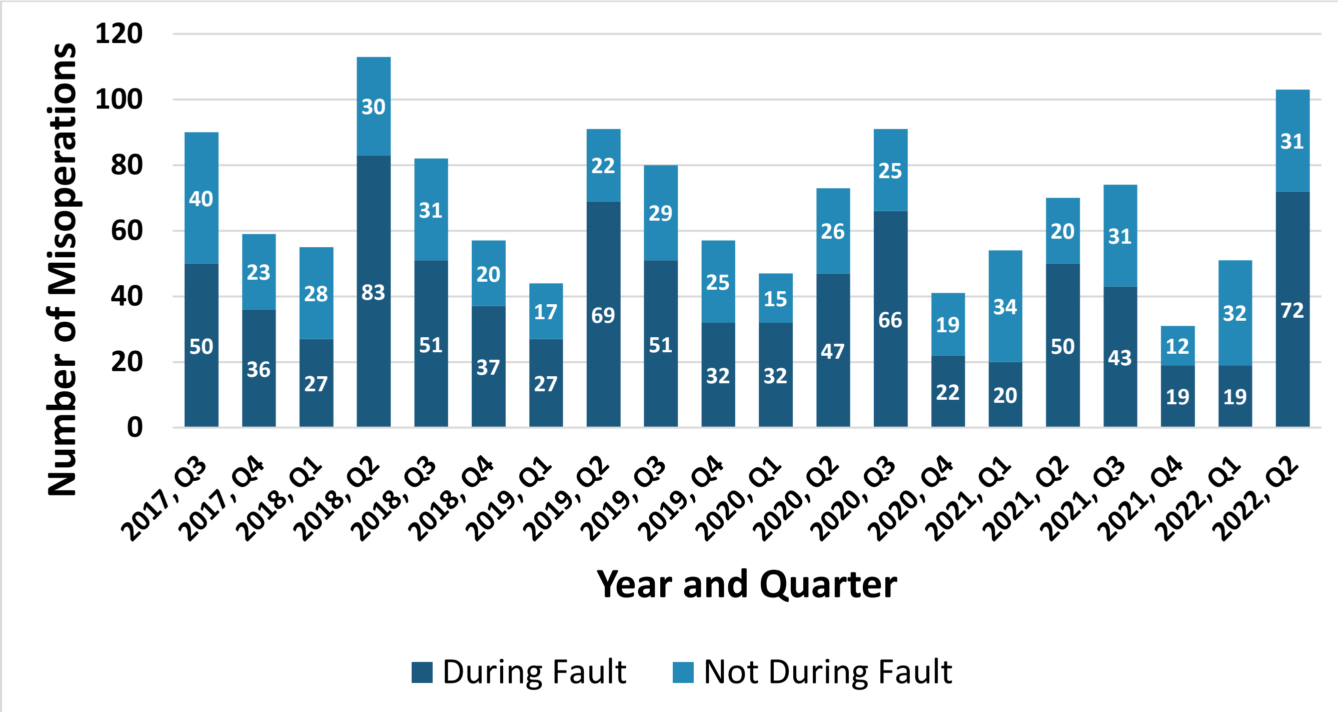



**Figure G13: Fault Associated and Non-Fault Associated Misoperations**

There was a total of 46 misoperations that occurred in the MRO region between December 1, 2021 and February 28, 2022. Examining these misoperations reveals that human error-related misoperations attributed to as-left personnel errors, design errors, incorrect settings, and logic errors, continue to account significant number of the misoperations total. As illustrated in Figure G14, of the 46 misoperations that occurred during this timeframe, nearly half were attributed to human errors. 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:

- FERC, NERC, and Regional Entity staff released in November of 2021 the Joint Review of Protection System Commissioning Programs report. The report discusses best commissioning practices and areas of improvement observed from participating entities within the ERO Enterprise.

- MRO, in collaboration with the MRO Protective Relay Subgroup (PRS), hosted a MRO Protection System Commissioning Webinar in July of 2022 highlighting the findings of the above mentioned report.

- A recurring “Commissioning Practices” topic has been added to the MRO PRS quarterly agenda. This topic will provide PRS members the opportunity to present on their company’s current commissioning practices and discuss commissioning challenges they face.

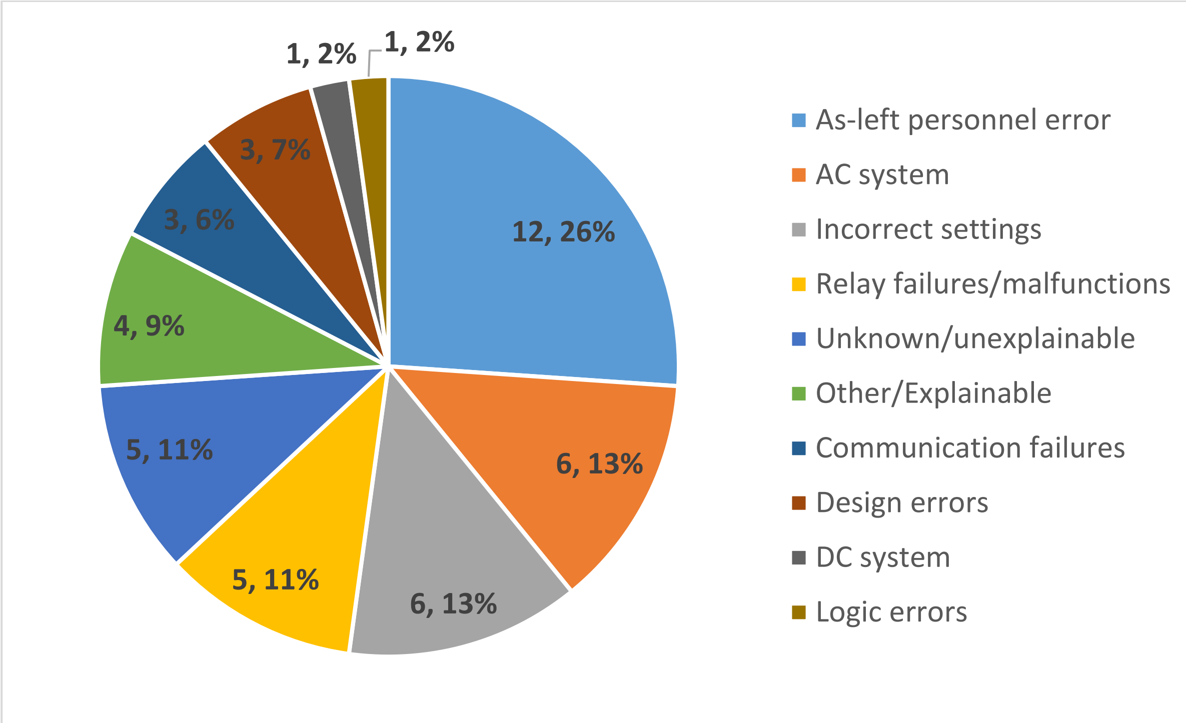



**Figure G14: Winter 2021 Misoperations by Cause**

## 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 studied. It means there is a 10 percent chance that the 90/10 forecast would occur, while a 90 percent chance that it would not be exceeded. In other words, the forecast would be exceeded, on average, only once every ten years.

Figure G15 shows the four-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. SPC actual peak demand exceeded the normal and extreme forecast last winter. SPC recorded a new all-time winter peak load in 2021 winter. MH actual and all-time values contain interruptible (non-firm) load that was served at the time, since MH had sufficient generating resources to do so. This resulted in the actual load being at or higher than the extreme forecast.

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 – 43,661 MW in February 2021

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, which can result in significant weather diversity on any given day.


**Figure G15: 4-Year Historical Winter Load Forecast**

# FOCUS AREAS FOR WINTER 2022

The following focus areas represent MRO's independent evaluation of the generation and transmission system for the 2022 winter season, as well as potential operational concerns that should be considered during this same timeframe:

- MISO is projecting insufficient firm generation available to meet forecasted seasonal peak load with typical maintenance and forced outages this winter. Based on extreme winter conditions, results indicate insufficient capacity to cover the anticipated extreme winter peak demands.

- Forced outages during the winter season could increase the risk of operating reserve shortages in SPC during peak load times depending on the amount of generation lost due to such forced events. In case of extreme winter conditions combined with large generation forced outages, SPC would utilize available demand response programs, short-term power transfers from neighboring utilities, maintenance rescheduling and/or short-term load interruptions.

- While the SPP reserve margin shows a robust amount of excess capacity, there is still a potential risk of capacity shortfall based on past performance impacts during extreme weather events despite the current projected reserve margin capacity for the upcoming winter season.

- The potential coal delivery issues in MISO and SPP could be an emerging reliability issue for the upcoming winter.

- Conventional generation MW-Weighted Equivalent Forced Outage Rates (WEFOR) for 2019 and 2021 were higher than the four-year moving average. Long-term trends continue to indicate increasing generation forced outage rates due to component fatigue and an aging fleet. Additionally, with higher penetrations of intermittent resources, conventional generation is cycling more, which increases the number of forced outages due to component failures. Conventional generation resource performance and availability is key for meeting projected winter demand. A rapidly changing resource mix and increased levels of renewable energy resources is also creating significant challenges for operators, particularly with real-time wind forecasting errors. Continued monitoring and awareness of renewable generation uncertainty during peak load periods is crucial and essential to the reliability of the BPS in MRO's region. As the dependence on intermittent resources continues to increase, there will be a greater need for fast responding dispatchable resources capable of following large unexpected changes in intermittent resource output.

- Situational awareness of unplanned generation outages and low wind forecasts, along with employing operating mitigations like demand response during extreme weather conditions can help BAs reconcile the uncertainty associated with operating reserve requirements and manage real-time energy shortfalls within their footprint. Furthermore, with the current resource mix, the time of greatest risk may not be during winter peak periods, especially as the resource mix evolves. The electric power industry needs to develop new and enhanced methods to evaluate supply adequacy, especially when a significant amount of generation capacity has an intermittent fuel source that is difficult to forecast and an increased reliance on natural gas that is used for home heating needs.

# APPENDIX A

| Cause Type | Portion of MWh lost |
|---|---|
| Fuel piping and valves A | 69.75% |
| Seal oil system and seals A | 5.84% |
| AC inverters | 4.49% |
| Circulating water piping | 3.65% |
| Automatic turbine control systems – digital control and monitoring | 3.45% |

**Table I1: Combined Cycle Gas Turbine 2021 Winter Outage Causes**

| Cause Type | Portion of MWh lost |
|---|---|
| Fuel piping and valves | 18.88% |
| Stator windings; bushings; and terminals | 18.51% |
| Circulating water pump motors | 4.48% |
| Other exhaust problems | 4.45% |
| Lack of fuel: Contract or Tariff allows for interruption | 3.48% |

**Table I2: Combined Cycle Gas Turbine 2017-2021 Winter Outage Causes**

| Cause Type | Portion of MWh lost |
|---|---|
| Fuel piping and valves | 53.17% |
| Gland seal system | 11.85% |
| Seal oil system | 6.83% |
| Circulating water piping | 4.26% |
| Turning gear and motor | 4.09% |

**Table I3: Combined Cycle Steam 2021 Winter Outage Causes**

| Cause Type | Portion of MWh lost |
|---|---|
| Stator windings, bushings and terminals | 14.41% |
| Fuel piping and valves | 11.36% |
| Buckets or blades | 5.48% |
| Circulating water pump motors | 4.17% |
| Steam turbine to gas turbine coupling | 4.08% |

**Table I4: Combined Cycle Steam 2017-2021 Winter Outage Causes**

| Cause Type | Portion of MWh lost |
|---|---|
| Stator windings; bushings; and terminals | 40.26% |
| Other turbine problems | 13.20% |
| Emergency generator trip devices | 9.20% |
| Switchyard circuit breakers – (not outside management control) | 6.32% |
| Other runner problems | 6.03% |

**Table I5: Hydro 2021 Winter Outage Causes**

| Cause Type | Portion of MWh lost |
|---|---|
| Stator windings; bushings; and terminals | 45.22% |
| Other turbine problems | 10.46% |
| Emergency generator trip devices | 6.96% |
| Other runner problems | 6.43% |
| Stator; general | 6.01% |

**Table I6: Hydro 2017-2021 Winter Outage Causes**