2023 MRO REGIONAL SUMMER ASSESSMENT

June 7, 2023

MIDWEST RELIABILITY ORGANIZATION

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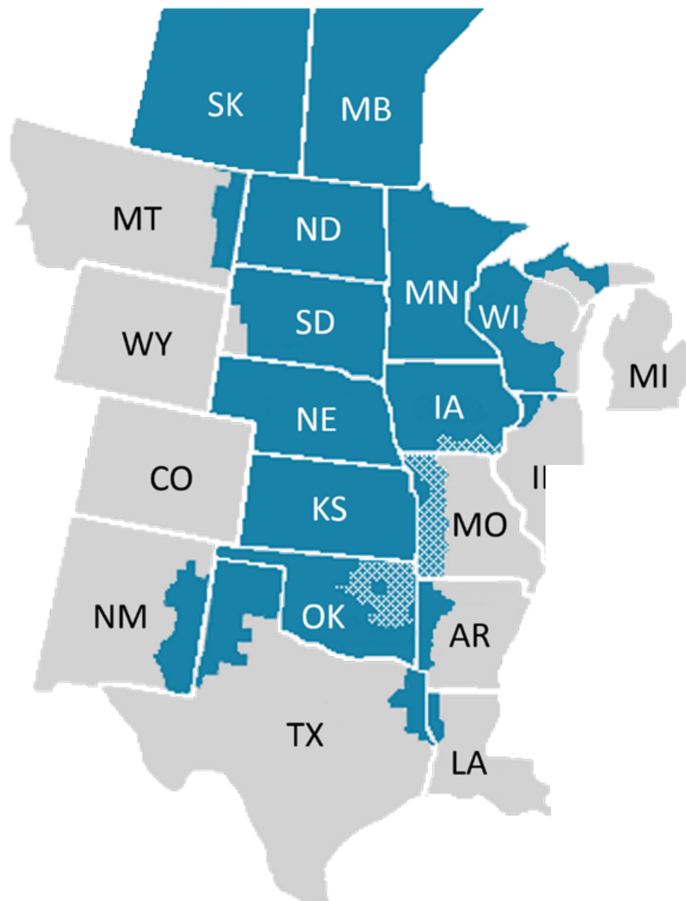
PREFACE

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

EXECUTIVE SUMMARY

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

The 2023 RSA focuses on the summer months of June through September and provides an evaluation of resource and transmission system adequacy needed to meet projected summer 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

- MH, MISO, SPC and SPP are projecting sufficient capacity available to meet normal forecasted seasonal peak load with typical maintenance and forced outages this summer.
- Above-normal summer peak load and/or unplanned outages could result in insufficient capacity to cover anticipated extreme summer peak demands. These scenarios would place MISO and SPP at high risk of implementing Energy Emergency Alerts (EEAs) and would likely require use of available demand response programs and short-term power transfers from neighboring utilities.
- MH anticipates resources are sufficient to meet reserve margin requirements under extreme demand for the 2023 summer season.
- Performance of wind generation during periods of high demand is a key factor in determining whether there is sufficient electricity supply on the system. MISO and SPP may face challenges in meeting normal or extreme peak demand if wind resource output is below historical norms.
- Conventional generation Weighted Equivalent Forced Outage Rates (WEFOR) for 2022 were higher than the five-year moving average.
    - Long-term trends continue to indicate increasing generation forced outage rates due to component fatigue and an aging fleet. This may be due in part to higher penetrations of intermittent resources that result in conventional generation cycling more than originally designed, causing component failures.
    - Continuing to monitor these long-term trends more closely during peak load periods is crucial and essential to bulk power system (BPS)[1] reliability.
- Human error is the primary contributing factor for system protection misoperations. Utilizing a robust system of controls, including human performance tools, throughout a project lifecycle can reduce misoperations due to human error.

[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.

Recommendations

To reduce the risk of energy shortfalls on the bulk power system this summer, MRO recommends the following actions:

- Reliability Coordinators (RCs), Balancing Authorities (BAs), Transmission Operators (TOPs) and Generator Operators (GOPs) should maintain situational awareness of unplanned generation and transmission outages, abnormal and extreme weather conditions, and low wind forecast periods and employ operating procedures as needed to ensure adequate resource availability.
- RCs, BAs and Generator Owners (GOs) should have safeguard protocols in place to ensure adequate generation resources are available prior to the summer season high demand period. State and provincial regulators should have plans in place at the start of summer for managing emergency requests from grid operators.
- PCs, Resource Planners (RPs) and Transmission Planners (TPs) need to develop new and improved methods to assess and evaluate supply adequacy, especially when a significant amount of generation capacity has an intermittent fuel source that can have significant forecast error.

PURPOSE

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

MRO staff annually assesses the RC and PC areas within the region to determine reliability and resource adequacy. PCs are the entities responsible for integrating transmission facilities, service plans, resource plans, and protection systems to ensure reliability. PCs collaborate with TPs to assess resource and transmission impacts within an interconnected area. RCs have a wide area view of the system and are responsible for real-time, reliable operation of the bulk power 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 2023 RSA is an independent staff assessment that utilizes some of the same data as NERC's 2023 Summer Reliability Assessment (SRA) 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 2023 summer 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 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 portion of the MISO footprint within the MRO region. 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

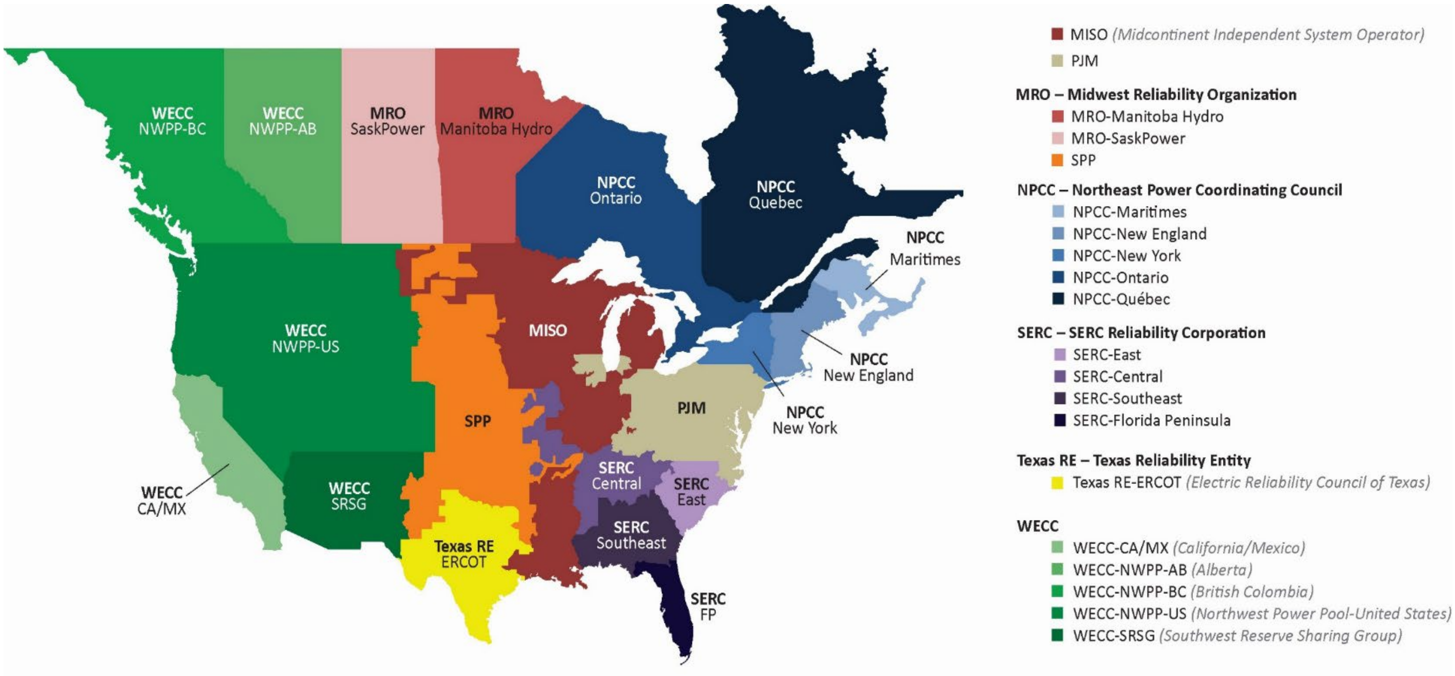


Figure C1: NERC Assessment Areas

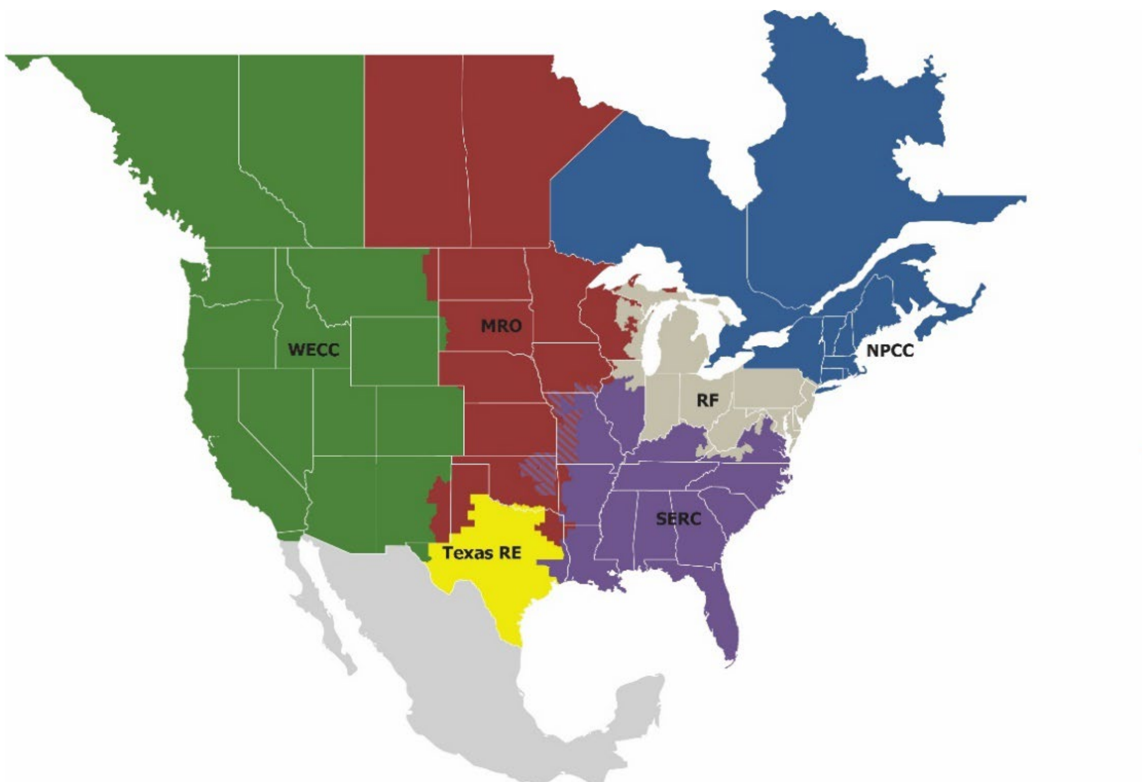


Figure C2: Regional Entity Boundaries

MRO REGISTRATION AND CERTIFICATION

Registration

There are 234 registered entities on the NERC Compliance Registry (NCR) in the MRO region. These entities are material to the reliability of the bulk power system. Functional types/scopes define the criteria each function performs, as owners, operators, and users of the bulk power system. The number of registered entities on the NCR ebbs and flows with the addition of new entities and/or the changes to existing entities' operational structure or functions. The registration process is fundamental to both the enforcement of mandatory reliability standards and the performance of reliability assessments. Functional registrations determine the entities that pose a material risk to the bulk power system and identify those entities that MRO will work closely with.

RC, BA, TOP, GO and GOP entities have an important role during summer weather operations by providing accurate operational data for analysis. The trend over the last five years shows minimal growth in all functions with the exception of the GO/GOP functions. Over this five-year period, MRO has registered approximately sixty (60) additional (roughly thirty (30) each) GOs and GOPs related to new facilities and/or ownership changes. The increase in registered GO and GOP functional types 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. Generation data provided by GOs and GOPs is crucial to TOP, BA and RC's planning and real-time operations model accuracy and critical to bulk power system reliability.

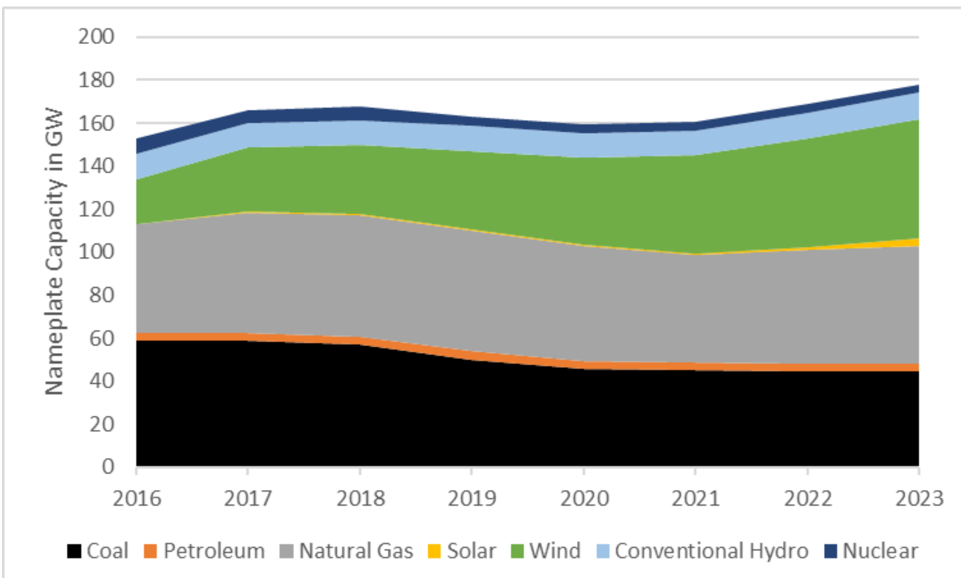


Figure D1: MRO Historical Resource Mix by Fuel Types

Certification

Real-time actions of the 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 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 five year period and averages five Certification Review activities per year. This seasonal reliability assessment 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)[3] elements.

[3] All Transmission Elements operated at 100kV or higher and Real Power and Reactive Power resources connected at 100kV or higher.

2023 SUMMER SEASONAL FORECAST

The 2023 summer seasonal forecast includes the months of June through September 2023.

Anticipated Summer Resource and Peak Demand Scenario

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

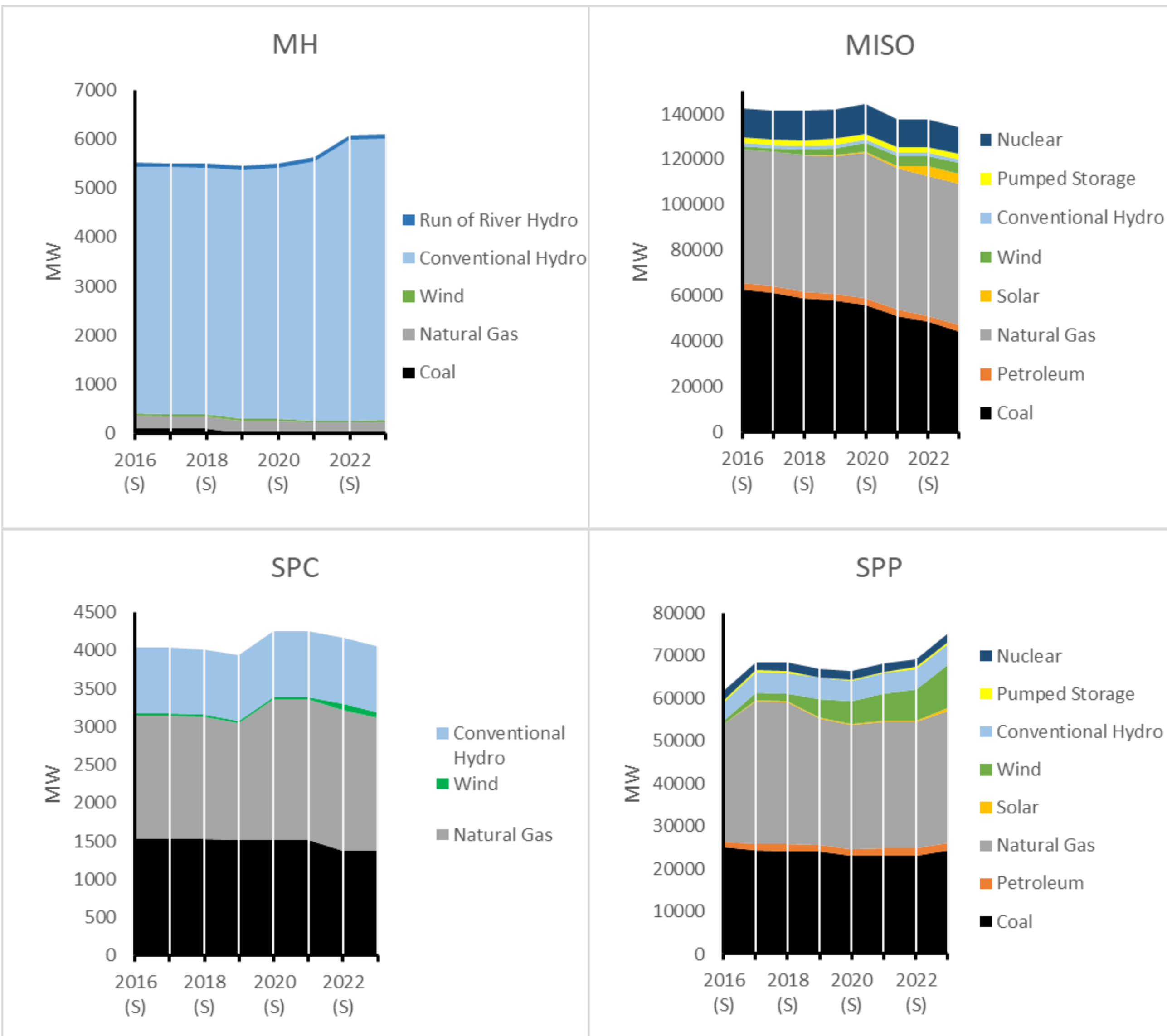


Figure F1: Generation by Fuel Type at Time of Summer Peak

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 and solar in MISO and SPP. Because of 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 nameplate capacity. For this reason, MISO and SPP wind and solar capacity accreditation is significantly lower than the total existing nameplate capacity. As penetration of intermittent resource increases, forecast errors in the output of intermittent resources available in the short-term (hours or days) become more significant. BAs may need to increase Operating Reserves to account for the uncertainty in short-term resource output.

Impacts from new technology and resource types could create reliability challenges in the foreseeable future for the MRO region. Rooftop solar, battery storage, and other distributed behind the meter generation resources will have 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 be dramatically different from what they are today.

Fossil-steam, gas, and petroleum generating plant cooling systems are less effective when cooling water input temperatures are higher. This can lead to reduced output in summer months. The increase in cooling water temperatures and low river water levels that can occur in summer may impact generators with once-through cooling, thereby reducing output capability. Environmental limitations on discharge temperatures can lead to similar restrictions. The extreme peak demand scenarios in Table F2 examine how extreme or prolonged hot and humid 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 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 is used by the industry to ensure energy availability through increased capacity and reserve margins, and 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 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, which 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 to evaluate energy availability that will provide reliable and secure operations of the bulk power system at all times.

MISO's Installed Capacity (ICAP) Planning Reserve Margin Requirements (PRMR) declined from 17.9 percent last summer to 15.9 percent for this summer 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 a number of study improvements as a result of 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.

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

The risk of reduced output from SPP generation resources that rely on cooling water from the Missouri River and other water sources is lower in 2023 than it was in the summer of 2022. This is due to additional snow and rain this winter and spring. However, SPP reserve margins have fallen this summer because of increased peak demand projections and declining anticipated resources.

SPC's 2023 summer PRMR increased to 15 percent from historic 11 percent to adequately address energy risks due to changing resource mix. There were no changes to MH's PRMR.

The summer seasonal risk scenario, which includes the cumulative impact of the occurrence of multiple low-probability events, is lower than the winter season due to better predictability of load and generation availability during the summer 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 generator maintenance outages for specified period/conditions, (e.g., average of maintenance outages for June through September 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 June through September 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 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 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 for conventional generators are based on the ICAP, which represents physical generating capacity adjusted for ambient weather conditions while renewables, such as wind and solar, capacity contributions are based on historic average values. Table F1 displays anticipated reserve margins with typical maintenance and forced outages and normal load forecast for each assessment area. The normal peak load projections are based on 50/50 weather forecasts and are provided on a coincident[4] basis for the assessment areas.

Based on the normal weather forecast with typical maintenance and forced outages as shown in Table F1, MISO, SPC and SPP are projecting insufficient resources to meet respective PRMRs for this summer. MISO has the largest deficit in resources to meet its planning reserve margin requirements. However, the operating conditions indicate that MISO, SPC and SPP have sufficient expected resources to serve the normal 50/50 peak load. The risk of being unable to meet reserve requirements at peak demand this summer in MISO is reduced compared to 2022 summer because of additional firm import commitments and a lower peak demand forecast. However, supply conditions in MISO have tightened since last summer due to a decrease in peak generation capacity when compared to the 2022 summer season. This is partially due to the retirement of coal and other conventional generation resources since last summer. Projected shortfalls will continue without an increase in predictable generation supply.

A process to determine the risk retiring generation poses to reliability, and to prevent or delay retirement of generators required to maintain reliable operations, is needed to mitigate potential risks of insufficient energy supplies during peak summer conditions. At least until new, predictable resources are available. Maintaining a higher reserve margin requirement will also compensate for declining energy margins.

Assessment Area	Anticipated Resources	Typical Maintenance and Forced Outages	Anticipated Resources with Typical Outages	Normal Peak Load	Anticipated Reserve Margin with Typical Outages	PRMR
MH	3,950	106	3,844	3,060	**25.6%**	12.0%
MISO	143,668	21,853	121,815	116,825	**4.3%**	15.9%
SPC	4,503	568	3,935	3,489	**12.8%**	15.0%
SPP	65,583	5,450	60,133	52,626	**14.3%**	19.0%

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

The worst-case scenario for summer 2023 considers increased resource outages and derates combined with an extreme peak load forecast as shown in Table F2.

The reserve margin percentage in Table F3 predicts the likelihood of an area issuing EEAs and is calculated using the difference between Extreme Low Generation plus Operational Mitigations and Extreme Peak Load.

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

Assessment Area	Anticipated Resources with Typical Outages	Extreme Derates	Extreme Low Generation	Operational Mitigations	Extreme Low Generation + Operational Mitigations	Extreme Peak Load
MH	3,844	10	3,834	0	3,834	3,390
MISO	121,815	8,950	112,865	2,400	115,265	123,871
SPC	3,935	372	3,563	347	3,910	3,633
SPP	60,133	7,196	52,937	0	52,937	55,126

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

Assessment Area	Extreme Low Generation + Operational Mitigations	Extreme Peak Load	Reserve Margin Under Extreme Conditions	Operating Reserves	Likelihood to issue EEAs
MH	3,834	3,390	**+13.1%**	150	Low
MISO	115,265	123,871	**-6.9%**	2,400	**High**
SPC	3,910	3,633	**+7.6%**	337	Low
SPP	52,937	55,126	**-4.0%**	2,000	**High**

Table F3: Reserve Margin Percentage under Extreme Summer Conditions

The extreme low generation plus operational mitigation scenario in Table F3 shows that MISO and SPP resources fall below anticipated demand. Under the extreme summer peak demand and outage scenario studied, MISO and SPP are at increased risk to issue EEAs and implement operating mitigations, such as demand response programs and short-term power transfers from neighboring utilities, to meet the resource requirements during extreme summer peak demand.

SPC is a winter-peaking region, but also experiences high load in summer during extreme hot weather. The likelihood of operating reserve shortages in SPC during extreme summer peak load is low. However, large generation forced outages that occur with planned transmission tie-line maintenance work or generation maintenance work scheduled during the summer months, could lead to SPC issuing EEAs and implementing operating mitigations. These mitigations could include demand response programs, short-term power transfers from neighboring utilities, and if necessary, load interruptions. MH anticipates resources are sufficient to meet reserve margin requirements under extreme demand for the 2023 summer season.

This worst-case scenario has a much higher than expected number of resource derates (partial outage with associated reduction in capacity) when combined with excessively hot and humid days. Extreme hot weather is becoming more prevalent in the Midwest and in the South. Recent events have shown prolonged hot temperatures and drought could occur and jeopardize the reliable operation of the bulk power system.

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 summer 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[5] 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. FERC recently rejected SPP's ELCC accreditation filing for wind and solar resources. As a result, SPP is calculating wind based on historical availability during peaks and is assuming 4,500 MW of availability for 2023 summer.

Figure F2: Wind and Solar Photovoltaic Nameplate and Peak Capacity

5 Garver, L. L. (1966) "Effective Load-Carrying Capability of Generating Units." IEEE Transactions on Power Apparatus and Systems. Vol PAS-85.

2023 Summer 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 2023 summer season. Although MH has experienced unanticipated higher than normal summer load conditions in the past, no changes are required to operating plans/procedures or seasonal resource planning for the upcoming summer season because anticipated reserve margins exceed the reference margin level. Six of the seven units at the Keeyask Hydro Station are in commercial operation for summer 2023.

MISO

Midcontinent Independent System Operator (MISO) projects sufficient capacity available for the upcoming 2023 summer season based on normal weather conditions. The risk of being unable to meet reserve requirements at peak demand this summer is lower than in 2022 due to additional firm imports and lower peak load forecast. MISO may need to utilize Load Modifying Resources (LMRs) during extreme conditions 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.

Though risk has been identified for extreme summer season scenarios, MISO operators anticipate that system reliability can be maintained using Load Modifying Resources (LMRs) and when necessary and available, scheduling 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 summer conditions.

SPC

Saskatchewan Power Corporation (SPC) is a winter peaking region, but also experiences high load in summer during extreme hot weather. No impactful fuel supply or transportation issues with coal or natural gas facilities are expected for the upcoming summer season. The risk of operating reserve shortages during extreme summer 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 is scheduled during summer months. SPC may have to rely on demand response programs, short-term power transfers from neighboring utilities, and if necessary, load interruptions during extreme demand from high temperatures.

SPP

Southwest Power Pool (SPP) is projecting a low likelihood of emerging reliability issues impacting the area for the upcoming summer 2023 season under normal conditions. In the past year, SPP experienced some resource retirements and unexpected forced outages that lasted for an extended period. The result was a 1.5 to 2 GW decrease of available capacity compared to the previous summer season. This trend could result in tight energy conditions on peak summer days when demand is high and the availability of wind generation is low. 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 the summer peak season. Although reliability issues, such as extreme weather events and weather forecast errors can disrupt real-time operations, SPP has comprehensive procedures that help mitigate the impact of such events.

Using the current operational processes and procedures, SPP will continue to monitor reliability of the system throughout the 2023 summer season and will adjust as needed to ensure that real time reliability is maintained throughout the summer timeframe.

2022 SUMMER SEASONAL REVIEW

The 2022 summer 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 Summer 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 industry stakeholders.

The MRO region saw a total of seventeen transmission events on the system in 2022, two of which occurred during the 2022 summer months. Both events involved the unintended operation of protection systems. MRO continues to collaborate with registered entities through the Protective Relay Subgroup (PRS) on efforts to reduce protection system misoperations. MRO worked with NERC to publish one lesson learned for the 2022 summer season to share information regarding the following reliability concern: Unintended Consequences of Altering Protection System Wiring to Accommodate Failing Equipment. This lesson learned was developed to demonstrate the consequences of not removing failing equipment in a timely manner and illustrated system impacts when a simple wiring change is not carefully planned and engineered. In collaboration with the PRS, MRO held a webinar in July 2022 that reviewed protection system commissioning practices found in the joint FERC, NERC and Regional Entities Joint Review of Protection System Commissioning Programs report that was published in November of 2021.

MRO has worked closely with entities over the past five years to analyze these significant transmission events and in general the region has seen a decrease in the average BPS impact. Figure G1 illustrates MRO's Event Severity Index, which includes all events and allows for comparison of the impact of each event 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 impact of all the events each year, which MRO uses as a general indicator of how entities are limiting the impacts of events on the BES. The primary focus of MRO is to limit large-impact events, especially those that could potentially lead to a cascading event.

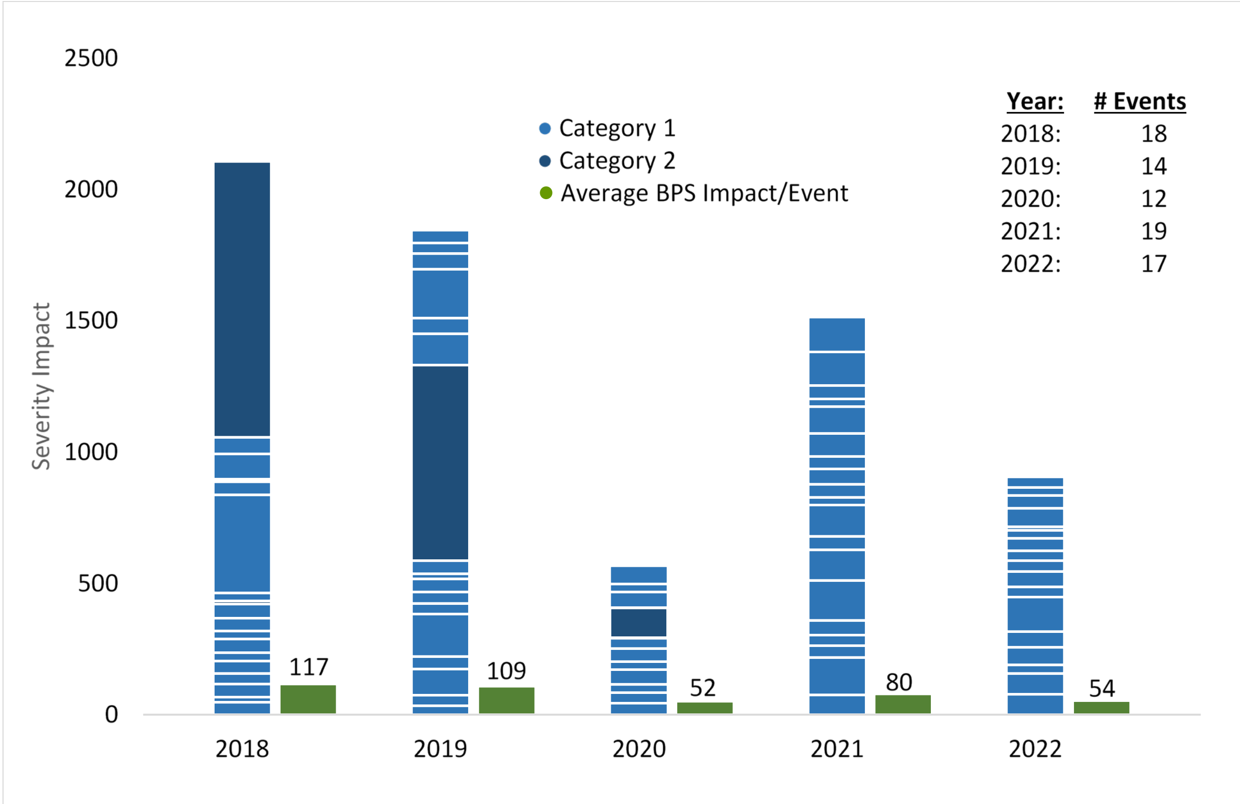


Figure G1: MRO Event Severity Index as of December 2022

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 the two BES events that occurred during the summer of 2022, including the event category, number of BES facilities lost, MW of generation lost, and MW of load lost.

June 20, 2022 Transmission Event

Event Category: 1a

- # of BES facilities Interrupted: 6
- MW of Generation Lost: 0 MW

- MW of Load Lost: 34.7 MW

On June 20, 2022, at 12:54 p.m. CST, a fault on the 115kV side of a 345/115kV transformer caused a lock out via the transformer differential protection, as well as the operation of a 345kV line to an adjacent substation. The failure that created the initial fault caused another fault 2.5 seconds later, on another line connected to the 115kV bus. A device failure in the differential relaying for a second 345/115kV transformer at the same substation caused a trip and lock out of the second transformer and initiated a transfer trip, which led to two additional 345kV line outages. The system was restored to service at 2:22 p.m. CST. The failed relay was disabled and sent to the manufacturer for analysis.

June 24, 2022 Transmission Event

Event Category: 1a

- # of BES facilities Interrupted: 4
- MW of Generation Lost: 13 MW
- MW of Load Lost: 0 MW

On June 24, 2022, three lightning strikes occurred at 7:40 p.m. CST within a generating facility. The lightning strikes occurred near a common tower shared by two 115kV transmission lines, which cleared instantaneously via the Permissive Overreaching Transfer Trip (POTT) scheme protection. Another 115kV line open ended at the remote station due to a misoperation on zone 1 distance protection with the local end remaining closed. The three transmission outages islanded two generators from the system, resulting in one of the islanded generators tripping on reverse power protection.

The three transmission lines were restored to service within 12 minutes and the generator was restored in 4 hours and 56 minutes.

Protection calculations for the relay misoperation were verified and the relay was retested to ensure correct operation.

Loss of Energy Management System Events

Described below are the event categories in the Loss of EMS Event Time Duration chart shown in Figure G2.

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 were three Category 1h (loss of monitoring or control at a control center) EMS-related system events within the MRO region in the summer of 2022 with an average duration of 91 minutes. This was significantly less than the 2022 average event duration of 144 minutes.

A common factor identified in these EMS events was occurrence either during or shortly after routine maintenance procedures. This was the case with the summer 2022 events where the cause of the events directly related to human error during 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.

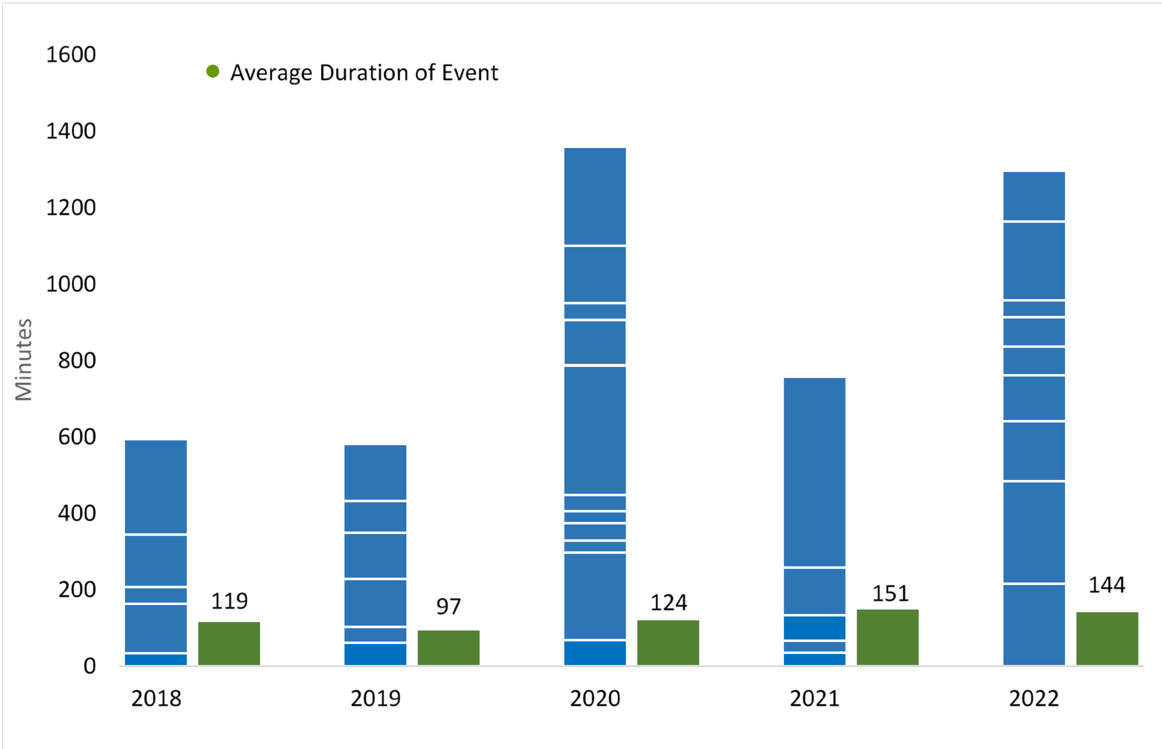


Figure G2: Loss of EMS Event Time Duration

Energy Emergency Alerts

An energy emergency is a condition that occurs when a load serving entity or BA has exhausted all other resource options and can no longer meet its expected load and operating reserves. EEAs are issued by the RC. NERC Reliability Standard EOP-011-2 addresses the effects of operating emergencies by ensuring each TOP and BA has developed an Operating Plan(s) to mitigate operating emergencies, and that those plans are coordinated within an RC area. To ensure that all RCs clearly understand potential and actual energy emergencies, NERC established three levels of EEAs. More information on the three EEA levels can be found in EOP-011-2 Emergency Operations Reliability Standard.

The MRO region experienced five energy emergencies during the summer of 2022. Details are as follows:

<u>June 12, 2022 – EEA Level 2 Event</u>

On June 12, 2022, at 10:40 p.m. CST an entity declared an EEA2. A forced outage on a 345kV line reduced import capability in the area prompting an EEA1. As load increased, an EEA2 was issued. Interruptible load, DC Tie imports, and load-side management actions were implemented. After the load peaked, an EEA0 was issued at 1:45 a.m. CST when the entity was able to meet all obligations.

<u>June 16, 2022 – EEA Level 2 Event</u>

On June 16, 2022, at 7:37 p.m. CST an entity declared an EEA2. A forced outage on a 345kV line reduced import capability in the area prompting an EEA1. A gas turbine generator failed to start and the entity was unable to import reserves. The EEA2 was declared to cover the Most Severe Single Contingency (MSSC). Area Control Error (ACE) was maintained throughout this event. An EEA1 was issued once sufficient reserves were available to cover the MSSC and the entity was able to meet obligations. EEA0 was issued at 8:36 p.m. CST.

July 18, 2022 – EEA Level 2 Event

On July 18, 2022, at 5:01 p.m. CST, an entity declared an EEA1 when approximately 350 MW of generation was lost due to shaft vibration. The output of another generator was approximately 150 MW of the 300 MW max output and all other units were online as required. When the EEA1 was declared, the operating reserves were at 292 MW when 320 MW was required. An EEA2 was declared when wind generation decreased and an operating reserve of 279 MW of the required 292 MW was reached. No load was shed. Imports of approximately 150 MW were secured and an EEA0 was declared at 6:48 p.m. CST.

July 29, 2022 – EEA Level 2 Event

On July 29, 2022, at 12:31 p.m. CST, an entity declared an EEA2 once operating reserves reached 292 MW when actual load was higher than forecasted, higher ambient temperatures increased de-rates on the gas generation fleet, and wind production was zero (0) MW. A demand response curtailment was enacted of approximately 35 MW. Loads decreased and wind production increased to allow an EEA0 to be declared at 6:00 p.m. CST.

August 15, 2022 – EEA Level 1 Event

On August 15, 2022, at 11:51 a.m. CST, an entity declared an EEA1. Actual system loads were higher than forecasted due to higher-than-expected temperatures. Wind production was low and all units available were brought online. Operating reserves were at 292 MW when 301 MW was required. Imports of approximately 85 MW were secured and EEA0 was declared at 5:41 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. Reporting for both solar and wind will become mandatory on January 1, 2024.

Resource Mix

A diverse mix of fuel types is reflected in MRO's 2023 summer peak accredited capacity as shown in Figure G3. Conventional generation with large rotating mass (i.e., 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 55,000 MW of installed nameplate wind capacity. However, only about 14,000 MW of wind is accredited for 2023 summer peak demand. Multiple proposed projects exist in the MISO and SPP generation interconnection queue that will add approximately 35,000 MW of nameplate wind capacity to the MRO region by summer 2032. Operational challenges associated with large amounts 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 intermittent resources such as wind and solar is also contributing to operational complexity in terms of 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. Approximately 51,000 MW of proposed solar projects exist in the MISO and SPP generation interconnection queue for installation by summer 2032. It is important to note that not every wind and solar project on the interconnection queue will be built, as some requests may withdraw 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.

The move away from conventional generation to intermittent resources require BAs to have unloaded capacity available that can ramp quickly and respond to reduced outputs from intermittent resources. Unloaded capacity refers to any portion of online generation capacity that is not serving load and offline generation capacity that can come online quickly to serve load. 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 operator 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.

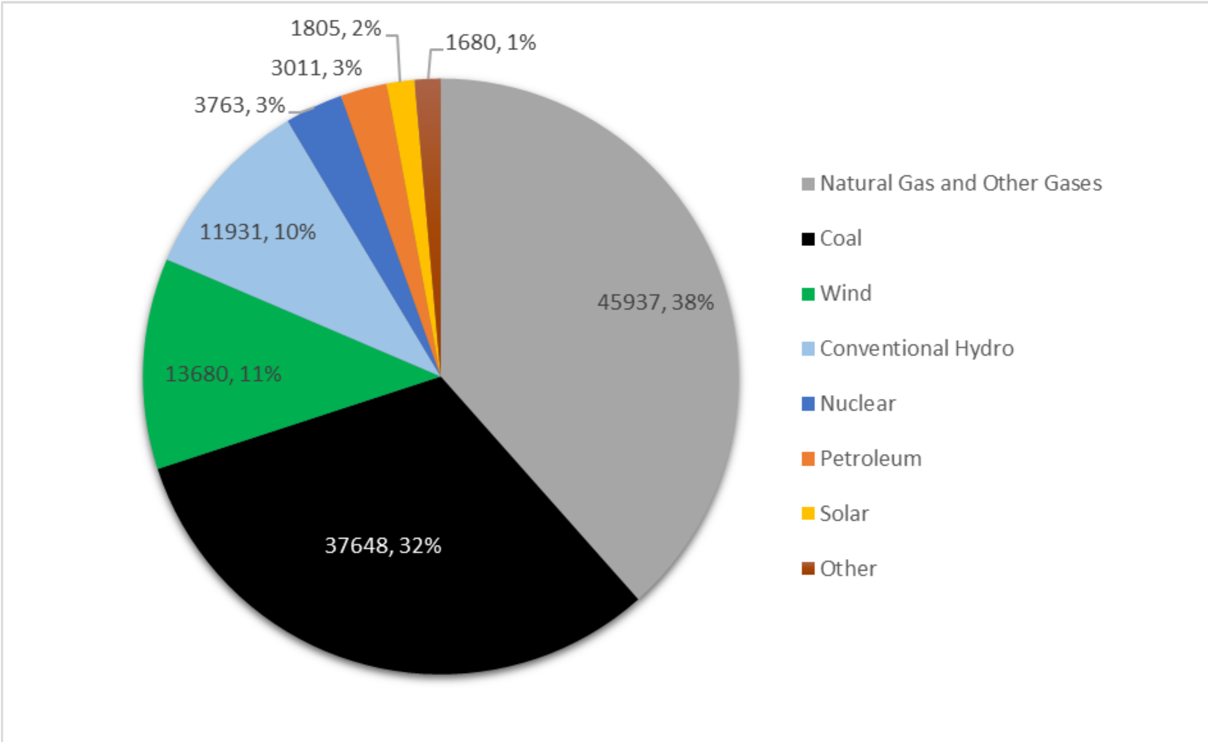


Figure G3: MRO 2023 Summer Peak Capacity by Fuel Types

The largest single contributor of generation by peak capacity in the MRO region is natural gas, of which approximately 70 percent of gas plants are located in the southern portion of the region. Coal plants and wind turbine generators make up the next largest portions of the generation mix. Generation unavailability can have a substantial impact on reliability. Useful metrics for generator unavailability are the equivalent forced outage rates (EFOR)[6] and Megawatt Weighted EFOR or (WEFOR)[7]. For the MRO region, the annual conventional generator forced outage rates for all seasons is shown in Figure G4 and is on an upward trend over the five-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 partially attributed to a cold weather event that occurred in February 2021. An increased WEFOR in 2022 continues a trend in rising WEFOR over the moving 5-year average. The elevated WEFOR in 2022 is further broken down in Figure G5, showing monthly WEFOR by year. 2022 summer season forced outages were comparable to the average summer season WEFOR, but 2022 winter season forced outages were higher than the previous winter season WEFOR. Notably, severe winter storms in the Midwest in December 2022 drove WEFOR across unit types to their highest levels in the five-year span. 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 cycled to follow load and operating at minimum output more often, increasing the number of forced outages due to component failures.

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[6] 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

[7] 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.

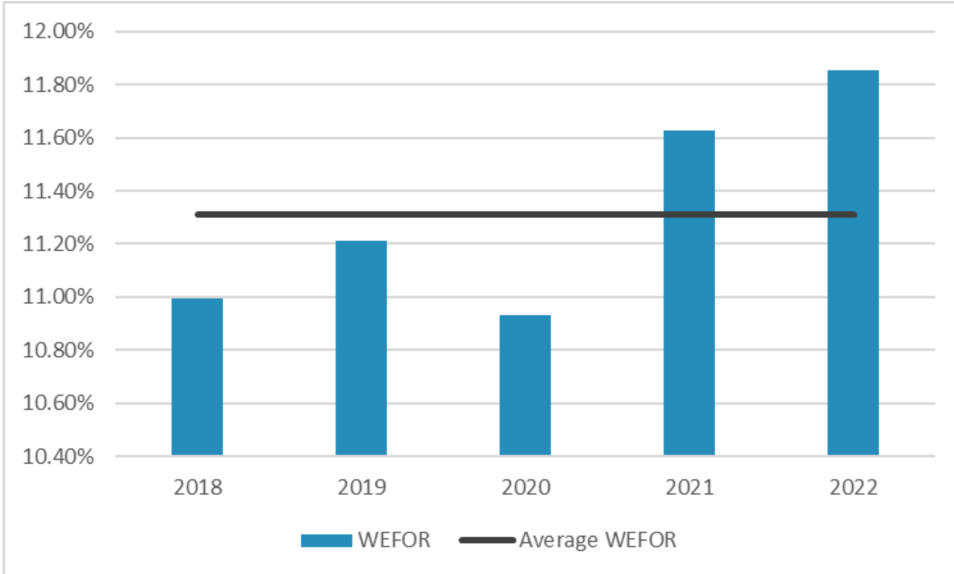


Figure G4: MRO Annual Generator MW-Weighted EFOR

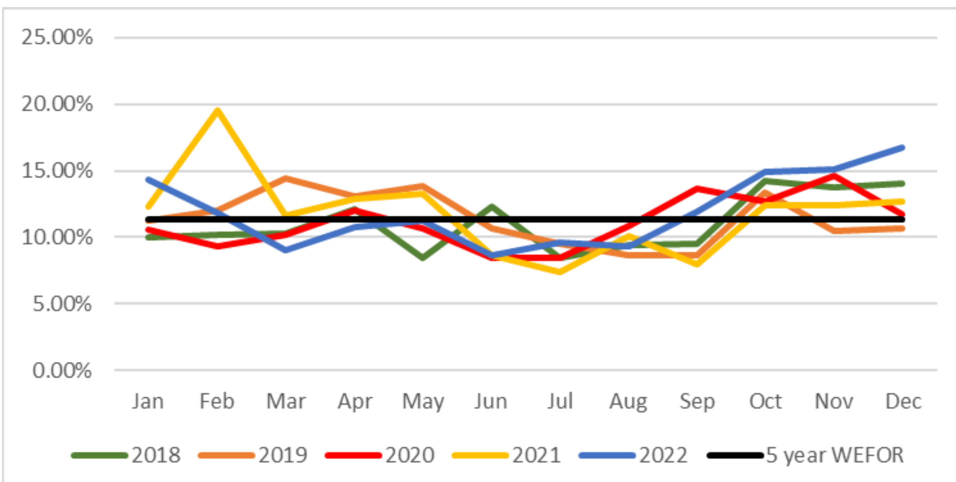


Figure G5: MW-Weighted EFOR by Month

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 2022 and five-year historical event impact in the MRO footprint over the summer months.

Figure G6 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. Even though fossil-steam generation shows a high event impact of 17,298 GWh, the total event impact of 25,739 GWh for all generation types has less impact to the BES. The 2022 summer season saw a substantially higher event impact than 2021 summer, though comparable to the average event impact over the five-year span. This is partially due to event impact and total WEFOR in summer 2021 being substantially better than the five-year average. However, sizable impact events during the 2022 summer season for fossil steam facilities produced higher event impacts as well as increased WEFOR percentages in August and September.

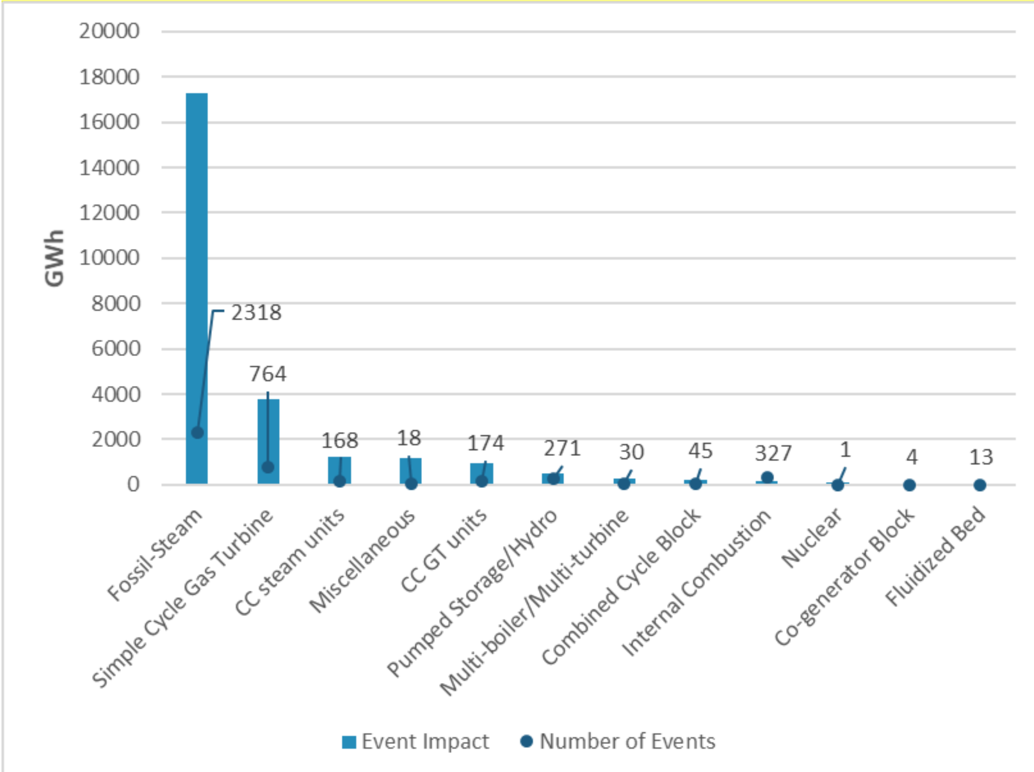


Figure G6: Total Event Impact and Number of Event Impact for Summer 2022

Table G1 shows the top causes of forced outages, forced derates, and startup failures by event impact for fossil-steam plants in summer 2022. Table G2 shows the same information for the five-year historical summer season.

Cause Type	Portion of MWh lost
Waterwall (furnace wall)	6.05%
Unit Auxiliaries Transformer	5.53%
First Reheater	3.95%
Buckets or Blades C	3.86%
Circulating Water Pumps	3.19%

Table G1: Fossil-Steam 2022 Summer Outage Causes

Cause Type	Portion of MWh lost
Waterwall (furnace wall)	5.39%
Plant Modifications Strictly for Compliance (with new or changed regulatory requirements)	4.16%
Differential Expansion	2.68%
First Reheater	2.63%
Air Heater (regenerative)	2.62%

Table G2: Fossil-Steam 2018-2022 Summer Outage Causes

Fossil steam outages were driven by a wide variety of causes over the 2022 summer period and were seen consistently across the fleet, except for Unit Auxiliary Transformers. This transformer cause code was primarily attributed to a single isolated high duration event. Waterwall was the primary outage cause for summer 2022. Notably, between the 2018 and 2022 summer periods, causes for fossil steam outages were dominated by cases of extreme forced outage 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 are due to aging, fatigue, or component failure from frequent cycling. The sizable increase in event impact is largely attributed to increases in the most common outage types, with waterwall outages being substantially more impactful in the summer of 2022 along with increases in reheater outages. This, in addition to some impactful auxiliary transformer outages, describe forced outages that are comparable with the increasing five-year trend of summer fossil-steam forced outage performance.

Table G3 show the top causes of forced outage, forced derate, and startup failure by event impact for simple cycle gas turbines in summer 2022. Table G4 shows the same data for the five-year historical summer period.

Cause Type	Portion of MWh lost
Other compressor problems	15.42%
Engine vibration	13.23%
Seal oil system and seals B	4.93%
Lack of fuel: Contract or Tariff allows for interruption	4.23%
Lube oil system A	4.21%

Table G3: Simple Cycle Gas Turbine 2022 Summer Outage Causes

Cause Type	Portion of MWh lost
Lack of fuel: Physical failures of fuel supply or delivery/transportation of fuel	8.50%
Lack of fuel where the operator is not in control of contracts; supply lines; or delivery of fuels	8.17%
Other compressor problems	5.15%
Engine vibration	4.40%
High pressure blades/buckets B	3.64%

Table G4: Simple Cycle Gas Turbine 2018-2022 Summer Outage Causes

The 2022 summer event impact was greatly elevated over the 2021 summer season. However, 2022 was comparable with the average event impact over the five-year span. In 2022, event impact was heavily clustered around other compressor problems and engine vibrations, which account for much of the increase over the previous season's event impact. These are dominated by a few events of extreme length on smaller units and not demonstrating a larger trend. Similarly, the other mechanical failures of lube oil systems and seal oil systems were both overshadowed by small numbers of high duration events on medium sized units. "Lack of fuel: contract or tariff allows for interruption" is a well-distributed event cause in the summer of 2022 across a variety of units and unit sizes, and maps to the top cause codes of the five-year span. It remains an ongoing concern for this generation class, especially during the winter season.

Summer 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. 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. Higher forced outage rates of fossil-steam and simple cycle gas could impact the generation resource availability during extreme summer peak demand and increase the number and duration of EEA events. Maintaining a robust and reliable fleet of dispatchable resources is needed to serve energy and integrate 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 both regionally and North American-wide, provides useful data in reliability analyses. This section summarizes the transmission outages experienced during the summer of 2022.

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.

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

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

Table G5: AC Transmission Circuit Miles

Figure G7 shows 100kV and above automatic outages that include both momentary (for 200kV and above) and sustained outages for June through September for 2018 through 2022. As shown in Figure G7, automatic outages for August and September of 2022 were considerably lower than previous years. Whereas June and July of 2022 were comparable with previous years. The tall blue bar for August 2020 is largely due to a severe derecho that impacted the Midwest on August 10-11. During those two days, 58 sustained 100-199kV outages were reported. This is over half of the number of outages typically recorded for the whole month of August. This illustrates how significantly a single severe weather event can impact BES reliability. There were only three 400-599kV outages during 2022 summer, one was initiated by Lightning and two were initiated by Failed AC Equipment. Since there were so few 400-599kV operations, they are not included in the analysis below.

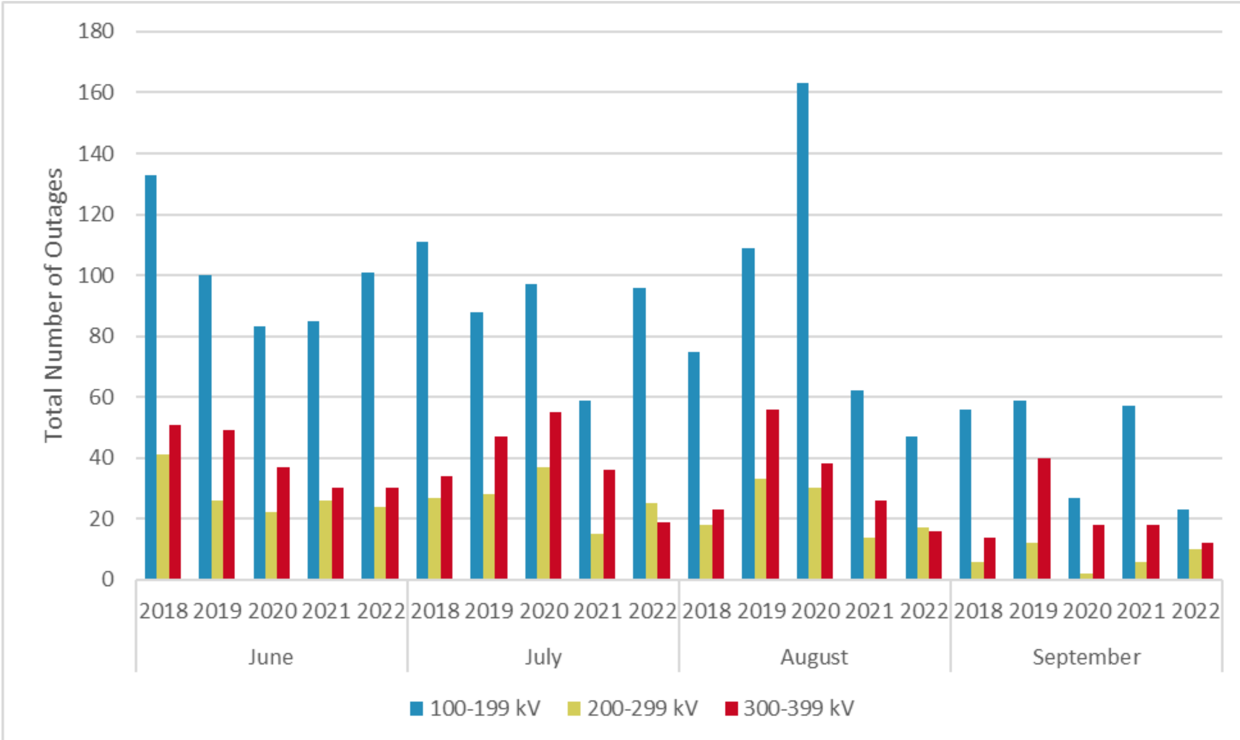


Figure G7: Summer 2018-2022 Automatic Outages by Month

Momentary outages are automatic outages (non-operator initiated) with a duration of less than one minute. If the circuit recloses and trips again within a minute of the initial outage, it is only considered one outage. Figure G8 shows the major causes of momentary outages for 200kV and above for June through September from 2018 through 2022. Figure G8 indicates that most momentary outages during this timeframe were weather related, primarily due to lightning. Figure G8 also illustrates a significant number of momentary outages with an unknown cause. This may indicate that thorough line inspections after transient faults during weather events are typically not performed. It may also indicate that even if an inspection is performed, a definitive cause for transient faults cannot be determined. For the five momentary outage causes shown, 2022 had 36 percent fewer outages than 2021.

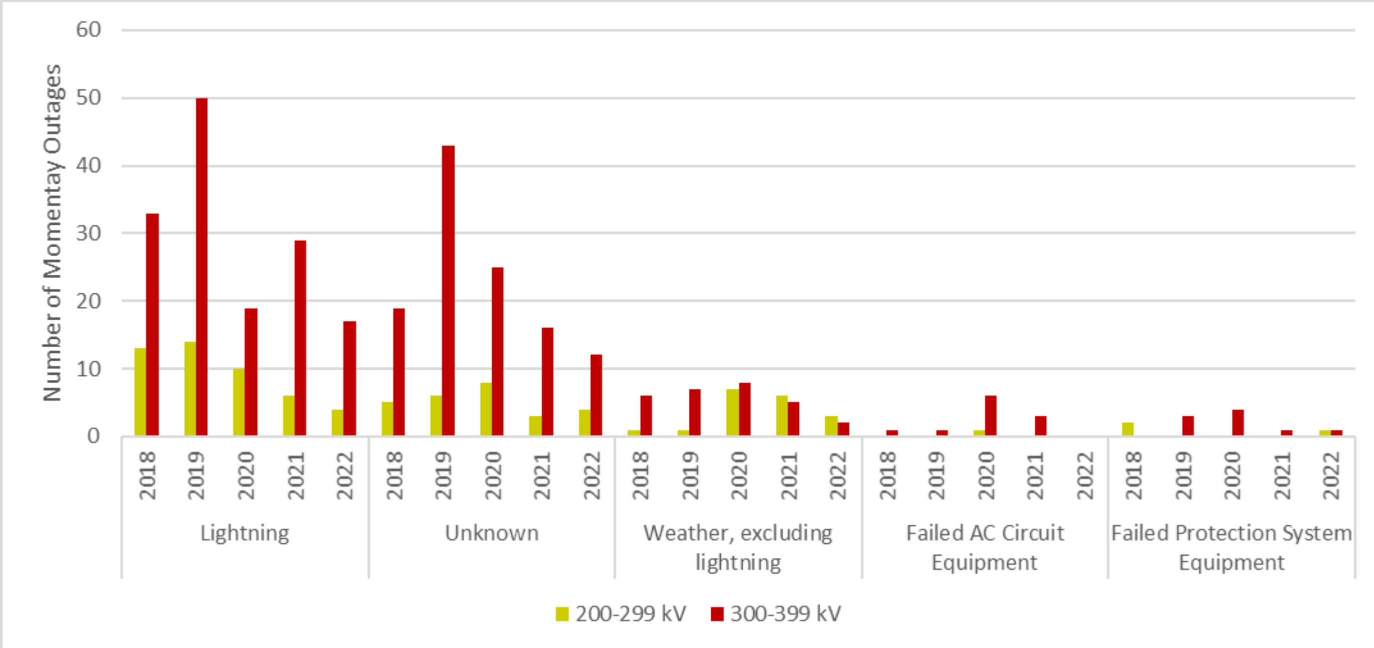


Figure G8: Summer 2018-2022 Momentary Outages by Cause

The TADS definition of a sustained outage is an automatic outage with a duration of one minute or greater. Figure G9 below shows that failed AC circuit equipment was the most significant contributor to sustained 115kV outages during the summer of 2022. However, for the six sustained outage causes shown, 2022 had 8 percent fewer outages than 2021.

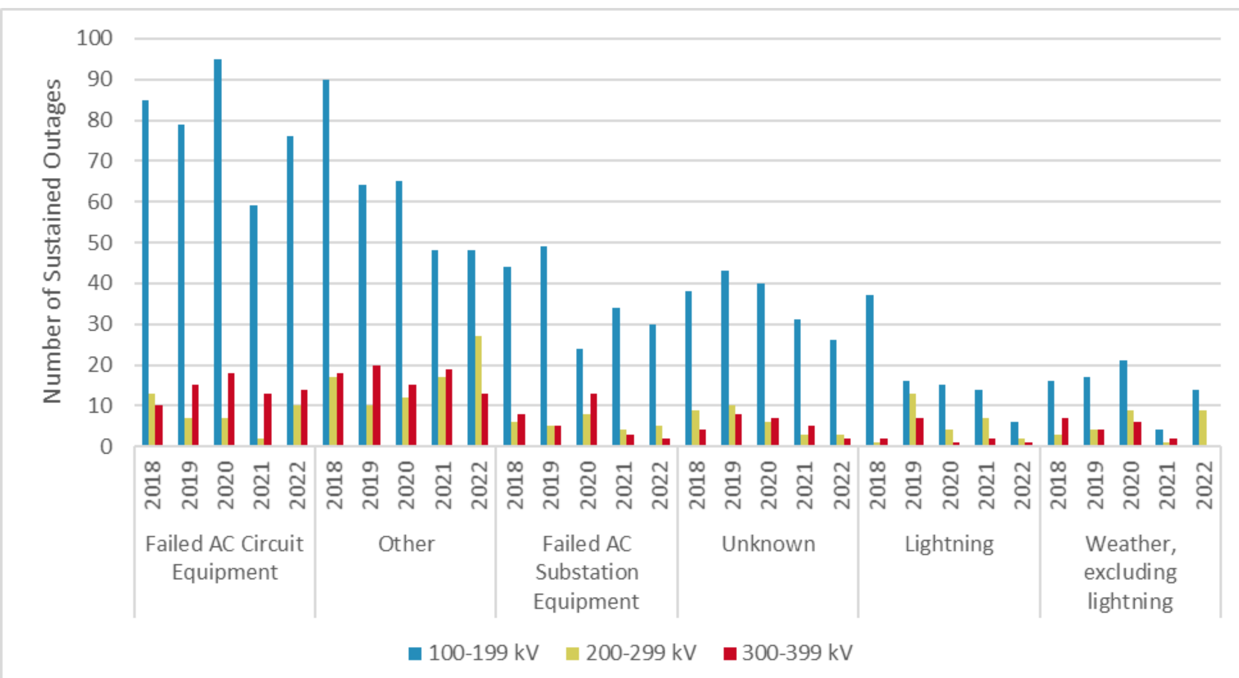


Figure G9: Summer 2018-2022 Sustained Outages by Cause

Figure G10 reflects the yearly summer total outages per 100 circuit miles for 100-399kV circuits. The chart clearly shows a decrease in yearly outages between 2020 and 2021, with outages levelling off in 2022. The reason for this decrease may be partly attributed to the unusually dry weather pattern that existed across much of the MRO region, since weather is a major contributor to outages. The high number of outages for 300-399kV circuits in 2019 was due to momentary outages, which were at least 55 percent higher than any other year shown in figure G10. Over 76 percent of the momentary outages in 2019 were coded as either Lightning or Unknown.

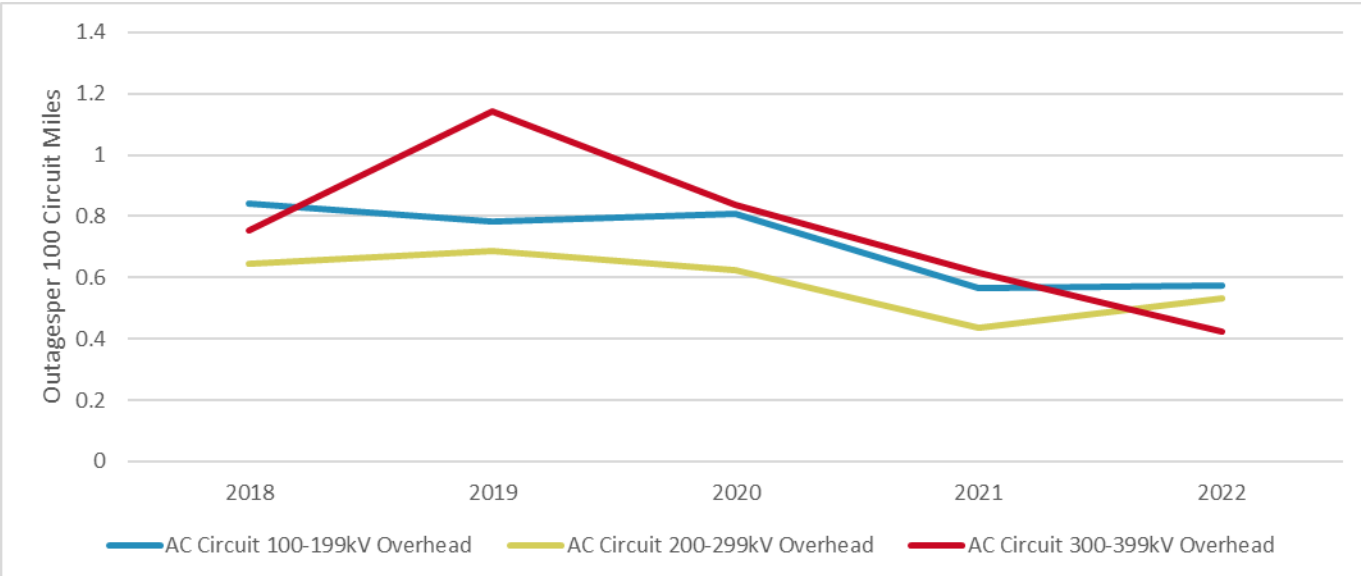


Figure G10: Total Transmission Outages per 100 Circuit Miles

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 G11 from the 2022 NERC State of Reliability report.

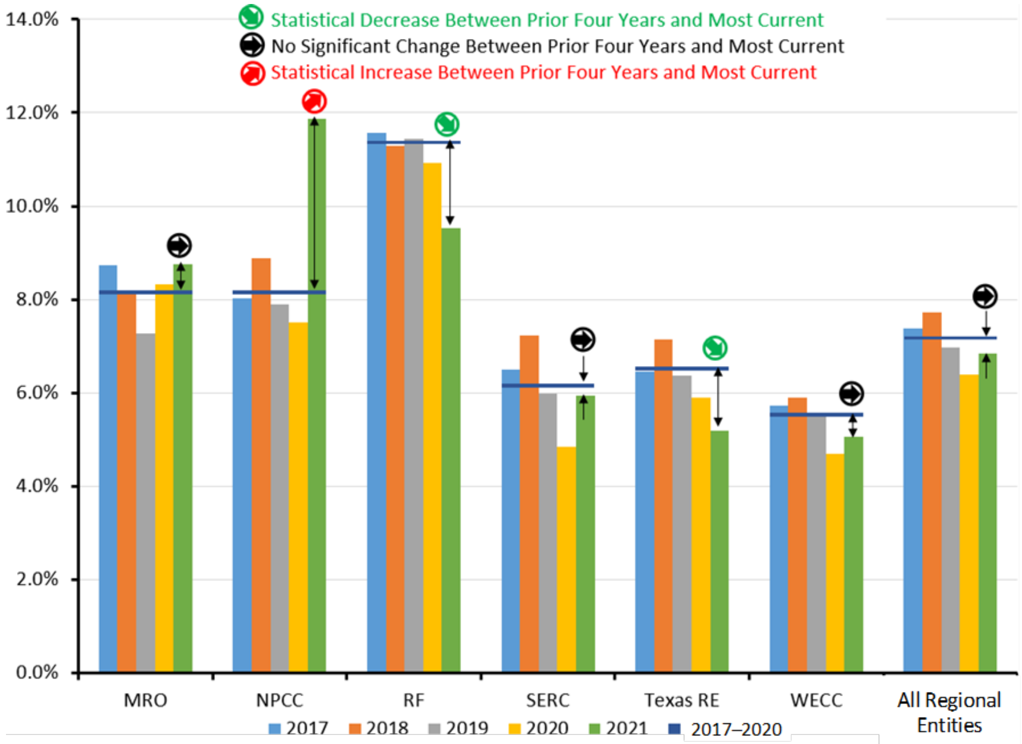


Figure G11: Year-Over-Year Changes and Trends in the Annual Misoperations Rate by Region

There were 3,298 operations and 281 misoperations reported within the MRO region in 2022 for a misoperation rate of 8.52 percent. Figure G12 shows the misoperation rate had been trending downward until 2020. The upward trend seen in 2020 and 2021 did not continue in 2022, but the decrease in the misoperation rate was marginal.

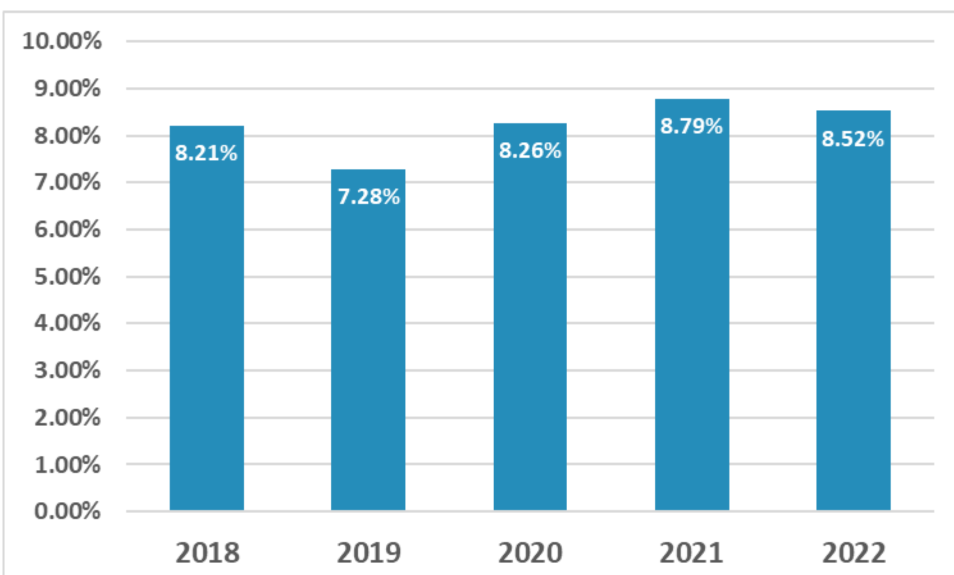


Figure G12: MRO Misoperation Rate by Year

Figures G13 and G14 provide context for the misoperation rate for 2022. Total protection system operations increased about 25 percent in 2022 from the previous year and total misoperations increased approximately 22 percent, resulting in a slightly lower misoperation rate. Overall, Figures G13 and G14 show that 2022 was an average year for both total operations and misoperations.

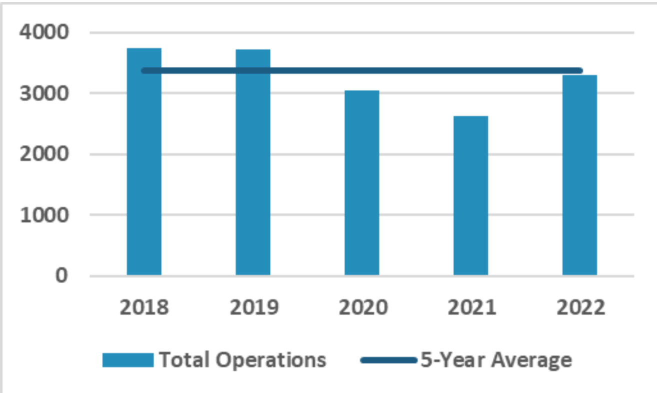


Figure G13: Protection System Operations by Year

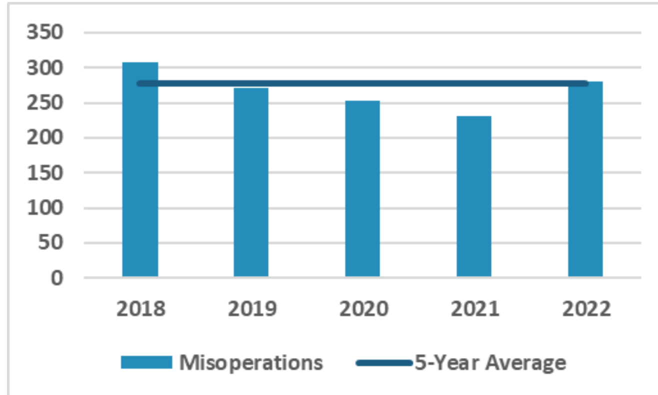


Figure G14: Misoperations by Year

The cause for the significant increase in total operations from the previous year is difficult to pinpoint. Of the 3,298 total operations that were reported in MIDAS for 2022, 2,290 of them occurred at voltages less than 200kV. Of those 2,290 outages, only 794 of them were sustained outages; the other 1,496 were momentary outages. As neither TADS nor MIDAS collects outage cause data on momentary outages at voltages less than 200kV, the causes of those outages remain unknown to MRO. Those outages made up approximately 45 percent of the reported outages that occurred in 2022, and although similar percentages were seen in previous years, MRO cannot definitively attribute the increase 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, as shown in Figure G15 below.

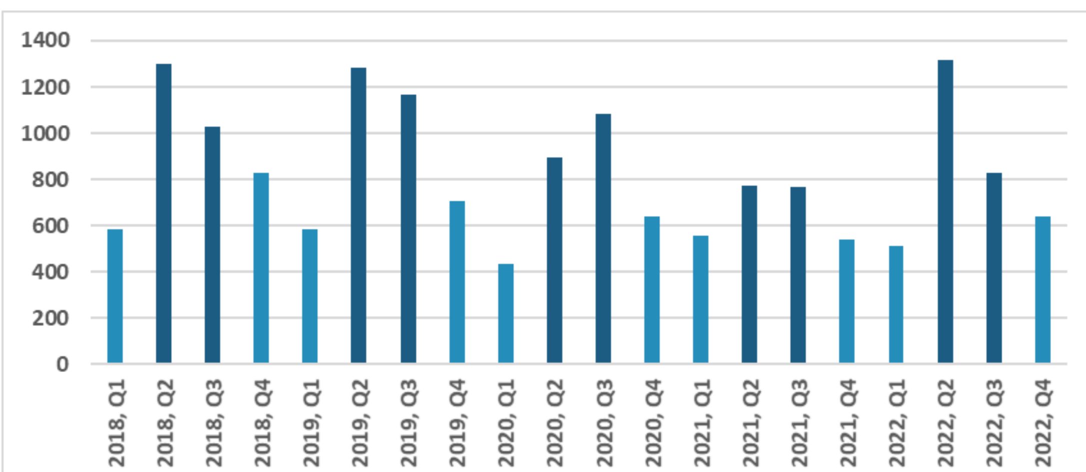


Figure G15: Total Operations (Spring/Summer vs. Autumn/Winter)

MIDAS reports are completed and reported by entities quarterly. The second and third quarters of the year (April 1 through September 30) align closest to the summer season (June 1 through September 30) for this assessment. As shown in Figure G16, many misoperations are not associated with a fault. Non-fault associated misoperations have a smaller variance than misoperations associated with a fault 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.

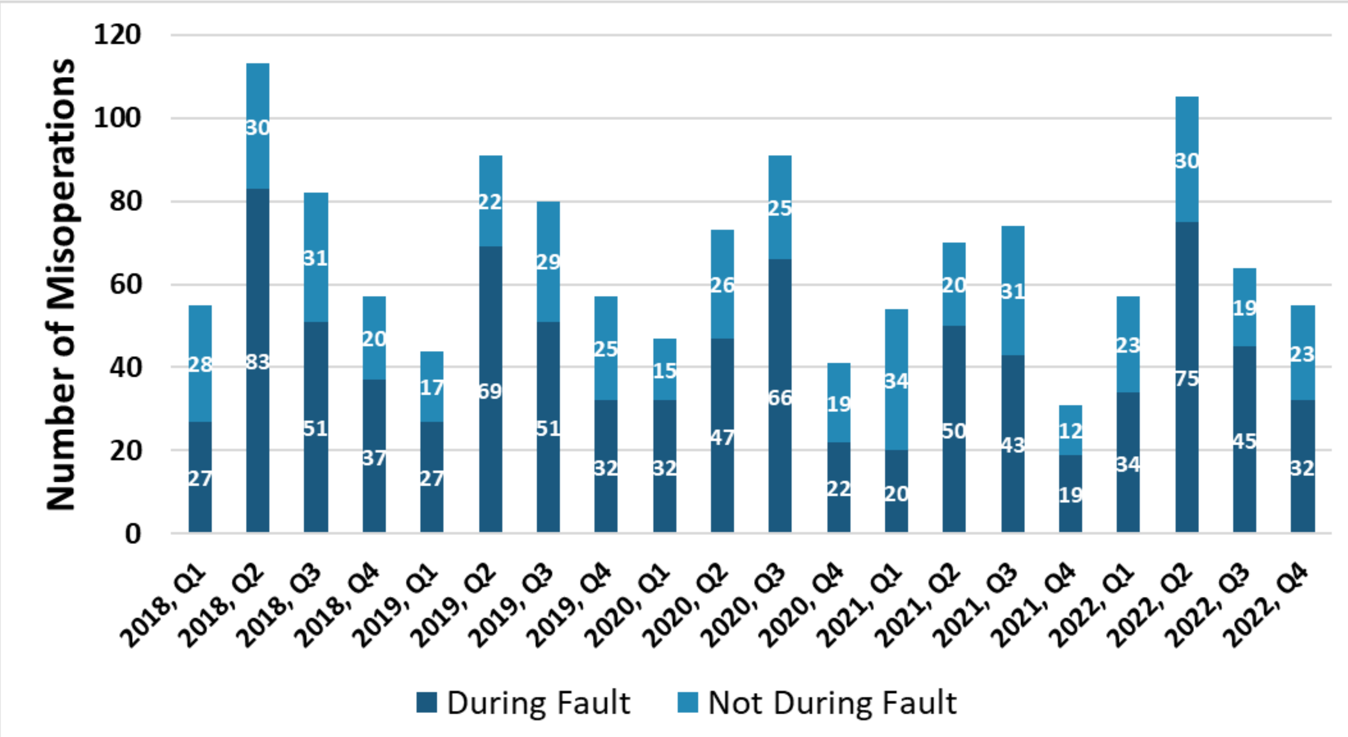


Figure G16: Fault Associated and Non-Fault Associated Misoperations

There was a total of 93 misoperations that occurred in the MRO region between June 1, 2022, and September 30, 2022. Examining these misoperations reveals several areas for improvement. As illustrated in Figure G17, of the 93 misoperations that occurred during this timeframe, 28 percent were attributed to human errors (i.e., as-left personnel errors, design errors, incorrect settings, and logic errors) as opposed to equipment failures. 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 much as possible through human performance tools.

In 2021, FERC, NERC, and Regional Entity staff released a Joint Review of Protection System Commissioning Programs report that documents how robust protection system commissioning programs can help reduce these types of misoperations. MRO PRS held a webinar on Protection System Commissioning highlighting the report in 2022. Additionally, NERC will host a misoperation workshop late in 2023 to address ERO-wide misoperation trends.

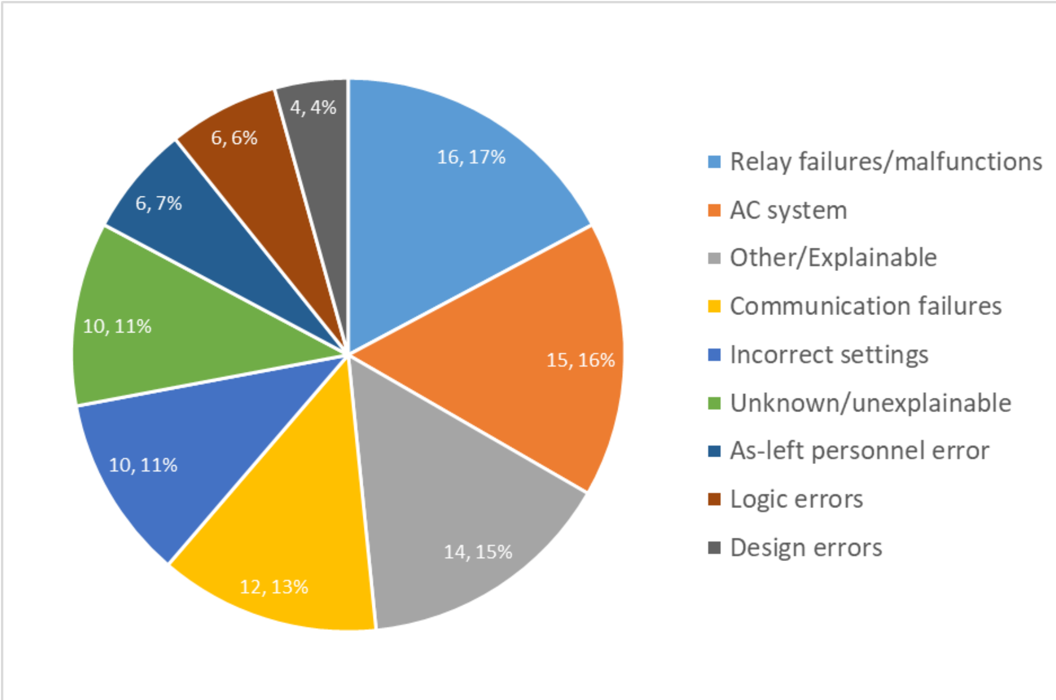


Figure G17: Summer 2022 Misoperations by Cause

Historical Summer Load Forecast

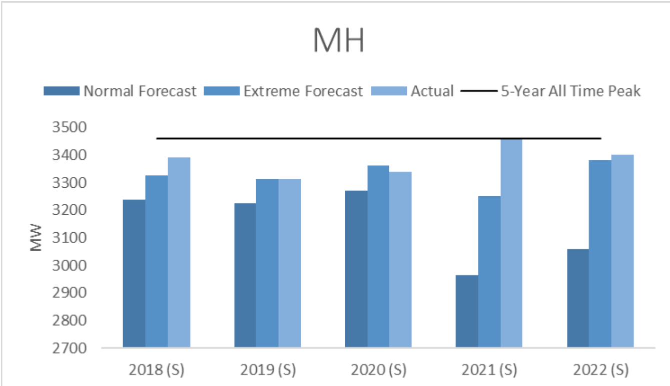
To account for weather effects as accurately as possible, entities provide a forecast based on normal weather, or assumed temperatures consistent with the past 30 years (approximately) of meteorological data. This is also referred to as the 50/50 demand forecast, which means that each year, the probability 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 demand 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.

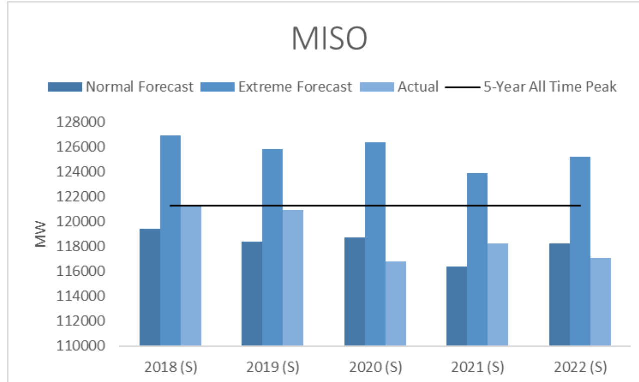
Figure G18 shows the five-year historical summer normal (50/50) and extreme (90/10) demand forecasts, along with actual and all-time summer peak load for each assessment area in the MRO region. SPC and SPP actual peak demand exceeded the normal forecast last summer while MISO actual peak demand was below the normal peak load forecasts. 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 higher than the extreme demand forecasted. SPC and SPP recorded new all-time summer peak load in 2022, while MISO's 2022 summer peak demand remained below the normal forecast and did not experience a similar weather pattern to that of SPP. SPC predicted the normal load forecast accurately for last summer. New and better forecasting tools are beginning to produce better normal load forecasts.

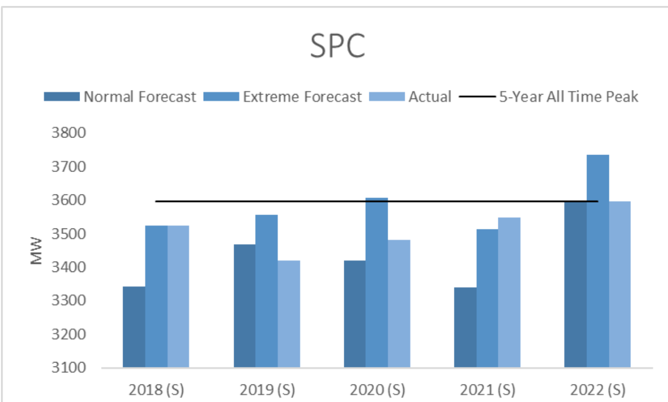
The historical five-year, all-time highest summer hourly average demand recorded for each of the MRO assessment areas are as follows:

- MH – 3,461 MW in July 2021
- MISO – 121,233 MW in June 2018
- SPC – 3,597 MW in September 2022
- SPP – 53,243 MW in July 2022

Actual weather conditions that occurred at the time of peak load can be compared to the forecasted weather conditions 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, resulting in significant weather diversity on any given day.







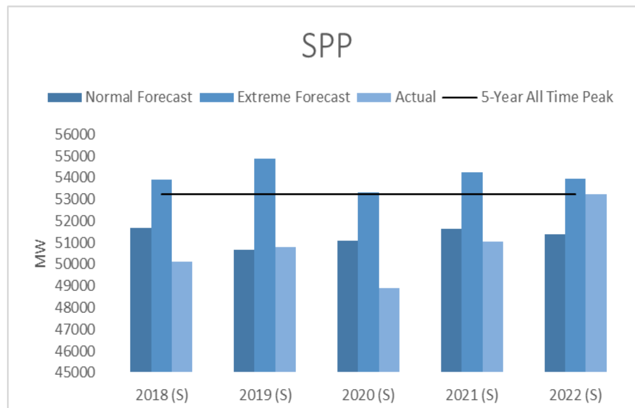


Figure G18: 5-Year Historical Summer Load Forecast

FOCUS AREAS FOR SUMMER 2023

MRO's independent evaluation of the generation and transmission system for the 2023 summer season identifies the following potential operating concerns that should be areas of focus during this same timeframe:

- Above-normal summer peak load and resource outage conditions could increase the risk of operating reserve shortages and firm load interruptions in MISO and SPP, depending on the amount of generation lost due to such forced outage events.
    - MISO and SPP are at increased risk to issue EEAs and implement operating mitigations such as demand response, non-firm imports and if necessary, short-term load interruption under extreme peak summer conditions.
- Conventional generation resource performance and availability is key for meeting projected summer demand. Conventional generation WEFOR for 2022 were higher than the five-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.
    - A rapidly changing resource mix and increased levels of renewable energy resources are 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 bulk power system 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 ramping quickly to follow 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 summer 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 along with an increased reliance on natural gas that is also used for home heating.
- Human errors continue to be the highest contribution to protection system misoperations. It is important to utilize a robust system of controls throughout a project lifecycle to ensure that human errors are mitigated as much as possible through human performance tools.

APPENDIX A

Summer season forced outage, forced derate, and startup failure causes for generation types other than fossil steam and simple cycle gas turbines.

Cause Type	Portion of MWh lost
Exciter commutator and brushes	26.85%
Fuel piping and valves A	15.51%
Operator error	8.51%
Tube sheet fouling	7.37%
Generator output breaker	6.27%

Table I1: Combined Cycle Gas Turbine 2022 Summer Outage Causes

Cause Type	Portion of MWh lost
Stator windings; bushings; and terminals	27.27%
Fuel piping and valves A	4.80%
Stator core iron	4.60%
Exciter commutator and brushes	4.36%
Other miscellaneous balance of plant problems	4.05%

Table I2: Combined Cycle Gas Turbine 2018-2022 Summer Outage Causes

Cause Type	Portion of MWh lost
Reheat steam relief/safety valves	25.99%
Stator; General	16.15%
Exciter commutator and brushes	11.45%
Tube sheet fouling	7.42%
Gland seal system	6.12%

Table I3: Combined Cycle Steam 2022 Summer Outage Causes

Cause Type	Portion of MWh lost
Stator windings, bushings and terminals	22.00%
Reheat steam relief/safety valves	6.89%
Stator core iron	5.40%
Stator; General	4.89%
High pressure blades/buckets B	4.05%

Table I4: Combined Cycle Steam 2018-2022 Summer Outage Causes

Cause Type	Portion of MWh lost
Governor Oil System	21.71%
Generator lube oil system	16.01%
4160-volt conductors and buses	10.42%
Lack of water (hydro)	5.43%
Stator windings; bushings; and terminals	5.06%

Table I5: Hydro 2022 Summer Outage Causes

Cause Type	Portion of MWh lost
Governor Oil System	9.35%
Other turbine control problems (Report specific wicket gate controls; etc. using the code for the appropriate equipment item.)	9.31%
Other turbine problems	8.93%
Stator windings; bushings; and terminals	7.62%
Drought	4.71%

Table I6: Hydro 2018-2022 Summer Outage Causes