2022 MRO REGIONAL SUMMER ASSESSMENT

June 8, 2022

MIDWEST RELIABILITY ORGANIZATION

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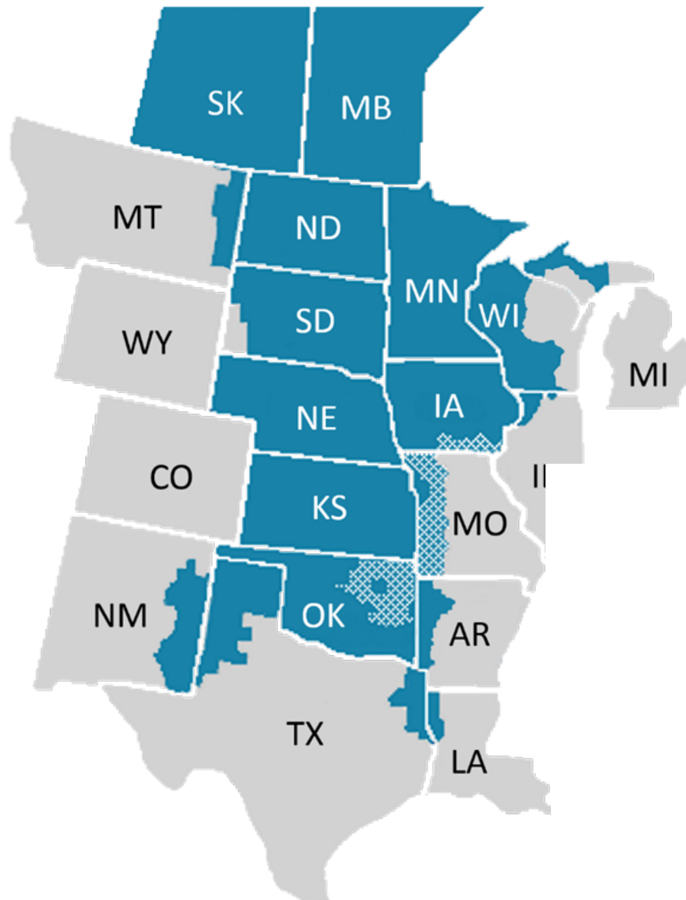
PREFACE

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 200 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 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 also includes a review of historical regional bulk power system performance during the 2021 summer season to identify trends that might impact system reliability during future summer seasons.

The 2022 RSA focuses on the months of June through September as the summer season and provides an evaluation of resource and transmission system adequacy necessary to meet projected summer peak demands during this timeframe. The historical performance data used in this assessment is collected and analyzed each quarter by MRO staff for registered entities in MRO's regional footprint. 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).

The following key RSA findings represent MRO's independent assessment of the 2022 summer season:

- Extreme summer peak load, coupled with unplanned generation outages resulting from prolonged hot temperatures, will likely exceed available capacity resources and require MISO, SPC and SPP Balancing Authorities (BAs) to issue Energy Emergency Alerts (EEAs) and employ operating mitigations such as demand response, non-firm imports from neighboring areas, and short-term load interruption.
    - **MISO North and Central areas are at high risk for energy emergencies.** MISO's recent annual 2022-2023 Planning Resource Auction (PRA) Results[1] indicate insufficient capacity to cover anticipated summer peak demand and increased risk of needing to implement temporary, controlled load sheds under extreme summer peak load coupled with unplanned generation outages. This is primarily the result of a decrease in generation capacity of 3.2 GW compared to the 2021 summer season and an increase of 1.7% in projected peak demand. There are some units that did not qualify for reserve capacity in PRA but may be available to serve energy through most of the summer. 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. Unless more capacity is built that can supply reliable generation, projected shortfalls such as this will continue.
    - **SPC is at an elevated risk for energy emergencies.** Anticipated resource capacity in SPC will be strained to meet a 7.5% projected increase in summer peak demand. The projected

[1] The Planning Resource Auction (PRA) is an annual capacity auction through which electricity providers can procure planning resources to meet MISO's resource adequacy requirements. Electric generators and aggregators of demand-side resources (like demand response) can sell resources into the auction, and electric providers serving customers can buy resources from the auction. The auction helps to determine whether there are adequate electric supplies to meet the anticipated peak customer demands for the entire MISO footprint, as well as whether there is enough supply in each MISO Local Resource Zone (LRZ) to ensure reliability of the grid at a local level.

increase is related to the economy returning to pre-pandemic levels, increased oil and gas development activities, and the revised forecast methodology used to capture summer peak demand. SPC is seeing tighter reserve margins as available resources approach planning reserve margin[2] levels. SPC is projected to have sufficient operating reserves[3] for normal peak conditions; however, external assistance may be needed in extreme conditions that cause above-normal generator outages or demand.

  - **SPP is at an elevated risk for energy emergencies.** Above-normal temperatures and continuing drought conditions over the western half of the United States will impact the Missouri River and other water sources used by SPP for generation resources and once-through cooling processes. This could lead to reduced output from these resources and require the implementation of emergency procedures to meet peak demand during periods of high generator unavailability because of insufficient cooling water.
  - MH anticipates resources are sufficient to meet reserve margin requirements under normal and extreme demand for 2022 summer season.

- 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.

[2] Planning reserve margin is designed to measure the amount of installed capacity available to meet expected demand in the planning horizon. As the planning reserve margin is a capacity based metric (M-1 Reserve Margin), it does not provide an accurate assessment of performance in energy limited systems.

[3] Operating reserve margin is the real-time generating capacity available to the system operator within a short interval of time to meet demand in case of sudden generator or transmission outages. Under normal conditions, the operating reserve is always at least the capacity of the largest generating plant and is lower than the planning reserve margin.

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 bulk power system (BPS)[4].

MRO staff annually assesses the Reliability and Planning Coordinator (RC and PC, respectively) areas within the MRO region for reliability and 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 on the 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 Regional Entities. MRO's 2022 RSA is an independent staff assessment that utilizes some of the same data as the NERC 2022 Summer Reliability Assessment and NERC's 2021 Long-Term Reliability Assessment, with a more targeted focus on the MRO region. In addition to providing an evaluation of the previous summer season system performance, this assessment also identifies reliability concerns for the upcoming 2022 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 Assessment. 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 1 illustrates the North American assessment areas and Figure 2 shows the North American Regional Entity footprints that are separate from the assessment areas.

[4] (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

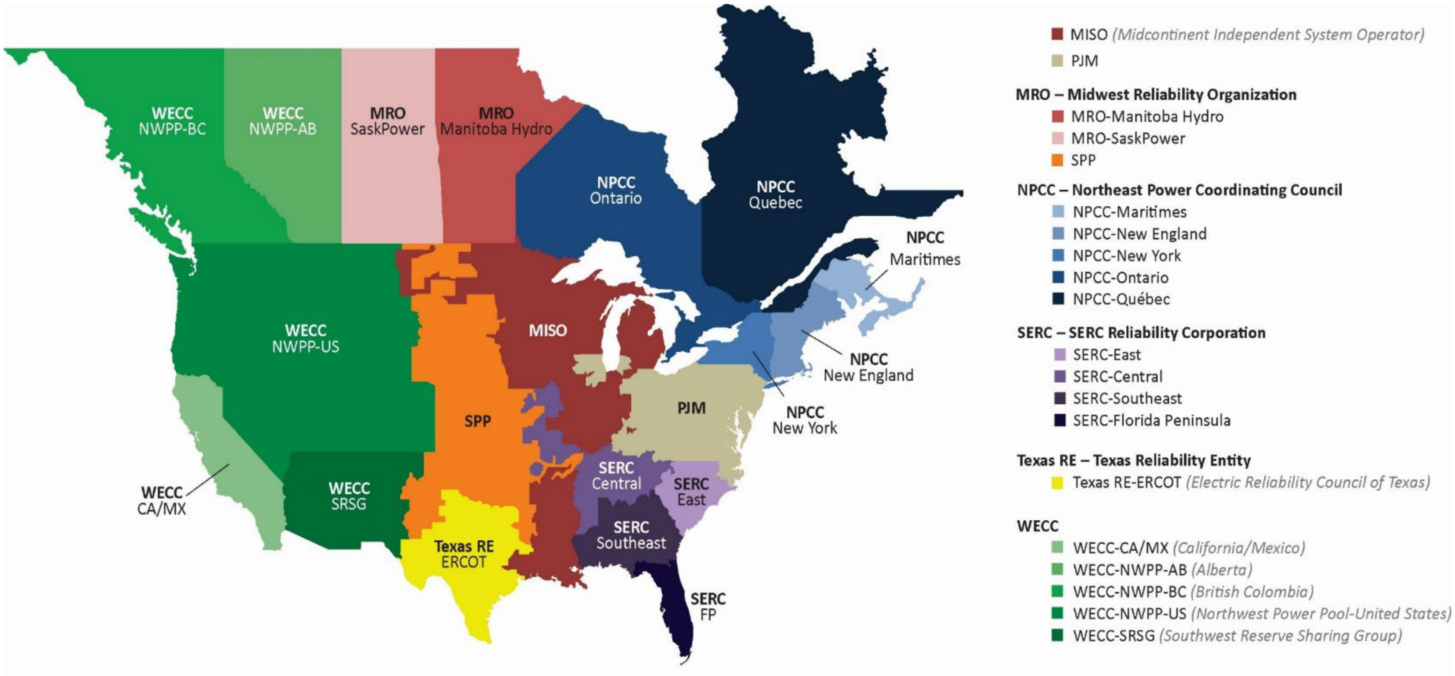


Figure 1: NERC Assessment Areas

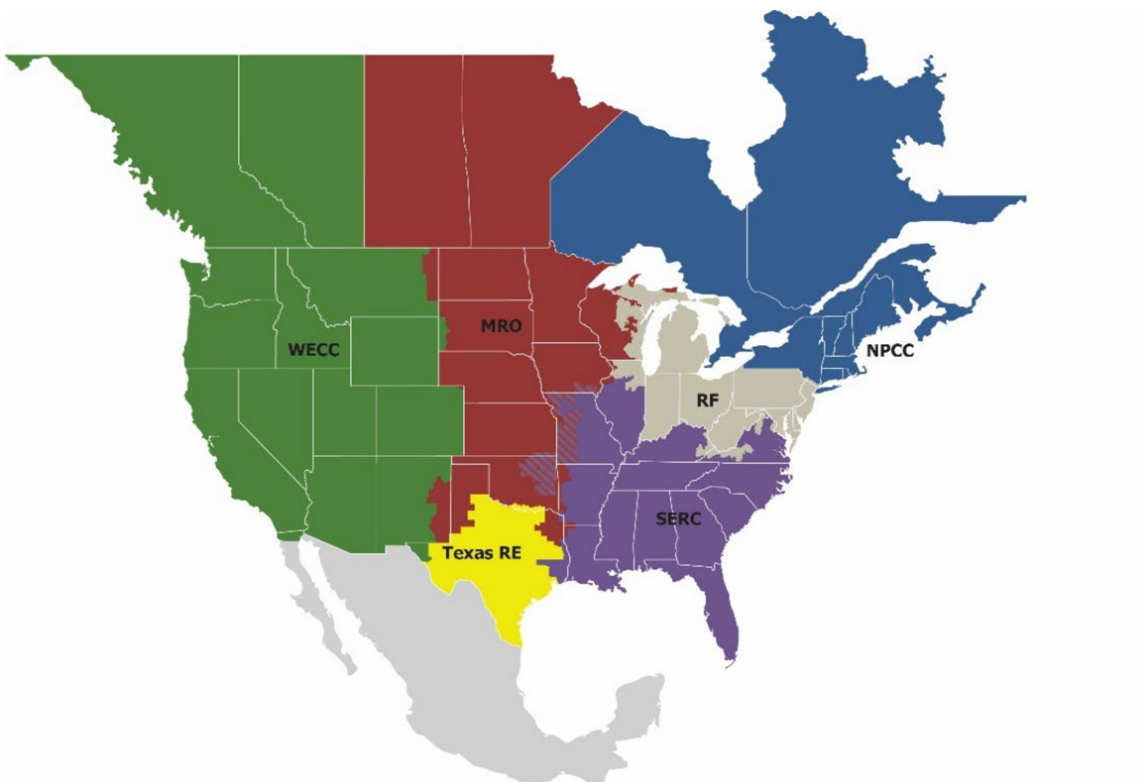


Figure 2: Regional Entity Boundaries

MRO REGISTRATION AND CERTIFICATION

Registration

There are more than 220 active registered entities on the NERC Compliance Registry (NCR) in the MRO region. There was a reduction in registration of owners and operators of new generating facilities over the past 12 months which leads to less new entities being established and being responsible for reliable operations. During this timeframe, the trend of Generator Owners and Generator Operators being registered as two separate entities continued. While there are larger Generator Owner/Operators operating in the MRO region, there are also two entities operating facilities owned by others which splits the compliance responsibilities of the facilities between two separate entities, one of these entities is operating over 1,100 MW of generation as part of its over 100,000 MW generation portfolio across North America.

Wind generation continues to increase in the MRO region, which is also seeing a slight growth in solar facilities. Bulk Electric System (BES[5]) solar facilities added a combined total of over 380 MW of capacity in 2021, and by the end of 2022 it is projected there will be an additional 1,500 MW of utility scale solar facilities online in the region.

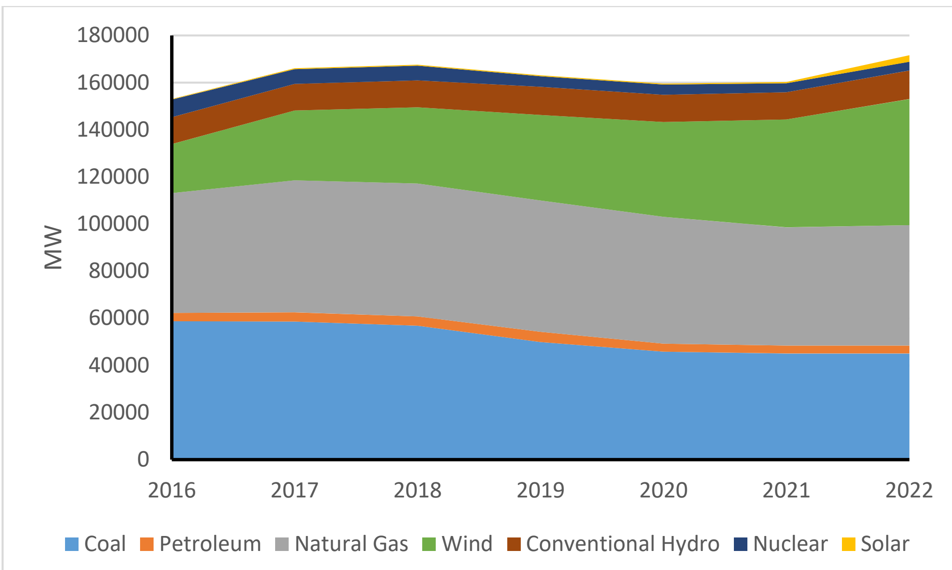


Figure 3: MRO Historical Nameplate Capacity by Fuel Types

Certification

The NERC certification process ensures that registered entities that have BES element operation and monitoring responsibilities are properly trained and capable of performing these responsibilities. These entities have more of a direct impact on BES reliability and require an additional layer of oversight. All BAs, RCs, and Transmission Operators (TOPs) registered in the NCR are certified to perform respective functions. The

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

certification process verifies each of these registered entities have the tools, trained staff, processes, procedures, and the necessary cyber and physical controls in place to meet the applicable NERC Reliability Standards. Certification is not a periodic activity. Once certified, entities are not subject to periodic certification activities if there are no material changes to an entity's scope of operations.

Material modifications to an entities operations are listed in the NERC Rules of Procedure: Appendix 5A – Organization Registration and Certification Manual as triggers for a certification review, summarized as:

- Changes to the registered entity's footprint
- Relocation of the entity's Control Center
- Modification of the entity's Energy Management System (EMS)

Certification reviews are focused on determining if all the necessary steps are in place to prepare the entity for a change that might impact operations. Areas of concern identified during the review provide an opportunity for the registered entity to make corrections with no compliance implications. As part of the certification review, registered entities may also receive non-binding recommendations. This seasonal reliability assessment directly focuses on these types of entities, specifically in the Performance Analysis, Event Analysis and the Situational Awareness review, which looks at the performance of BES elements.

2021 SUMMER SEASONAL REVIEW

The 2021 summer seasonal review provides a historical analysis of the following areas between the months of June and September:

- 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 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. Information on this program can be found in the NERC ROP Section 800. MRO follows the ERO Event Analysis Process that involves working with the registered entity to develop a brief report, performing a root cause analysis of the event, and documenting recommendations or lessons learned that can be shared with industry. The NERC Event Analysis home page can be found here: Event Analysis (nerc.com).

The MRO region saw a total of seventeen transmission events on the system in 2021, six of which occurred during the 2021 summer months. All six events that took place during the 2021 summer season 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 2021 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 what can happen when a simple wiring change is not carefully planned and engineered.

Figure 4 illustrates the MRO 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. The primary focus of MRO is to limit large impact events, especially those that could potentially lead to a cascading event. The average impact is lower in 2020 than in previous years, which may be attributed to several factors including the global pandemic's impact on the BPS. The BES average impact in 2021 was closer to that of previous years.

The average severity index of reported events on the BES in 2021 increased when compared to 2020. This may be attributed to additional system load experienced during the economic recovery in the aftermath of the height of the pandemic. While the number of reported events in 2021 was equal to those in 2018 and 2019, the average severity index was lower than both of those years and there were no events higher than category 1. In contrast, 2018 and 2019 each had one category 2 event occur.

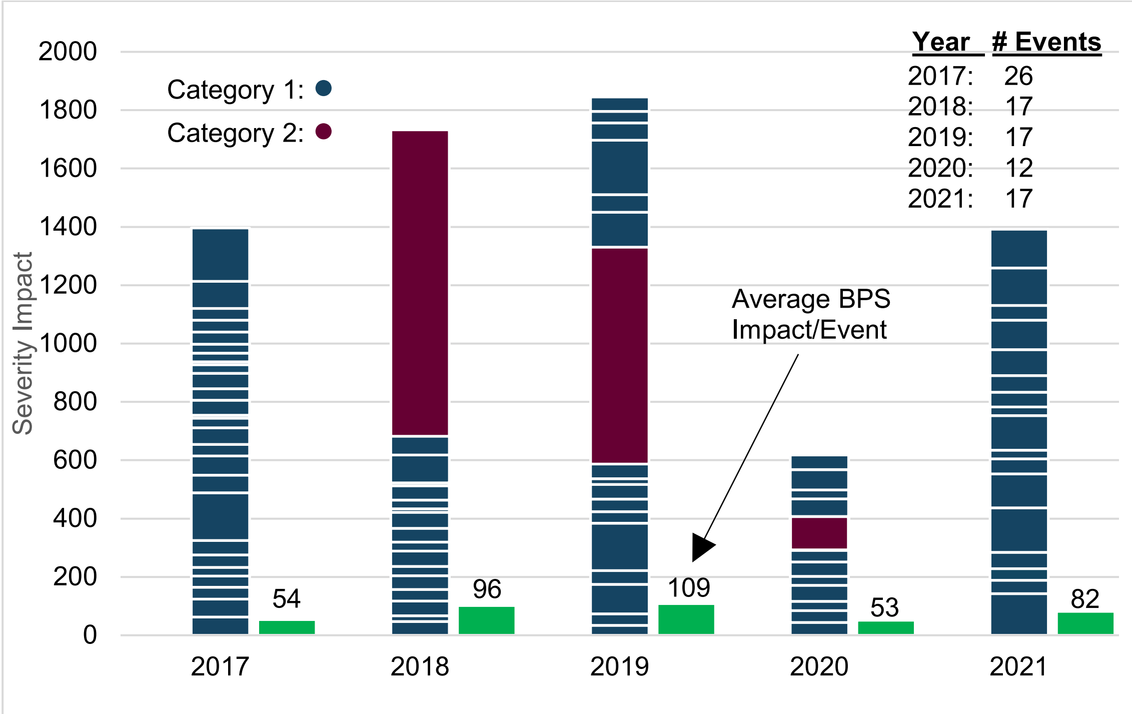


Figure 4: MRO Event Severity Index as of January 2022

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 six BES events that occurred during the summer of 2021, including the event category, number of BES facilities lost, MW of generation lost, and MW of load lost.

June 7, 2021 Transmission Event

Event Category: 1a

- # of BES facilities Interrupted: 4
- MW of Generation Lost: 0 MW
- MW of Load Lost: 23 MW

On June 7, 2021, at 10:27 p.m. CST, a 115 kV non-BES transmission line tripped and did not attempt to reclose while serving 23 MW of customer load. Severe thunderstorms had been reported in the area.

While attempting to re-energize the line, adjacent zones of protection operated causing two transmission line and two transformer outages. The system configuration at the time created a radial connection, resulting in a 23 MW load shed. Seven damaged structures were identified on the system. System personnel restored customer load at 3:33 am CST on June 8, 2021. As of this publication, no corrective actions have been identified.

June 10, 2021 Transmission Event 1

Event Category: 1a

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

On June 10, 2021, at 9:14 a.m. CST, a Capacitor Coupled Voltage Transformer (“CCVT”) was identified as failing. Prior to the CCVT being replaced, at about 8:28 pm the same day, the CCVT failed catastrophically. After the CCVT failure, three 161 kV lines opened. There were three misoperations during this event. Repairs were completed and the system was restored on June 11, 2021, at 8:32 p.m. CST.

A lessons learned was generated as a result of this event, details of which can be found at Unintended Consequences of Altering Protection System Wiring to Accommodate Failing Equipment

June 10, 2021 Transmission Event 2

Event Category: 1a

- # of BES facilities Interrupted: 6
- MW of Generation Lost: 235 MW
- MW of Load Lost: 90 MW

At 8:28 pm CST on June 10, 2021, a 3-phase fault occurred at a neighboring substation (see previous Event 1). A 161 kV circuit breaker failed to trip to isolate the fault because it did not receive a trip signal from the line protection relays. The breaker failure relaying also did not receive an initiate signal to start the breaker failure timer. The cause of this was later determined to be an as-left personnel error.

An incorrect transformer protection relay setting caused unnecessary trips for this fault. The resulting outages were five 161 kV lines, one 161/69 kV transformer, a 235 MW generator, and 90 MW of load. The system was restored at 10:56 pm CST on June 10, 2021. Relay settings were corrected following this event.

June 11, 2021 Transmission Event

Event Category: 1a

- # of BES facilities Interrupted: 3
- MW of Generation Lost: 0 MW
- MW of Load Lost: 0 MW

On June 11, 2021, at 3:26 p.m. CST, a 115 kV line relay operated and reclosed automatically. At approximately the same time, an adjacent line breaker tripped and a remote breaker on another adjacent line tripped, open ending the adjacent lines. A relay coordination issue was identified as the cause of the over trip. Severe thunderstorms had been reported in the area. The system was restored at 3:50 p.m. CST on June 11, 2021.

As of this publication, no corrective actions have been identified.

July 8, 2021 Transmission Event

Event Category: 1a

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

On July 8, 2021, at 8:29 p.m. CST, a 230 kV transmission line and one terminal of an adjacent 230 kV transmission line tripped and reclosed automatically. These operations briefly open-ended a 230 kV transmission line and two 230/115 kV transformers. This event also caused a Special Protection System (SPS) to operate. At the time of the event, radar indicated severe thunderstorms were in the area.

All facilities were restored to service at 8:30 p.m. CST on the same day. The total outage time was less than one minute.

July 23, 2021 Transmission Event

Event Category: 1a

- # of BES facilities Interrupted: 5
- MW of Generation Lost: 0 MW
- MW of Load Lost: 15 MW

At 8:09 a.m. CST on July 23, 2021, a phase arrestor for a 115 kV transmission line failed causing the line to trip high speed to clear the fault. The line attempted a high-speed reclose but failed, and at the same time a 345/115 kV transformer at one of the line terminals tripped due to an incorrect sudden pressure relay operation. This transformer lockout operation triggered a transfer trip signal to be sent to trip a 345 kV line.

During the high-speed reclose attempt on the 115 kV transmission line, a remote terminal line relay tripped and initiated a breaker fail operation. The breaker fail resulted in a lock-out-relay (LOR) operation causing an entire substation outage including 13.8 kV distribution buses for at least 20 minutes.

A project has been initiated to replace the sudden pressure relay. The failed lightning arrestors for the 115 kV transmission line were replaced.

Loss of Energy Management System Events

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 the summer of 2021 with a duration of 125 minutes. This was below the 2021 average event duration of 151 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 summer 2021 event where the cause of the event was directly related to human error during a maintenance activity.

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

Figure 5 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.

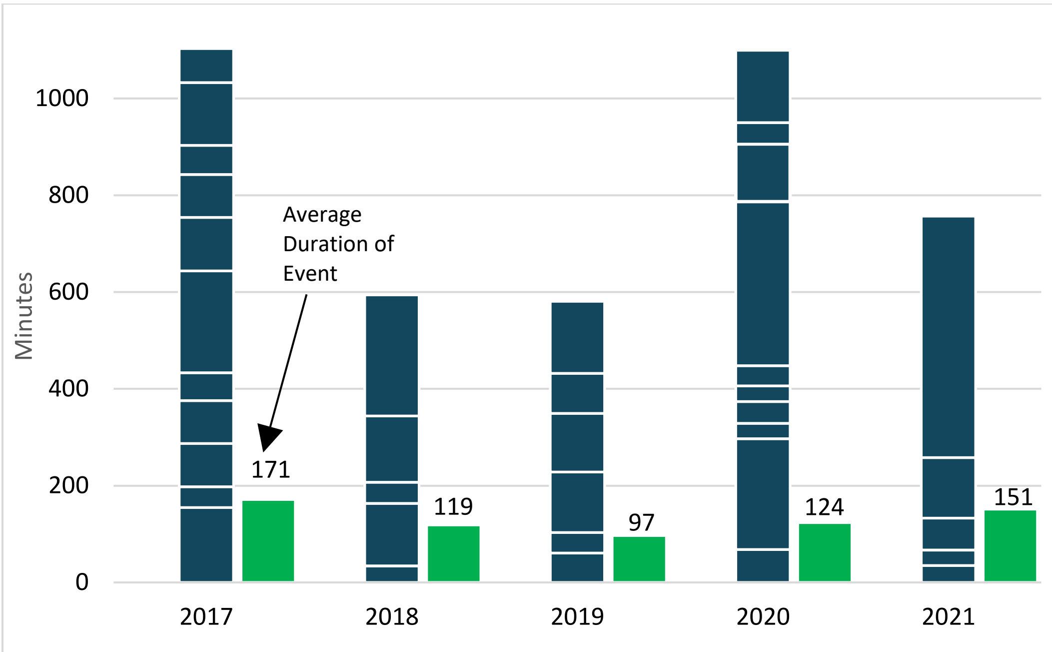


Figure 5: Loss of EMS Event Time Duration

The ERO EMS conducted an assessment on the loss of EMS functions from 2018 through 2020. The analysis focused on outage duration, EMS functions, and entity reliability functions. The analysis showed the loss of EMS functions did not lead to the loss of generation, transmission lines, or customer load and the number of state estimator/real time contingency analysis (SE/RTCA) and inter-control center protocol (ICCP) losses have declined between 2018 and 2020. The study also further showed that entities minimized the operational degradation from the loss of situational awareness risk due to EMS outage and that Management/Organization was identified as the leading root cause for EMS events. More information on the assessment can be found in NERC's Analysis and Risk Mitigations for Loss of EMS Functions (2018 - 2020) December 2021 publication. All the information used for this assessment was collected through the ERO EA process.

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. Energy Emergency Alerts (EEAs) are issued by the RC. NERC Reliability Standard EOP-011-1 was developed to address 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 has established three levels of EEAs. More information on the three EEA levels can be found in EOP-011-1 Emergency Operations Reliability Standard.

The MRO region experienced two energy emergencies during the summer of 2021. Details are as follows:

June 10, 2021 – EEA Level 2 Event

Due to above normal temperatures, forced generation outages and higher than forecasted load in the RC footprint, the RC declared an EEA Level 2 effective from 1:00 p.m. until 7:00 p.m. CST on June 10, 2021.

The RC implemented the following EEA protocols:

- Commit Available Maximum Energy (Emergency Only) resources
- Ensure emergency ranges of resources are being offered into the market
- Local balancing authorities (LBA's) can reduce load via LMM (Load Management Measures)* Stage 1
- Implement Emergency pricing – Highest available economic and emergency offer at Maximum Generation Emergency Event (Tier 2)
- Implement LMR's (Load Modifying Resources)**

* Load Management Measures (LMM) Stage 1 – Load management actions that can be taken to reduce demand to preserve or maintain Operating Reserves that are NOT included in Emergency Demand Responses or LMRs.

** Load Modifying Resource (LMR) - These are either Demand resources or Behind the Meter Generation that have an obligation to reduce demand or increase generation during declared system emergencies.

The RC was able to resume normal operations and cancel the Energy Emergency at 5:00 p.m. CST on June 10, 2021. No firm load was shed during this event.

July 2, 2021 – EEA Level 3 Event

Due to the extreme heat in the RC footprint, the RC had approximately 1,368 MW of generation unavailable due to the higher ambient temperatures. A cooling equipment failure at a 300 MW generating plant caused a reduced output of 100 MW resulting in a 200 MW loss in generation. The higher than average temperatures caused higher loads than were forecasted.

The RC expected to have sufficient generation to meet the load requirements, but due to the sudden loss of the generator, the RC declared an EEA Level 3 at 3:30 p.m. CST.

The RC curtailed 147 MW of non-firm exports and reduced load by 49 MW through demand response from a single customer. The RC also requested emergency imports from adjacent RCs.

The RC was able to resume normal operations and cancel the Energy Emergency at 2:24 a.m. CST on July 3, 2021. No firm load was shed during this event.

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 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. Currently, a mandatory reporting requirement is being developed.

Resource Mix

The MRO region has a diverse resource mix as shown in Figure 6 of available 2022 summer peak accredited capacity. Conventional generation that traditionally provided essential reliability services 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 53,400 MW of installed nameplate wind capacity. However, only about 10,000 MW of wind is capacity accredited to be available during the 2022 summer peak demand. Multiple projects exist in the MISO and SPP generation interconnection queue, that when installed would add approximately 80,100 MW of nameplate wind capacity to the MRO region by summer 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. The increase in renewable generation also adds operational complexity to resource commitment and dispatch. With the large amount 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 projected to become the second prominent renewable source following wind. It is estimated about 50 GW of planned solar capacity will be installed in the region by 2031.

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 the resource forecast uncertainty associated with wind and solar resources.

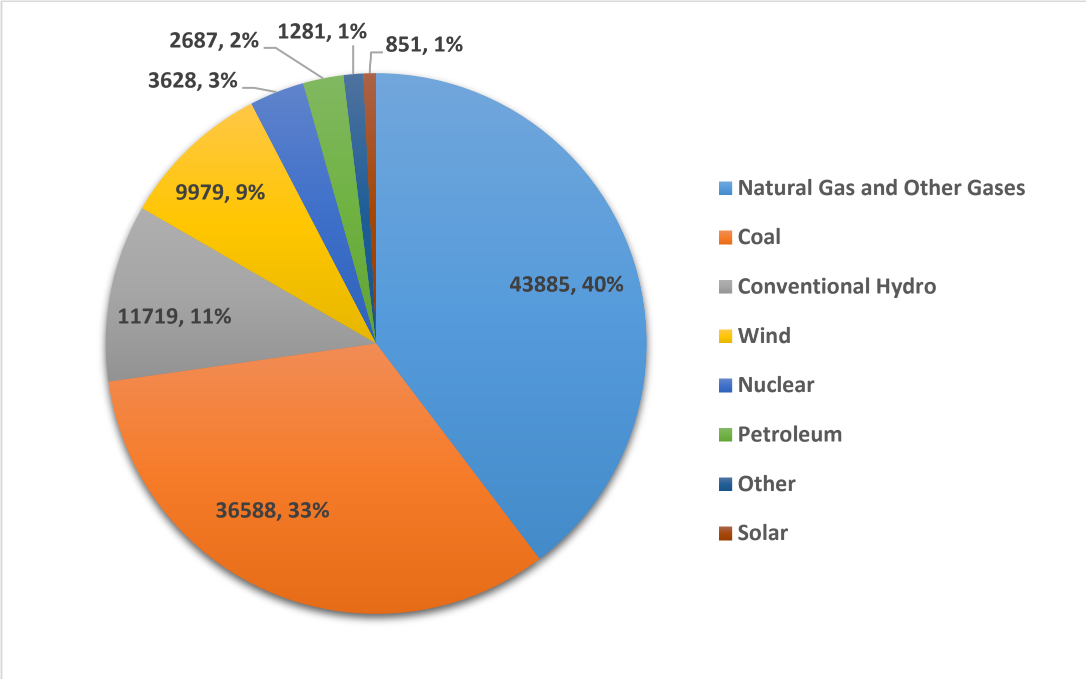


Figure 6: MRO 2022 Summer Peak Capacity by Fuel Types

The largest single contributor of generation by peak capacity in the region is natural gas plants, but coal plants and conventional hydro make up large portions of generation as well. Generation unavailability can have a substantial impact on reliability. Particularly of interest are the equivalent forced outage rates (EFOR) and derates impacting available generation. For the MRO region, the annual conventional generator forced outage rates for all seasons as shown in Figure 7 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 slight uptick in 2021 was attributed to the cold weather event in February 2021.The Weighted Equivalent Forced Outage Rate (WEFOR)[6] 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, with load following, and operating at minimum load operation more often, which increases the number of forced outages due to component failures.

[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.

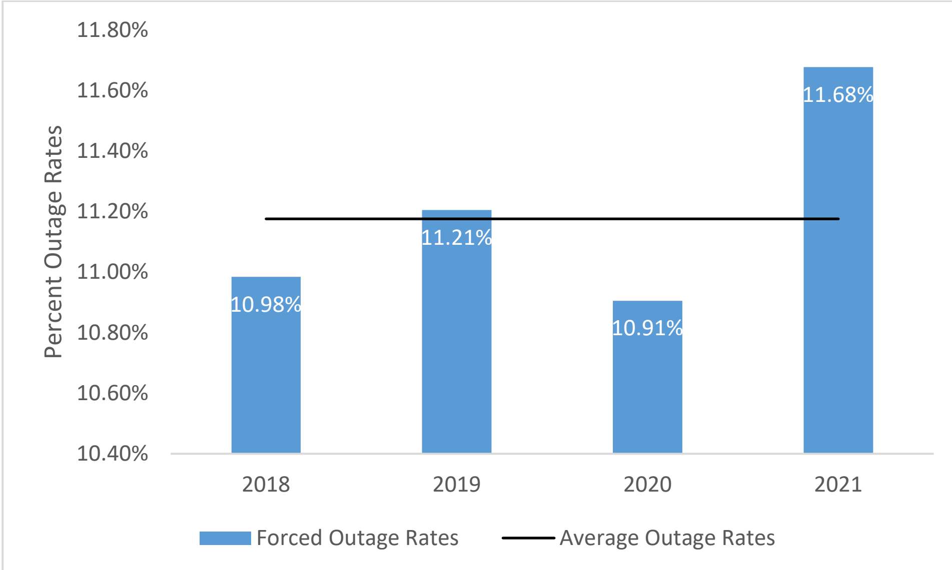


Figure 7: MRO Annual Generator MW-Weighted EFOR

Figure 8 is a comparison of the summer 2021 performance of the conventional fleet against average summer performance over the last four years. Simple cycle gas turbines have a larger than average forced outage rate followed by multi-boiler/multi-turbine, internal combustion, and fossil-steam generators.

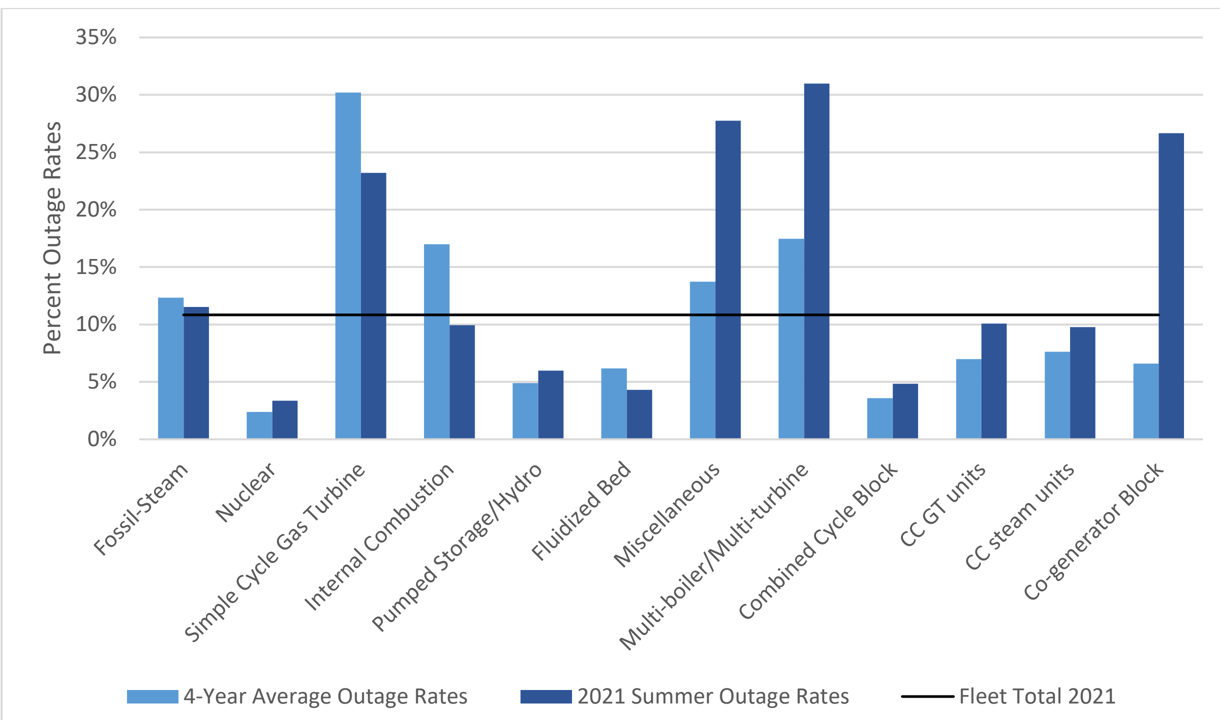


Figure 8: MRO 2021 Summer MW-Weighted EFOR by Unit Types

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 three-year historical event impact in the MRO footprint over the summer months.

Figure 9 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 internal combustion engines show a high number of event impact of 2,955, the total event impact of 11 gigawatt hours 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 summer 2021.

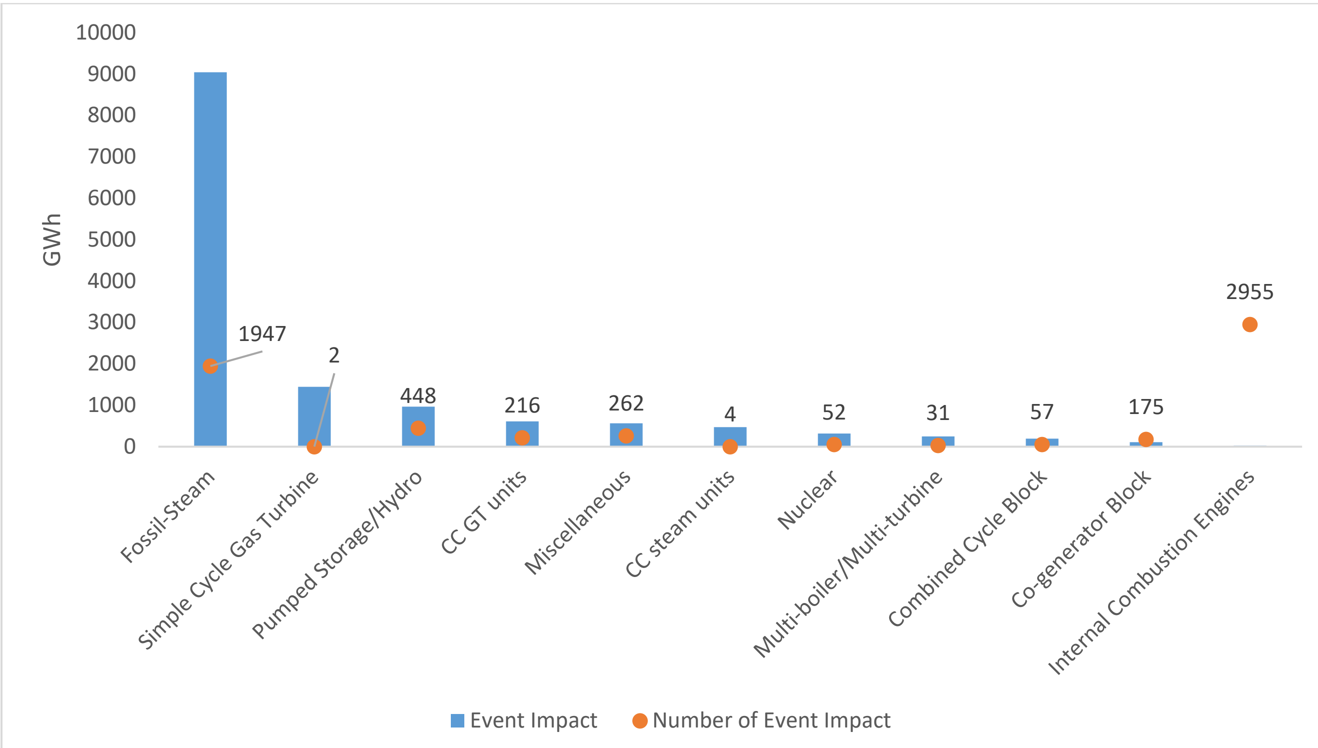


Figure 9: Total Event Impact and Number of Event Impact for Summer 2021

Tables 1 and 2 show the top five causes of forced outages, forced derates, and startup failures for fossil-steam plants in summer 2021 and for the three-year historical summer season period.

Cause Type	Portion of MWh lost
Slag and ash removal problems	5.29%
Main transformer	3.92%
Condenser tube leaks	3.88%
Waterwall (Furnace wall)	3.50%
Baghouse systems; general	3.46%

Table 1: Fossil-Steam 2021 Summer Outage Causes

Cause Type	Portion of MWh lost
Waterwall (Furnace wall)	6.59%
Plant modifications strictly for compliance with new or changed regulatory requirements (scrubbers; cooling towers; etc.)	6.26%
Air heater (regenerative)	5.30%
Forced draft fans	3.01%
Second super heater	2.75%

Table 2: Fossil-Steam 2019-2021 Summer Outage Causes

Fossil steam outages were driven by a wide variety of causes over the 2021 summer period and were evenly distributed. The slag and ash removal problems category was the primary outage cause for summer 2021, while the three-year average summer outage was mainly driven by furnace water wall and outages due to forced derates by compliance-related plant modifications. The large event impact reflects not only fossil-steam's large portion of generation, but the amount of lost megawatt hours. This suggests a higher likelihood of fossil-steam units suffering from a forced outage or derate across the region, possibly due to aging, fatigue, or component failure from frequent cycling.

Tables 3 and 4 show the top five causes of forced outage, forced derate and startup failure for simple cycle gas turbines in summer 2021 and for the three-year historical summer period.

Cause Type	Portion of MWh lost
High pressure blades/buckets	16.51%
Other exhaust problems	16.00%
Fuel nozzles/vanes	9.81%
Shaft seals	8.51%
Other DCS problems	5.78%

Table 3: Simple Cycle Gas Turbine 2021 Summer Outage Causes

Cause Type	Portion of MWh lost
Other DCS problems	9.05%
High pressure blades/buckets	8.79%
Storms (ice; snow; etc.)	4.28%
Generator bearings and lube oil system (including thrust bearings on hydro units)	4.25%
Other miscellaneous gas turbine problems	4.06%

Table 4: Simple Cycle Gas Turbine 2019-2021 Summer Outage Causes

Simple cycle gas turbine outages are clustered in the 2021 summer season, with over 56 percent of megawatt hours lost is attributable to the top five causes. This is more pronounced than the three-year average. The events highlight persistent problems for this generator class during the summer period with these cause codes contributing 26 percent of all event impacts over the three-year span. 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 for the 2021 summer.

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, as well as what system improvements are being implemented by owners and manufacturers to reduce forced outages. 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. Additionally, maintaining a robust and reliable fleet of balancing resources that is needed to serve energy along with integrated renewables.

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 100 kV 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 summer 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. Sustained outages for one minute or greater are reported for outages to elements operated at 100 kV and above. Momentary outages of less than one minute are only reported for elements operated at or above 200 kV. Figure 10 shows 100 kV and above automatic outages that include both momentary (for 200 kV and above) and sustained outages for June through September for 2016 through 2021. There were two 400-599 kV outages during the summer of 2021. One was caused by Human Error and the second one was classified as Other. As shown in Figure 10, automatic outages for July and August of 2021 were considerably lower than previous years. June of 2021 is in line with previous years. September of 2021 was considerably higher than September of 2020, but in line with other years. The tall blue bar for August of 2020 is largely due to the severe derecho that swept through the Midwest on August 10-11, 2020. During those two days alone, 58 sustained 100–199 kV outages were reported. This is over half of the number of outages typically recorded for the month of August. This illustrates how significantly a single severe weather event can impact the BES.

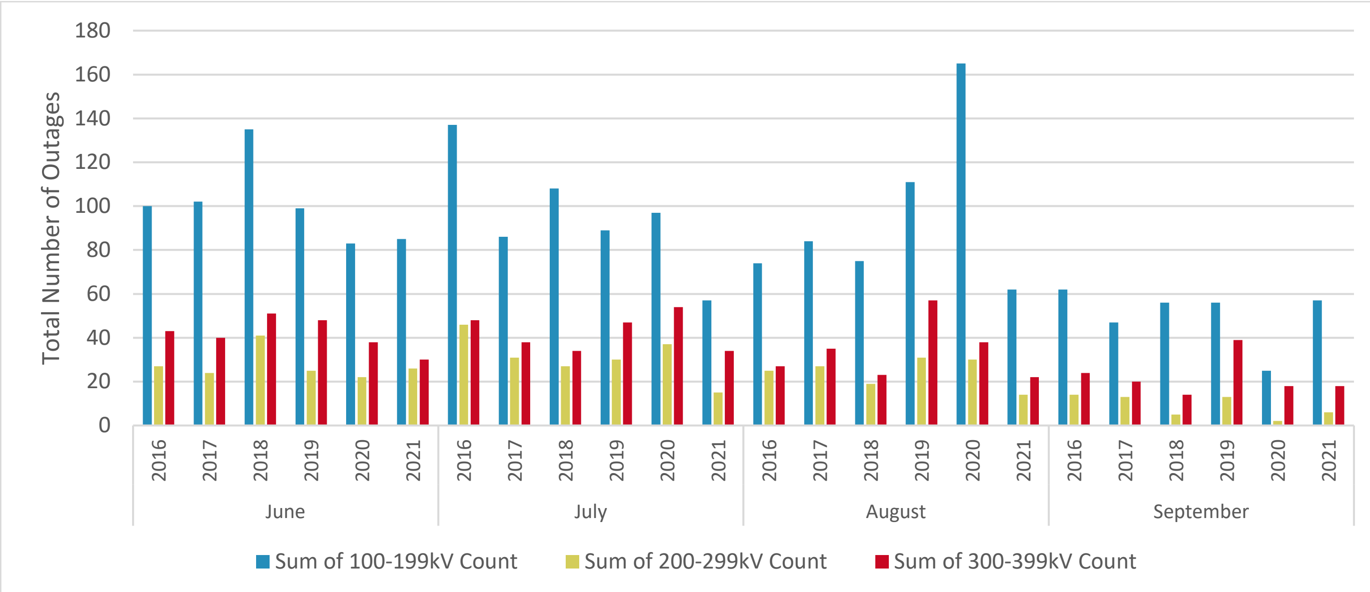


Figure 10: Summer 2021 Automatic Outages by Month

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 11 shows the major causes of momentary outages for 200 kV and above for the months of June through September for 2016 through 2021. Figure 11 indicates that most momentary outages during this timeframe were weather related, primarily caused by lightning. Figure 11 also illustrates a significant number of momentary outages have an unknown cause. 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 a large number of transient faults cannot be determined.

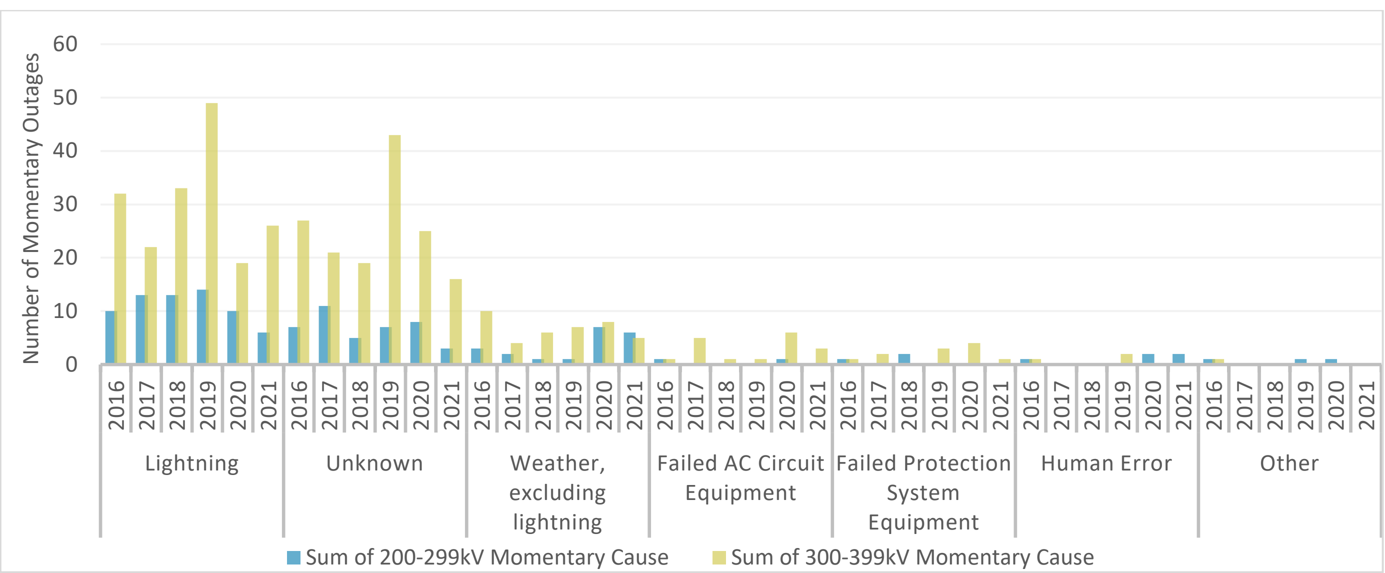


Figure 11: Summer 2021 Momentary Outages by Cause

The TADS definition of a sustained outage is an automatic outage with a duration of one minute or greater. Figure 12 below shows that failed AC circuit equipment was the most significant contributor to sustained 115 kV outages during the summer of 2021. Overall, there were fewer sustained outages during this timeframe in 2021 across all voltage classes.

The 2021 MRO Regional Summer Assessment highlighted that in 2020 vegetation contact was the fifth highest cause for sustained outages in 100-199 kV circuits. Figure 12 shows that the number of vegetation-related outages for the summer of 2021 was significantly less. It was the ninth highest cause of sustained outages for the 100-199 kV circuits.

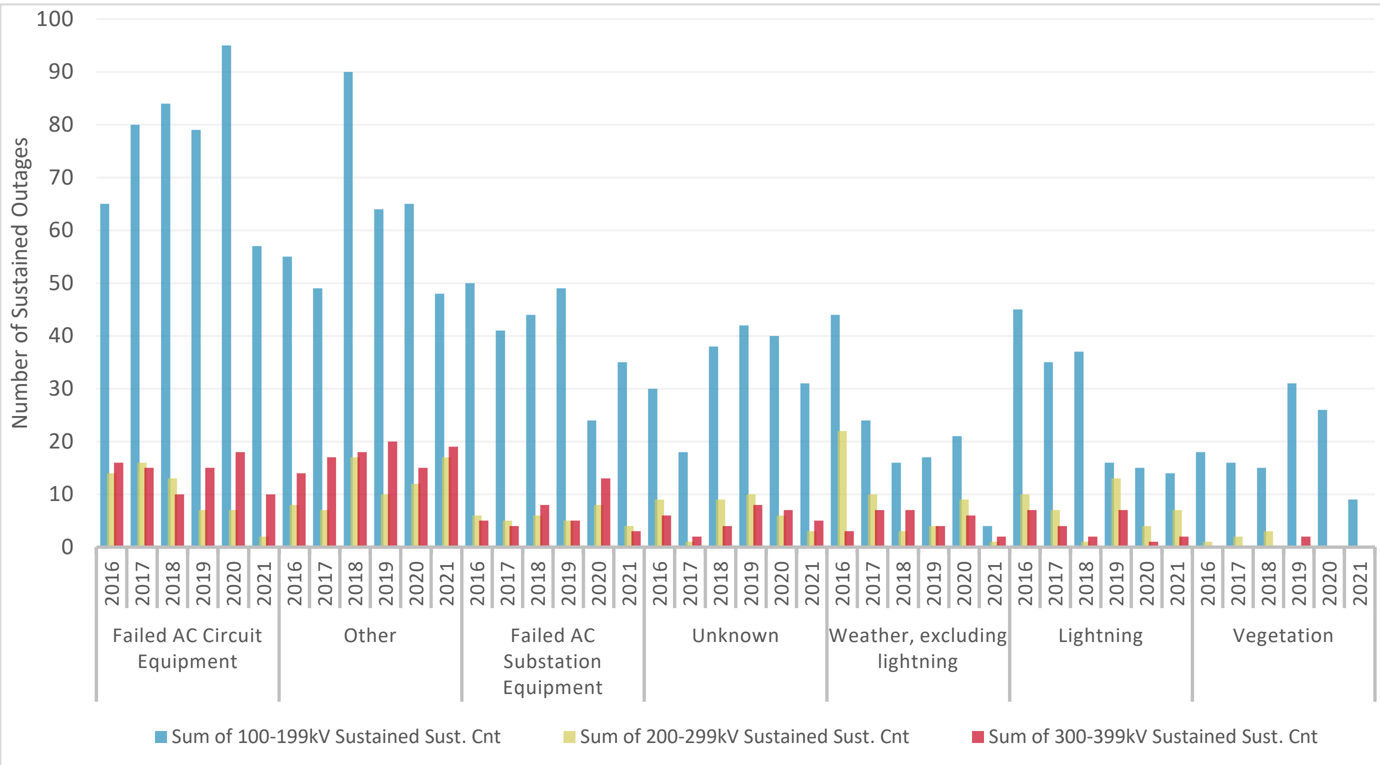


Figure 12: Summer 2021 Sustained Outages by Cause

Figure 13 reflect the yearly summer total outages per 100 circuit miles for 100-399 kV circuits. The chart clearly shows a decrease in the yearly outages between 2020 and 2021. The reason for this decrease may be partly attributable 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 300-399 kV circuits in 2019 were caused by momentary outages, which were at least 55 percent higher than any of the other years shown in figure 13. Over 76 percent of the momentary outages for 2019 were coded as either lightning or unknown.

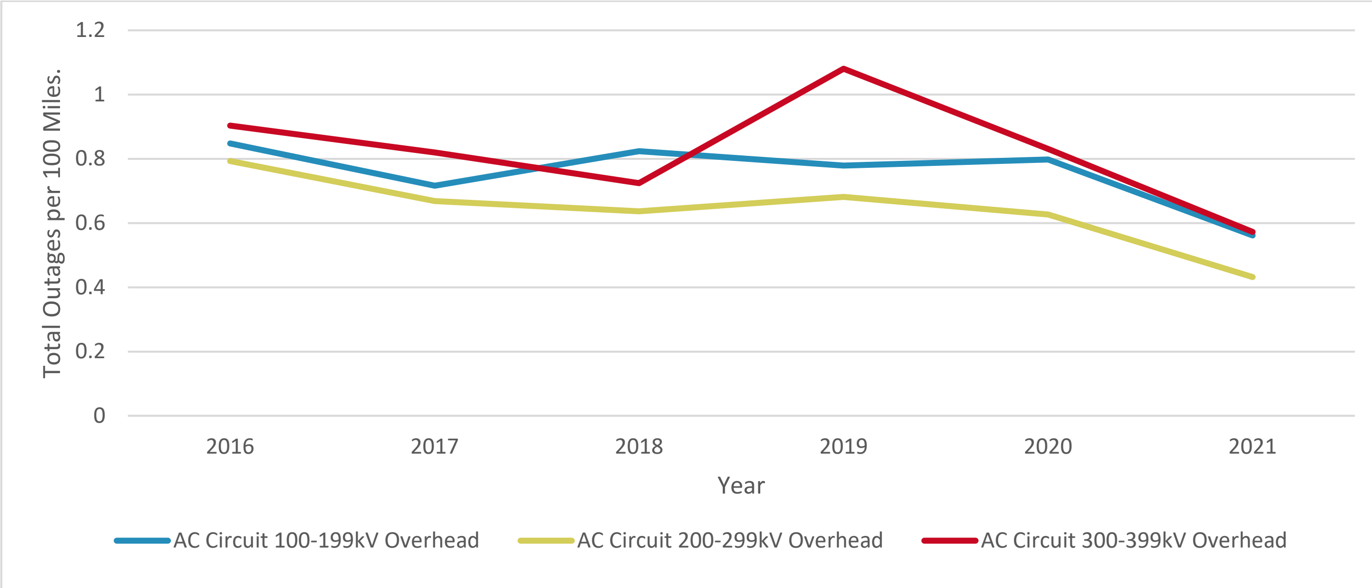


Figure 13: Total Transmission Outages per 100 Circuit Miles

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 14 from the 2021 NERC State of Reliability report.

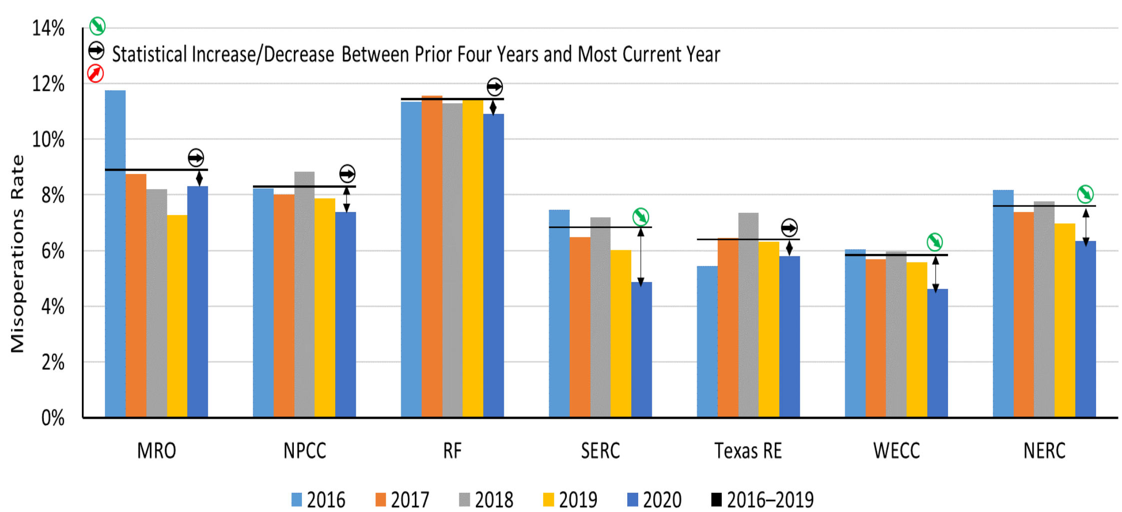


Figure 14: Year-Over-Year Changes and Trends in the Annual Misoperations Rate by Region

There were 2,628 operations and 231 misoperations reported within the MRO region in 2021 for a misoperation rate of 8.79 percent. Figure 15 shows the misoperation rate had been trending downward until 2020. The upward trend seen in 2020 continued in 2021.

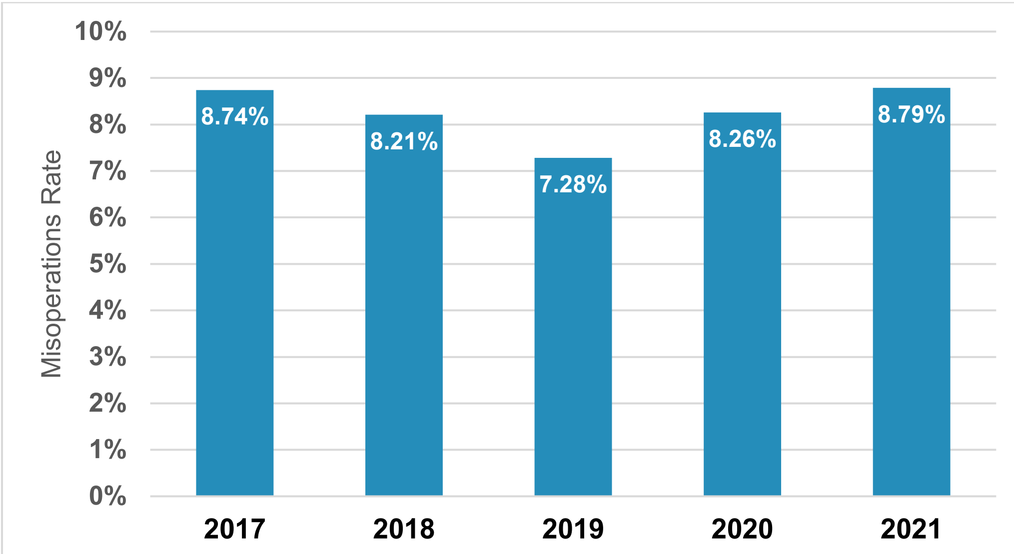


Figure 15: MRO Misoperation Rates by Year

Figure 16 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.

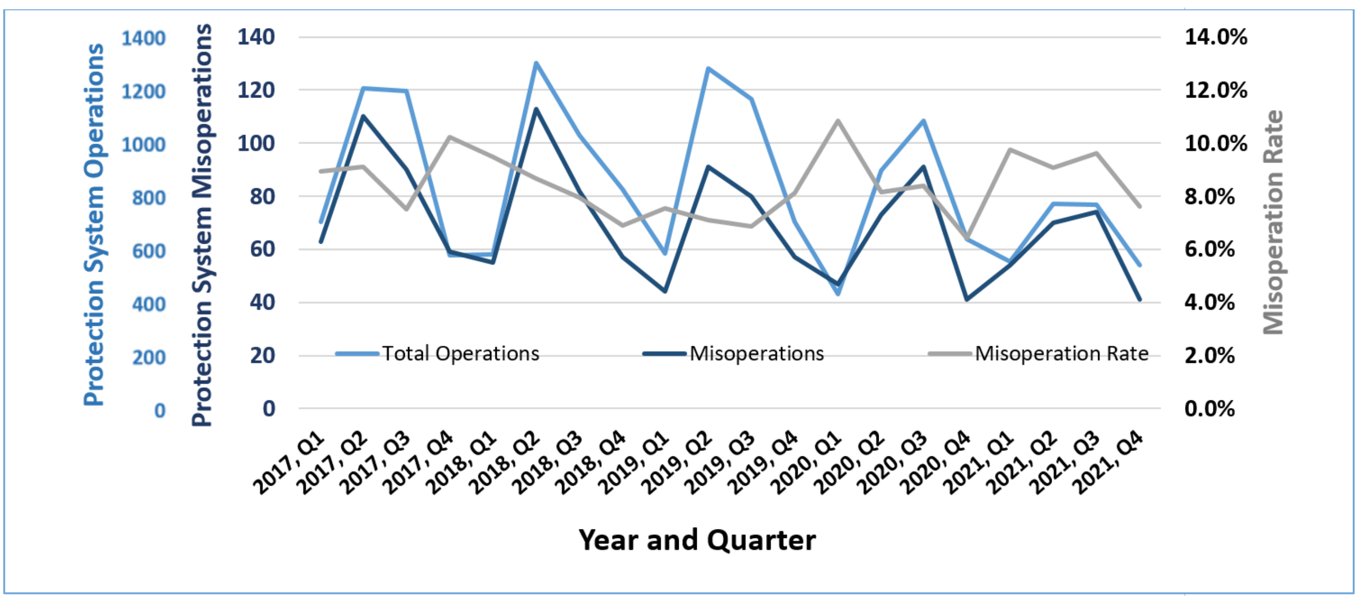


Figure 16: Protection System Operations and Misoperations Rate

The cause for the significant drop in total operations from previous years is difficult to pinpoint. Of the 2,628 total operations that were reported in MIDAS for 2021, 1,850 of them occurred at voltages less than 200 kV.

Of those 1,850 outages, only 656 of them were sustained outages, the other 1,194 were momentary outages. As neither TADS nor MIDAS collects outage cause data on momentary outages at voltages less than 200 kV, 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. Figures 11 and 12 show approximately a 45 percent reduction in weather-related sustained and momentary outages in the summer of 2021. 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 second and third quarters of the year (April 1 through September 30) aligns closest to the summer season (designated June 1 through September 30) for this assessment. As shown in Figure 17, 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.

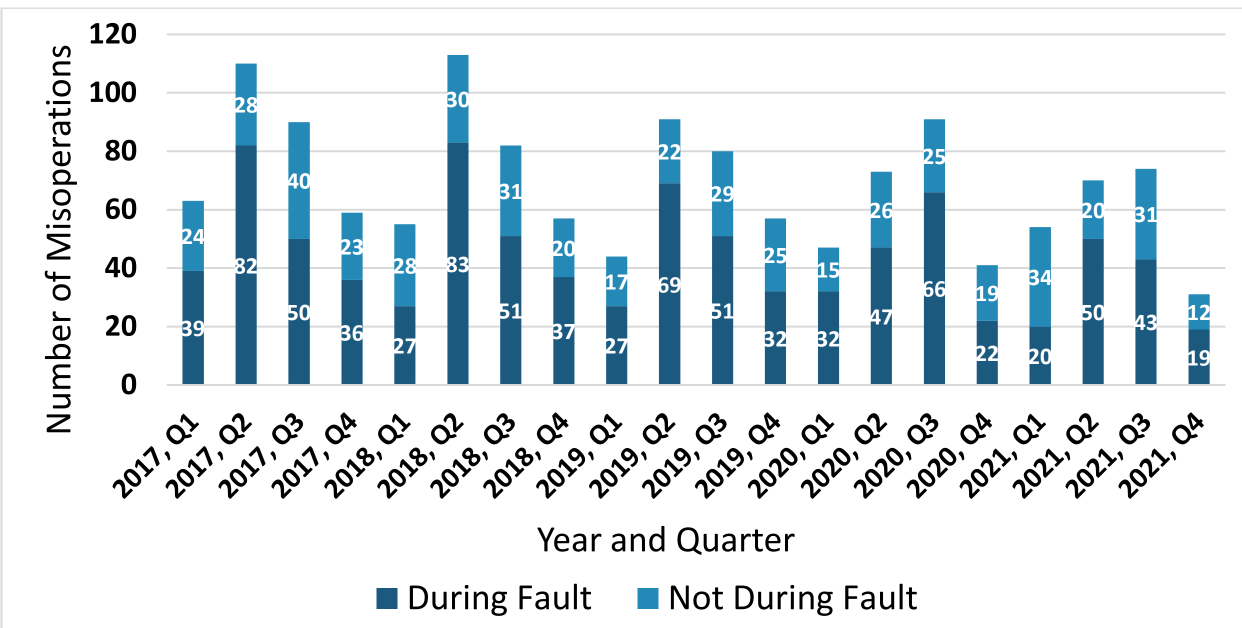


Figure 17: Fault Associated and Non-Fault Associated Misoperations

There was a total of 81 misoperations that occurred in the MRO region between June 1, 2021 and September 30, 2021. Examining these misoperations reveals several areas for improvement. As illustrated in Figure 18, of the 81 misoperations that occurred during this timeframe, one-third were attributable 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 thoroughly as possible through human performance tools.

FERC, NERC, and Regional Entity staff recently released a Joint Review of Protection System Commissioning Programs report that delves into how robust protection system commissioning programs can help reduce these types of misoperations. Additionally, MRO is planning to conduct outreach to registered entities on protection system commissioning in July 2022.

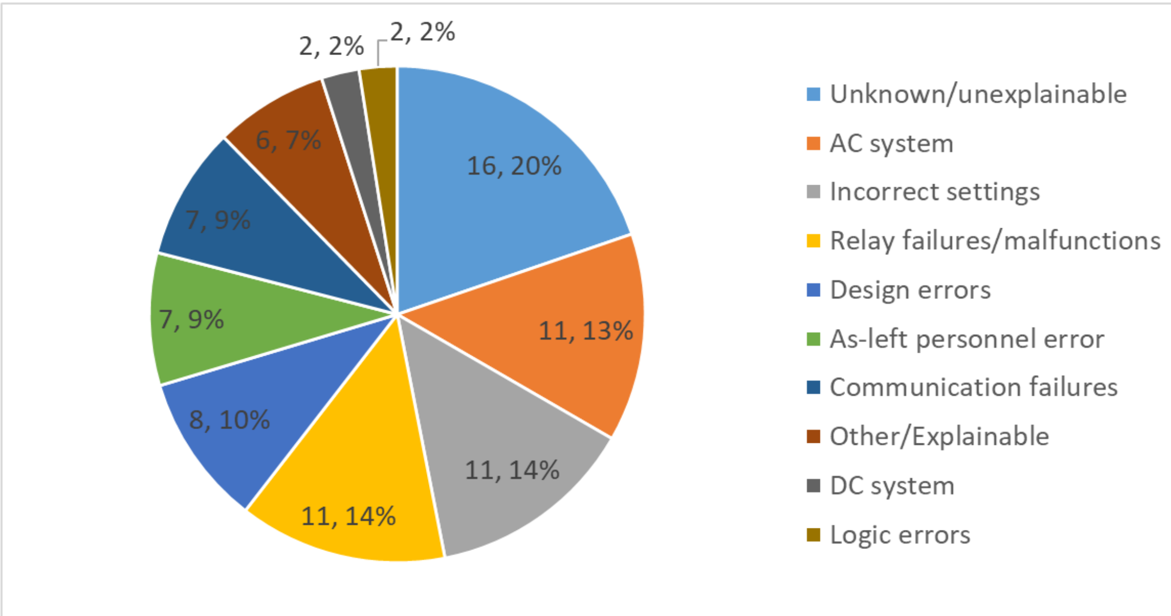


Figure 18: Summer 2021 Misoperations by Cause

Historical Summer Load Forecast

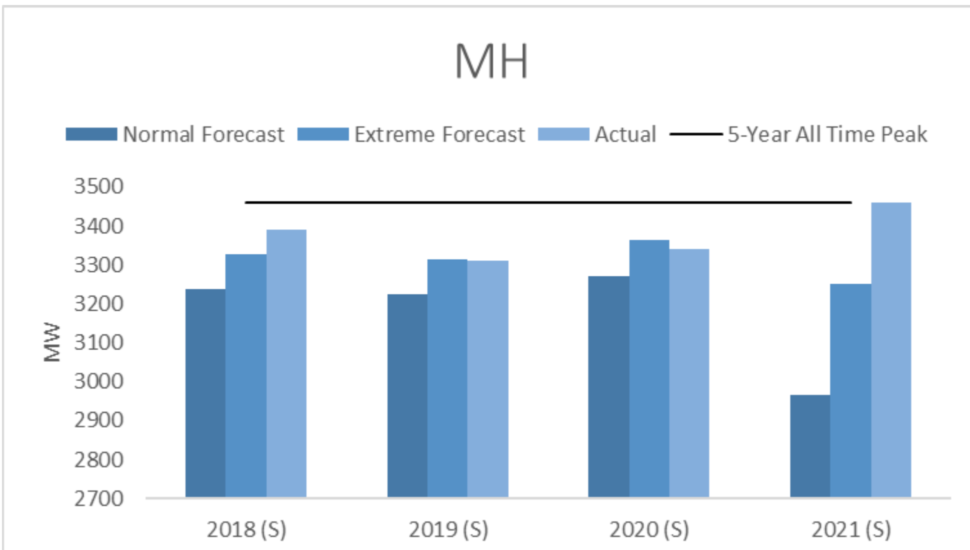
To account for weather effects as accurately as possible, entities provide a forecast based on normal weather, or assumed temperatures consistent with approximately the past 30 years of meteorological data. This is also referred to as the 50/50 forecast, which means that, each year, the probability of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

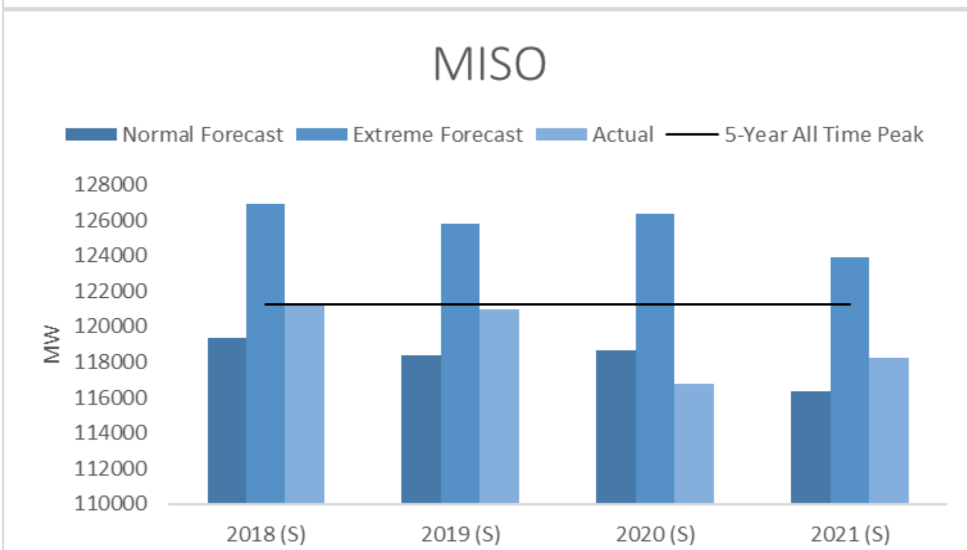
Figure 19 shows the four-year historical summer normal (50/50) forecast and extreme (90/10) forecast, along with actual and all-time summer peak load for each PC in the MRO region. MH and SPC actual peak demand exceeded the extreme forecast last summer while MISO and SPP actual peak demand has been at or below the extreme projected 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 forecast. MH, SPC and SPP recorded a new all-time summer peak load in 2021, while MISO's 2021 summer peak demand was at 118,259 MW.

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 2021
- MISO – 121,233 MW in 2018
- SPC – 3,547 MW in 2021
- SPP – 51,037 MW in 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.





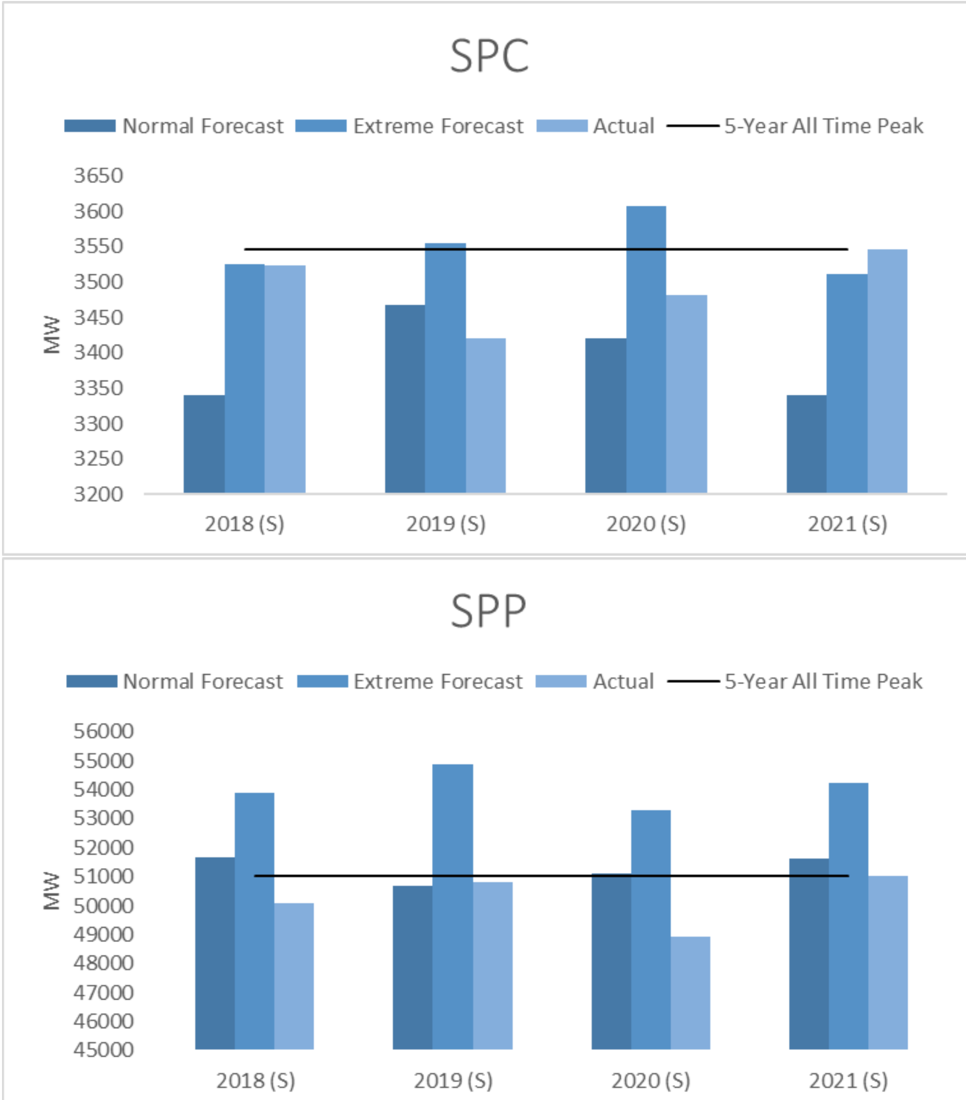


Figure 19: 4-Year Historical Summer Load Forecast

2022 SUMMER SEASONAL FORECAST

The 2022 summer seasonal assessment includes the months of June through September 2022.

Anticipated Summer 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 demand. Figure 20 below illustrates the 2022 and six-year historical generation by fuel type at the time of summer peak for each of the PCs in the MRO region:

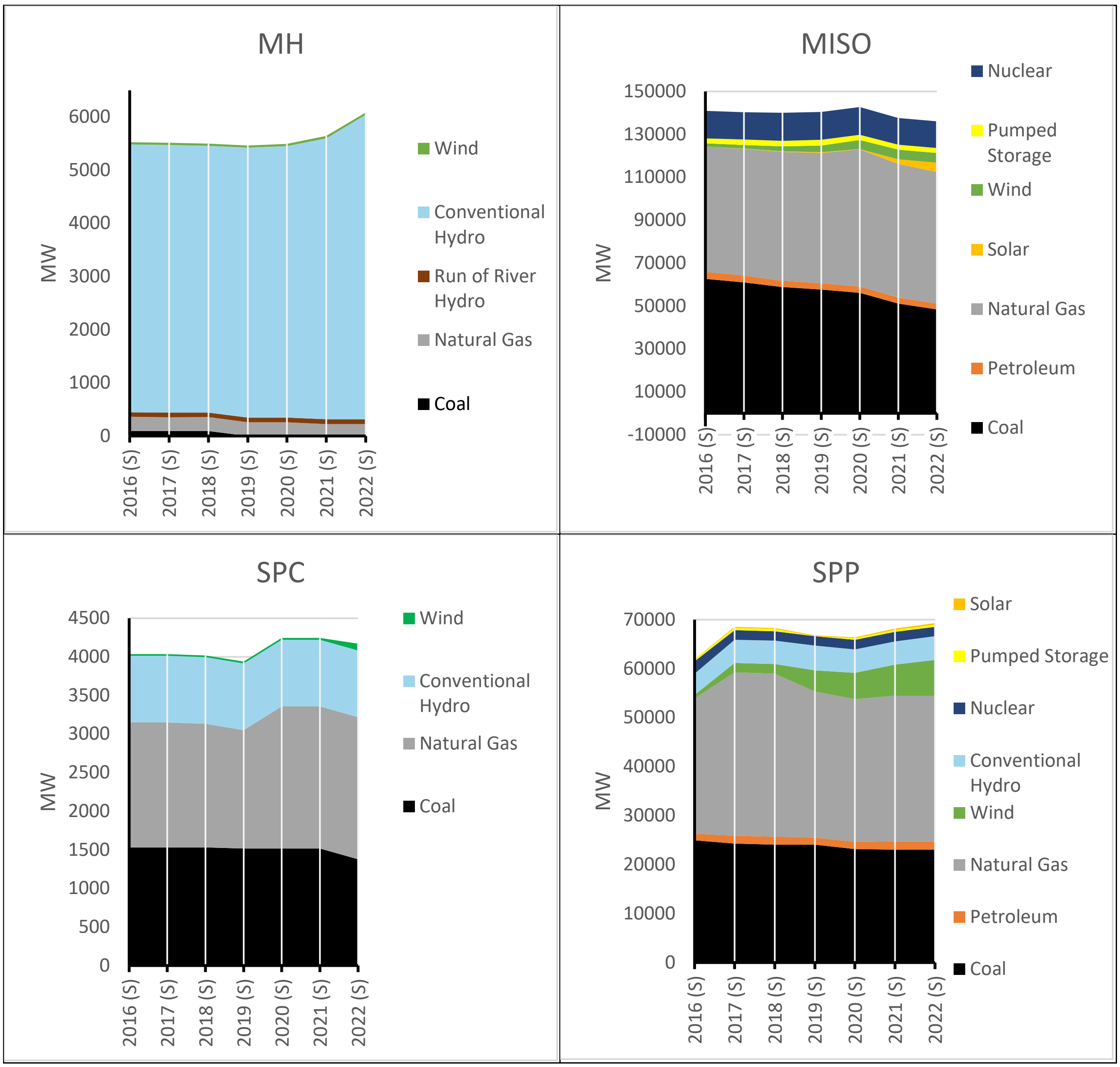


Figure 20: Generation by Fuel Type at Time of Summer Peak

Each PC has a slightly different resource mix. MH is predominantly conventional hydro, while 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 electric capacity output of wind depends on weather conditions, on-peak wind capacity contributions are 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.

Fossil-steam, gas and petroleum generating plants are susceptible to extreme hot temperatures that can lead to reduced output capacity when not properly cooled in summer months. Cooling water temperatures and low river water levels can impact generators with once-through cooling, reducing output capacity. Environmental limitations on discharge temperatures can lead to similar restrictions. The extreme peak demand scenarios in Tables 6 and 7 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 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 indicates the reliability risk of the actual system peak exceeds 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 capacity and reserve margin projections that assume adequate fuel supply. However, recent increases in extreme weather events present new challenges as fuel sources are inherently less secure with the rapid growth of intermittent resources 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 power industry needs to develop new and better methods to evaluate energy availability that will provide reliable and secure operations of the BPS.

The summer seasonal risk scenario, which includes the cumulative impact resulting from the occurrence of multiple low-probability events, is lower than the winter season due to better predictability of load and generation available during the summer season. Tables 5 and 6 show the risk scenarios if peak demand exceeds forecast using the following definitions:

- **Anticipated Resources**: Existing resources plus Net Firm Transfers plus Planned resources.
- **Net Internal Demand**: Total Internal Forecast Demand minus Demand Side Management.
- **Reserve Margin**: Measure of the amount of generation capacity available above projected load to reliably meet expected demand.
- **Typical Maintenance and Forced Outages:** Historical average of maintenance and forced outages for a specified period/conditions or area-specific methodology for determining anticipated maintenance and forced outages.
- **Extreme Derates**[7]: Reduced capacity contribution due to generator resource performance in extreme conditions (i.e. low wind or solar output, low-hydro due to drought and thermal derates due to extreme heat).
- **Extreme Low Generation**: Anticipated Resource minus Outages/Extreme Derates
- **Operational Mitigations:** Emergency procedures (e.g., additional imports, voluntary load curtailment,

[7] Derate is a partial outage with an associated reduction in capacity.

voltage reductions, public appeals, and foregoing reserve requirements) that would be employed in extreme conditions.

- **Extreme Peak Load:** Sum of Net Internal Demand and seasonal load adjustment (90/10 forecasted load).

Table 5 displays anticipated reserve margins with typical 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[8] basis for the assessment areas. MISO and SPC significantly fell below their reserve margin requirements and have insufficient resources for the upcoming 2022 summer season. The anticipated resources are based on the Installed Capacity (ICAP), which represents physical generating capacity adjusted for ambient weather conditions.

MISO projects a capacity shortfall of 1,230 MW based on the recent 2022-2023 PRA results showing the Unforced Capacity Value (UCAP)[9] basis as tighter than normal operating conditions for MISO North and Central areas due to increased load forecast, less capacity entering the PRA due to retirements, and the decreased accredited capacity of new resources. There are some units that did not qualify for reserve capacity in the PRA but may be available to serve energy through most of the summer. The operating conditions indicate that MISO North and Central areas are at increased risk for temporary, controlled load sheds under extreme summer peak load coupled with unplanned generation outages. MISO is projecting a 5 GW shortfall in firm generation to meet projected peak load for the month of July, resulting in a greater likelihood of operating mitigations such as load modifying resources or non-firm imports to meet reserve requirements under normal peak summer conditions. Unless more capacity is built that can supply reliable generation, projected shortfalls such as those highlighted above will continue.

SPC's anticipated reserve margin for summer 2022 is forecasted at 12.2 percent, which is slightly above the reserve margin requirement of 11 percent. This is mainly due to a 7.5 percent increase in total internal demand forecasted for the 2022 summer season when compared to 2021. The increase is related to the economy returning to pre-pandemic levels; increased oil and gas development activities, and a revised forecast methodology for capturing summer peak demands. SPC is projected to have sufficient operating reserves for normal peak conditions; however, above-average seasonal temperatures and increased forced outages for generation will require external assistance from Alberta, Manitoba and/or SPP.

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	3,893	177	3,716	3,059	**21.5%**	12.0%
MISO	143,197	21,155	122,042	118,220	**3.2%**	17.9%
SPC	4,033	344	3,689	3,596	**2.6%**	11.0%
SPP	67,101	9,384	57,717	51,382	**12.3%**	16.0%

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

[9] MISO's UCAP value is the percentage of installed capacity available after a unit's forced outage rate is calculated and typically is five to ten percent less than a resource's installed capacity.

Table 5: Anticipated Reserve Margin with Typical Outages and Normal Forecast

The worst-case scenario for summer 2022 considers increased resource outages and derates combined with an extreme peak load forecast as noted in Table 6.

The reserve margin percentage in Table 7 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	3,716	70	3,646	0	3,646	3,381
MISO	122,042	9,648	112,394	2,400	114,794	125,192
SPC	3,689	154	3,535	0	3,535	3,734
SPP	57,717	8,299	49,418	2,000	51,418	53,952

Table 6: Extreme Summer 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	3,646	3,381	**+7.8%**	Low
MISO	114,794	125,192	**-8.3%**	High
SPC	3,535	3,734	**-5.3%**	High
SPP	51,418	53,952	**-4.7%**	High

Table 7: Reserve Margin Percentage under Extreme Conditions

The extreme low generation plus operational mitigation scenario in Table 7 above shows that MISO, SPC and SPP resources fall below the extreme peak load, due to extreme outages and derates. Under the extreme peak demand and outage scenario studied, MISO, SPC and SPP 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 a much higher than expected number of generation outages and derates (partial outage with an associated reduction in capacity) when combined with excessively hot and humid days. Extreme hot weather is becoming a common occurrence in the Midwest and in the South. Recent events have shown prolonged hot and humid temperatures could occur and jeopardize the reliable operation of the BPS.

Distributed Energy Resources (DER)

The NERC DER Report defines 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 in some areas of the country on generation, transmission, and distribution systems.

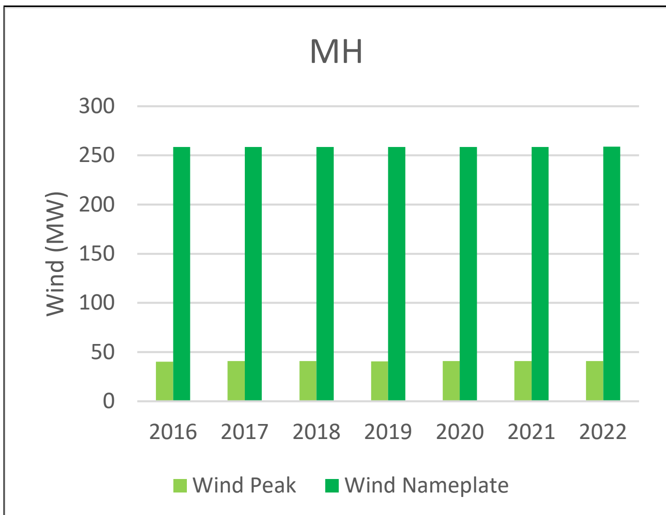
This is particularly true for those resources that are connected to the BPS, but not defined as BES resources. MH, MISO, SPC, and SPP do not anticipate any reliability issues related to DERs given their capacity is very low compared to overall system load during the 2022 summer assessment period. Table 8 shows the installed DERs (rooftop solar PVs, small wind turbines, gas-powered generators, etc.), and the nameplate capacity for each of the assessment areas. Peak capacity is the amount of DER projected to be available during the period of peak demand.

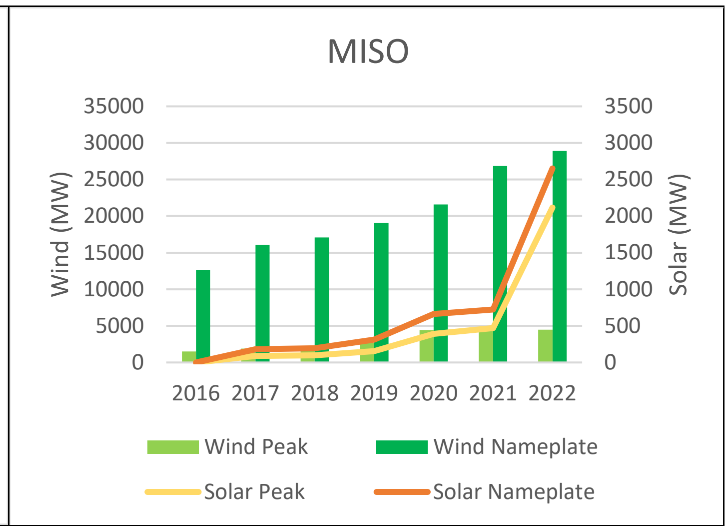
Assessment Area	2021 Summer Nameplate (MW)	2022 Summer Nameplate (MW)	2022 Summer Peak Capacity (MW)
MH	35	36	0[10]
MISO	861	861	431
SPC	35	38	0[11]
SPP	45	45	42

Table 8: Total Installed DER Nameplate and Peak Capacity

Wind and Solar Resources

MISO and SPP continue to see an increase in wind and utility scale solar photovoltaic penetration in the region. Figure 21 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[12] 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.





[10] Available peak capacity is zero as it is not counted for the Reserve Margin purpose.

[11] Available peak capacity is zero as it is not counted for the Reserve Margin purpose.

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

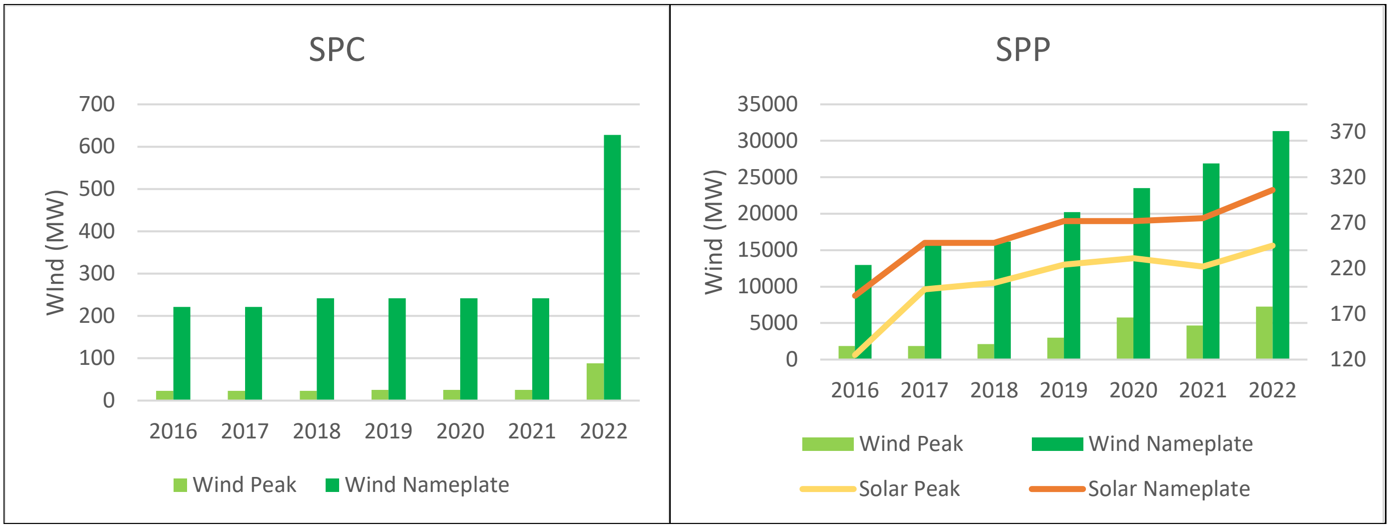


Figure 21: Wind and Solar Photovoltaic Nameplate and Peak Capacity

2022 Summer Outlook

The following sections describe the projected reliability conditions for each PC footprint in the MRO region.

MH

Manitoba Hydro is not anticipating the development of any emerging reliability issues for the 2022 summer season. Although Manitoba Hydro experienced unanticipated higher than normal load conditions last summer, no changes are required to operating plans/procedures or seasonal resource planning for the upcoming summer. The anticipated reserve margin significantly exceeds the reference margin level for the upcoming summer peak season. Four of the seven Keeyask units with approximately 93 MW each are now in service and two additional Keeyask units are anticipated to come online this summer. The seventh and final unit of Keeyask is in advanced commissioning and is now anticipated to be in service for winter 2022-2023.

MISO

MISO projects a capacity shortfall for the upcoming 2022 summer season as tighter than normal operating conditions may be observed in the MISO North and Central areas. The operating conditions indicate that MISO North and Central areas have a slightly increased risk of the need to implement temporary, controlled load sheds. MISO's 2022 summer peak load forecast also showed an increase in system peak demand mainly driven by economic forecast from post-COVID recovery. Summer scenarios with high resource outages and high demand may require utilization of 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.

Regional Directional Transfer (RDT) Update

The 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. The flows across the RDT in summer months are not as impactful as winter months. However, damage to a 4-mile section of 500 kV transmission line by a tornado during a severe storm on December 10, 2021, impacted the 1,000 MW of firm transfers between the MISO Midwest and southern MISO system. This is the 500 kV transmission line connecting Entergy's Dell Substation and AECI's New Madrid Substation. As a result, MISO's firm Contract Path Capacity decreases to 0 MW until the Dell–New Madrid line is returned to service. MISO will continue to operate to the full 3,000 or 2,500 MW transfer level, but all transmission will be “non-firm, as-available” service until the 500 kV line is restored, expected by June 30, 2022. These “non-firm, as-available” transfers will be curtailed down to 0 MW under system emergencies or to prevent load shed conditions.

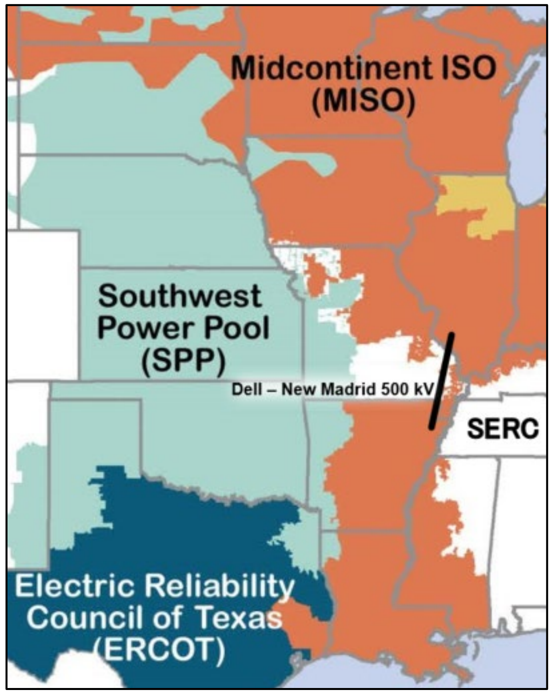


Figure 22: Dell – New Madrid 500 kV Line

Though risk has been identified for this upcoming summer season, MISO operators anticipate that system reliability can be maintained using Load Modifying Resources (LMR) 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

Anticipated resource capacity in SPC will be strained to meet the anticipated 7.5% increase in projected peak demand for this summer. The projected increase is related to load growth from economy returning to pre-pandemic levels, increased oil and gas development activities, and a revised forecast methodology for capturing summer peak demands. SPC is seeing tighter reserve margins as available resources approach planning reserve margin levels. Existing resources are adequate to meet SPC’s operating reserve requirements for normal weather this summer; however, external assistance from increased power transfer from MH and SPP is expected to be needed in extreme conditions that cause above-normal generator outages or demand. Additional assistance from Alberta via asynchronous tie (Swift Current to McNeil) with Saskatchewan may be available depending on operating conditions.

SPC experiences high load in summer due to extreme hot weather. The risk of operating with reserve shortages during peak load times or declaring an EEA could increase if large generation forced outages combined with large, planned maintenance outages occurs during peak load times. In case of extreme thermal conditions combined with large generation forced outages, SPC would also utilize available demand response programs and short-term load interruptions.

SPP

SPP does not anticipate any emerging reliability issues impacting the area for the 2022 summer season; however, operational challenges for the upcoming season include managing wind energy fluctuations and ensuring capacity sufficiency during high load with statistically coinciding low wind conditions. SPP often experiences sharp ramps of its wind generation, and at times these ramps can cause transmission system congestion as well as scarcity conditions. During periods of high load, SPP may experience capacity concerns if wind fails to perform to its overall accreditation. In preparing for these operational challenges, SPP performs operations seasonal assessments and utilizes the Generation Assessment Process (GAP) to help ensure that adequate generation is available to serve load.

Other than the aforementioned concerns with ongoing drought conditions that could impact water sources used for once-through cooling, SPP is not aware of any projected fuel shortages or operating challenges related to its generating fleet. Low water can impact the generation's capacity output and reduce its ability to support congestion management and serve load. These extreme conditions are studied in SPP's seasonal assessment process to identify mitigations prior to peak conditions. Using the current operational processes and procedures, SPP will continue to assess the needs for the 2022 summer season and will adjust as needed to ensure that real-time reliability is maintained throughout the summer timeframe.

Focus Areas for Summer 2022

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

- MISO anticipates a capacity shortfall this summer that places it at high risk of energy emergencies for MISO North and Central areas. MISO's recent annual 2022-2023 Planning Resource Auction (PRA) Results indicates insufficient capacity to cover the anticipated summer peak demands and an increased risk for implementing temporary, controlled load sheds. Capacity in MISO North and Central areas fell by 3.2 GW compared to last summer. MISO is projecting a 5 GW shortfall in firm generation to meet projected load this summer resulting in a greater likelihood of operating mitigations, such as deployment of load modifying resources or non-firm imports to meet reserve requirements under normal peak summer conditions.

- Anticipated resource capacity in SPC will be strained to meet projected peak demand this summer as a result of pandemic economic recovery and load growth activities. SPC is seeing tighter reserve margins as available resources approach planning reserve margin levels. SPC is projected to have sufficient operating reserves for normal peak conditions; however, external assistance is expected to be needed in extreme conditions that cause above-normal generator outages or demand.

- Above-normal temperatures and continued drought conditions over the western half of the United States will impact the Missouri River and other water sources used by SPP for generation resources that rely on once-through cooling processes. This could lead to reduced output from these resources and require the implementation of emergency procedures to meet peak demand during periods of high generator unavailability because of insufficient cooling water.

- Extreme summer peak load coupled with unplanned generation outages due to prolonged hot temperatures will likely exceed available capacity resources and require MISO, SPC and SPP BAs to issue EEAs or max-gen alerts, and employ operating mitigations such as demand response, non-firm imports from neighboring areas, and short-term load interruption.

- 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 summer 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 summer peak periods, especially as the resource mix evolves. The electric power industry needs to 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.

APPENDIX A

Cause Type	Portion of MWh lost
Feed water pump drive - motor	32.62%
Rotor; General	18.23%
Blade Path Temperature Spread	7.21%
IP Desuperheater/attemperator spray nozzles	5.00%
Other feed water pump problems	3.79%

Table A1: Combined Cycle Steam 2021 Summer Outage Causes

Cause Type	Portion of MWh lost
Stator windings; bushings; and terminals	35.38%
Stator core iron	9.03%
High pressure blades/buckets	6.79%
Feed water pump drive - motor	5.52%
Other catastrophe	3.00%

Table A2: Combined Cycle Steam 2019-2021 Summer Outage Causes

Cause Type	Portion of MWh lost
Rotor Windings	19.95%
Fuel Piping and Valves	18.78%
Blade Path Temperature Spread	10.51%
Other fuel system problems	6.24%
Boiler water condition (not feed water quality)	4.77%

Table A3: Combined Cycle Gas Turbine 2021 Summer Outage Causes

Cause Type	Portion of MWh lost
Stator windings, bushings and terminals	38.75%
Stator core iron	5.81%
Other miscellaneous balance of plant problems	5.39%
Other miscellaneous auxiliary system problems	4.42%
Fuel piping and valves	3.11%

Table A4: Combined Cycle Gas Turbine 2019-2021 Summer Outage Causes

Cause Type	Portion of MWh lost
Other turbine problems	21.77%
Drought	14.63%
Governor Oil System	14.31%
Other runner problems	9.67%
Closed cooling water heat exchangers	6.96%

Table A5: Hydro 2021 Summer Outage Causes

Cause Type	Portion of MWh lost
Other turbine control problems (Report specific wicket gate controls; etc. using the code for the appropriate equipment item.)	14.79%
Other turbine problems	14.13%
Governor Oil System	8.27%
Drought	7.59%
Other runner problems	5.02%

Table A6: Hydro 2019-2021 Summer Outage Causes