Resource Adequacy Reforms
Conceptual Design
DRAFT
August 16, 2021
Purpose Statement

This paper provides the conceptual design for MISO’s Resource Adequacy reforms including Seasonal Resource Adequacy Requirements, Availability based Accreditation, Seasonal Planning Resource Auctions and Minimum Capacity Requirements.

Executive Summary

MISO’s August 2020 whitepaper, *Aligning Resource Availability and Need, Changing Reliability Requirements for an Evolving Fleet*, highlighted the significant resource portfolio transformation underway in the MISO footprint, changing risk patterns driven by growing variability and uncertainty, and that changes to planning, markets and operations will be needed to manage these developments. The report noted the important role Resource Adequacy plays in assessing system needs and that traditional approaches that rely only on summer peak loads will no longer suffice. Resource Adequacy analysis should reflect risks and their associated magnitude throughout the year, including enhanced consideration of variable energy resources, planned and forced outages, and firm and non-firm external support.

MISO is facing a Reliability Imperative during this period of unprecedented change and this will be the main driver of transformation over the next five years. In order to position MISO to meet the challenges of the Reliability Imperative, MISO proposes Resource Adequacy reforms in three primary areas.

- **Sub-Annual Resource Adequacy Requirements.** Transition from the current summer-based construct to four distinct seasons. Expected outcomes are to: (1) Identify reliability needs unique to each season; (2) Align Resource availability with seasonal needs; and (3) Facilitate seasonal outages or partial year operations.

- **Improved Availability based Accreditation.** Assure resources are available when needed most by aligning resource accreditation with availability in the highest risk periods. Expected outcomes are to: (1) Increase confidence in capacity that MISO can count upon; (2) Provide improved signals for availability and coordination; and (3) Improve outage coordination processes.

- **Minimum capacity requirement.** Require at least 50% of capacity to be secured for each Load Serving Entity, prior to the Planning Resources Auction. Expected outcomes are to: (1) Support MISO reliability with the changing risk profile and lower excess reserve margins; and (2) Reinforce a fundamental assumption that all Load Serving Entities are appropriately planning.

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1 MISO, August 2020. Available at, 20200824 Aligning RAN - Reliability Requirements470050.pdf (misoenergy.org)
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1. Introduction

The term "Resource Adequacy" refers to the electric industry's ability to serve peak demand while also providing enough excess supply to achieve an agreed-upon level of grid reliability. In the MISO footprint, the responsibility for achieving resource adequacy rests with Load Serving Entities (LSEs) with oversight by states as applicable by jurisdiction. MISO facilitates these efforts by administering tariff-defined Resource Adequacy Requirements, which LSEs use to demonstrate their ability to serve peak demand and provide a sufficient margin of excess supply.

Consistent with the guiding principles of MISO's Resource Availability and Need (RAN) initiative, the proposed enhancements will create better availability, flexibility, and visibility of resources to meet MISO's changing system needs. Seasonal requirements, including seasonal auctions, will ensure MISO's Resource Adequacy Requirements reflect reliability needs and required capabilities across the year. Accreditation reforms will ensure Resources committed during the Seasonal Planning Resource Auctions receive accreditation based on their Reliability Contribution during the times of highest need.

2. Seasonal Resource Adequacy Requirements

Recognizing the increasing variability of reliability needs and resource availability across the year, the current annual Loss of Load Expectation process used to establish an annual Planning Reserve Margin requirement is no longer sufficient to address reliability risks throughout the year. MISO makes three recommendations to help manage this shift: (1) Identify reliability needs unique to each season; (2) Align resource availability with seasonal needs; and (3) Facilitate seasonal outages or partial year operations.

2.1 Loss of Load Expectation Study Requirements

The methodology of the LOLE study needs to change to effectively model seasonal variables. This includes calculating Planning Reserve Margin Requirements (PRMR) and Local Reliability Requirements (LRR) on a seasonal basis. This can be achieved through seasonal risk allocation, outage modeling, improving modeling of non-firm external support, and hourly modeling of intermittent resources.

**Seasonal Risk Allocation:** In order to calculate seasonal requirements appropriately, each season must have an LOLE target. The seasonal requirements will be determined via a two-step LOLE analysis. For the first step, the LOLE model will be solved to an annual LOLE value of 0.1d/year to determine the natural LOLE distribution. If this results in a minimum of 0.01 LOLE in all four seasons then the seasonal requirements will be determined directly from this step and there will be no need for additional analysis. If a season has an LOLE of less than 0.01 from step 1, then an additional step will be performed to solve that season to an LOLE of 0.01. The 0.01 LOLE target was chosen because it is a large enough target to allow the model to converge but small enough to be able to calculate requirements while not greatly exceeding an annual LOLE of 0.1. This method also ensures that requirements in seasons where the LOLE is naturally greater than 0.01 are not artificially increased resulting in increased cost to market participants.

**Outage Modeling:** Seasonal forced outage rates based on five-year historic GADS data will be used for all thermal units. Additionally, an adjustment will be applied within the model to account for increased forced outages during extreme weather events. When the temperature drops below a certain threshold in the model, the outage rates for thermal resources will be increased to represent the correlation between extreme temperatures and forced outages that is observed in real-time.
Five-year average planned outage rates from GADS will be included in the model for all thermal resources. SERVM (the software used to conduct the LOLE study) will schedule planned outages using the flexible outage method. This allows the model to keep a portion of the planned outages fixed and optimally schedule the remaining outages to represent the flexibility to reschedule outages as needed.

**Non-Firm External Support:** One of the benefits of being part of the Eastern Interconnection is the ability to import energy from neighboring regions as needed. Historical Net-Scheduled Interchange (NSI) was used to determine a probabilistic distribution of non-firm imports into the MISO region which was used as an input to the LOLE model. During the LOLE simulations, SERVM randomly draws from this distribution of non-firm imports which is used to serve the hourly load. This methodology is a better representation of non-firm imports when compared to the current annual practice (which assumes a static value) as it captures the variability observed in operations.

**Intermittent Resources:** Wind and solar resources will be modeled with hourly profiles that correspond to each of the 30 load shapes within SERVM.

More details on the specific modeling assumptions can be found in the MISO Sub-annual LOLE Modelling Methodology Documentation.²

### 2.1.1 Seasonal Planning Reserve Margin Requirements

A Planning Reserve Margin (PRM) will be determined for each of the four seasons by performing an LOLE analysis with seasonal input assumptions. The LOLE model will be used to meet the seasonal LOLE targets by adjusting the capacity within the model up or down as needed. If the LOLE is less than the target for a season, then a perfect unit with a negative capacity value and zero forced outage rate will be added to the model. This is equivalent to adding load and is consistent with the current practice under the annual construct³. If the LOLE is greater than the target for a season, then proxy combustion turbine generators of typical size of 160 MW and class average EFORD will be added to the model until the seasonal LOLE target is achieved. Once the seasonal LOLE targets are met, the seasonal PRM values in terms of Unforced Capacity (UCAP) will be calculated and expressed as a percentage of seasonal coincident peak demand.

### 2.1.2 Zonal Local Reliability Requirement/Local Clearing Requirements

The zonal Local Reliability Requirements (LRR) will be determined using the same two-step process as the PRM analysis. Each zone will be treated as an isolated system, consistent with the existing LRR analysis. The seasonal LRR values will be calculated in terms of UCAP and expressed as a percentage of seasonal zonal coincident peak demand once the model has been solved to the appropriate LOLE targets. The seasonal LRR values will be used to determine the seasonal Local Clearing Requirements (LCR) values by subtracting the seasonal Capacity Import Limits (CIL) from the seasonal LRR.


³ [https://cdn.misoenergy.org/PY%202021%2022%20LOLE%20Study%20Report489442.pdf](https://cdn.misoenergy.org/PY%202021%2022%20LOLE%20Study%20Report489442.pdf)
2.1.3 Season Definitions

The seasonal RA construct will follow the definition of seasons as defined in Module A: Winter (December, January, February); Spring – (March, April, May); Summer (June, July, August); and Fall (September, October, November). This definition of seasons is used in various MISO processes including Financial Transmission Rights (FTR) and Seasonal Resource Assessments.

2.1.4 Capacity Import/Export Limits

Consistent with the existing transfer limit analysis methodology defined in BPM-011, seasonal transfer analyses will be performed to determine seasonal Capacity Import Limits (CILs) and Capacity Export Limits (CELs), capturing the seasonal variation of transfer limits for each Local Resource Zone (LRZ). Planning year seasonal peak powerflow models and input files developed from MISO Transmission Expansion Plan (MTEP) studies built for timeframes matching the effective periods of transfer limit analysis will be used to perform transfer analyses for each season, including Summer Peak, Fall Peak, Winter Peak, and Spring Peak study models. Seasonal MTEP powerflow models will include both approved and planned transmission projects through MISO MTEP planning process (outlined in Appendix A and Targeted A projects in the MISO Tariff) with effective dates on or before the effective date of the study models. Single-element contingencies in MISO and its seams areas will be evaluated and all facilities under MISO functional control and seams facilities of 100kV and higher will be monitored. First Contingency Incremental Transfer Capacity (FCITC) analysis will be performed for each of seasonal powerflow models to identify limiting constraints with a generation to generation transfer modeled. Additional Generation Limited Transfer (GLT) analysis and voltage limited transfer analyses may be performed on an as needed basis if certain scenarios occur as described in BPM-011. The resulting seasonal Zonal Import Ability (ZIA) will be used to determine seasonal zonal Local Clearing Requirement (LCR) for each LRZ.

3. Resource Accreditation Overview

Aligning resource accreditation with historic availability during the highest risk periods is necessary to ensure resources committed under MISO’s Resource Adequacy capacity construct are available to reliably meet Seasonal Planning Reserve Margin Requirements and Local Resource Zone Local Clearing Requirements. These changes to accreditation seek to: (1) increase confidence in capacity that MISO can count upon; (2) provide improved signals for availability and coordination; and (3) improve outage coordination processes.

3.1 Accreditation for Thermal Resources

Resource accreditation should reflect the anticipated capability and availability of planning resources during times when they are most needed. Historically, accreditation for conventional generation has been based only on forced outage rates defined in MISO’s Generator Availability Data System (GADS). This current approach may not effectively reflect the actual availability and capability of resources during times when capacity needs are highest -- during periods of peak demand, high generation outages, low levels of renewable generation output or a combination of these.

The current resource accreditation processes, or Unforced Capacity, is determined based on their performance between September 1 and August 31 of the three years prior to the planning year. Market participants submit North American Electric Reliability Corporation’s (NERC) GADS data to MISO on a quarterly basis. This data is utilized to calculate Unforced Capacity (UCAP), which is communicated to market participants on December 15 prior to the
Planning Resource Auction. The proposed rules will continue to utilize the same period to evaluate availability for determining Seasonal Accredited Capacity (SAC).

The data and analysis below utilizes complete planning years for determining RA Hour, Offered Availability, and calculating SAC. The proposed changes will continue to base accreditation on the three prior years starting September 1 through August 31 of the year prior to the planning year. The accreditation for the three prior years reflects the cumulative availability of a Resource over the three years i.e., is not equally weighted.

MISO proposes a tiered weighting structure to determine individual resource accreditation by season based on each resource’s real time offered availability during all hours and hours with the tightest operating conditions and accounting for coordinated planned outages. An Unforced Capacity accreditation to Seasonal Accredited Capacity conversion ratio is proposed to align seasonal requirements with seasonal accreditation.

### 3.2 Resource Adequacy Hours

Resource Adequacy (RA) Hours represent the periods of highest risk and greatest need during a season and throughout the year. They include Emergency Declaration periods and the hours when the operating margin, a measure of available supply capacity above demand and reserve requirements, is at its lowest. RA Hours will be determined seasonally, based on emergency events, the tightest 3 percent of operating margin hours, and a maximum operating margin threshold established at 25 percent. RA Hours will be used to determine each resources' availability for calculating its seasonal accreditation. The number of RA Hours in a season can exceed the target when a high number of hours during declared system or sub-regional emergencies occurs.

Provisions also ensure seasons have a minimum target number or RA Hours by supplementing any deficient hours with Annual Average Offered Capacity (AAOC) over all RA hours across the year. Under the current design approach and historical analysis, this is expected to occur infrequently. The RA Hours used for determining the AAOC are the tightest 3 percent of operating margin hours across the years and emergency events.
RA Hours will be determined on a sub-regional basis, reflecting the growing frequency of sub-regional emergencies. Causes of these emergencies often include: trapped capacity in one sub-region due to the contractual transfer limits, increasing sub-regional challenges driven by portfolio differences, and the impacts of extreme weather including hurricanes, cold weather events, and renewable penetration.

3.2.1 Tier 2 RA Hours Definition

RA Hours are defined over the three most recent historical planning years, based on declared MaxGen alert, warning and event hours supplemented by the tightest 3 percent of hours per season where the realized operating margin for the region is at or below the threshold of 25 percent. To reflect the distinct risk of capacity sufficiency across the MISO footprint, RA hours are defined by MISO North/Central and South separately.

3.2.1.1 Hourly Margin % Calculation

Hourly Margin in MW is defined as equation (1):

\[ \text{Margin (MW)} = \text{Total Offer} + \text{Net Scheduled Interchange} - \text{Load} - \text{Operating Reserve} \quad (1) \]

in which Load is calculated as equation (2):

\[ \text{Load} = \text{Total Generation Injections} + \text{Net Scheduled Interchange} \quad (2) \]

where Total Generation Injections are generation schedules from the Unit Dispatch System (UDS)

Thus, the hourly Margin in MW can be calculated as outlined below

\[ \text{Margin} = \text{Total Offer} - \text{Total Generation Injections} - \text{Reserve} \]

Net Scheduled Interchange is implicitly reflected in the margin calculation above but has no impact on the overall margin calculation used for RA hour identification.

Margin (MW) is further broken down to online and offline components, which are used for the hourly operational margin (%) definition as below:

\[ \text{Margin (\%)} = \frac{\text{Online margin (MW)} + \text{Offline margin (12-hour lead time)(MW)}}{\text{Real Time (RT) Load (MW)}} \]

1. \( j \) denotes either Central/North or South region;

\[ \text{Online margin (MW)} = \sum_{\text{unit } i \text{ in region } j} (\text{EmergencyMax}_i - \text{Energy MW}_i - \text{cleared operating reserve}_i) \]

if a generation unit is online and under normal dispatch control

\[ \text{Offline margin (MW)} = \sum_{\text{unit } i \text{ in region } j} \text{Emergency Max}_i - \text{cleared offline supplemental reserve (MW)} \]

if (i) a generation unit is offline; (ii) it’s cold-start lead-time is less than or equal to 12 hours; and (iii) is not on outage

Load Modifying Resource (LMR), and Emergency Demand Response (EDR) are excluded in the Online margin (MW) and Offline margin (MW) calculations.
3.2.1.2 RA Hour Selection (Tier 2)

Sub-regional tight margin hours (Tier 2 RA hours) are selected through the following process for each season of a planning year:

1. Hours where MaxGen declarations are in effect automatically become Seasonal RA Hours, including all MaxGen Alert, Warning, or Event hours declared in each season as listed in Table 1. System-wide MaxGen hours apply to both Central/North and South regions.

<table>
<thead>
<tr>
<th>Date</th>
<th>Start (EST)</th>
<th>End (EST)</th>
<th>Region</th>
</tr>
</thead>
<tbody>
<tr>
<td>6/4/2018</td>
<td>09:00</td>
<td>2200</td>
<td>South</td>
</tr>
<tr>
<td>7/5/2018</td>
<td>11:00</td>
<td>2200</td>
<td>North/Central</td>
</tr>
<tr>
<td>9/15/2018</td>
<td>13:05</td>
<td>2000</td>
<td>South</td>
</tr>
<tr>
<td>9/17/2018</td>
<td>12:00</td>
<td>2100</td>
<td>System</td>
</tr>
<tr>
<td>1/30/2019</td>
<td>05:00</td>
<td>2200</td>
<td>North/Central</td>
</tr>
<tr>
<td>1/31/2019</td>
<td>07:00</td>
<td>12:00</td>
<td>North/Central</td>
</tr>
<tr>
<td>5/16/2019</td>
<td>14:00</td>
<td>22:00</td>
<td>South</td>
</tr>
<tr>
<td>5/17/2019</td>
<td>12:00</td>
<td>20:00</td>
<td>South</td>
</tr>
<tr>
<td>5/22/2019</td>
<td>12:00</td>
<td>22:00</td>
<td>South</td>
</tr>
<tr>
<td>6/3/2019</td>
<td>12:00</td>
<td>22:00</td>
<td>South</td>
</tr>
<tr>
<td>6/20/2019</td>
<td>14:00</td>
<td>19:00</td>
<td>South</td>
</tr>
<tr>
<td>2/21/2020</td>
<td>07:30</td>
<td>09:00</td>
<td>South</td>
</tr>
<tr>
<td>7/7/2020</td>
<td>13:00</td>
<td>20:00</td>
<td>North/Central</td>
</tr>
<tr>
<td>2/15/2021 to 2/19/2021</td>
<td>07:00 on 15th</td>
<td>11:00 on 19th</td>
<td>South</td>
</tr>
<tr>
<td>2/16/2021</td>
<td>07:00</td>
<td>14:00</td>
<td>North/Central</td>
</tr>
</tbody>
</table>

Table 1 MaxGen Hours used for RA Hour (Tier 2)

2. For the rest of non-MaxGen declaration hours in each season of a planning year, additional Tier 2 RA Hours with the tightest margin will be identified until reaching the 3 percent of hours (approximately 65 hours) for each season; if a season already has more than 65 hours because of MaxGen declaration, skip this step.

3. Finally, apply a maximum margin threshold to exclude hours that are with an operational margin greater than 25 percent. By examining the cumulative count of hours at different level of operational margin (below 40 percent) in each season in a planning year, applying a 25 percent margin threshold (Figure 1 & 2) provides a good balance between having adequate number of RA hours and selecting the set of RA hours that are truly tight. For summer, the needed 65 hours for the season is reached well before the 25 percent margin threshold. On the other hand, in fall, winter and spring seasons, the 65 hours line intersects the cumulative hour line either near or above the 25 percent margin. Using a 20 percent margin threshold would exclude too many RA hours in seasons other than summer in multiple planning years and result in small sample size of RA hours.
Figure 1: Cumulative distribution of operation margin in Central/North region

Figure 2: Cumulative distribution of operation margin in South region
Some seasons will have more than 65 hours because of MaxGen declarations, while some other seasons in Central/North have less than 65 hours if there are hours excluded based on the 25 percent maximum margin threshold criteria and a low number of hours with MaxGen declarations (Table 2). The variation in seasonal Tier 2 RA Hours between North/Central and South regions also reflects MISO’s regional difference in terms of demand, supply, and weather conditions. This lack of seasonal Tier 2 RA Hour in North/Central also reflects MISO’s regional difference in terms of demand, supply and weather conditions.

<table>
<thead>
<tr>
<th></th>
<th>Central/North</th>
<th>South</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Summer</td>
<td>Fall</td>
</tr>
<tr>
<td>PY18to19</td>
<td>65</td>
<td>65</td>
</tr>
<tr>
<td>PY19to20</td>
<td>65</td>
<td>65</td>
</tr>
<tr>
<td>PY20to21</td>
<td>65</td>
<td>41</td>
</tr>
<tr>
<td>Total</td>
<td>260</td>
<td>236</td>
</tr>
</tbody>
</table>

Table 2: Count of Seasonal Tier 2 RA Hours

### 3.2.1 Seasons or Periods with Insufficient Seasonal RA Hours

As illustrated in Table 2, during some seasons there are instances of insufficient RA hours to meet the target of 65 hours, which reduce the basis for the accreditation calculation and may overstate or understate expected availability and performance. Additionally, while a season may have the target number of RA Hours specific resources may still have fewer than the 65 hour target if they have exempt tier 2 planned outages that overlap with one or more RA Hours.

For resources that have seasons with fewer than the target number (65 hours) of Seasonal RA Hours for a planning year, a resource’s Annual Average Offered Capacity (AAOC) backfills its availability only for the number of deficient hours, as expressed in the following equation:

\[
Backfilled\, availability_{i,s,y} = \text{Max}(65 - \text{Number of Seasonal RA Hours}_{s,y}, 0) \ast Annual\, average\, offered\, capacity_{i,s,y};
\]

in which \(i\) denotes a generation unit; \(s\) denotes a season, and \(y\) denotes a planning year.

A resource’s annual average offered capacity is calculated by averaging its availability during the annual RA hours as defined below:

Similar to the process of selecting seasonal RA Hour, Annual Tier 2 RA hours are selected through the following process for each sub-region, Central/North and South, in a planning year separately:

1. MaxGen declaration hours are automatically Annual RA Hours, including all declared MaxGen Alert, Warning, or Event hours in a planning year as listed in Table 2 above. System-wide MaxGen declaration hours apply to both Central/North and South regions.
2. For the rest of non-MaxGen declaration hours in a planning year, additional annual Tier 2 RA Hours with the lowest Margin are identified until reaching the tightest 3 percent of hours (approximately 260 hours) for
each planning year for each sub-region, Central/North and South, separately. Given that the 3 percent tightest annual Tier 2 margin hours naturally fall below the 25 percent margin threshold, there is no need to re-apply the 25 percent maximum margin threshold as was done during the process of selecting seasonal RA hours.

Note that like seasonal RA Hour identification, annual RA hours exclude hours when a resource has a tier 2 exemption and they will not be a part of the 260 hours on which AAOC is based. Table 3 shows the number of annual RA hours in each season. Compared to the counts in Table 2, the annual Tier 2 RA hours mostly cluster during summer and fall, reflecting the natural of higher load during these two seasons.

| Planning Year | Central/North | | | | South |
|---------------|----------------|---|---|---|---|---|---|
|               | Summer | Fall | Winter | Spring | Total | Summer | Fall | Winter | Spring | Total |
| 2018-2019     | 143  | 77   | 40    | 0      | 260   | 141  | 93   | 0      | 26     | 260   |
| 2019-2020     | 202  | 47   | 0     | 11     | 260   | 160  | 94   | 6      | 0      | 260   |
| 2020-2021     | 207  | 12   | 37    | 4      | 260   | 114  | 36   | 100    | 10     | 260   |
| Total         | 552  | 136  | 77    | 15     |       | 415  | 223  | 106    | 36     |       |

Table 3: Count of Annual Tier 2 RA Hours

3.3 Tiered Resource Accreditation

Resource Accreditation should reflect the anticipated capability and availability of Planning Resources during times when they are most needed. Utilizing offered availability, including actual performance during RA Hours provides an improved measure of expected availability. MISO proposes a two-tiered weighting structure to calculate resource accreditation, reflecting general availability while emphasizing availability during times of greatest need.

Each Resource will have its Seasonal Accredited Capacity (SAC) determined based on its Real-Time offered availability (Emergency Maximum Limit) during seasonal RA Hours (Tier 2) as described in Section 3.1 and Non-RA Hours (Tier 1). The number of Tier 2 RA hours may vary during individual seasons when the 25% maximum margin threshold is applied or individual resources receive outage exemptions, impacting sample sizes of RA hours and corresponding accreditation calculations. If tier 2 RA Hours for a season in a Planning Year fall below the 3% target of 65 hours, Annual Average Offered Capacity will be used to supplement for the deficient number of hours as part of the tier 2 portion of the accreditation calculation. Seasonal Tier 1 Non-RA Hours on the other hand include all hours in a season of a planning year, except Tier 2 seasonal RA Hours.

Figure 3 illustrates the process of calculating Tier 1 and Tier 2 Seasonal Accredited Capacity (SAC), and the following sections uses a hypothetical example to describe each step in detail.4
### 3.3.1 STEP 1: Prepare Hourly Real-Time Offered Availability Dataset

The first step is to prepare the hourly Real-Time Offered Availability dataset for a Resource, including (1) hourly timestamp (EST); (2) offered availability (EmerMax MW); (3) cold start lead time (in hours); (4) binary indicator if a resource is having an out-of-service outage based on commit status and cross-referenced with records in Control Room Operations Window (CROW) Outage Scheduler; and (5) identifier indicating if a Resource is online. **Figure 4** provides a sample screenshot of the dataset, using a sample Resource located in Central/North region. If a Resource is in Derated status but not Out-of-Service, it’s offered availability already accounts for the impact of derates.

**Calculation example:**
This sample Resource is located in Central/North region, it has seasons without 65 Tier 2 RA hours (as shown in Table 2). Hence the annual average offer availability is needed for backfilling its availability later in STEP 4. In STEP 2 the RT Offer EmerMax data is paired with Annual Tier 2 RA Hour by timestamp. Availability (MW) during Annual Tier 2 RA hour is then generated through these following steps:

1. Set availability = Min (ICAP, Real-Time Offer EmerMax) during Annual Tier 2 RA hour; this step caps RT Offer EmerMax at ICAP;

2. Set availability = zero if a Resource is in out-of-service outage (based on outage identifier) during Annual Tier 2 RA hour

3. Set availability = zero if a Resource is not online and not in outage and has cold start lead time greater than 12 hours during RA hour.

Figure 5 shows the sample dataset fragment after generating the availability (MW) during Annual Tier 2 RA hour through the steps described above. Cold Leadtime refers to the sum of a resource’s start-up and notification time.
3.3.3 STEP 3: Prepare Calculation for Seasonal Accredited Capacity

STEP 3 prepares dataset for SAC calculation calculates seasonal average offered availability by first pairing the RT Offer EmerMax data with Seasonal Tier 1 Non-RA Hour and Tier 2 RA Hour by timestamp. Availability (MW) during both tiers of RA hours is then generated through this process:

For availability during Tier 1 Non-RA hour:
(1) Set availability = Min (ICAP, Real-Time Offer EmerMax) during Tier 1 Non-RA hour; this step caps RT Offer at ICAP;
(2) Set availability = zero if a Resource is in out-of-service outage (based on outage identifier) during Tier 1 Non-RA hour

For availability during Tier 2 RA hour:
(1) Set availability = Min (ICAP, Real-Time Offer EmerMax) during Tier 2 RA hour; this step caps RT Offer at ICAP;
(2) Set availability = zero if a Resource is in out-of-service outage (based on outage identifier) during Tier 2 RA hour
(3) Set availability = zero if a Resource is not online and not in out-of-service outage and has cold start lead time greater than 24 hours during Tier 2 RA hour.

Figure 6 shows the sample dataset fragment after generating the availability (MW) during Seasonal Tier 1 and Tier 2 RA hour through the steps described above.
For each planning year, the annual average offered availability is calculated as the sum of availability over annual Tier 2 RA hours, divided by the total number of annual Tier 2 RA hours in each planning year (Table 3).

Table 4: Sample calculation of annual average offer availability

3.3.5 STEPs 4 and 5: Calculation for Tier 1 and Tier 2 Seasonal Accredited Capacity

STEPS 4 and 5 complete the calculation of Seasonal Accredited Capacity for Tier 1 and Tier 2 respectively.

For Tier 1, Seasonal Accredited Capacity is calculated as the sum of availability over seasonal Tier 1 Non-RA hours, divided by the total number of seasonal Tier 1 Non-RA hours across rolling three planning years (Table 55).
Table 5: Sample calculation of Tier 1 Seasonal Accredited Capacity

For Tier 2, Seasonal Accredited Capacity is calculated as the sum of availability over seasonal Tier 2 RA hours, supplemented with annual average offered availability for deficiency hours, then average over total number of Tier 2 hours across three planning years (Table 6).

Table 6: Sample calculation of Tier 2 Seasonal Accredited Capacity

3.3.6 Tier Weighting

The final Seasonal Accredited Capacity (SAC) value is the weighted averaged over its values from two tiers as calculated from steps above. Assigning heavier weighting of 80% towards Tier 2 tight condition hours ensures the alignment between a resource’s Seasonal Accredited Capacity value and its availability and performance during times of highest risks and greatest needs.

The corresponding tier weightings are:

\[ SAC_{Tier1\_weighting} = 20\% \]

\[ SAC_{Tier2\_weighting} = 80\% \]

\[ SAC = SAC_{Tier1\_value} \times SAC_{Tier1\_weighting} + SAC_{Tier2\_value} \times SAC_{Tier2\_weighting} \]

3.3.7 New Resource Accreditation Calculation

Units with insufficient performance data will utilize a class average proxy for accreditation as done today but this class average is based on SAC rather than UCAP. Classes for class averages will remain the same as they are today.
on a UCAP basis. However, how the class average is determined will be based on a ratio of the resource’s SAC to ICAP for a particular class. New resources will apply this ratio to a resource’s ICAP to determine its class average SAC. Class averages for a particular season will be utilized only when there is less than a full season’s worth of data. Newer resources that have a complete season’s worth of data but less than a full year that participate in a season with a limited number of RA hours will back fill that season’s RA hours using the class average SAC value for that particular resource.

### 3.3.8 Calculation Adjustment for Missing Seasons

To the extent possible, seasonal accreditation is based on offer data from the same season. When a Resource is not committed for a season (including when it has been replaced for a majority of the season) or has greater then 60 days in a season when it was either fully or partially on outage that season will not be considered in future accreditation calculations for the Resource. As long as a Resource has at least one season for which it was committed and not on outage the accreditation calculations will be based on offers during the RA hours for that season (included any AAOC backfill hours as needed to get to 65 hours); if it does not meet the one season requirement then the class average method described in section 3.3.7 above will be utilized.

### 3.4 Seasonal Deliverability

For seasonal deliverability, similar to the current process, if a unit does not have full Network Resource Interconnection Service (NRIS) granted for its seasonal output, to the extent the output is within the total granted Energy Resource Interconnection Service (ERIS) and does not violate the generator’s Generator Interconnection Agreement (GIA), it can:

1. Request additional NRIS through the established process in Attachment X or
2. Procure firm Transmission Service Requests (TSRs) to bridge that deliverability gap for sub-annual needs.

This proposal can be implemented for Planning Year 23-24. Further enhancements and additional seasonal NRIS products may be introduced and evaluated through the Interconnection Process Working Group (IPWG)

### 3.5 Intermittent and LMR Accreditation

In addition to the proposed offer based accreditation for conventional resources, MISO proposes to align accreditation for non-thermal resources with seasonal approach, including intermittent resources and Load Modifying Resources.

#### 3.5.1 Wind Resources

Wind resources are currently accredited through an Annual Effective Load Carrying Capability (ELCC) with capacity credits allocated based on each individual wind resource performance over eight peak demand summer hours. Under a seasonal construct, accreditation for seasons will be based on Seasonal ELCC with capacity credit allocated based on eight seasonal peak hours.

MISO Wind ELCC Report:

#### 3.5.2 Non-Wind Intermittent Resources

Under the current annual construct, non-wind intermittent resources are accredited based on historical output during hours 15, 16 and 17 EST from June through August. Seasonal accreditation will be based on historic output
during hours 15, 16 and 17 EST for the relevant spring, summer, and fall months. Winter accreditation will be based on hours 8, 9, 19 and 20 EST for the winter months. The selected hours represent the typical seasonal peak demand hours.

### 3.5.3 Load Modifying Resources

#### 3.5.3.1 Demand Response

Beginning in the 2022-23 planning year, Demand Response resources will be accredited based on lead time and number of calls per year. The lead time requirements will remain unchanged, but the number of calls will be modified to reflect a seasonal construct. Based on a 2019 analysis, 15 annual calls are sufficient for 100 percent credit.

For the planning year 2023-24 Load Modifying Resources must be available for a minimum number of calls for each season as follows: five for summer, five for winter, three for spring, and three for fall to get 100 percent seasonal accreditation for each respective season. These requirements are supported by historical analysis that showed 15 annual calls is sufficient for 100 percent credit.

![Figure 7 Resource capacity credit based on # of calls per year](image)

#### 3.5.3.2 Behind-the-Meter Generation

Intermittent behind-the-meter generation (BMTG) will be accredited like all other non-wind intermittent resources under a seasonal construct. Thermal BTMG with historic GADS data will be accredited based on their seasonal forced outage rates. Thermal BTMG with no GADS history will be accredited based on the class average seasonal forced outage rates. All BTMG will be subject to the same lead times and call limits as DR.

### 3.6 Resource Qualification

#### 3.6.1 Generation Verification Test Capacity

The current Generation Verification Test Capacity process has three steps:

1. Generator Operators (GO) conduct a single test between September 1 and August 31 prior to the planning year.
2. Correct to historical MISO summer coincident peak conditions.


A GADS integration is run to bring the Generation Verification Test Capacity (GVTC) from PowerGADS to the Module E Capacity Tracking (MECT) tool.

Under a seasonal construct, the GO would still conduct a single test between September 1 and August 31. MISO would publish four historical MISO coincident seasonal peak dates and times for the last five years. The GO would correct the single test to each of the seasonal peak conditions and submit four seasonally corrected GVTC values by October 31.

### 3.6.2 Installed Capacity (ICAP) Deferral

Installed Capacity (ICAP) deferral, formerly known as GVTC Deferral, requires a market participant to submit notice by February 15, post credit no later than March 1, and test and submit before the last business day of May prior to the start of the planning year.

The February 15 notice and March 1 credit posting timeline still apply, and the credit requirement would continue to be calculated as the deferred ICAP megawatts multiplied by 90 days of the daily Cost of New Entry (CONE). However, the deferral notice would be modified to indicate to which season the deferral applied and the credit would be held until the resource tested. The testing would need to be performed and submitted prior to the last business day prior to the start of the applicable season, otherwise the existing ICAP Deferral Non-Compliance Charge structure applies. No changes are proposed to the ICAP Deferral Non-Compliance Charges.

### 4. Planning Resource Auction

Participants in the Planning Resource Auction (PRA) may offer resources for each season in the upcoming planning year during the PRA Offer Window period, which occurs over the last four business days in March. During the first 20 business days in April, MISO will build four Simultaneous Feasibility Test (SFT) models to meet seasonal requirements. Results for each upcoming planning year season that pass the SFT auction run will be posted and valid by the 20th business day in April. Results for seasons where unacceptable constraints are found will have their SFT model rebuilt and re-run for one additional iteration. MISO will accept the best result of the two iterations for that season and post the result by the 20th business day of April.

#### 4.1 Auction Timing

Under a seasonal construct, the PRA offer window will remain as the last four business days of March. The auction period is expanded to occur within the first 20 business days of April, allowing a maximum of two SFT auction run iterations per season. PRA Results will be posted on the 20th business day in April.
4.2 Participation, Monitoring and Mitigation

4.2.1 Physical Withholding of Zonal Resource Credit (ZRC) offers into the PRA

The move to seasonal auctions calls for minor modifications that ensure these same protections continue to work going forward. Primarily, it is the exemptions from auction participation in Section 64.1.1.g of Module D that need to be adapted for a seasonal approach.

4.2.2 Economic Withholding

MISO proposes modifications to the per megawatt-day amount of annual Cost of New Entry (CONE) that can be considered in the reference levels for seasonal auctions. Under an annual approach it was appropriate to simply divide the annual CONE value by the number of days in the planning year but under a seasonal approach CONE may only be allocated over a single season. In recognition of this, MISO’s proposal allows offers up to each zone’s annual CONE value divided by 90 days. (e.g., $90,000/90 days = $1,000 per megawatt-Day). The conduct threshold for identifying economic withholding for ZRC offers will be set at 10 percent of the offer cap (approximately $100/MW Day) for those resources that do not have a relevant facility specific Reference Level since annual CONE could be allocated across just one season instead of all four under the status quo.

4.2.3 Resource Auction Participation Eligibility

Currently, Resources that are on outages for more than 90 days of the 120 days are not eligible to participate in the Planning Resource Auction\(^5\). MISO will remove the auction participation preclusion based on planned outage lengths prior to the auction previously proposed at 30 days. Resource Owners will need to modify Planning

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\(^5\) Module D, Section 64.1.1.g.xii. Market Participants with capacity expected to be on outage for any ninety (90) or more of the first 120 Calendar Days in the Planning Year will be precluded from participation in that PRA.
Resource Auction (PRA) Offer submittals to manage clearing of Resources that may require replacement or need to be available as replacement capacity. For example, offers may reflect avoidable costs for Resources performing maintenance. IMM Technology-Specific Avoidable-Costs (misoenergy.org).

4.3 Offer and Price Caps

Currently, Resources clear for the whole year or not at all. The current price cap, set at the Cost of New Entry, may preclude resources otherwise economic for one or more seasons from participating in the auction.

4.3.1 Offer Cap

An LRZ may fail to clear its target PRMR in fewer than all four seasons. Seasonal offer caps, reference levels and withholding conduct thresholds need to take this into account to enable some resources to participate in the seasonal auctions. Offers higher than the daily allocation of the annual CONE value could be cleared and set prices when needed to enable resources to cover their avoidable costs. Therefore, seasonal offers will be allowed to exceed the current megawatt-day value of the annual CONE (e.g., up to $1,000 per megawatt day) to enable resources to offer their going-forward costs if they only clear in one season.

The Maximum Auction Clearing Price will be based on annual CONE and the number of seasons an LRZ, group of LRZs, or the MISO footprint is deficient in the Planning Resource Auction. MISO will continue to allow facility and technology specific reference levels in consultation with the IMM that consider relevant costs per section 64.1.4 of Module D.

The conduct threshold will be set at ten percent of the seasonal Offer Cap.

4.4 Auction Inputs

4.4.1 Converting Planning Reserve Margin Requirements based on Unforced Capacity to PRMR based on Seasonal Accredited Capacity

PRMR are established by the LOLE Study based on unforced capacity (UCAP). Historically, the PRMR and the accredited capacity used to meet the PRMR have been aligned and in UCAP terms. Because MISO has proposed to move to a Seasonal Accredited Capacity (SAC) for resources, the PRMR produced by the LOLE study would be misaligned with how resources are accredited. In order to translate the PRMR UCAP to a PRMR SAC, MISO proposes to use a ratio of SAC compared to UCAP and multiplying by the PRMR UCAP (PRMR_{SAC}). The ratio of SAC to UCAP is calculated by adding the Thermal SAC to the Non-Thermal UCAP and dividing by total UCAP. The reason the Non-Thermal UCAP is included in the numerator is because Non-Thermal UCAP is roughly equivalent to Non-Thermal SAC. MISO will continue to look at ways to improve LOLE modeling, which includes producing requirements aligned with accreditation or SAC. This would eliminate the need for a ratio to be applied.

\[
PRMR_{SAC} = PRMR_{UCAP} \times \left( \frac{RATIO_{SAC/UCAP}}{} \right)
\]

\[
RATIO_{SAC/UCAP} = \frac{SAC_{Thermal} + UCAP_{NonThermal}}{UCAP_{Thermal} + UCAP_{NonThermal}}
\]
4.4.2 Local Resource Requirements and Local Clearing Requirements

Similar to the aforementioned conversion ratio derived for calculating system wide reserve requirements based on SAC, zonal conversion ratios will be determined for each of LRZs by dividing total SAC by total UCAP within each zone.

\[
\text{Zonal Ratio}_{SAC/UCAP} = \frac{\text{Zonal SAC}_{\text{Thermal}} + \text{Zonal UCAP}_{\text{NonThermal}}}{\text{Zonal UCAP}_{\text{Thermal}} + \text{Zonal UCAP}_{\text{NonThermal}}}
\]

Then zonal LCRs based on SAC will be calculated by multiplying the UCAP LCRs derived from LOLE analysis by each respective zonal conversion ratio.

\[
\text{Zonal LCR}_{SAC} = \text{Zonal LCR}_{UCAP} \times \left( \text{Zonal Ratio}_{SAC/UCAP} \right)
\]

4.4.3 Load Forecasts

The supplied Coincident Peak Demand and LRZ Peak Demand forecasts are for each season and include the demand expected for the Coincident Peak Demand hour during the season, augmented to include the normal demand from forecasted demand resources, whether registered as LMRs or not registered with MISO. The forecasts shall include demand that would have occurred but for the existence of energy efficiency resources that have been in operation less than 4 years. All submissions for such forecast values include distribution losses, but not transmission losses. All demand forecasts reflect a 50 percent probability that the demand will not exceed the forecasted demand for the relevant time period.

4.4.4 Transmission Losses

Under the current annual PRA construct, MISO calculates annual transmission losses for each LBA and zone based on the MISO coincident peak hour. Under the seasonal PRA construct, transmission losses are calculated at the published seasonal peak hour of MISO and are made available by MISO on both the market portal and its public website.

4.5 Obligation for Cleared Capacity Resources

4.5.1 Must Offer Requirement

Currently resources are committed for an entire planning year and their must-offer requirement is the same throughout the year despite lower load expectations outside of summer. Under a seasonal approach, resource capabilities and capacity requirements are tailored to each season and resources that may be committed for one season may not be committed in other seasons. The must-offer requirement only applies for those seasons in which a resource is committed and the must-offer calculation is specific to each season as the relevant parameters — such as GVTC and deliverability — may be different in different seasons.

There are no substantive changes to deliverability in the upcoming filing. Deliverability demonstrated seasonally will impact ZRCs as it does today. The must offer is ICAP times the % of total ZRCs a resource clears (for example, a unit
eligible for 10 ZRCs that clears 5 will have a must offer of 50% of its ICAP). Given stakeholder concern, MISO proposes adding the issue of deliverability to the RASC Management Plan for further discussion, including with the Independent Market Monitor.

4.5.2 ZRC Replacement Requirements

Future seasonal PRMRs are expected to be lower than today's annual summer-peak target. Current capacity replacement requirements only for suspensions and retirements are no longer sufficient. Moving to a seasonal construct with availability based accreditation, the performance and availability of committed capacity to meet seasonal requirements will be critical. Relying on Resources on planned outages for a large portion of a season is not consistent with availability based accreditation and seasonal requirements. The proposal establishes a maximum threshold number of planned outage days or planned derate days in a season that will require replacement when exceeded. The threshold days could vary by season, for example, a lower threshold for Summer and Winter. The latest proposal is to set it at 30 days. Historically, the number of outages and planned outage lengths have varied by season.

An after-the-fact determination will be made following each season to determine if Resources were on planned outages or planned derates that exceeded the threshold and if such Resources met replacement requirements. A non-compliance charged will be assessed for days exceeding the threshold (see next section). Exemptions granted through the outage coordination process do not relieve a Resource owner of the ZRC replacement obligation.

MISO systems and processes will continue to accommodate ZRC replacement transactions. Current replacement rules regarding deliverability and zonal transfer limits will still apply.

4.5.3 Financial Non-compliance Charge for Failure to Replace

Currently, Resources that convert UCAP to ZRCs and retire or suspend prior to the end of the Planning Year and fail to replace do not face any explicit non-compliance charges under the tariff. This creates uncertainty and fails to quantify the consequences of failure to replace. In the past, this has led Market Participants to seek waivers from FERC as opposed to complying with the tariff requirements. The proposal is to implement a financial charge for failing to replace ZRCs associated with the Resource’s capacity for failing to comply with the failure to replace retired, suspended ZRCs, or ZRCs whose Resource has Planned Outages that exceed the seasonal planned outage threshold for replacement. The proposed ZRC Replacement Non-Compliance Charge is a daily charge, equal to the amount of ZRCs that failed to be replaced multiplied by sum of the Auction Clearing Price and the daily CONE value. Distribution of ZRC Replacement Non-Compliance Charges will be distributed to LSEs that have met their PRMR during the Planning Year on a pro rata basis, based upon the LSE’s share of total PRMR for the Transmission Provider Region. [See ICAP Deferral Non-Compliance Charges Section 69A.7.9.c.iii.] Billing, invoicing, default and uplift provisions will be similar to the ICAP Deferral Non-Compliance Charge.

---

6 Module E-1, section 69A.3.1.h. If a planning resource for which a market participant converts unforced capacity into ZRCs is retired or suspended prior to the end of the planning year, such market participants must replace the cleared ZRCs with uncleared ZRCs.
5. Coordinated Planned Outages

5.1 Outage Coordination Process Changes

Given the outage correlation observed during reliability events as part of the RAN efforts, planning Resource Outages will continue to play a significant role in resource accreditation. Reforms and enhancements to MISO’s Outage Coordination processes and procedures to enhance the determination of Seasonal Accredited Capacity are described below.

5.1.1 Outage Approval and Outage Exemptions

Generation outage tickets submitted into CROW (Control Room Operations Window) are reviewed for exemptions and approvals. Outage approvals and exemptions have separate purposes and criteria but bridge the gap between the planning and operational horizons. Approvals are a part of reliability analysis in the Outage Coordinated Planning process. Exemptions are a part of the Resource Accreditation process. Approval can be granted without an exemption and vice versa.

Outage exemptions are usually given at the time of outage submittal review or in response to a CROW ticket change request. The purpose of the exemption is to ensure that resources are not penalized for unavailability for a sufficiently coordinated outage. The criteria for exemptions are outage lead time and adequate Maintenance Margin.

Approval may be finalized closer to outage date. The purpose of generation outage approval is to ensure continued reliable operation of the Bulk Electric System (BES). The criteria for outage approval include reliability analysis and verification that an outage does not conflict with other outages or cause unacceptable system conditions.

5.1.2 Maintenance Margin

The use of Maintenance Margin is a proactive measure that may provide an early window of opportunity for MISO and Generator Operators to resolve a potential risk to supply adequacy. Maintenance Margin is the maximum megawatt of generation that can be taken out of service for planned maintenance for a given time-period without impacting supply adequacy for MISO’s Balancing Authority Area, including MISO sub-regions. Maintenance Margin has been enhanced significantly since RAN discussions began in 2017 and further enhancements are being developed to improve the information available to resource owners scheduling outages. Additional details regarding the Maintenance Margin calculation are in Attachment F of BPM-008.

5.1.3 Timely Submittal of Outages for Approval

Generator Owners or Generator Operators must submit their planned maintenance outage schedules for all generation facilities 10 MW and above to MISO for a minimum rolling 24 months period (36 months for nuclear generator resources) and updated daily. The outage schedules are reviewed and coordinated per Section 4.3 of BPM-008. Planned outage requests submitted with less than a 24 months (36 months for nuclear generator resources) notice shall be considered late and not timely submitted.

5.1.4 Outage Exemption Evaluation

In addition, Generator Owners or Generator Operators are at risk of adjustments of the forced outage rate unless an exemption is provided.

Exemptions will be provided if one of the following conditions are met:
5.1.4.1 Current RAN Phase 1 Exemption Rules

- The Generator Owner or Generator Operator schedules its first Generator Planned Outage 120 days or more in advance of the outage start date and 120 days or more beyond the end date of any previously scheduled outages for the unit.

- Subsequent generator unit outage requests 120 days or more in advance and Generator Owners or Generator Operators Generator Planned Outage less than 120 days in advance and at least 14 days in advance of outage start date. Proposed Generator Planned Outage to occur entirely during a period that the subregion containing the generator unit has an adequate projected margin, at the time the outage is provided to the Transmission Provider. There is adequate margin when the Maintenance Margin is greater than or equal to zero megawatts after subtracting the megawatts of the requested Proposed Generator Planned Outage. The request shall be determined based on highest queued request.

- Generator Owner or Generator Operator reschedules its Generator Planned Outage at the Transmission Provider’s request, including outages submitted less than 14 days in advance of the start date.

5.1.4.2 Three-level Exemption Proposal

To better align the Resource Adequacy Hours approach of Tier 1 All hours and Tier 2 tight margin hours with MISO Outage Coordinated planning, MISO developed a three-level exemption process Figure 9. The three levels are: Full exemption Tier 1 and Tier 2), partial exemption (Exempt Tier 1 Only), and no exemption.

<table>
<thead>
<tr>
<th>Maintenance Margin &gt;=0 for duration of outage</th>
<th>Maintenance Margin &lt;0 for any day in the duration of outage</th>
</tr>
</thead>
<tbody>
<tr>
<td>&gt;120 days, no outage in previous 120 days.</td>
<td>Exempt Tier 1 &amp; 2</td>
</tr>
<tr>
<td>&gt;120 days, outage in previous 120 days or between 31-119 days</td>
<td>Exempt Tier 1 Only</td>
</tr>
<tr>
<td>14-30 days and no harm*</td>
<td>Exempt Tier 1 Only</td>
</tr>
</tbody>
</table>
Outage moved per MISO request | Full Exemption (weather, forced, conditions in BPM-008 section 4.3) | N/A |
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Rescheduled to a better margin</td>
<td></td>
</tr>
</tbody>
</table>

**Figure 9 Proposed exemption levels**

Full Exemption (Exempt Tier 1 and Tier 2) will be provided if one of the following conditions are met:

- The Generator Owner or Generator Operator schedules its first Generator Planned Outage 120 days or more in advance of the outage start date and 120 days or more beyond the end date of any previously scheduled outages for the unit. The proposed Generator Planned Outage is to occur entirely during a period in which the subregion containing the generator unit has an adequate projected margin at the time the outage is provided to the Transmission Provider. There is adequate margin when the Maintenance Margin is greater than or equal to zero megawatts after subtracting the megawatts of the requested Proposed Generator Planned Outage. The request shall be determined based on highest queued request.

- Generator Owner or Generator Operator reschedules its Generator Planned Outage at the Transmission Provider’s request due to:
  - Proposed Generator Planned Outage to occur entirely during a period that the subregion 120 days or more in advance of the outage start date and 120 days or more beyond the end date of any previously scheduled outages for the unit. Generator Planned Outage has inadequate margin at time of submittal and moves to a time of adequate margin.
  - Weather, forced outages, and other conditions listed in BPM-008 section 4.3. This includes outages submitted less than 14 days in advance of the start date.

Partial Exemption (Exempt Tier 1 Only) will be provided if one of the following conditions are met:

- The Generator Owner or Generator Operator schedules its first Generator Planned Outage 120 days or more in advance of the outage start date and 120 days or more beyond the end date of any previously scheduled outages for the unit. Proposed Generator Planned Outage to occur during a period that the subregion containing the generator unit has an inadequate projected margin, at the time the outage is provided to the Transmission Provider. There is inadequate margin when the Maintenance Margin is less than or equal to zero megawatts, for any day of outage, after subtracting the megawatts of the requested Proposed Generator Planned Outage. The request shall be determined based on highest queued request.

- Subsequent generator unit outage requests 120 days or more in advance and/or Generator Owners or Generator Operators Generator Planned Outage less than 120 days in advance and at least 31 days in advance of outage start date. Proposed Generator Planned Outage to occur entirely during a period in which the subregion containing the generator unit has an adequate projected margin, at the time the outage is provided to the Transmission Provider. There is adequate margin when the maintenance margin is greater than or equal to zero megawatts after subtracting the megawatts of the requested Proposed Generator Planned Outage. The request shall be determined based on highest queued request.

- Generator Owners or Generator Operators Generator Planned Outage less than 31 days in advance and at least 14 days in advance of outage start date. Proposed Generator Planned Outage to occur entirely during a period that the subregion containing the generator unit has an adequate projected margin, at the time the
outage is provided to the Transmission Provider and outage passes all no harm tests/analysis for approval. There is adequate margin when the Maintenance Margin is greater than or equal to zero megawatts after subtracting the megawatts of the requested Proposed Generator Planned Outage. The request shall be determined based on highest queued request.

- Generator Owner or Generator Operator reschedules its Generator Planned Outage at the Transmission Provider’s request due to:
  
  o Inadequate margin for the duration of outage, at the time the outage is provided to the Transmission Provider. Maintenance Margin is less than zero megawatts after subtracting the megawatts of the requested Proposed Generator Planned Outage. Does not include outages submitted less than 14 days in advance of the start date.

5.1.5 No Harm Test

Outages submitted between 14 to 30 days of start date will be evaluated for final approval and exemption status together. No harm tests include, but are not limited to outage approval, compliance with all applicable operation guides, review of possible conflicting outages or system conditions, and system capacity (Maintenance Margin, Multiday Operational Margin, 30-day margin). It also includes criteria outlined in BPM-008 section 4.3: ability to maintain voltage required by nuclear generation resources, or to meet any other nuclear plant interface requirements; ability to maintain the transmission system within system operating limits using normal (non-emergency) operating procedures or restore the transmission system to normal operating conditions following a single contingency with the use of normal (non-emergency) operating procedures; or does not have the potential for credible contingencies to significantly affect transmission system reliability of metropolitan areas.

6. Minimum Capacity Requirement (MCR)

6.1 MCR Proposal Overview

The MCR, as proposed, would require each market participant and their affiliates with load serving obligation to cover 50 percent of their PRMR minus the 50 MW de minimis threshold with ZRCs procured prior to the PRA via either a FRAP or Self-Scheduled in the auction. With the sub-regional application this would apply to PRMR and ZRCs in both the North/Central subregion and the South subregion respectively.

\[
MCR = \left[ \frac{PRMR}{2} \right] - 50 \text{ MW}
\]

Equation 1: Calculation of MCR

To comply with the MCR, an MP's total amount of ZRCs procured via FRAP or Self-Schedule just need to exceed the MCR amount. Any deficiencies would then be assessed a non-compliance charge.

6.1.1 Timeline and Sub-Annual Applicability

Load is initially submitted to MISO in the last quarter prior to the planning year, initially due October 31. The PRM is then established in November in the year's annual LOLE report and prior to December a Market Participant’s MCR will be available. Determination of compliance of the MCR will transpire during a two week review period to confirm compliance.
6.1.2 MCR Non-compliance Charge

In addition to the reasons above on the timing of measuring MCR compliance, one additional piece is that the Cost of New Entry (CONE) value is not determined until after the auction settles. The proposed MCR Non-compliance Charge is 150 percent of the determined zonal daily CONE value. Once daily CONE is known, an MCR Non-Compliance Charge, applied on a megawatts-ratio share of where the MP’s MCR obligation was not met, will be collected. Because the risk of non-compliance impacts the whole footprint and ZRCs from any part of the two separate pools qualify, the collected penalties would be distributed on a load ratio share to all complying market participants in the North/Central or South subregions respectively.

Non-Compliance Charge if MCR > ZRCs = (MCR – ZRC)*MW-weighted daily CONE value

Equation 2: Calculation of MCR Non-Compliance Charge

The MCR is to be applied regionally, then by subregion after two years of implementation. The level of the MCR Non-Compliance Charge applied, like other capacity deficiency charges defined in the sub-annual construct discussed in section 4.1.1, depend on the number of deficient seasons and distributed over the determined number of deficient seasons.

7. Transition

A phased in transition is proposed to allow for implementation of new outage coordination rules, processes, and exemptions that will impact future calculations of Seasonal Accredited Capacity values. Additionally, the locational requirement for MCR is proposed to be implemented two years after it is initially put in place to give LSEs time to procure capacity where it is needed.

7.1 Accreditation Performance Periods for Transition

The FERC regulatory timeline will dictate when provisions will become effective and when new accreditation rules take effect. As currently planned, the new outage rules and exemptions to Tier 2 and RA Hour determination will take effect in September 2022. The current Resource performance period for accreditation is measured starting September 1 through August 31 of the three years immediately prior to the Planning Year. Seasonal Accredited Capacity (SAC) will be determined on a seasonal basis for each of the three prior years (still September to August) ahead of the initial Seasonal Planning Resource Auction for Planning Year 2023-2024. Initially, for Resource Performance history prior to September 2020, SAC will be determined using the Tier 1 and Tier 2 weighted calculations using RA Hours, RT offered availability, outage information, including RAN Phase 1\(^7\) outage exemptions until the new outage exemption approach is implemented. Highlighted in yellow in Figure 10 below, after September 2022, Seasonal Accredited Capacity values will be determined using the new outage rules, for the 2024-2025 Planning Year. Full use of the new outage rules for determining SAC will occur in Planning Year 2026-2027.

<table>
<thead>
<tr>
<th>Planning Year 23-24</th>
<th>9/1/2019</th>
<th>9/1/2020</th>
<th>9/1/2021</th>
</tr>
</thead>
<tbody>
<tr>
<td>8/31/2020</td>
<td>8/31/2021</td>
<td>8/31/2022</td>
<td></td>
</tr>
</tbody>
</table>

\(^7\) RAN Phase 1 is explained in further detail in Section 5.0 of this whitepaper
7.2 Minimum Capacity Requirements Transition

The 50 percent requirement will apply to year one, Planning Year 2023-24, of the seasonal capacity construct. The sub-regional requirement will apply to year three, Planning Year 2025-26, of the seasonal capacity construct.

8. Parameter and Variable Definitions

Emergency $\text{max}_i = \text{Emergency maximum limit for resource } i$

$\text{PRMR}_{\text{SAC}} = \text{Planning Reserve Margin Requirement based on Seasonal Accredited Capacity}$

$\text{PRMR}_{\text{UCAP}} = \text{Planning Reserve Marging Requirement based on Unforced Capacity}$

$\text{RATIO}_{\text{SAC/UCAP}} = \text{Ratio of Seasonal Accredited Capacity to Unforced Capacity}$

$\text{SAC}_{\text{Thermal}} = \text{Seasonal Accredited Capacity for Thermal Resources.}$

$\text{UCAP}_{\text{NonThermal}} = \text{Unforced Capacity for Non-Thermal and other Resources not offered in the Market}$

$\text{UCAP}_{\text{Thermal}} = \text{Unforced Capacity for Thermal Market Offered Resources}$

$\text{GVTC: Generation Verification Test Capacity}$

$\text{PRM: Planning Reserve Margin}$

$\text{PRMR: Planning Reserve Margin Requirement}$
ICAP: Installed Capacity
LSE: Load Serving Entity
NSI: Net Scheduled Interchange
LOLE: Loss Of Load Expectation
ELCC: Effective Load Carrying Capability
RA hours: Resource Adequacy hours
GADs: Generating Availability Data System
EFORD: Equivalent Forced Outage Rate
LCR: Local Clearing Requirement
LRR: Local Reliability Requirement
CIL: Capacity Import Limit
CEL: Capacity Export Limit
MTEP: MISO Transmission Expansion Plan
FCITC: First Contingency Incremental Transfer Capacity
GLT: Generation Limited Transfer
ZIA: Zonal Import Ability
AAOC: Annual Average Offered Capacity
BTMG: Behind the Meter Generation
DR: Demand Response
LMR: Load Modifying Resources
MECT: Module E Capacity Tracking
MP: Market Participant
CONE: Cost of New Entry
SFT: Simultaneous Feasibility Test
SPRA: Seasonal Planning Resource Auction
MTLF: Medium Term Load Forecast
ERIS: Energy Resource Interconnection Service
NRIS: Network Resource Interconnection Service
TSR: Transmission Service Request
GIA: Generation Interconnection Agreement
UDS: Unit Dispatch System
DIR: Dispatchable-Intermittent- Resource
EDR: Emergency Demand Response