Resource Adequacy Reforms
Conceptual Design
DRAFT
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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 Obligations.

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 Obligation.** Require at least 50% of capacity to be secured for each Market Participant’s total Load Serving Entity Planning Reserve Margin Requirement less a 50 MW de minimis threshold, 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](https://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%202020%2022%20LOLE%20Study%20Report489442.pdf](https://cdn.misoenergy.org/PY%202020%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.

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 and at a subregional or Planning Area level, based on emergency events, the tightest 3 percent of operating margin hours (65 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 Operating Margin % Calculation

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

\[
Margin (MW) = Total \ Offer + Net \ Scheduled \ Interchange - Load - Operating \ Reserve
\]

in which Load is calculated as equation (2):

\[
Load = Total \ Generation \ Injections + Net \ Scheduled \ Interchange
\]

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

\[
Margin = Total \ Offer - Total \ Generation \ Injections - Reserve
\]

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:

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

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

- **Online margin (MW)_j** = \( \sum_{i \ in \ region \ j} (Emergency \ Max_i - Energy \ MW_i - cleared \ operating \ reserve_i) \)
  if a generation unit is online and under normal dispatch control

- **Offline margin (MW)_j** = \( \sum_{i \ in \ region \ j} Emergency \ Max_i - cleared \ offline \ supplemental \ reserve(MW)_j \)
  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 because they require emergency declarations in order to access.
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:

\[
\text{Backfilled availability}_{i,s,y} = \text{Max}(65 - \text{Number of Seasonal RA Hour}_{s,y}, 0) \times \text{Annual average offered capacity}_{i,y};
\]

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.

<table>
<thead>
<tr>
<th>Planning Year</th>
<th>Summer</th>
<th>Fall</th>
<th>Winter</th>
<th>Spring</th>
<th>Total</th>
<th>Summer</th>
<th>Fall</th>
<th>Winter</th>
<th>Spring</th>
<th>Total</th>
</tr>
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<tbody>
<tr>
<td>2018-2019</td>
<td>143</td>
<td>77</td>
<td>40</td>
<td>0</td>
<td>260</td>
<td>141</td>
<td>93</td>
<td>0</td>
<td>26</td>
<td>260</td>
</tr>
<tr>
<td>2019-2020</td>
<td>202</td>
<td>47</td>
<td>0</td>
<td>11</td>
<td>260</td>
<td>160</td>
<td>94</td>
<td>6</td>
<td>0</td>
<td>260</td>
</tr>
<tr>
<td>2020-2021</td>
<td>207</td>
<td>12</td>
<td>37</td>
<td>4</td>
<td>260</td>
<td>114</td>
<td>36</td>
<td>100</td>
<td>10</td>
<td>260</td>
</tr>
<tr>
<td>Total</td>
<td>552</td>
<td>136</td>
<td>77</td>
<td>15</td>
<td>415</td>
<td>223</td>
<td>106</td>
<td>36</td>
<td></td>
<td>36</td>
</tr>
</tbody>
</table>

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.
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) start-up notification 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.
STEP 2: Prepare Calculation for Annual Average Offered Capacity

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.

<table>
<thead>
<tr>
<th>PY season</th>
<th>mthour</th>
<th>RT Offer EmerMax (MW)</th>
<th>Cold Leadtime (hours)</th>
<th>Outage Identifier (1-out-of-Service)</th>
<th>Online Identifier (1-online)</th>
<th>Annual RA Hour Identifier (Central + North)</th>
<th>Availability in Annual RA Hour (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2018 fall</td>
<td>9:00</td>
<td>112.3</td>
<td>16</td>
<td>0</td>
<td></td>
<td></td>
<td>112</td>
</tr>
<tr>
<td>2018 fall</td>
<td>9:00</td>
<td>112.3</td>
<td>16</td>
<td>0</td>
<td></td>
<td></td>
<td>112</td>
</tr>
<tr>
<td>2018 fall</td>
<td>9:00</td>
<td>112.3</td>
<td>16</td>
<td>0</td>
<td></td>
<td></td>
<td>112</td>
</tr>
<tr>
<td>2018 fall</td>
<td>9:00</td>
<td>112.3</td>
<td>16</td>
<td>0</td>
<td></td>
<td></td>
<td>112</td>
</tr>
<tr>
<td>2018 fall</td>
<td>9:00</td>
<td>112.3</td>
<td>16</td>
<td>0</td>
<td></td>
<td></td>
<td>112</td>
</tr>
<tr>
<td>2018 fall</td>
<td>9:00</td>
<td>112.3</td>
<td>16</td>
<td>0</td>
<td></td>
<td></td>
<td>112</td>
</tr>
<tr>
<td>2018 fall</td>
<td>9:00</td>
<td>112.3</td>
<td>16</td>
<td>0</td>
<td></td>
<td></td>
<td>112</td>
</tr>
<tr>
<td>2018 fall</td>
<td>9:00</td>
<td>112.3</td>
<td>16</td>
<td>0</td>
<td></td>
<td></td>
<td>112</td>
</tr>
</tbody>
</table>

Figure 5: Sample fragment after STEP 2

STEP 3: Prepare Calculation for Intermediate 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.

### Table 4: Sample calculation of annual average offer availability

<table>
<thead>
<tr>
<th>PY</th>
<th># of RA Hours</th>
<th>Sum of Availability (MW) over Annual Tier 2 RA Hours</th>
<th>Annual Average Offered Availability (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>PY18to19</td>
<td>260</td>
<td>24,473</td>
<td>94</td>
</tr>
<tr>
<td>PY19to20</td>
<td>260</td>
<td>28,750</td>
<td>111</td>
</tr>
<tr>
<td>PY20to21</td>
<td>260</td>
<td>24,818</td>
<td>95</td>
</tr>
</tbody>
</table>
3.3.5 STEPs 4 and 5: Calculation for Tier 1 and Tier 2 Intermediate Seasonal Accredited Capacity

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

For Tier 1, Intermediate 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).

For Tier 2, Intermediate 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 5: Sample calculation of Tier 1 Intermediate Seasonal Accredited Capacity

<table>
<thead>
<tr>
<th>PY</th>
<th>Season</th>
<th># of Tier 1 non-RA Hours</th>
<th>Sum of Availability (MW) over Tier 1 Non-RA Hours</th>
<th>3-year average SAC</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>B</td>
<td>C = SUM(B1, B2, B3)/SUM(A1, A2, A3)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>PY18co19</td>
<td>summer</td>
<td>2,143</td>
<td>240,685</td>
<td>109</td>
</tr>
<tr>
<td>PY19co20</td>
<td>summer</td>
<td>2,143</td>
<td>231,227</td>
<td>88</td>
</tr>
<tr>
<td>PY20co21</td>
<td>summer</td>
<td>2,143</td>
<td>228,083</td>
<td></td>
</tr>
<tr>
<td>PY18co19</td>
<td>fall</td>
<td>2,119</td>
<td>205,846</td>
<td></td>
</tr>
<tr>
<td>PY19co20</td>
<td>fall</td>
<td>2,119</td>
<td>215,953</td>
<td></td>
</tr>
<tr>
<td>PY20co21</td>
<td>fall</td>
<td>2,143</td>
<td>137,231</td>
<td></td>
</tr>
<tr>
<td>PY18co19</td>
<td>winter</td>
<td>2,095</td>
<td>209,552</td>
<td>100</td>
</tr>
<tr>
<td>PY19co20</td>
<td>winter</td>
<td>2,183</td>
<td>227,857</td>
<td></td>
</tr>
<tr>
<td>PY20co21</td>
<td>winter</td>
<td>2,095</td>
<td>202,140</td>
<td></td>
</tr>
<tr>
<td>PY18co19</td>
<td>spring</td>
<td>2,166</td>
<td>215,841</td>
<td>105</td>
</tr>
<tr>
<td>PY19co20</td>
<td>spring</td>
<td>2,194</td>
<td>246,386</td>
<td></td>
</tr>
<tr>
<td>PY20co21</td>
<td>spring</td>
<td>2,143</td>
<td>220,783</td>
<td></td>
</tr>
</tbody>
</table>

### Table 6: Sample calculation of Tier 2 Intermediate Seasonal Accredited Capacity

<table>
<thead>
<tr>
<th>PY</th>
<th>Season</th>
<th># of Tier 2 RA Hours</th>
<th>Sum of Availability (MW) over Tier 2 RA Hours</th>
<th>Annual Average Offered Capacity (MW) over Deficiency hours</th>
<th>Sum of Availability (MW) over Deficiency hours</th>
<th>Sum of Total Availability (MW)</th>
<th>Tier 2 3-year average SAC</th>
</tr>
</thead>
<tbody>
<tr>
<td>Formula Key</td>
<td>A</td>
<td>B</td>
<td>C = Max(0,65 hours - A, B)</td>
<td>D</td>
<td>E = C*D</td>
<td>F = B*E</td>
<td>G = A+C</td>
</tr>
<tr>
<td>PY18co19</td>
<td>summer</td>
<td>65</td>
<td>7,178</td>
<td>0</td>
<td>94</td>
<td>6</td>
<td>7,174</td>
</tr>
<tr>
<td>PY19co20</td>
<td>summer</td>
<td>65</td>
<td>7,300</td>
<td>0</td>
<td>111</td>
<td>0</td>
<td>7,300</td>
</tr>
<tr>
<td>PY20co21</td>
<td>summer</td>
<td>65</td>
<td>7,300</td>
<td>0</td>
<td>95</td>
<td>0</td>
<td>7,300</td>
</tr>
<tr>
<td>PY18co19</td>
<td>fall</td>
<td>65</td>
<td>7,187</td>
<td>0</td>
<td>94</td>
<td>0</td>
<td>7,187</td>
</tr>
<tr>
<td>PY19co20</td>
<td>fall</td>
<td>65</td>
<td>6,738</td>
<td>0</td>
<td>111</td>
<td>0</td>
<td>6,738</td>
</tr>
<tr>
<td>PY20co21</td>
<td>fall</td>
<td>41</td>
<td>2,930</td>
<td>24</td>
<td>95</td>
<td>2,930</td>
<td>5,211</td>
</tr>
<tr>
<td>PY18co19</td>
<td>winter</td>
<td>65</td>
<td>2,471</td>
<td>0</td>
<td>94</td>
<td>0</td>
<td>2,471</td>
</tr>
<tr>
<td>PY19co20</td>
<td>winter</td>
<td>1</td>
<td>112</td>
<td>64</td>
<td>111</td>
<td>7,077</td>
<td>7,189</td>
</tr>
<tr>
<td>PY20co21</td>
<td>winter</td>
<td>65</td>
<td>1,011</td>
<td>0</td>
<td>95</td>
<td>0</td>
<td>1,011</td>
</tr>
<tr>
<td>PY18co19</td>
<td>spring</td>
<td>42</td>
<td>4,155</td>
<td>23</td>
<td>94</td>
<td>2,165</td>
<td>4,320</td>
</tr>
<tr>
<td>PY19co20</td>
<td>spring</td>
<td>14</td>
<td>1,572</td>
<td>51</td>
<td>111</td>
<td>5,639</td>
<td>7,212</td>
</tr>
<tr>
<td>PY20co21</td>
<td>spring</td>
<td>65</td>
<td>4,380</td>
<td>0</td>
<td>95</td>
<td>0</td>
<td>4,380</td>
</tr>
</tbody>
</table>

### 3.3.6 Tier Weighting

The Intermediate Seasonal Accredited Capacity (ISAC) 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 Intermediate Seasonal Accredited Capacity value and its availability and performance during times of highest risks and greatest needs.

The corresponding tier weightings are:

\[ ISAC_{Tier\_weighting} = 20\% \]
3.3.7 ISAC conversion to SAC in UCAP terms

Recognizing that PRMR derived through the LOLE study is based on Unforced Capacity (UCAP) and the proposed availability based accreditation values are on ISAC term, MISO adopted the IMM’s proposal of a UCAP to ISAC conversion ratio to convert thermal resource (Schedule 53) SAC values back to UCAP terms to better align requirements and resource accreditation. MISO will continue to look at ways to improve LOLE modeling, which includes producing requirements aligned with accreditation or SAC. This would ultimately eliminate the need for applying a conversion ratio to ensure alignment.

The weighted Intermediate Seasonal Accredited Capacity (ISAC) value will be converted back to SAC in UCAP term by the equation below:

$$ SAC_{Resource \_i} = ISAC_{Resource \_i} \times RATIO_{UCAP \_to \_ISAC} $$

where

$$ RATIO_{UCAP \_to \_ISAC} = \frac{\text{Sum}(UCAP_{Schedule \_53 \_resources})}{\text{Sum}(ISAC_{Schedule \_53 \_resources})} $$

3.3.8 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.

3.3.9 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 than 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.

3.3.10 Calculation Adjustment for Capacity Increases

In the case of an increase in generating Capacity of a Generation Resource, the historical values for Hourly Emergency Maximum Limit will be adjusted up for those hours prior to such increase going into effect as set forth in the Business Practices Manual for Resource Adequacy to reflect the additional expected availability in the Schedule 53 calculations.
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.
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.

Figure 8 Timeline based on changes to the RA Construct
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 the number of days in the Season. (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 daily annual CONE values (approximately $25/MW Day) for those resources that do not have a relevant facility specific Reference Level.

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 Auction⁴. 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 manage Planning Resource Auction (PRA) Offer submittals in concert with the IMM where applicable to account for the clearing of Resources that may require replacement or need to be available as replacement capacity. For example, offers above the economic withholding threshold (10% of CONE/365) may reflect certain avoidable costs per Module D of the Tariff, IMM Technology-Specific Avoidable-Costs (misoenergy.org).

Additionally, there are existing exclusions (and one new one) that enables a Market Participant to forego offering their excess ZRCs into the PRA. The new one applies when a Resource has submitted a Generator Planned Outage for greater than 31 days in a Season. The Market Participant for the Resource can ask the IMM for a determination that it won’t be investigated for physical withholding if it doesn’t offer the ZRCs from that Resource into that Season of the PRA.

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.

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⁴ 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.
4.3.1 Offer Cap

An LRZ may fail to clear its target PRMR in fewer than all four seasons. Seasonal offer caps and reference levels 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 in ZRC Shortage or ZRC Near-Shortage Conditions in the Planning Resource Auction. ZRC Shortage Conditions exist in any Season in a PRA in which there is an insufficient volume of ZRC Offers to cover LCR or the total PRMR for the LRZ, group of LRZs, or Sub-Regional Resource Zone (SRRZ), or the total PRMR for the SRRZ minus the Sub-Regional Import Constraint (SRIC). ZRC Near-Shortage Conditions exist in any Season in a PRA in which there is sufficient volume of ZRC Offers in the LRZ, group of LRZs, or SRRZ to cover PRMR and locational requirements, but the Season’s Auction Clearing Price is greater than the daily CONE value (i.e., 1/365 times CONE). 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 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.

4.4.2 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 31 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. Like today, committed Resources that experience a Catastrophic Generator Outage that are expected to be out greater than 6 months are not required but have the option to replace with uncleared ZRCs in any applicable seasons and then be entitled to receive accreditation based on a class average.

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 that applies to retired and suspended ZRCs as well as

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5 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.
ZRCs whose Resource has full or partial planned outages that exceed 31 days. The proposed ZRC Replacement Non-Compliance Charge would be settled daily based on 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.

4.6 Planning Resource Auction Settlement

New make-whole payments are required to be added to the PRA Settlement provisions because of the ex-post adjustment will set reduced Auction Clearing Prices when more than one Season clears in ZRC Shortage Conditions or ZRC Near-Shortage Conditions which could be below actual ZRC Offer costs.

4.6.1 Auction Clearing Price Adjustments.

The final Auction Clearing Price will be set based on annual CONE and the number days in all applicable Seasons when an LRZ, group of LRZs, or the MISO footprint clear with less than the required number of ZRCs or the Season’s initial Auction Clearing Price clears above daily CONE in a Planning Resource Auction. Under such conditions certain cleared ZRC Offers may exceed the final ACPs and may be eligible for make-whole payments.

4.6.2 ZRC Offer Revenue Sufficiency Guarantee Credits

ZRC Offers may not reflect the actual costs of providing capacity if a Planning Resource clears in multiple Seasons but its annual costs are compressed into each season’s ZRC Offer to ensure recovery if the Resource only clears in a single Season. To account for this, ZRC Offer Revenue Sufficiency Credits will consider a Resource’s revenues from all cleared Seasons and credits a Resource if needed to meet the minimum of the following amounts: (i) the sum of cleared ZRC Offer price segments multiplied by the cleared ZRC Offer Volumes multiplied by the number of days in the Season; (ii) annual CONE; or (iii) the applicable reference level costs for resources that obtained technology or facility-specific Reference Levels for cleared Seasons. This formulation will prevent the ZRC Offer Revenue Sufficiency Credit from contributing to over-recovery of costs.

4.6.3 ZRC Offer Revenue Sufficiency Guarantee Charges

ZRC Offer Revenue Sufficiency Charges will be assessed as the sum of all ZRC Offer Revenue Sufficiency Credits for a Season distributed to Market Participants representing LSEs in an LRZ, group of LRZs, or SRRZ clearing under ZRC Shortage Conditions or Near ZRC Shortage Conditions on a pro rata basis, based upon their respective LSE’s share of total PRMR in the appropriate LRZ, group of LRZs, or SRRZ.

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. Outage Approval can be granted without an Tier 1 or Tier 2 exemptions 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>Generator Outage Submission Criteria</th>
<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 prior to outage start date, and &gt;120 days from end of previous outage for unit</td>
<td>Exempt Tier 1 &amp; 2</td>
<td>Exempt Tier 1 Only</td>
</tr>
<tr>
<td>&gt;120 days Prior to Outage Start date and &lt;120 days from end of Previous outage for unit or Outage submitted between 31-119 days Prior to outage start date</td>
<td>Exempt Tier 1 Only</td>
<td>No Exemption</td>
</tr>
<tr>
<td>14-30 days prior to outage start date and passes No Harm Test</td>
<td>Exempt Tier 1 Only</td>
<td>No Exemption</td>
</tr>
<tr>
<td>Outage moved per MISO request</td>
<td>Exempt Tier 1 &amp; 2</td>
<td>Exempt Tier 1 &amp; 2</td>
</tr>
</tbody>
</table>
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 in-adequate projected margin, at the time the outage is provided to the Transmission Provider. There is in-adequate 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:
  - 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 Obligation (MCO)

6.1 MCO Proposal Overview
The MCO, 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 supplied into the PRA as a self-schedule or economic offer or procured prior to the PRA via either a FRAP or ZRC transaction. With the sub-regional application this would apply to PRMR and ZRCs in both the North/Central (the First Planning Area) and the South (the Second Planning Area) respectively.

\[
MCO = \left( \frac{MP \text{ total } PRMR}{2} \right) - 50 \text{ MW de minimis threshold}
\]

Equation 1: Calculation of MCO

To comply with the MCO, an MPs total amount of ZRCs procured or brought to the PRA need to meet or exceed the MCO 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 MCO will be available. Determination of compliance of the MCO will be known leading up to and at the time the PRA is run.
6.1.2 MCO Non-compliance Charge

The MCO Non-compliance Charge is set at 150 percent of the determined zonal daily Cost of New Entry (CONE) value. Once daily CONE is known, an MCO Non-Compliance Charge, assessed on a per-megawatt basis for the amount the MCO exceeds the ZRCs. The collected non-compliance charges would then be distributed to all MPs their MCO on MW ratio share of the total MISO MCO that was met by all MPs with an MCE during the applicable Season of the Planning Year. The distribution will transition from a footprint-wide to a Planning Area basis along with the transition described below.

\[
\text{Non-Compliance Charge if MCO}>\text{ZRCs} = (\text{MCO} - \text{ZRC})*\text{MW-weighted daily CONE value}
\]

Equation 2: Calculation of MCO Non-Compliance Charge

The MCO is to be applied regionally, then by subregion after two years of implementation. The level of the MCO 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 MCO 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 2022, 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\textsuperscript{6} outage exemptions until the new outage exemption approach is effective and implemented for Planning Years 2024-2025 and beyond. 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></td>
<td>8/31/2020</td>
<td>8/31/2021</td>
<td>8/31/2022</td>
</tr>
</tbody>
</table>

\textsuperscript{6} RAN Phase 1 is explained in further detail in Section 5.0 of this whitepaper
MISO will also transition to the weightings for Tier 1 and Tier 2 hours. Stakeholders requested a transition and MISO will not phase in the full 80% weighting until the third Planning Year ("PY") following initial implementation (i.e., the 2025/2026 Planning Year). Doing so will account for the fact that the historical RT offers, outages, and notification times used in the Schedule 53 calculations were submitted for resources without knowledge of the final accreditation methodology. Tier 2 would start at 60% in PY 2023/24, rise to 70% in PY 2024/25 and then reach the full 80% in PY 2025/26.

Additionally there is a transition to the new Generator Planned Outage Exemption rules: Outages with a start date prior to 9/1/2022 will be treated as Tier 2 exempt if they meet the RAN Phase 1 requirements described above. While outages that start 9/1/2022 or later will be evaluated according to the new rules in section 5.1.4.2. above.

### 7.2 Minimum Capacity Obligations Transition

The initial MCO rule 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 subject to market power evaluation and mitigation measures being filed and accepted by FERC.

### 8. Parameter and Variable Definitions

- Emergency max$_i$ = Emergency maximum limit for resource $i$
- PRMR$_{SAC}$ = Planning Reserve Margin Requirement based on Seasonal Accredited Capacity
- PRMR$_{UCAP}$ = Planning Reserve Marging Requirement based on Unforced Capacity


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

\[ \text{SAC}_{\text{Therm}} = \text{Seasonal Accredited Capacity for Thermal Resources.} \]

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

\[ \text{UCAP}_{\text{Therm}} = \text{Unforced Capacity for Thermal Market Offered Resources} \]

GVTC: Generation Verification Test Capacity

PRM: Planning Reserve Margin

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