ReliabilityFirst Summer 2023 Resource Reliability Risk Assessment

ReliabilityFirst (RF) performs a seasonal summer resource adequacy assessment based on data provided by PJM and MISO.[1] This article shares some highlights from the MISO, PJM, and RF assessments.

For the upcoming summer of 2023, under projected 50/50 demand forecasts, both MISO and PJM are expected to have adequate resources to satisfy their respective planning reserve requirements.

However, if resource outages and/or demand are experienced beyond the established projections, there is an increased likelihood that both Load Modifying Resources and Operating Reserves would need to be utilized to serve forecasted load.

The risk assessment, outlined below, evaluates the capability of both MISO and PJM to meet their planning reserve requirements under random resource outage scenarios based on historic Generator Availability Data System (GADS) outage data. While this analysis concluded that there should not be an issue of having enough resources to supply demand within the RF Region for the 2023 summer, there is an elevated risk if resource unavailability and load demand are higher than anticipated.

Within MISO, there is a risk of not meeting periods of higher than anticipated peak demand if wind generator energy output is lower than expected. Furthermore, the need for assistance from external (non-firm) resources during more extreme demand levels will also depend largely on wind energy resources and their output, if available.

[1] The MISO results were developed on data summitted prior to their capacity auction published results on May 17, 2023, and presented to the public on May 19, 2023. Revised values from the capacity auction are not anticipated to significantly change the results or identified risk in this assessment.

PJM Capacity and Reserves

Net capacity Resources[2]	187,03 MW
Projected Peak Reserves	45,232 MW
Net Internal Demand (NID)	141,771 MW
Planning reserve margin	31.9%

As listed in the table above, the anticipated PJM forecast planning reserve margin of 31.9% is greater than the required PJM planning reserve margin for the 2023 planning year of 14.9%. The planning reserve margin for this summer is slightly higher than the 2022 forecast level of 31.7%.

MISO Capacity and Reserves

Net Capacity Resources	143,668 MW
Projected Peak Reserves	26,843 MW
Net Internal Demand (NID)	116,825 MW
Planning reserve margin	23%

The MISO forecast planning reserve margin of 23%, seen in the table above, is greater than the required MISO planning reserve margin requirement of 15.9% for the 2023 planning year. The planning reserve margin for this summer is higher than the 2022 forecast level of 21.1%. This is mostly due to a decrease in Net Internal Demand (NID) and a larger amount of firm imports into the MISO region.

RF Footprint Resources

Net Capacity Resources	223,659 MW
Projected Peak Reserves	62,258 MW
Net Internal Demand (NID)	161,401 MW
Total Internal Demand (TID)	170,696 MW

Since PJM and MISO are projected to have adequate resources to satisfy their respective forecasted reserve margin requirements, the RF region is projected to have sufficient resources for the 2023 summer period as seen in the table above.

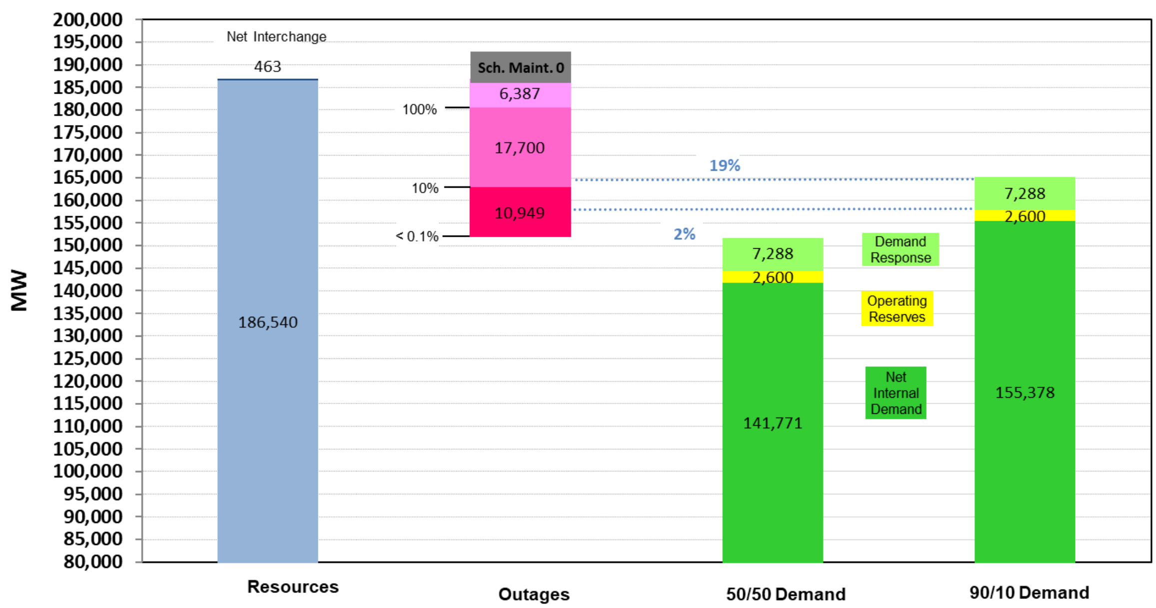
[2] Net capacity resources include existing certain generation and net scheduled interchange.

Random Generator Outage Risk Analysis

The following analysis evaluates the risk associated with random generator outages that may reduce the available resources below the load obligations projected for PJM or MISO. Reports and/or other data released by PJM, MISO or NERC for this same period may differ from the data reported in this assessment. This is due to different assumptions that were made by RF from the onset of the analysis. This analysis differs from NERC's in that RF used historical GADS data from a rolling 5-year period, which provided a range of outages that occur during the summer period (i.e., May through September). In contrast, the NERC Analysis polls each assessment area (i.e., MISO and PJM) and requests the average forced outages for weekdays in June through September, over the past three years. Both analyses provide a valid way to consider outage scenarios when projecting capacity and reserves. The forecasted maintenance outages used below are derived from PJM and MISO for the summer months.

The stacked bar charts in Exhibits 1 and 2 are the result of the ReliabilityFirst analysis and based on forecasted Summer 2023 demand and capacity resource data for the PJM and MISO RTOs. The daily operating reserve requirement for PJM and MISO at the time of the peak demand is also included as a load obligation. The range of expected generator outages is included for scheduled and random outages. The random outages are based on historic GADS outage data from May, June, July, August, and September of 2018 through 2022.[3]

Exhibit 1 - 2023 Summer PJM Resource Availability Risk Chart



[3] The distribution of random outages used for this assessment is not linear throughout the range of outages observed.

Referring to Exhibits 1 and 2, the committed resources in PJM and MISO are represented by the Resource bar in shades of blue and only include the net interchange that is a capacity commitment to each market (i.e., firm transactions). Additional interchange transactions that may be available at the time of the peak are not included as they are not firm commitments and are therefore not allowed in the calculation to satisfy each RTO's reserve margin requirement.

The firm demand and the demand that can be contractually reduced as a Demand Response (DR) are shown in shades of green. The firm demand constitutes the Net Internal Demand, with Total Internal Demand including the Demand Response (DR). The daily Operating Reserve requirement (shown in yellow) is between the NID and DR bars. There are two sets of stacked demand bars on the chart, one representing the 50/50 demand forecast and one representing the 90/10 demand forecast. The 50/50 demand forecast projects a 50% likelihood that demand exceeds 141,771 MW. The 90/10 demand forecast is a more extreme model, projecting a 10% chance that demand exceeds 155,378 MW. Since DR is utilized first to reduce the load obligation when there is insufficient capacity, this part is at the top of the demand bar. In the event that utilization of all DR is not sufficient to balance capacity with load obligations, system operators may first reduce operating reserves prior to interrupting firm load.

Between the resources bar and the demand bars is the outages bar. While scheduled outages during the summer season are generally minimal, there are scheduled outages planned during the summer that are reflected in the amount of Scheduled Maintenance (colored gray) in the Outage bar. The remainder of the Outage bar represents the probability or entire range of random outages. The pink area shows 100% of the random outages; rose shows less than 100% down to 10% probability of the random outages; and red shows less than 10% down to 0.1 % of the random outages occurring as indicated on the chart. These probabilities occurred during the five-year reference period (i.e., 2018 to 2022).

In the following discussion of the random outages, the analysis of random outages exceeding certain reserve margin targets is presented as a probability. These probabilities are not based on a true statistical analysis of the available daily random outage data. Rather than statistical probabilities, these numbers represent the percentage of the daily outages during the five prior summer periods. They are discussed as probabilities as a matter of convenience in describing the analysis results.

It should be noted that the Planning Reserve Requirement for each study area is below the total resource outages identified by RF. As an example, PJM's is 14.9% which equates to 21,100 MW, while the largest 5-year rolling resource outages identified in GADS is 35,036 MW.

In Exhibit 1, the top of the 90/10 Demand obligation bar for PJM represents Total Internal Demand with operating reserves. The 19% line between the Outage bar and the 90/10 Demand bar represents the probability that resource outages could cause Demand Response resources to be utilized. The 2% line indicates that after all of the demand response is utilized and a high outage scenario is present, operators will have to use other mitigating steps to balance load and capacity. This means that once resource outages exceed 22,000 MW there is the potential for

PJM to use DR and Operating Reserves to meet their internal load during a high demand (90/10) scenario.

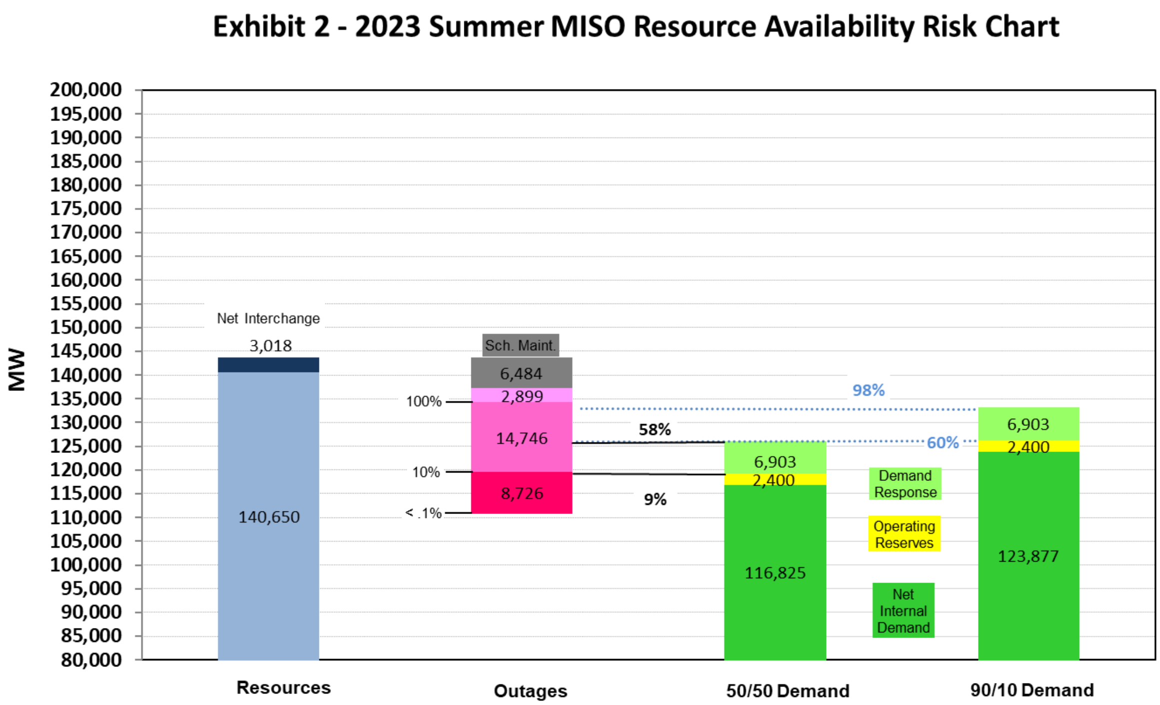


Exhibit 2 contains similar information to perform the same analysis for MISO. The top of the 50/50 Demand obligation with Demand Response and Operating reserves is 58%. During normal operating conditions, there is a 58% probability that resource outages could require Demand Response resources to be utilized. This means that once the random outages and schedule maintenance exceed 11,000 MW the potential for utilization of DR and Operating Reserves increase during 50/50 scenario. The top of the 90/10 demand obligation with the operating reserves has a 98 % probability that Demand Response will be required during high demand. Once the random outages and schedule maintenance exceed 10,500 MW, the potential for utilization of DR and Operating Reserves increases during the 90/10 scenario.

In the PJM chart (Exhibit 1), the random outages[3] represented by the bar above the 100% point is 6,387 MW. This means that the probability of there being at least 6,387 MW of random generation outages is 100%. Similarly, in the MISO Chart (Exhibit 2) at the 10% point, the outages represented by the bar above the 10% point is 17,645 MW (2,899 MW + 14,746 MW). This indicates that there is a 10% probability that there will be at least 17,645 MW of outages. As shown by the probabilities and corresponding amounts of random outages, the distribution of random outages is not linear throughout the range of outages observed.

To the right of the outages bar are the probabilities of the random generation outages that correspond to different levels of demand obligation. In other words, and referring to Exhibit 2, this means there is a 98% probability that Demand Response could be needed to meet the 90/10 demand scenario.

Through stakeholder engagements, ReliabilityFirst is encouraging all Generator Owners to carefully coordinate fuel supply, availability, and planned/unplanned outages with their Reliability Coordinators throughout the summer to address these risks.