BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | |
|---|---|
| Federal Power Act Section 202(c) | ) |
| Emergency Order: Midcontinent | ) |
| Independent System Operator | ) |
| (MISO) | ) |
| | ) |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

# Exhibit 111

# MISO June Operations Report

# MISO Monthly Operations Report

June 2025

# Reliability, markets and operational functions performed as expected in June

## AVERAGE & PEAK LOAD (GW)

## SYSTEM-WIDE LOAD PEAK

**120 GW**

June 23, Hour Ending (HE) 16

## SOLAR PEAK

**13.1 GW**

Jun 22, 2025, HE 11

## WIND PEAK

**21.5 GW**

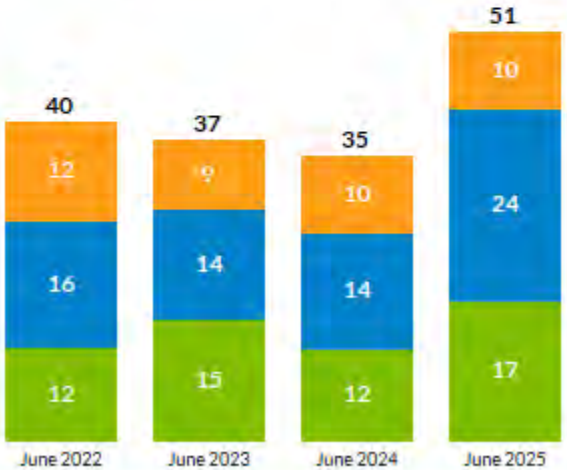
Jun 20, 2025, HE 23

## ENERGY FUEL MIX (TWh)

## REAL-TIME LMP ($/MWh)

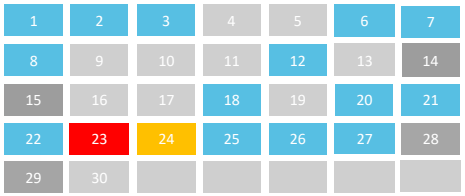
## AVERAGE FUEL PRICE ($MMBtu)

## AVERAGE DAILY GENERATION OUTAGE (GW)




## KEY OPERATING DECLARATIONS

### JUNE 2025




***06/06-06/08 South:*** *Conservative Operations*
***06/12 South:*** *Severe Weather Alert*
***06/18 Central:*** *Severe Weather Alert*
***06/20-06/21 North:*** *Severe Weather Alert*
***06/21-06/24 N/C:*** *Hot Weather Alert*
***06/23 N/C:*** *Max Gen Event – Step 1b*
***06/24 N/C:*** *Max Gen Warning*
***06/21–06/27 System:*** *Conservative Operations*

- *All-Time Solar Peak: 13.5 GW on May 31, 2025, HE 13*
- *All-Time Wind Peak: 25.7 GW on Jan 12, 2024, HE 19*
- *All-Time Load Peak: 127.1 GW on Jul 20, 2011, HE17*

*Awareness and Weather*
*Alerts and Warnings*
*Reliability Actions and Events*

# Dashboard

| Metric | Chart | June 2025 | May '25 | Apr '25 | Mar '25 | Metric | Chart | June 2025 | May '25 | Apr '25 | Mar '25 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | |
| Market Efficiency Metric | D | ▼ | ● | ● | ● | Unit Commitment Efficiency | H | ● | ● | ● | ● |
| | | | | | | | | | | | |
| Percentage Price Deviation | A | ■ | ■ | ■ | ● | Day Ahead Wind Generation Forecast Error | K | ● | ● | ● | ● |
| Monthly Average Gross Virtual Profitability | B | ● | ● | ● | ● | Day-Ahead Solar Generation Forecast Error | T | ● | ● | ● | ● |
| FTR Funding | C | ● | ● | ● | ● | Tie Line Error | L | ● | ● | ● | ● |
| RSG per MWh to Energy Price | E | ● | ● | ● | ● | Control Performance – BAAL | M | ● | ● | ● | ● |
| Day Ahead Mid-Term Load Forecast | F | ● | ■ | ▼ | ▼ | Control Performance – CPS1 and CPS1 12-month rolling | N | ● | ● | ● | ● |
| Short-Term Load Forecast | G | ● | ● | ■ | ● | ARS Deployment | P | ● | ● | ● | ● |
| Real-Time Obligation fulfilled by Day-Ahead Supply at the Peak Hour | I | ● | ● | ● | ● | | | | | | |
| | | | | | | | | | | | |
| System Impact Study Performance | Q | ▼ | ● | ▼ | ▼ | Settlement Disputes | S | ● | ● | ● | ● |

● *Expected* ■ *Concern/Monitor* ▼ *Review*

*Note: Dashboard metric criteria are reviewed and revised each year and is included in the Appendix.*

# Three metrics fell outside of the expected range for this month

| Metric | Expected Criteria | Actual | Status | Comments |
|---|---|---|---|---|
| Percentage Price Deviation | Absolute DA-RT price difference divided by DA LMP <=28.6% | 32.8% | Monitor | Periods of congestion, especially on June 23 and June 24, and Real-Time ancillary service product scarcity pricing throughout the month resulted in some price divergence between the Day-Ahead and Real-Time markets. |
| Market Efficiency Metric | >= 95% | 90.5% | Review | Excess Congestion Fund (ECF) performance for the month of June was largely impacted by the effects of the notable heat days (6/21-6/24) as well as outlier constraints. The high impact ECF constraints were driven by large Joint Operating Agreement payments to SPP, outages, Real-Time congestion management actions, and congestion forecast. |
| System Impact Study Performance | Studies completed in less than 60 days >=85% | Completed studies were done in more than 60 days | Review | Resource constraints impacted study completion timing. |

# Appendix

# MISO has worked collaboratively with stakeholders to review and implement the following changes on the Monthly Operations Report

## Removed

- Price Duration Curve – Peak Hours
- Price Duration Curve – Off-Peak Hours
- MISO Hubs RT Price Duration – Peak Hours
- MISO Hubs RT Price Duration – Off-Peak Hours
- Load Duration Curve
- Solar Energy and Daily Peak

## Modified

- Add hours to Manual Redispatch/Cap summary on the Reliability slide
- Provided regional breakdown for Real-Time Congestion Dollars
- Consolidated load and temperature information

## Added

- Add an Operator Actions for congestion management slide with details on Manual Redispatches/Caps
- Added a monthly solar slide that resembles the monthly wind slide
- Added a daily solar slide that resembles the daily wind slide

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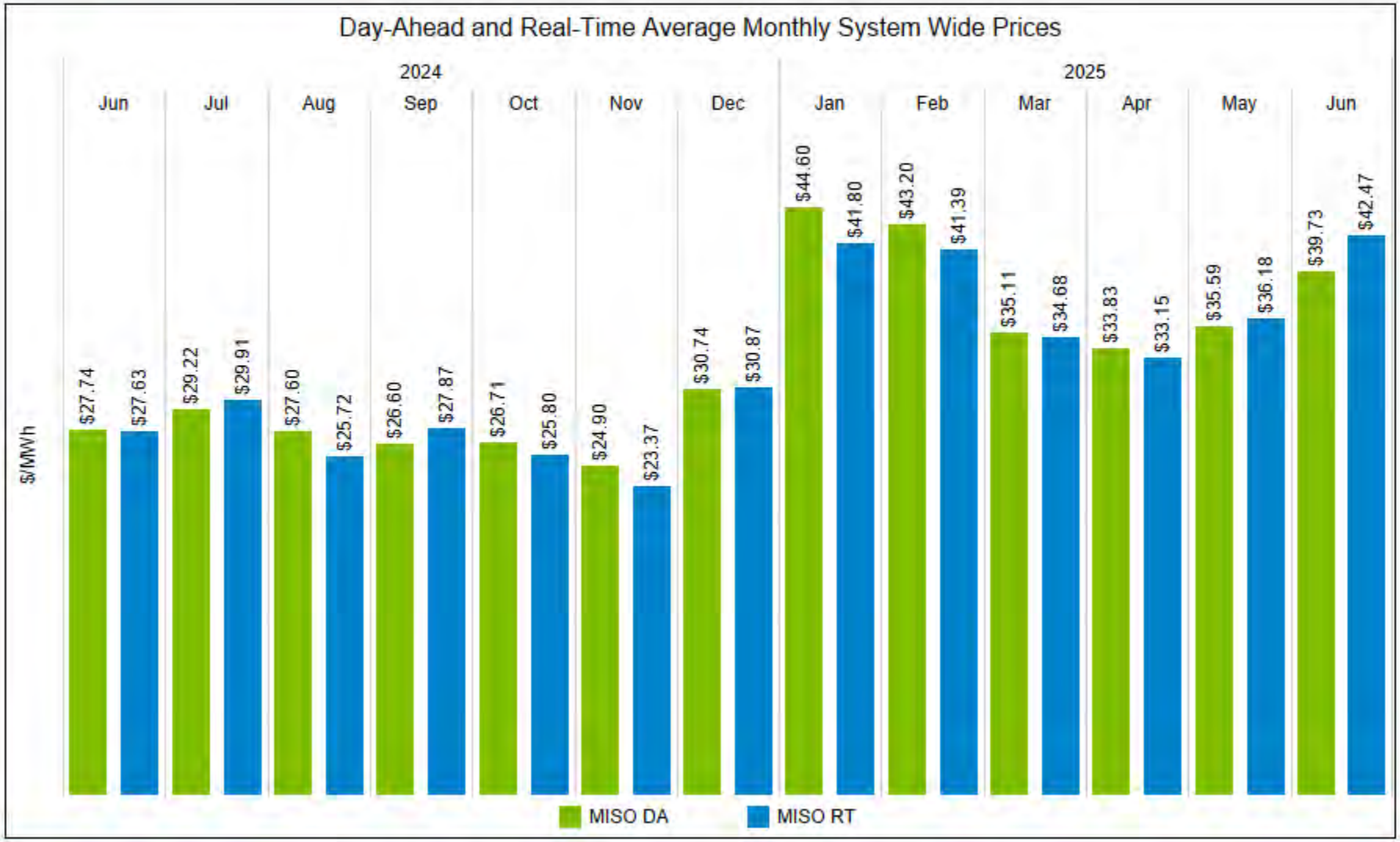
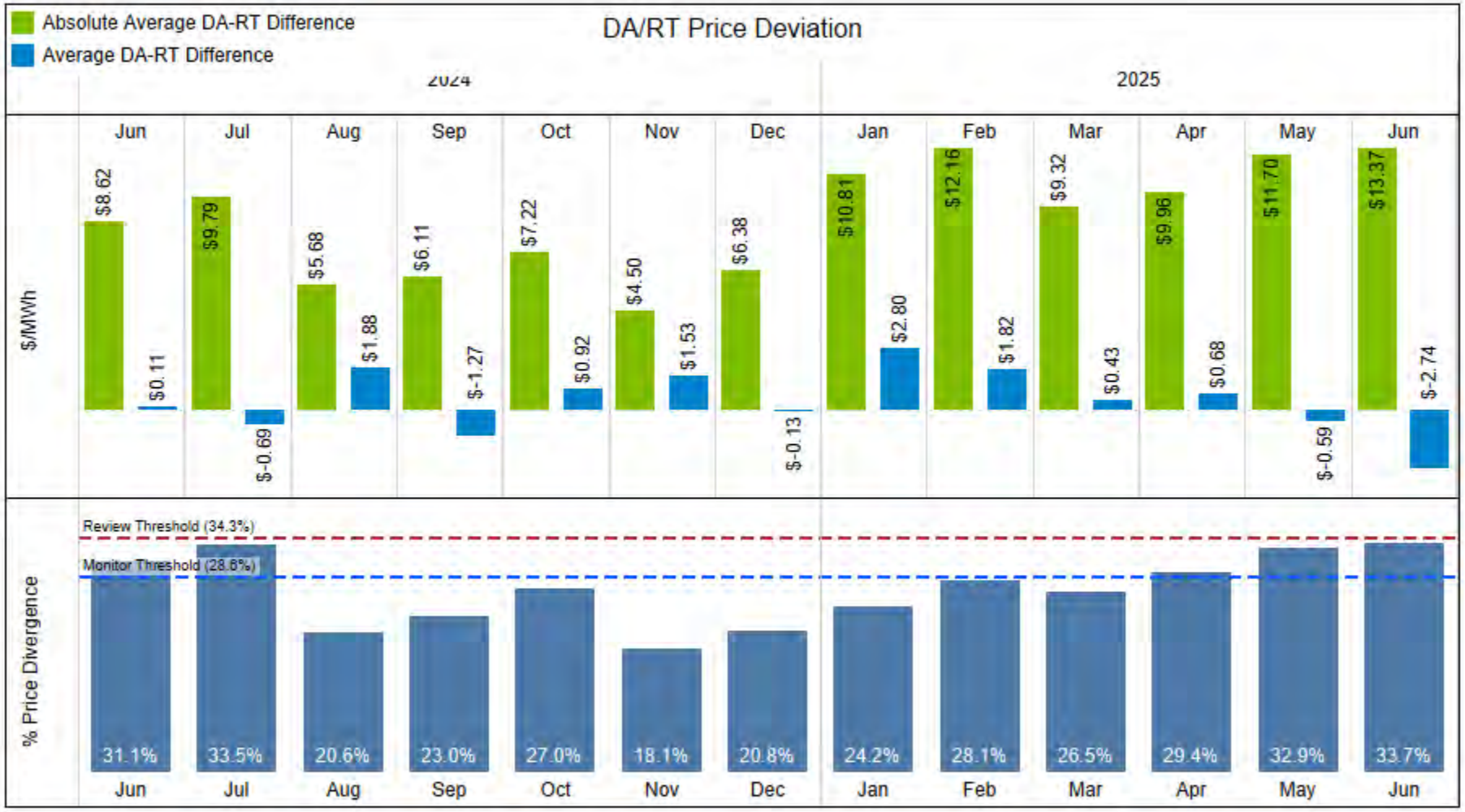
# MISO System-wide Day-Ahead and Real-Time Locational Marginal Pricing




*Note: MISO System-Wide price is based on the monthly hourly average of the active hubs*
*Source: MISO Market and Operations Analytics Department*

# Price Convergence: Day-Ahead and Real-Time Locational Marginal Pricing

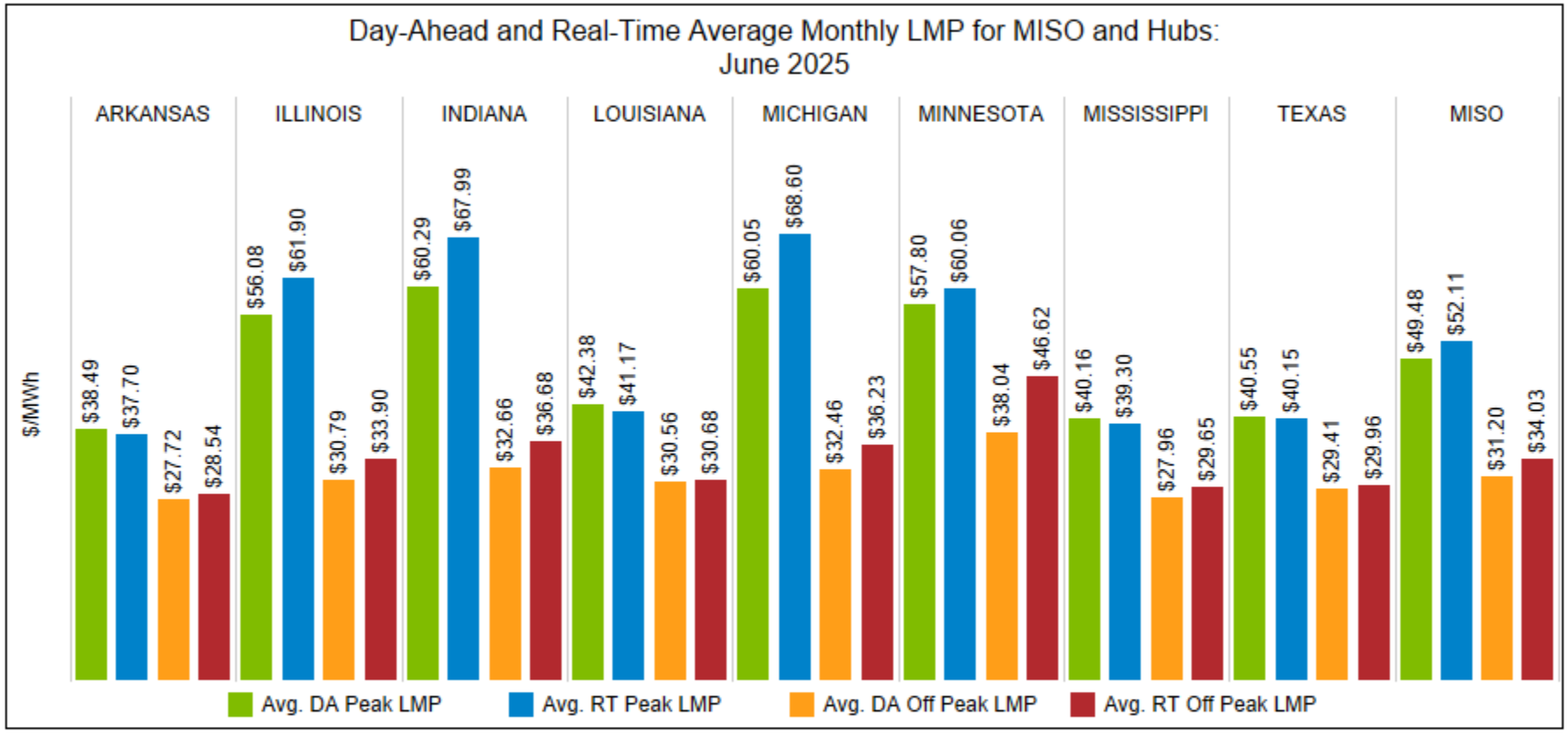
A




**Monthly deviation, expressed as a percent of average DA LMP, is calculated as the average of hourly absolute (DA-RT) price difference divided by the average of hourly DA LMPs for the month*

*Note: MISO System-Wide price is based on the monthly hourly average of the active trading hubs*
*Source: MISO Market and Operations Analytics Department*

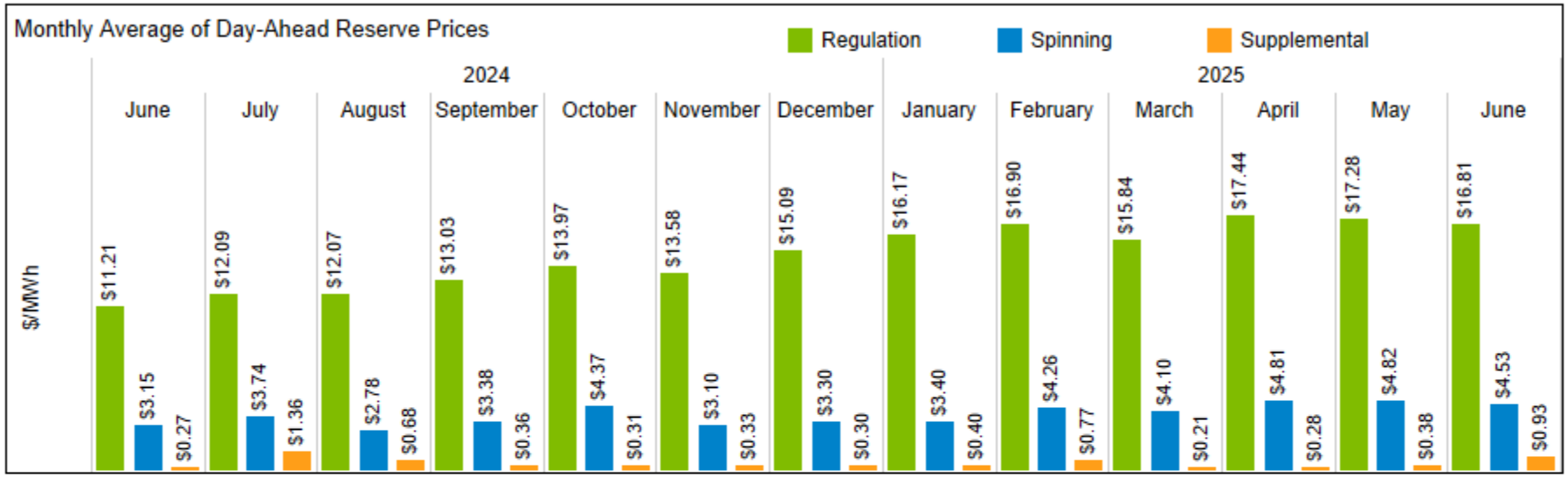
# MISO Day-Ahead and Real-Time Hub Locational Marginal Pricing

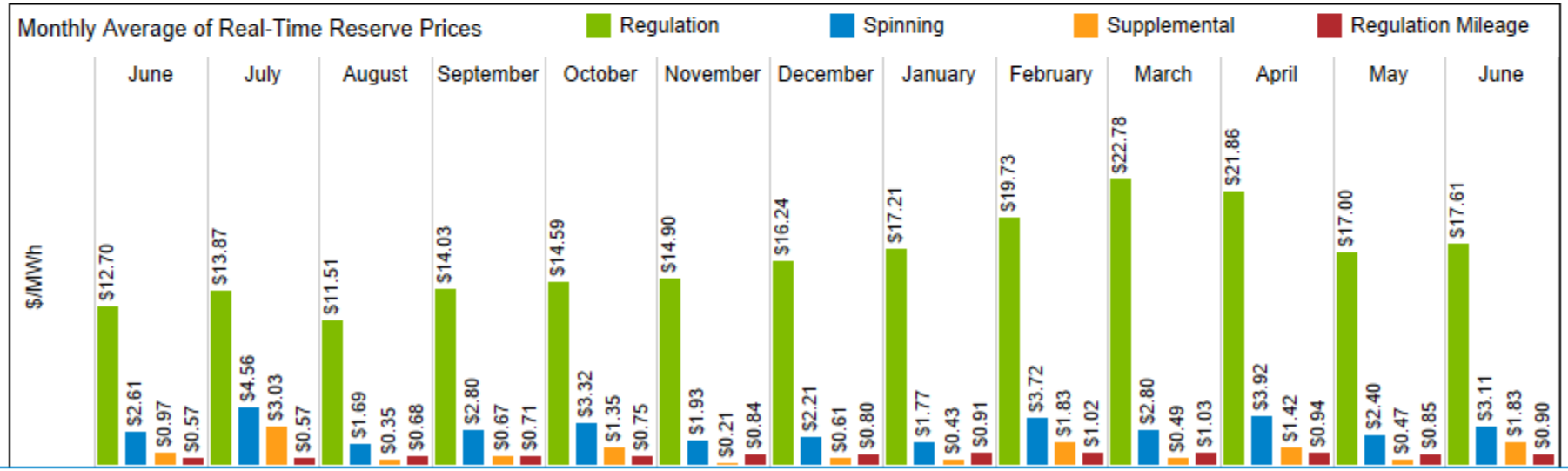



| | | ARKANSAS | ILLINOIS | INDIANA | LOUISIANA | MICHIGAN | MINNESOTA | MISSISSIPPI | TEXAS | MISO |
|---|---|---|---|---|---|---|---|---|---|---|
| Marginal Congestion Component of LMP ($/MWh) | DA Peak | -16.62 | -0.48 | 1.78 | -14.90 | 1.82 | -0.63 | -16.19 | -15.79 | -7.63 |
| | RT Peak | -23.91 | -1.42 | 2.06 | -22.70 | 2.91 | -2.36 | -23.51 | -23.17 | -11.51 |
| | DA Off Peak | -3.55 | -0.81 | -0.24 | -2.16 | -0.23 | 5.13 | -3.96 | -2.61 | -1.06 |
| | RT Off Peak | -5.71 | -0.78 | 0.54 | -5.11 | 0.35 | 10.78 | -5.28 | -5.53 | -1.34 |

*Source: MISO Market and Operations Analytics Department*

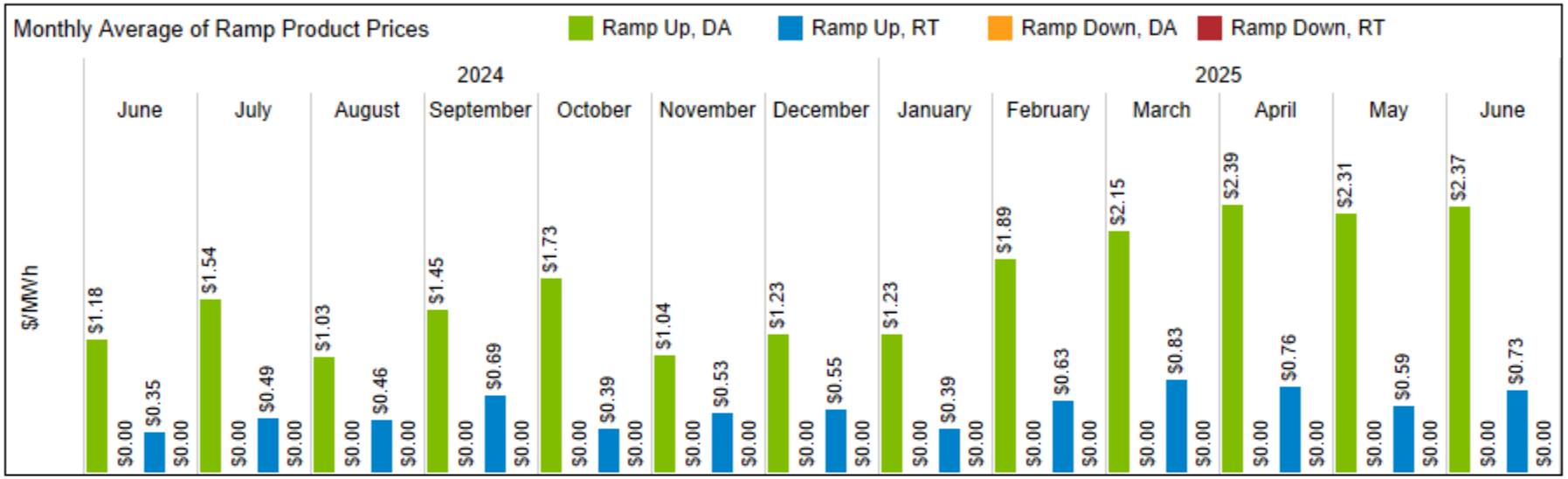
# Ancillary Services - Day-Ahead and Real-Time Market Clearing Prices

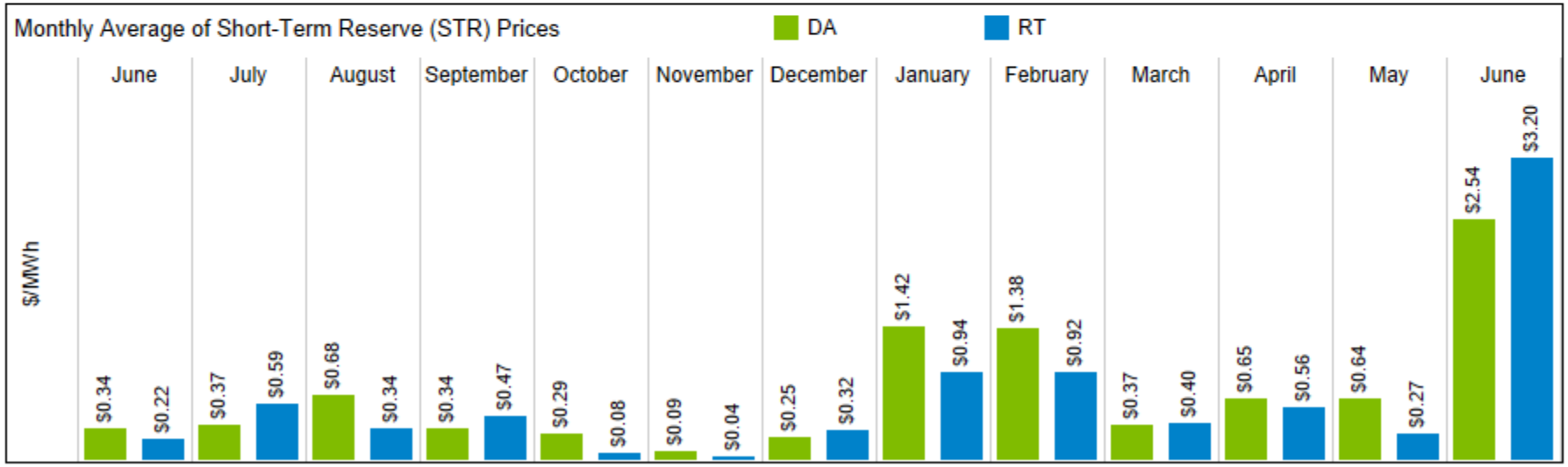



*Source: MISO Market and Operations Analytics Department*

# Ancillary Services - Day-Ahead and Real-Time Market Clearing Prices






*Source: MISO Market and Operations Analytics Department*

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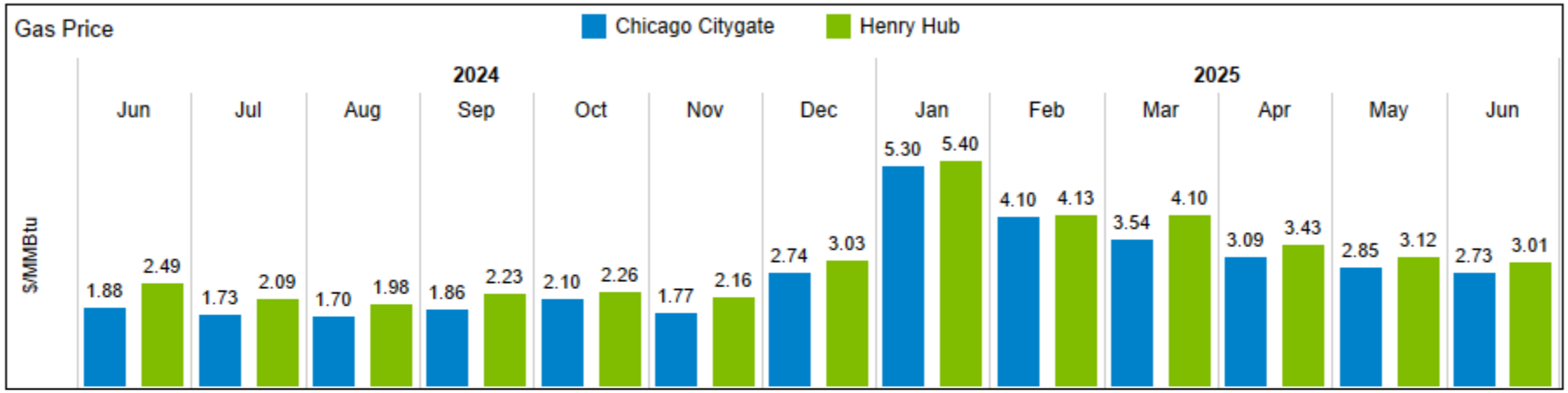
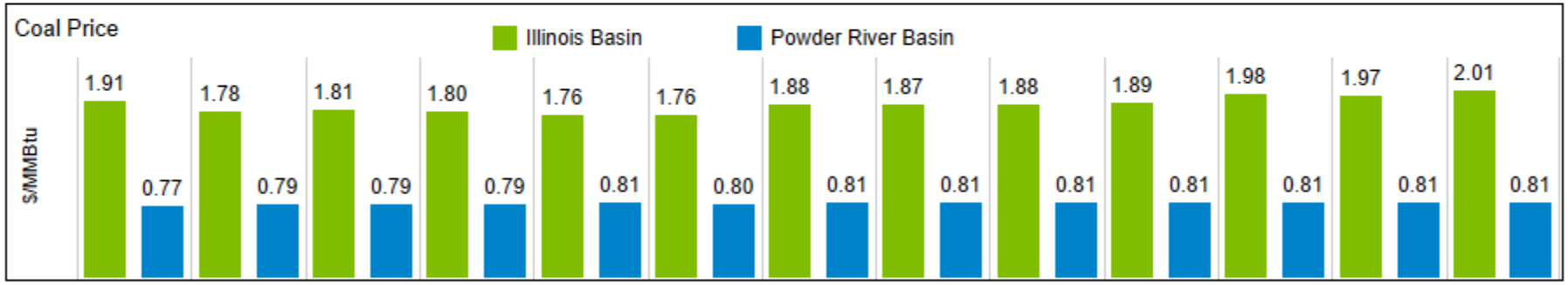
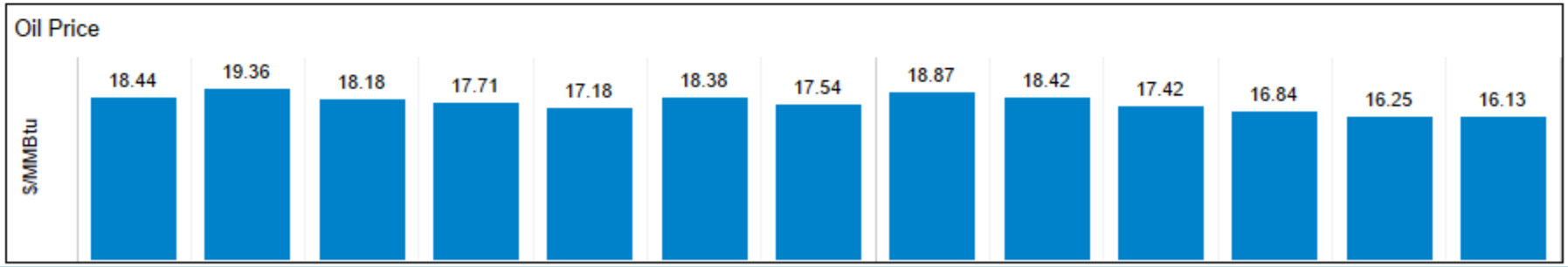
# Nominal Fuel Prices



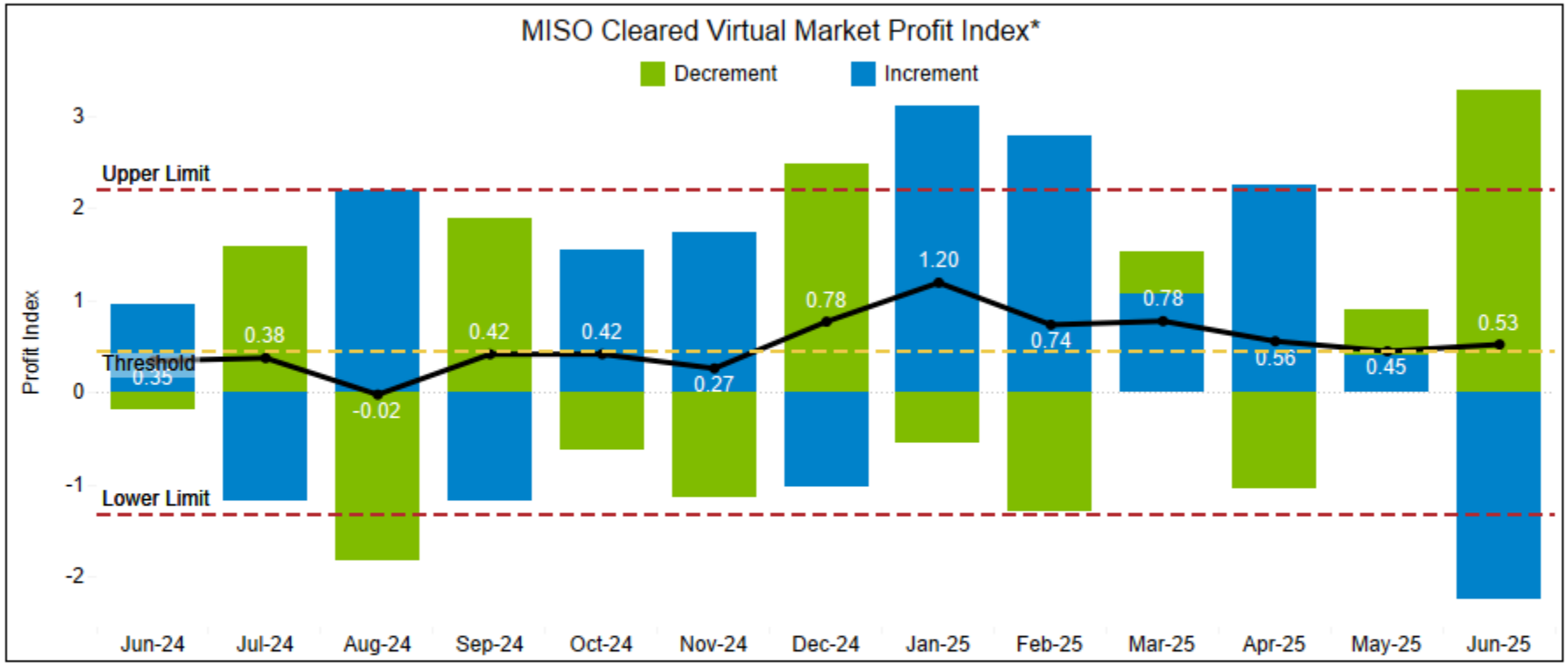




*Monthly oil prices are estimates and subject to change upon finalization*
*Source: EIA*

# Monthly Average Gross Virtual Profitability

B




**Monthly Standard Deviation**

| Jun-24 | Jul-24 | Aug-24 | Sep-24 | Oct-24 | Nov-24 | Dec-24 | Jan-25 | Feb-25 | Mar-25 | Apr-25 | May-25 | Jun-25 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1.09 | 2.96 | 0.86 | 1.32 | 1.21 | 1.74 | 1.50 | 2.60 | 2.21 | 1.16 | 1.15 | 2.04 | 1.61 |

** The virtual profitability market index is defined as the sum of profits/losses for all cleared virtual transactions divided by the volume (MWh) of total cleared transactions.*
** Virtual profits/losses are calculated by multiplying the cleared virtual MW and the imbalance between RT LMP and DA LMP for a cpnode, then summed across all cpnodes, all hours.*
** Upper Limit is Threshold (average of monthly indices from the previous year) plus Daily Average Standard Deviation for the previous 13 months (current reporting month inclusive)*
** Lower Limit is Threshold (average of monthly indices from the previous year) minus Daily Average Standard Deviation for the previous 13 months (current reporting month inclusi..*



*Source: MISO Market and Operations Analytics Department*

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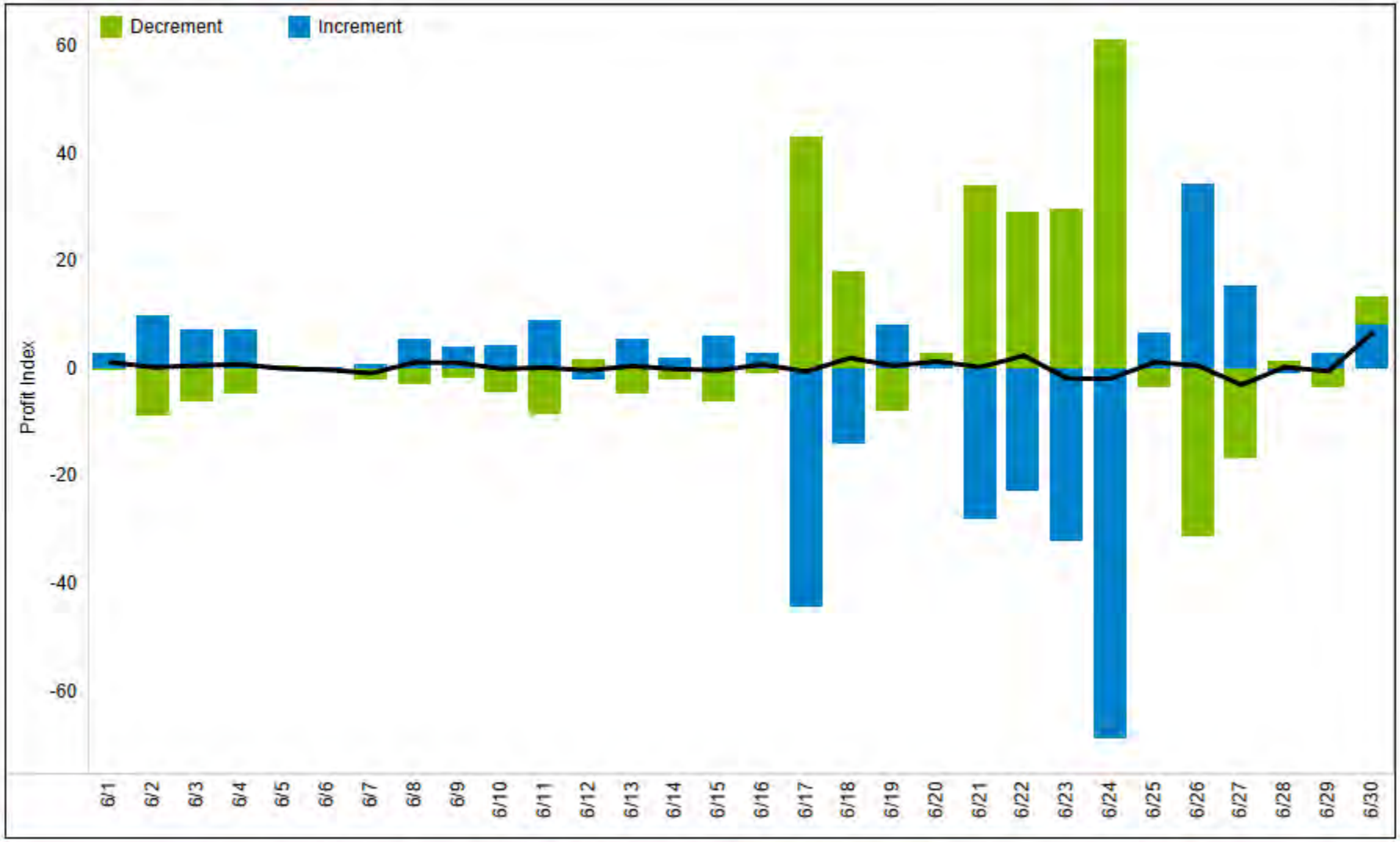
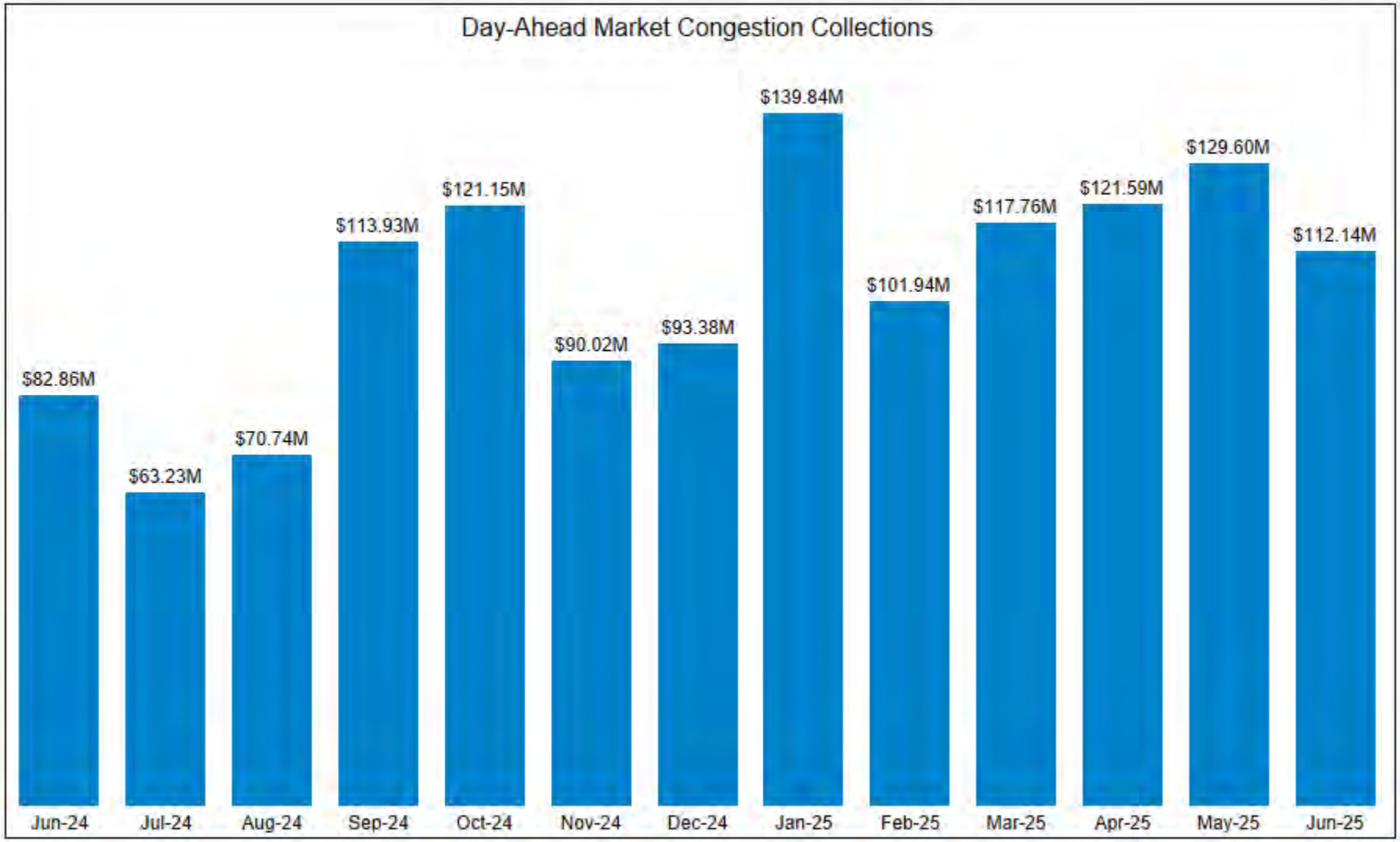
# Daily Gross Cleared Virtual Profitability



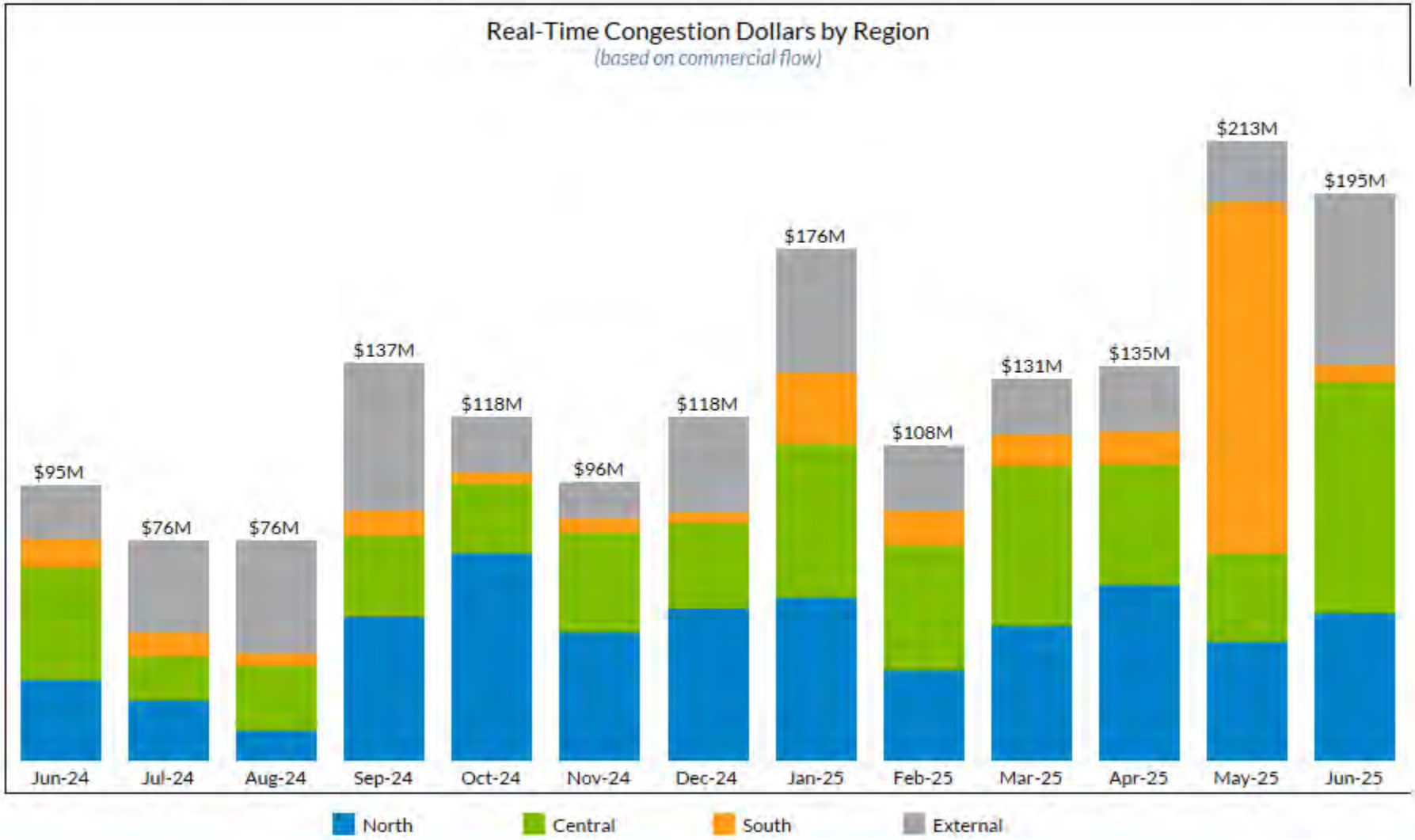

*The virtual profitability market index is defined as the sum of profits/losses for all cleared virtual transactions divided by the volume (MWh) of total cleared transactions*
*Source: MISO Market and Operations Analytics Department*

# Day-Ahead Congestion Collections




*Source: MISO Market and Operations Analytics Department*

# Real-Time Congestion Dollars by Region




*Includes External Constraints*
*Commercial Flow excludes* phase angle regulators and loop flows
*Source: MISO Market and Operations Analytics Department*

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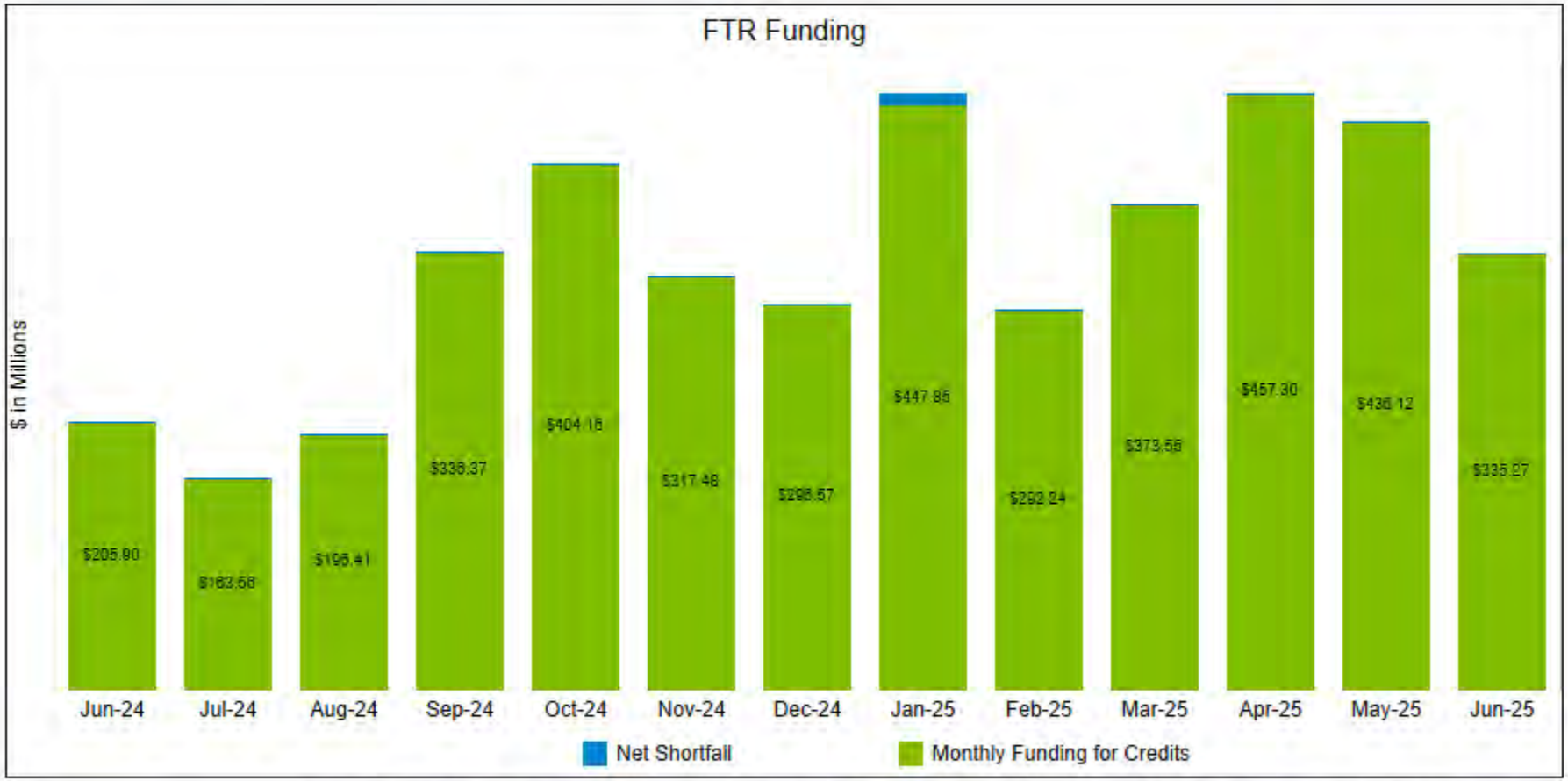
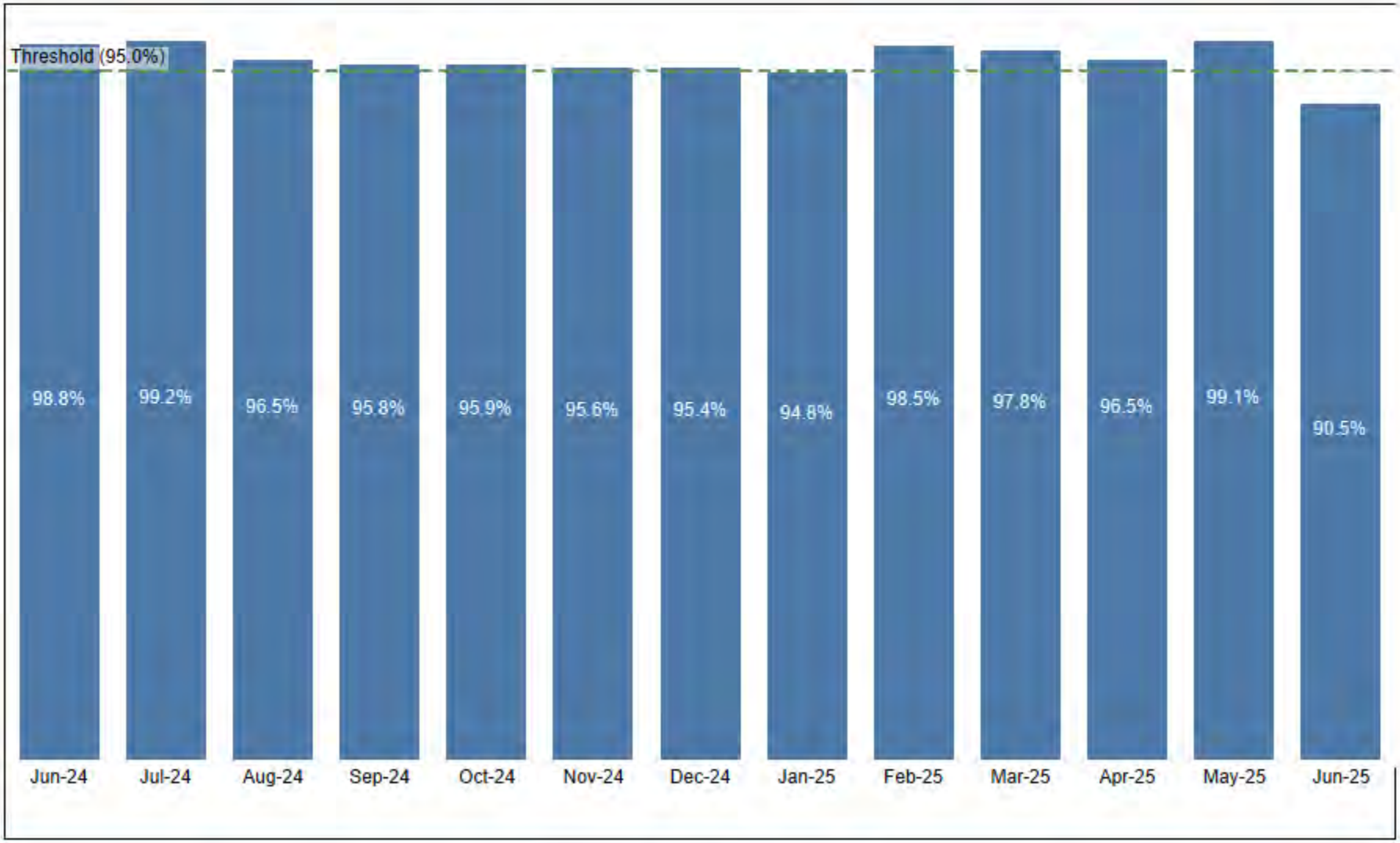
# Financial Transmission Rights, Monthly and Rolling Year-to-Date Allocation Funding




| | Jun-24 | Jul-24 | Aug-24 | Sep-24 | Oct-24 | Nov-24 | Dec-24 | Jan-25 | Feb-25 | Mar-25 | Apr-25 | May-25 | Jun-25 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Monthly FTR Allocation (%) | 100.0% | 100.0% | 100.0% | 99.9% | 100.0% | 100.0% | 100.0% | 97.8% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% |
| YTD FTR Allocation (%) | 95.6% | 96.3% | 96.7% | 97.1% | 97.5% | 97.8% | 98.0% | NA | NA | NA | 100.0% | 100.0% | 100.0% |

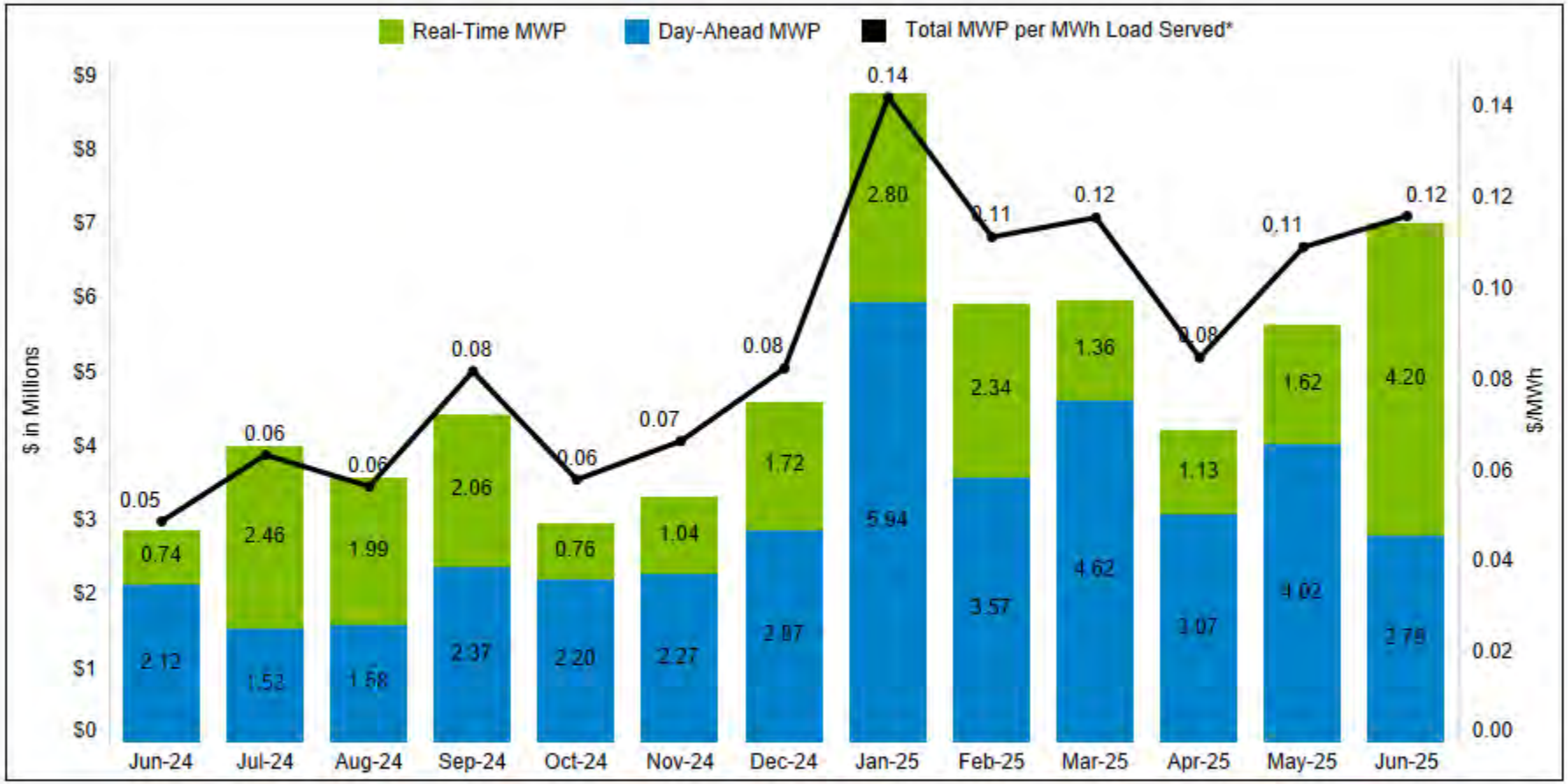
*YTD metric is applied beginning April*
*Values may change due to resettlement*
*Source: MISO Market ECF Report*

# Market Funding Efficiency




*Values may change due to resettlement*
*Source: MISO Market ECF Report*

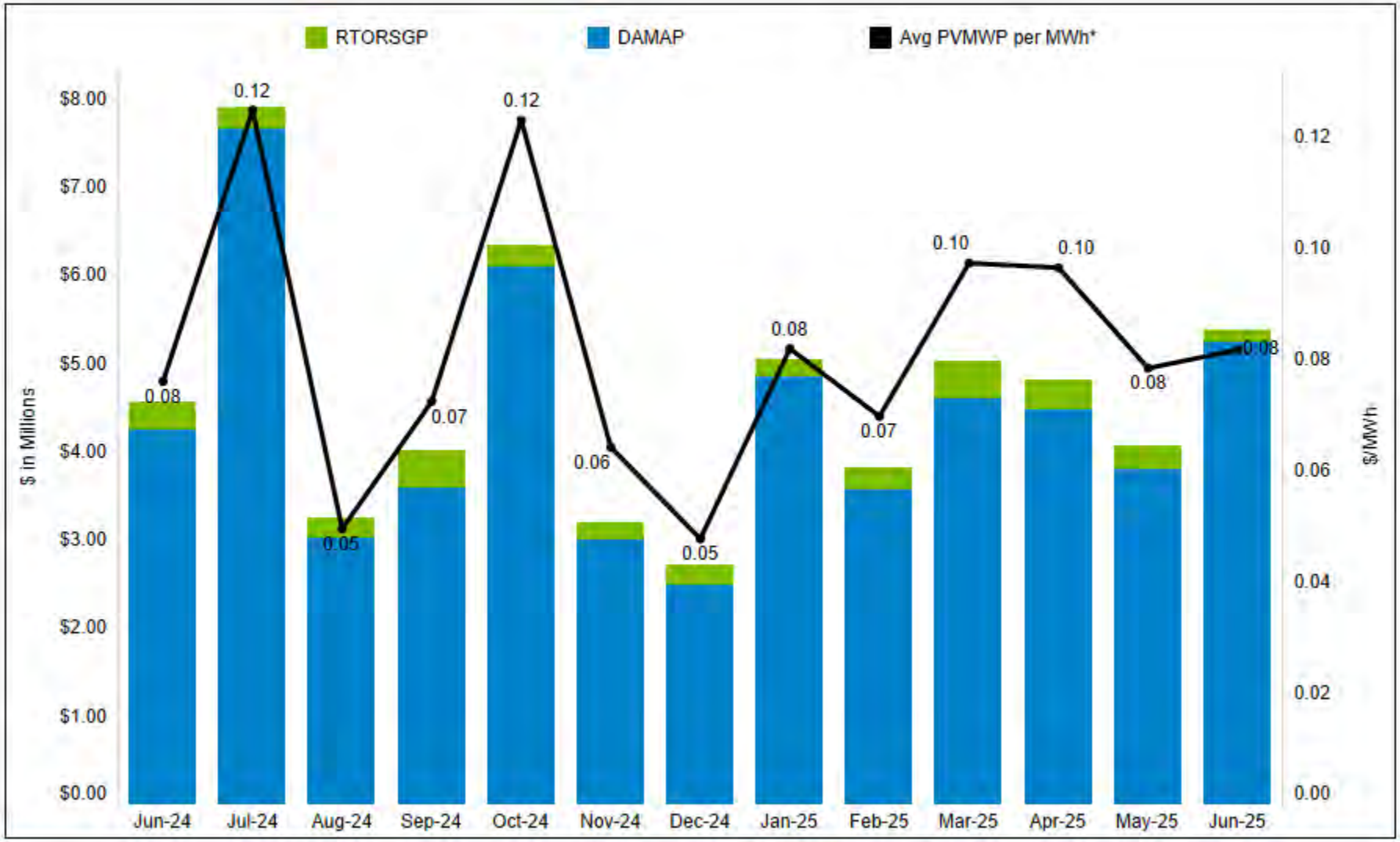
# Day-Ahead and Real-Time Revenue Sufficiency Guarantee




| | Jun-24 | Jul-24 | Aug-24 | Sep-24 | Oct-24 | Nov-24 | Dec-24 | Jan-25 | Feb-25 | Mar-25 | Apr-25 | May-25 | Jun-25 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Chicago Gas Prices ($/MMBtu) | 1.88 | 1.73 | 1.70 | 1.86 | 2.10 | 1.77 | 2.74 | 5.30 | 4.10 | 3.54 | 3.09 | 2.85 | 2.73 |
| Henry Gas Prices ($/MMBtu) | 2.49 | 2.09 | 1.98 | 2.23 | 2.26 | 2.16 | 3.03 | 5.40 | 4.13 | 4.10 | 3.43 | 3.12 | 3.01 |
| ^^RSG Per MWh to Energy Price (%) | 0.18 | 0.22 | 0.20 | 0.31 | 0.22 | 0.27 | 0.27 | 0.32 | 0.26 | 0.33 | 0.25 | 0.31 | 0.29 |

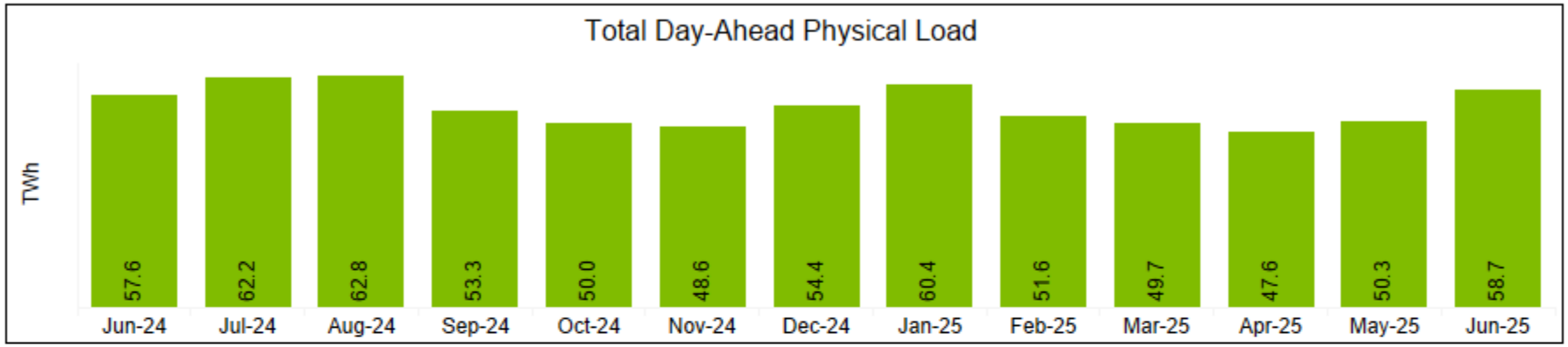
**Based on hourly ICCP Data; ^^metric value*
*Values may change due to resettlement*
*Source: The Web-based Revenue Sufficiency Gurantee Report*

# Price Volatility Make Whole Payment



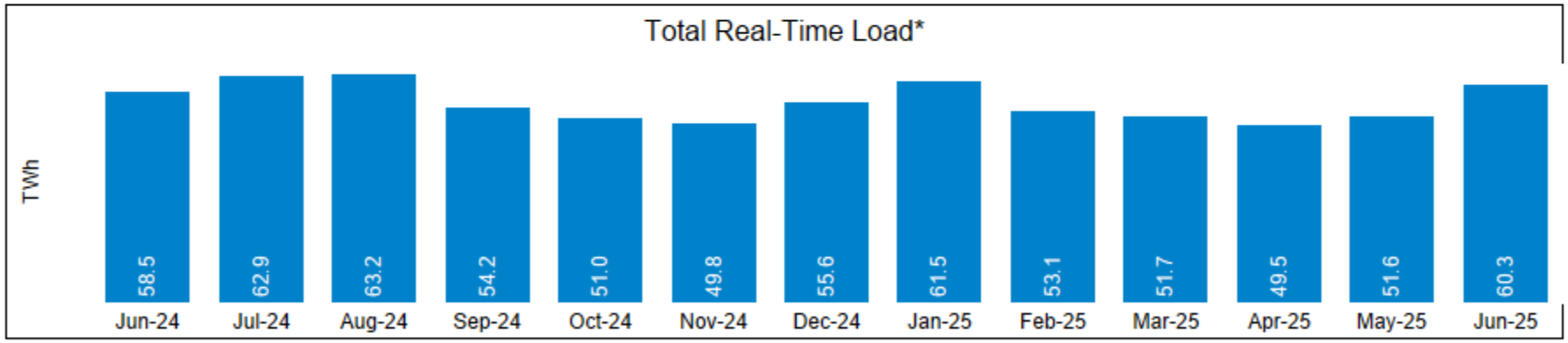

*Hourly ICCP data
Source: Web-based Revenue Neutrality Uplift Report

# Day-Ahead and Real-Time Cleared Physical Energy




Day-Ahead Cleared Load Value (including Virtuals)

| Jun-24 | Jul-24 | Aug-24 | Sep-24 | Oct-24 | Nov-24 | Dec-24 | Jan-25 | Feb-25 | Mar-25 | Apr-25 | May-25 | Jun-25 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| $1.92B | $2.37B | $2.20B | $1.74B | $1.57B | $1.44B | $2.06B | $3.20B | $2.68B | $1.93B | $1.87B | $2.14B | $2.97B |

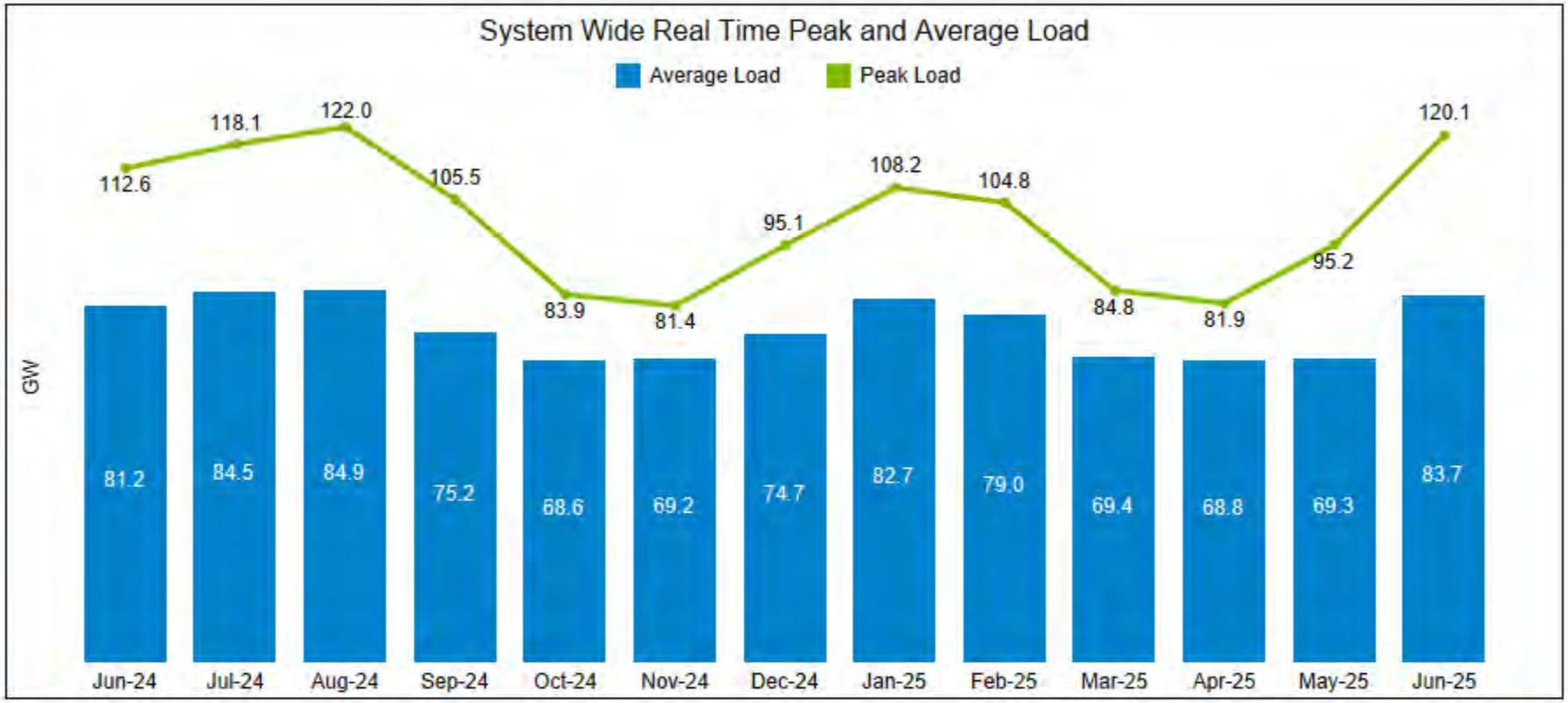



Real-Time Cleared Load Value ($ in Billions)

| Jun-24 | Jul-24 | Aug-24 | Sep-24 | Oct-24 | Nov-24 | Dec-24 | Jan-25 | Feb-25 | Mar-25 | Apr-25 | May-25 | Jun-25 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| $1.66B | $2.14B | $1.81B | $1.63B | $1.29B | $1.18B | $1.83B | $2.64B | $2.21B | $1.65B | $1.55B | $1.95B | $3.00B |

**Sum of Hourly ICCP Load Data*
*Source: MISO Market and Operations Analytics Department*

# Monthly System Load and Temperature




System Wide Load Weighted Temperature

| | Jun-24 | May-25 | Jun-25 |
|---|---|---|---|
| Average | 77°F | 63°F | 76°F |
| Maximum | 93°F | 83°F | 100°F |
| Minimum | 55°F | 47°F | 52°F |

Load Weighted Heating & Cooling Degree Days

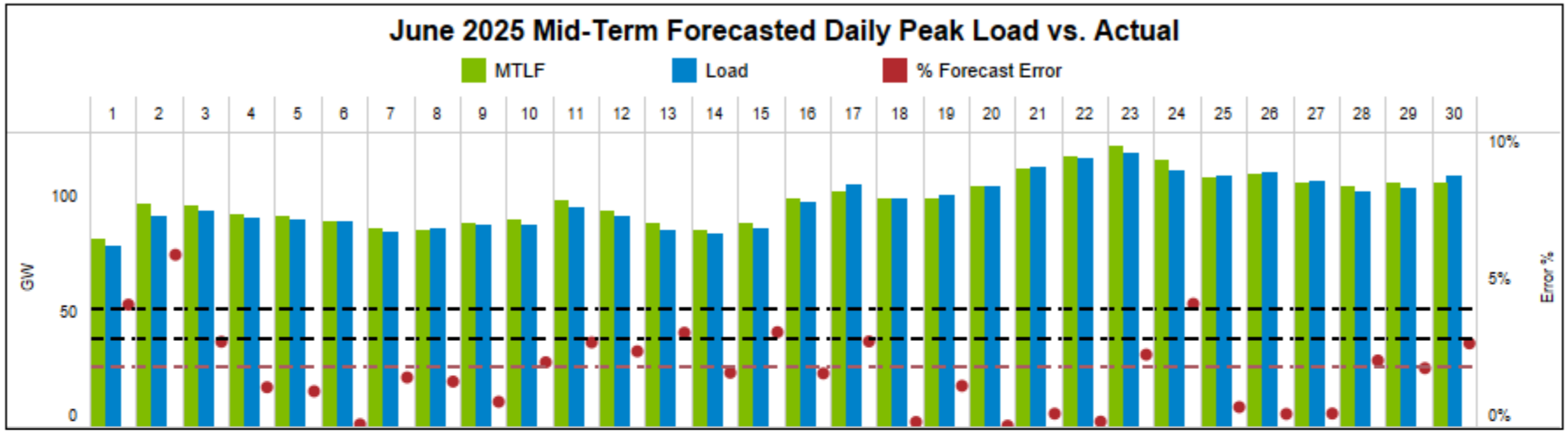
| | Average HDD | Std Dev HDD | Average CDD | Std Dev CDD |
|---|---|---|---|---|
| Jun-25 | 0.14 | 0.94 | 14.60 | 8.60 |
| May-25 | 2.30 | 3.41 | 3.73 | 4.90 |
| Jun-24 | 0.07 | 0.56 | 14.60 | 7.77 |

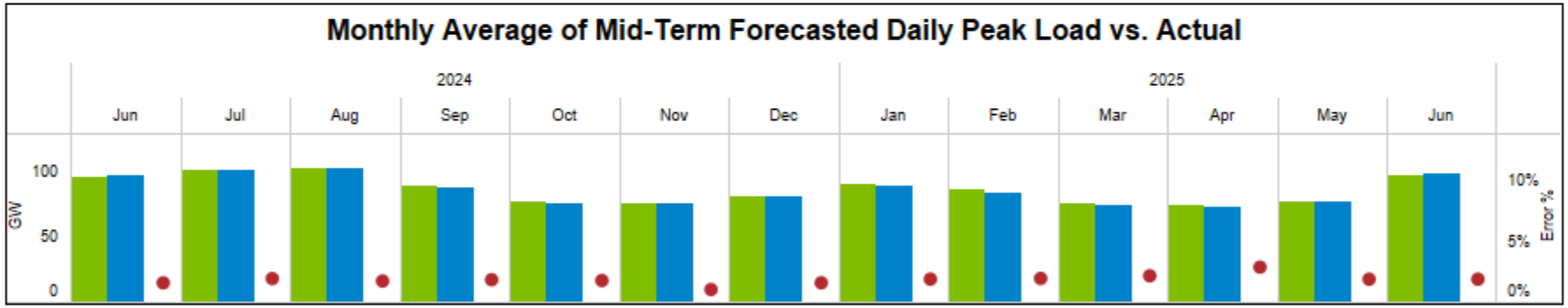
Hours with Load Greater than:

| | 100 GW | 80 GW | 60 GW |
|---|---|---|---|
| Jun-25 | 110 | 415 | 709 |
| May-25 | 0 | 62 | 653 |
| Jun-24 | 67 | 364 | 695 |

**Monthly data based on hourly ICCP Load Data; Hourly Integrated Peak Load Hour could differ from the Instantaneous Peak Load Hour.*
*Source: MISO Market and Operations Analytics Department*

# Day-Ahead Mid-Term Load Forecast*



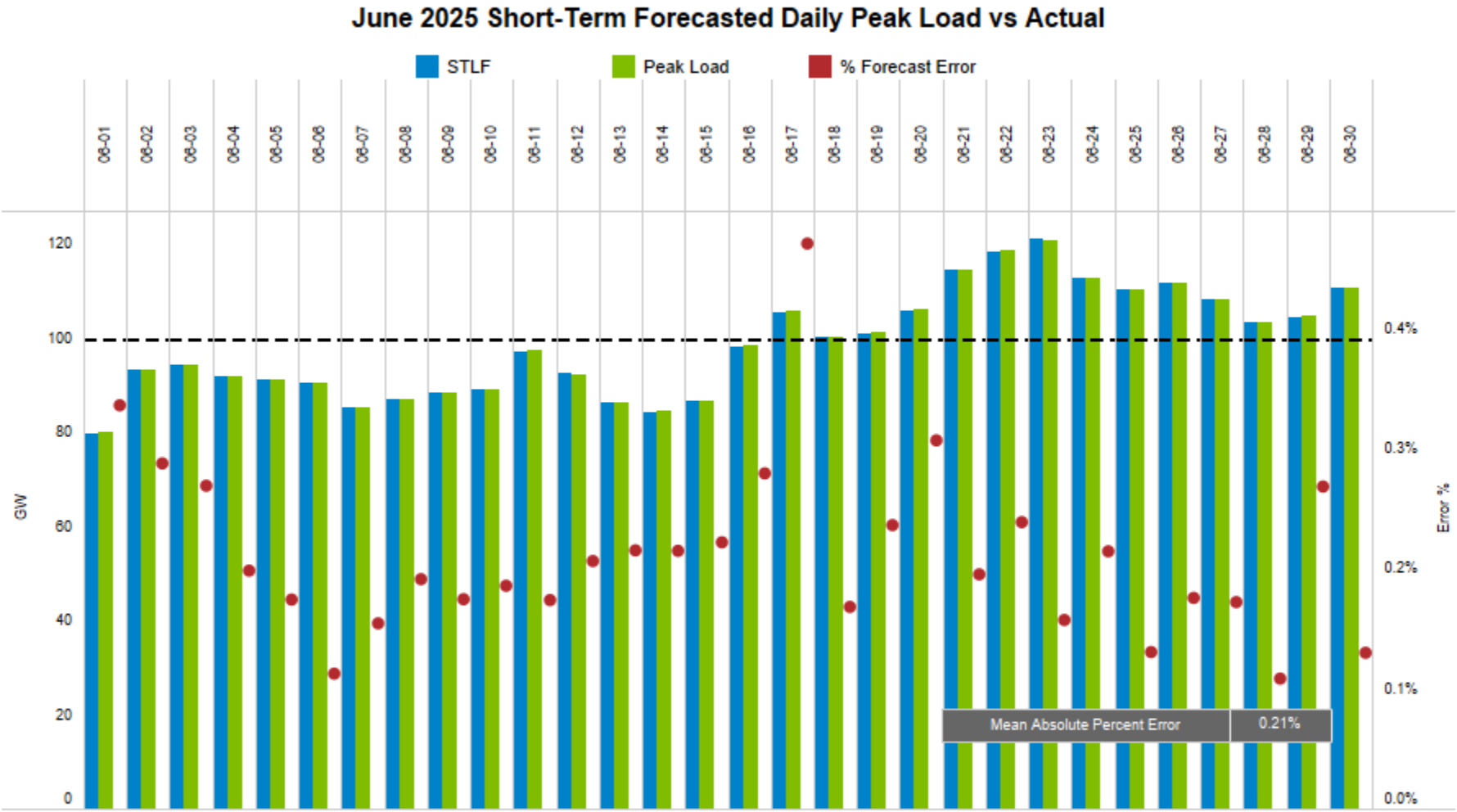

| | 2024 | | | | | | | 2025 | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun |
| % Std of Error (CV) | 90.18 | 76.54 | 67.80 | 71.09 | 68.94 | 101.98 | 81.76 | 77.55 | 60.87 | 54.00 | 40.07 | 78.67 | 71.95 |
| Mean of Error (MW) | 1,594 | 1,980 | 1,845 | 1,700 | 1,418 | 814 | 1,334 | 1,742 | 1,674 | 1,671 | 2,191 | 1,474 | 1,852 |
| Std of Error (MW) | 1,437 | 1,515 | 1,251 | 1,209 | 978 | 830 | 1,090 | 1,351 | 1,019 | 902 | 878 | 1,159 | 1,332 |

* Monthly data based on the average of the daily integrated peak hours in the month
* Daily data based on the integrated peak hour of the day
* Peak Day and Hour End based on Hourly Integrated Peak Load Hour

*Source: MISO Operations Risk Management*

# Short-Term Load Forecast*

G




Daily data based on the average of five-minute interval data at the peak hour of the day
Error Threshold calculated as 95% quantile of Forecast Error from Jan-Dec of the previous year

Peak Day and Hour End based on Hourly Integrated Peak Load Hour



*Source: MISO Operations Risk Management*

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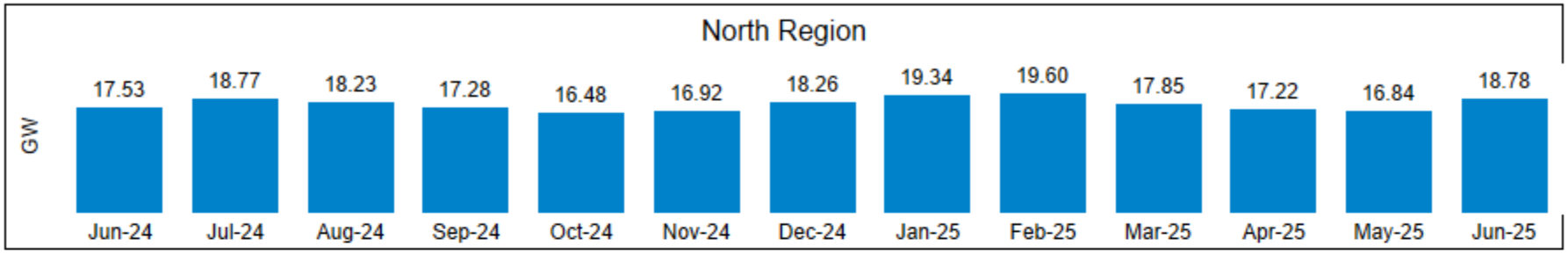
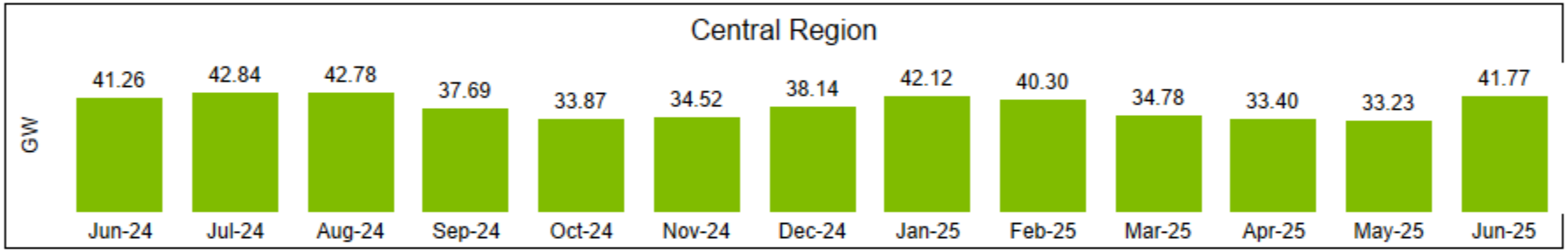
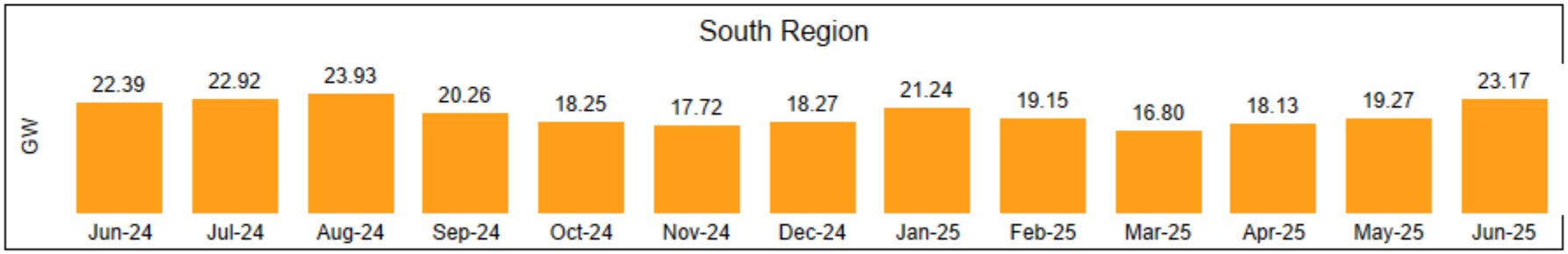
# Average Load by Region



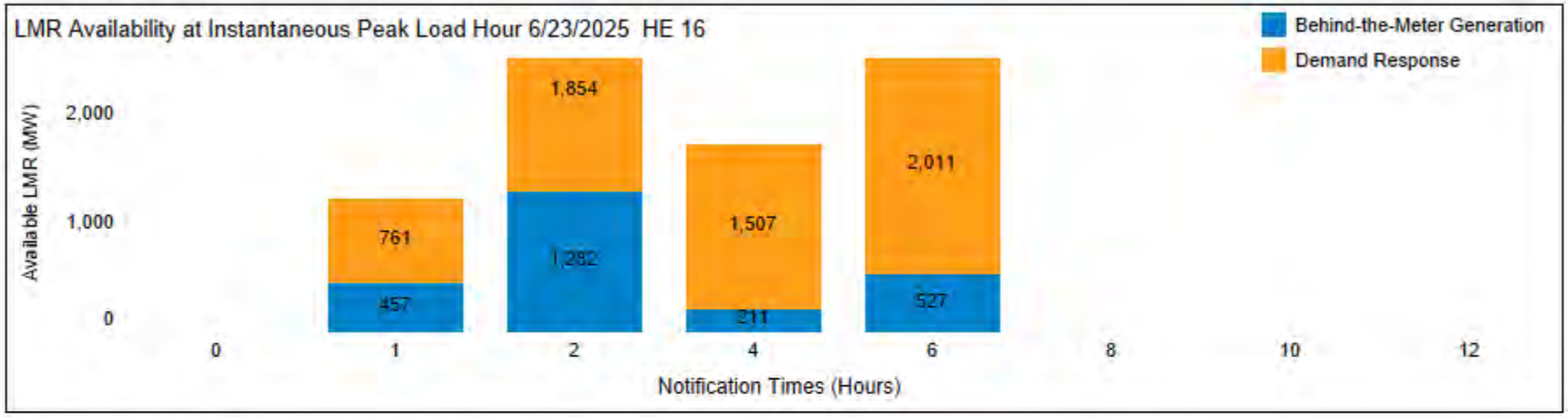



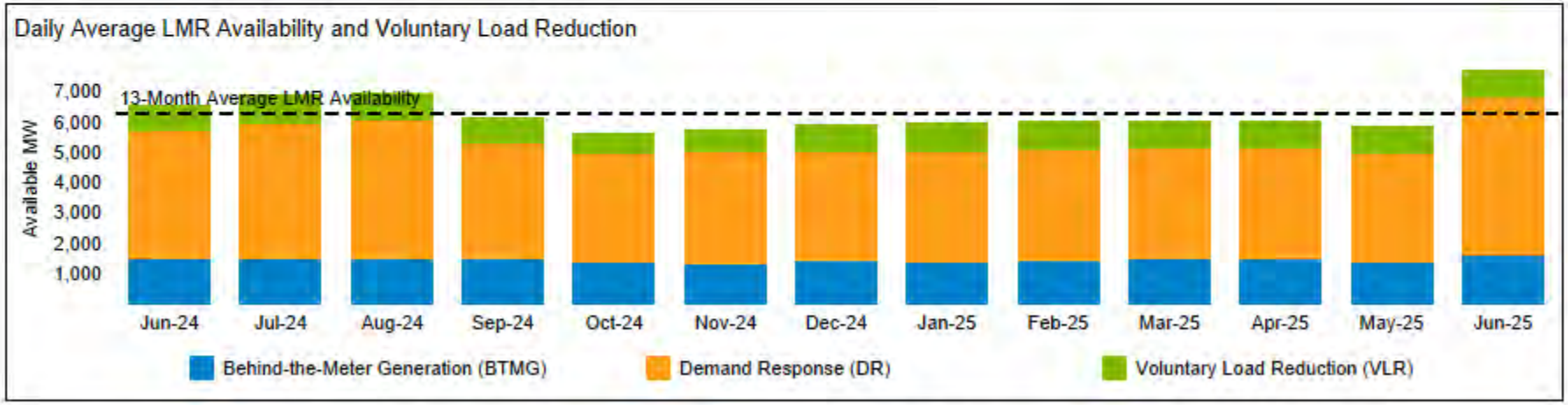

Hourly Integrated System Load Peak Hour Ending: 06/23/2025 16 EST

| | |
|---|---|
| North | 25.86 GW |
| Central | 65.78 GW |
| South | 30.29 GW |
| MISO | 119.31 GW |

*Monthly data based on hourly ICCP Load Data; Hourly Integrated Peak Load Hour could differ from the Instantaneous Peak Load Hour.
Source: MISO Market and Operations Analytics Department

# Market Participant entered Load Modifying Resource (LMR) Availabililty



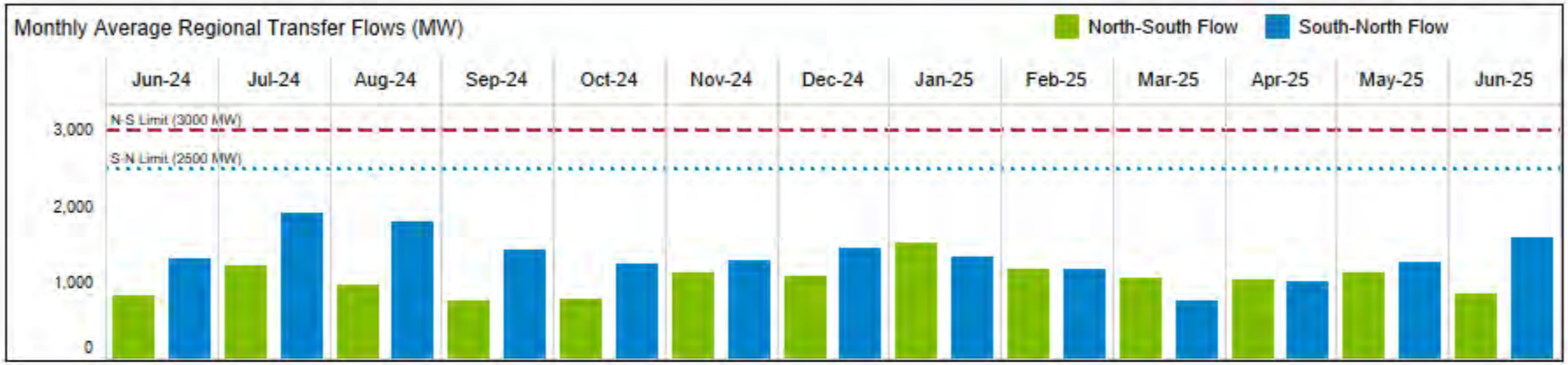

| PRA Auction | BTMG (MW) | DR (MW) | Total BTMG and DR (MW) |
|---|---|---|---|
| Summer 2024 | 4,144 | 8,109 | 12,253 |
| Summer 2025 | 4,283 | 9,004 | 13,287 |



*Source: MISO Markets and Operations Analytics Department*

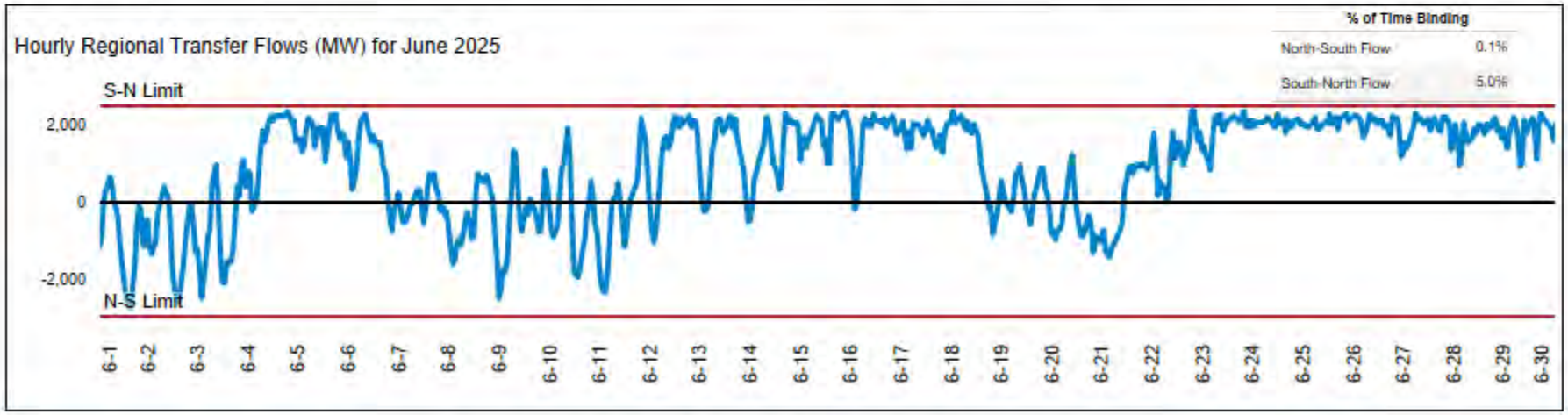
MISO

# Regional Directional Transfer**




Percentage of Time Regional Directional Flow

| | Jun-24 | Jul-24 | Aug-24 | Sep-24 | Oct-24 | Nov-24 | Dec-24 | Jan-25 | Feb-25 | Mar-25 | Apr-25 | May-25 | Jun-25 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| North-South Flow | 34% | 8% | 10% | 21% | 17% | 23% | 22% | 29% | 40% | 61% | 44% | 49% | 26% |
| South-North Flow | 66% | 92% | 90% | 79% | 83% | 78% | 78% | 71% | 60% | 39% | 56% | 51% | 74% |

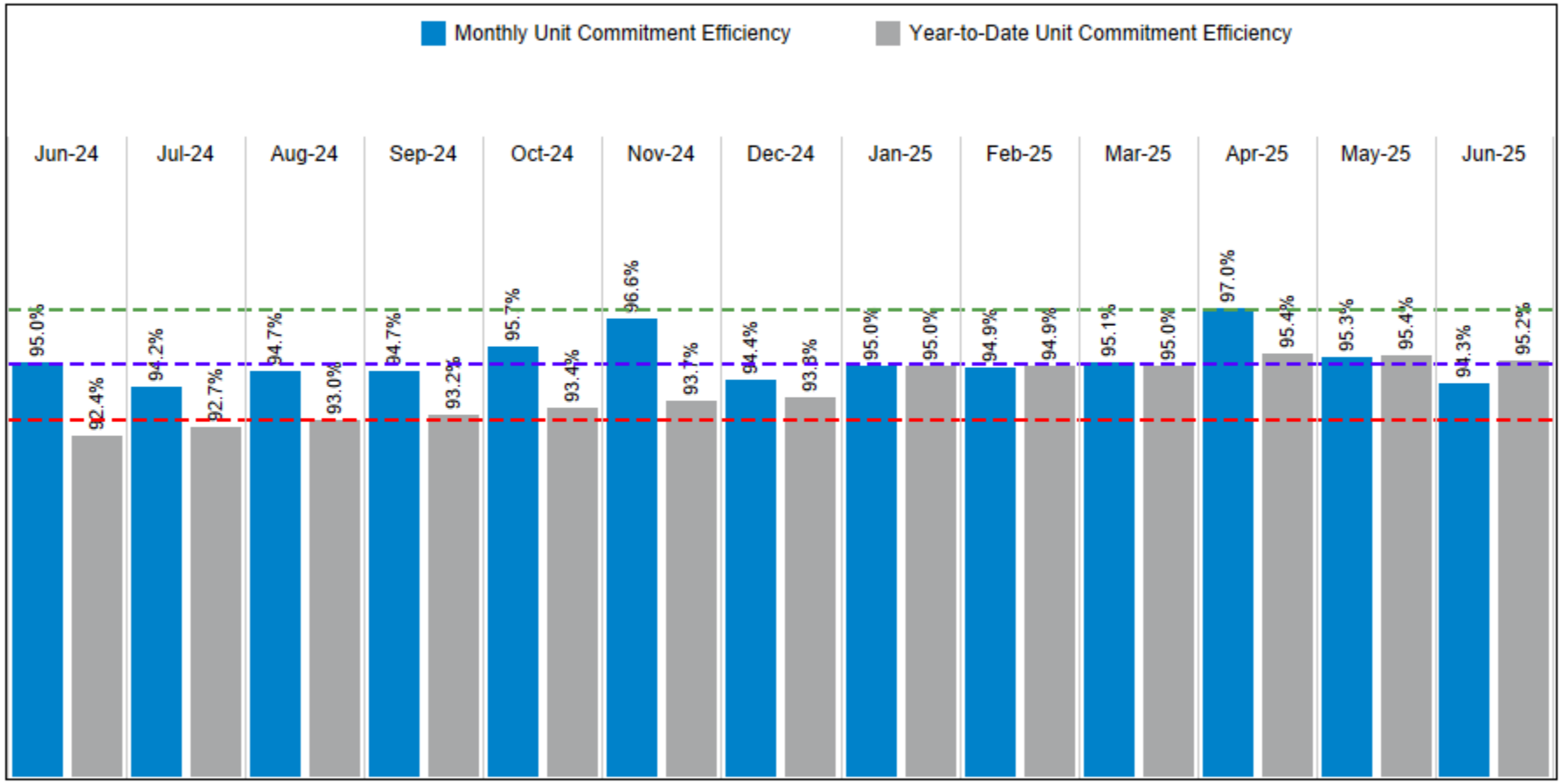



***Regional Directional Transfer between MISO South and Central/North Regions*
*Source: MISO Markets and Operations Analytics Department*

# Unit Commitment Efficiency

*Effectively commit generation to meet demand obligations and mitigate constraints*

H




| | Jun-24 | Jul-24 | Aug-24 | Sep-24 | Oct-24 | Nov-24 | Dec-24 | Jan-25 | Feb-25 | Mar-25 | Apr-25 | May-25 | Jun-25 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Actual Cost | $871M | $1,013M | $974M | $809M | $705M | $682M | $988M | $1,311M | $1,069M | $819M | $756M | $829M | $1,095M |
| Optimal Cost | $865M | $1,005M | $967M | $803M | $701M | $679M | $978M | $1,300M | $1,061M | $812M | $752M | $822M | $1,085M |
| Sunk Cost | $742M | $878M | $842M | $685M | $595M | $576M | $807M | $1,095M | $897M | $673M | $628M | $678M | $913M |

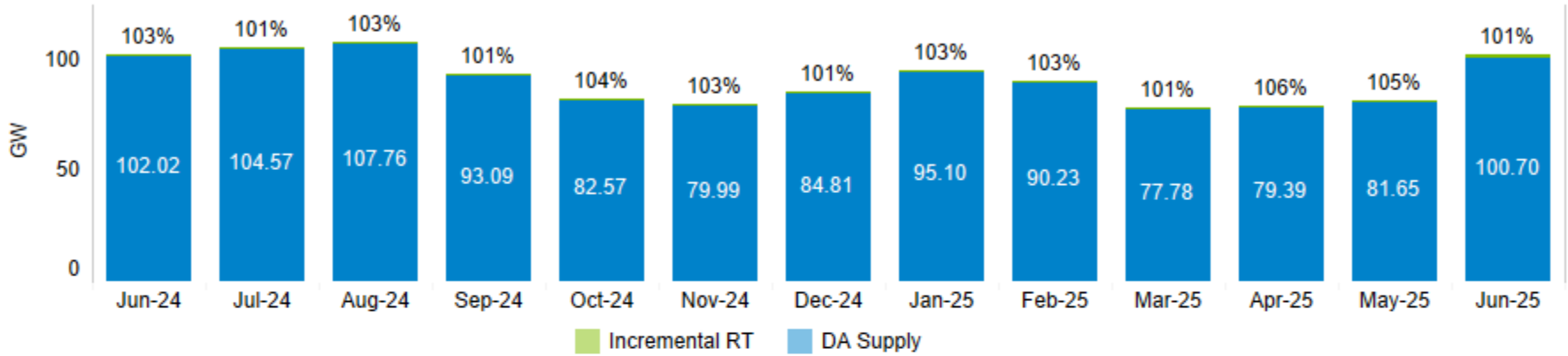
*Source: MISO Optimal Dispatch Calculator (ODC)*

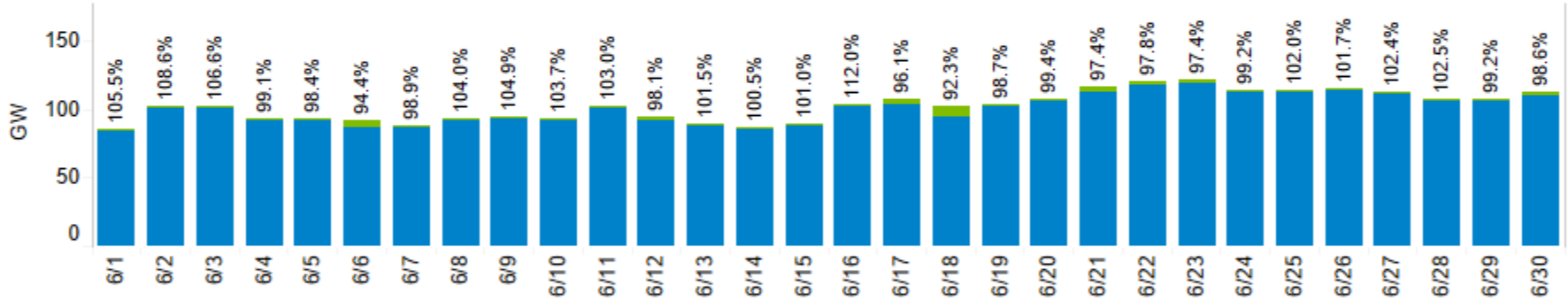
**Unit Commitment Efficiency = 1-((Actual cost – Optimal cost)/(Actual cost – Sunk cost))**



MISO

# Day-Ahead Supply and Real-Time Load Obligation at the Peak Load Hour



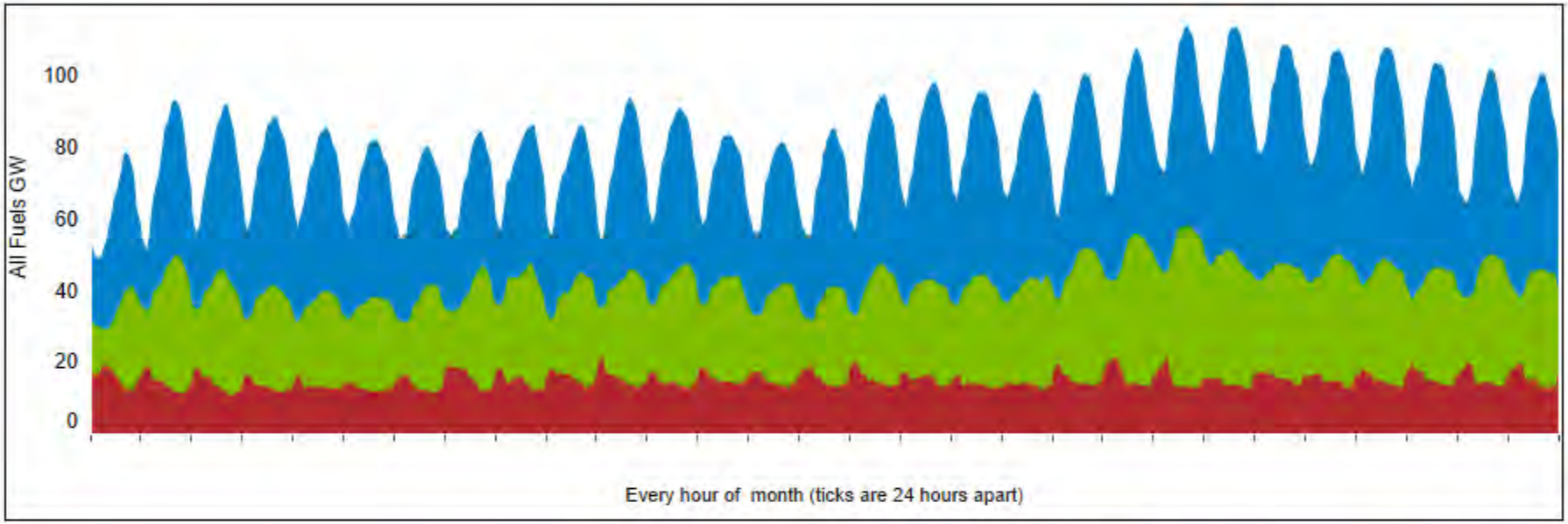

Incremental GW Commited in Real-Time

| 6/1 | 6/2 | 6/3 | 6/4 | 6/5 | 6/6 | 6/7 | 6/8 | 6/9 | 6/10 | 6/11 | 6/12 | 6/13 | 6/14 | 6/15 | 6/16 | 6/17 | 6/18 | 6/19 | 6/20 | 6/21 | 6/22 | 6/23 | 6/24 | 6/25 | 6/26 | 6/27 | 6/28 | 6/29 | 6/30 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| -4.44 | -8.08 | -6.38 | 0.83 | 1.50 | 5.11 | 1.00 | -3.60 | -4.41 | -3.30 | -2.92 | 1.78 | -1.33 | -0.39 | -0.91 | -11.03 | 4.21 | 7.84 | 1.32 | 0.68 | 3.02 | 2.70 | 3.15 | 0.97 | -2.21 | -1.87 | -2.58 | -2.65 | 0.84 | 1.52 |

**Day-Ahead Supply** is the Day-Ahead Economic Maximum received in Real-Time plus Behind-the-Meter plus Day-Ahead NSI at the Peak Hour
**Real-Time Obligation** is the Real-Time ICCP Load plus Real-Time Regulation Requirement plus Real-Time Spinning Requirement at the Peak Hour
**Real-Time Increment** is the Real-Time Obligation less Day-Ahead Supply at the Peak Hour
Percents calculated as Day-Ahead Supply divided by Real-Time Obligation

*Source: MISO Market and Operations Analytics Department*

# Self Committed and Economically Dispatched Energy - June 2025

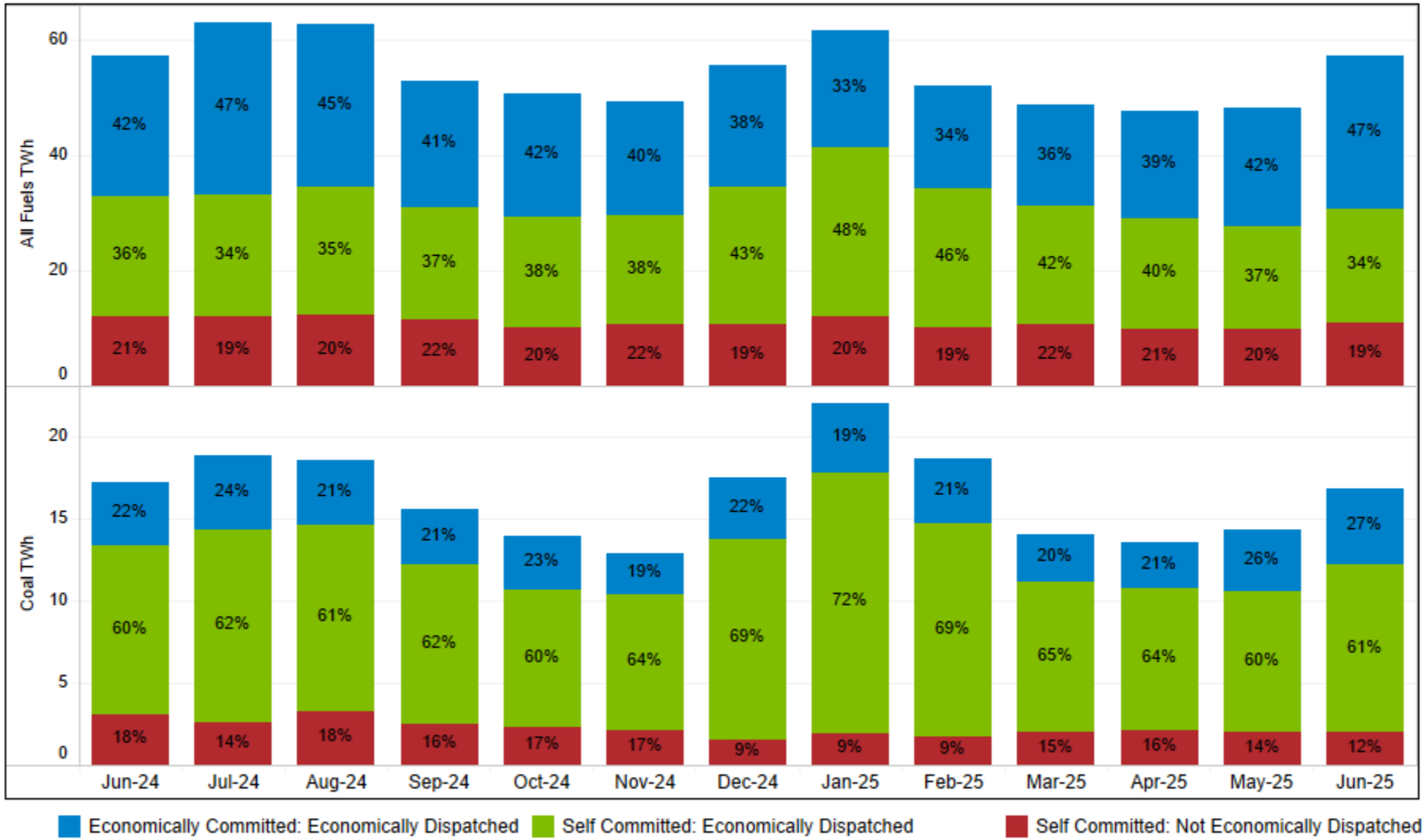



| | All Fuels | | Coal | | Gas | |
|---|---|---|---|---|---|---|
| | TWh | % | TWh | % | TWh | % |
| Economically Committed: Economically Dispatched | 26.8 | 47% | 4.6 | 27% | 17.8 | 75% |
| Self Committed: Economically Dispatched | 19.8 | 34% | 10.2 | 61% | 4.9 | 21% |
| Self Committed: Not Economically Dispatched | 10.9 | 19% | 2.0 | 12% | 1.0 | 4% |
| **Grand Total** | **57.5** | **100%** | **16.8** | **100%** | **23.7** | **100%** |

| | |
|---|---|
| Economically Committed: Economically Dispatched | Generation committed by MISO and dispatched on economic offers. |
| Self Committed: Economically Dispatched | Generation that is self-committed, but Resource Owners allow MISO to dispatch economically after the self-schedule portion of their resource offer is satisfied. Self-commitments can be used to manage local reliability, operational constraints, and fuel contract constraints. |
| Self Committed: Not Economically Dispatched | Energy from self-committed generation produced at its minimum level or is block-loaded and cannot be dispatched. Block Loaded energy is not necessarily uneconomic, but MISO has no ability to dispatch it based on economics. |

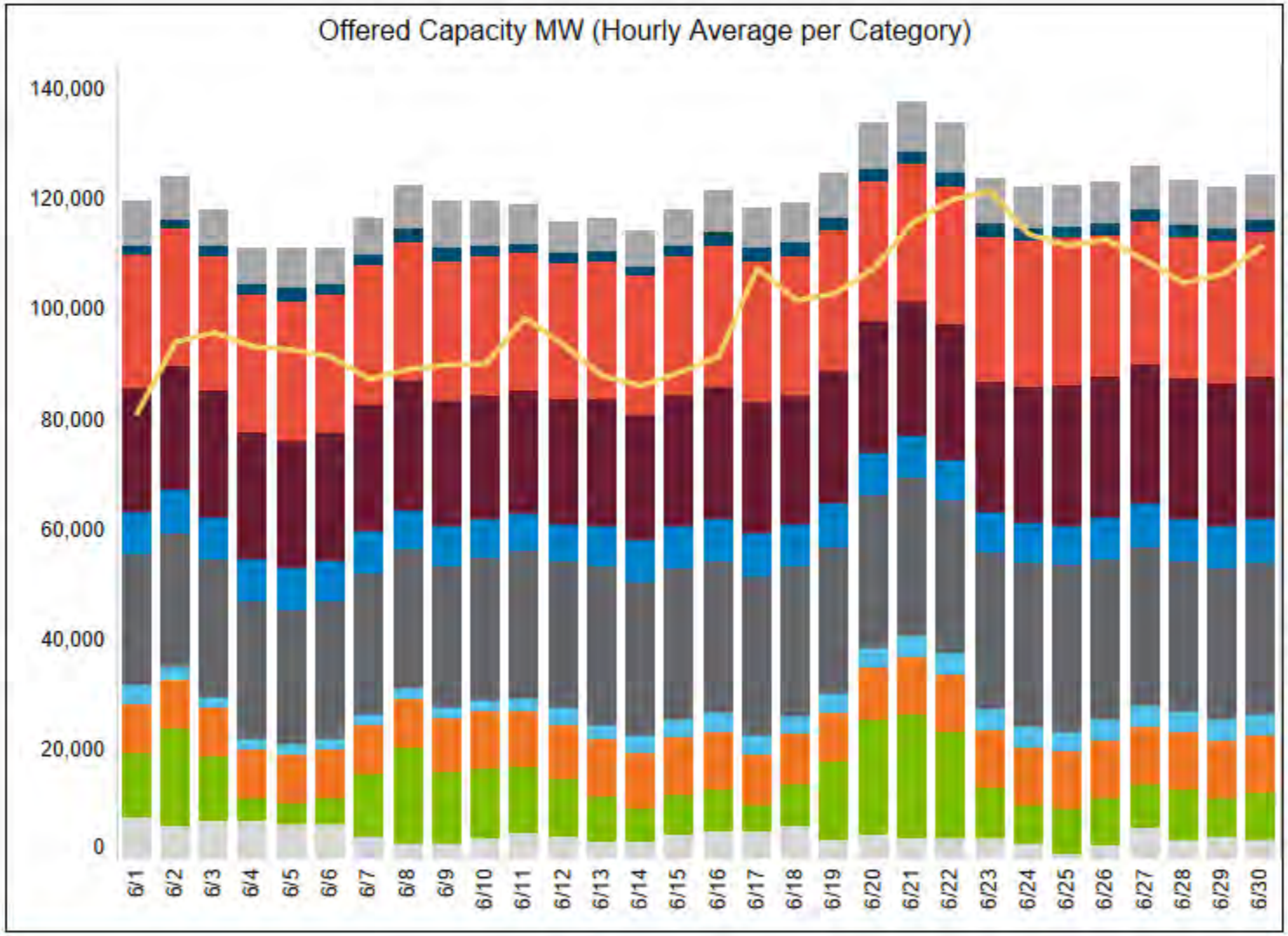
*Source: MISO Market and Operations Analytics Department*

# Monthly Trend - Self Committed and Economically Dispatched Energy




*Source: MISO Market and Operations Analytics Department*

# Offered Capacity and Real-Time Peak Load Obligation




Real-Time Obligation*
Other**
Oil
CT
CC
Gas***
Coal
Hydro
Nuclear
Wind
Avg NSI

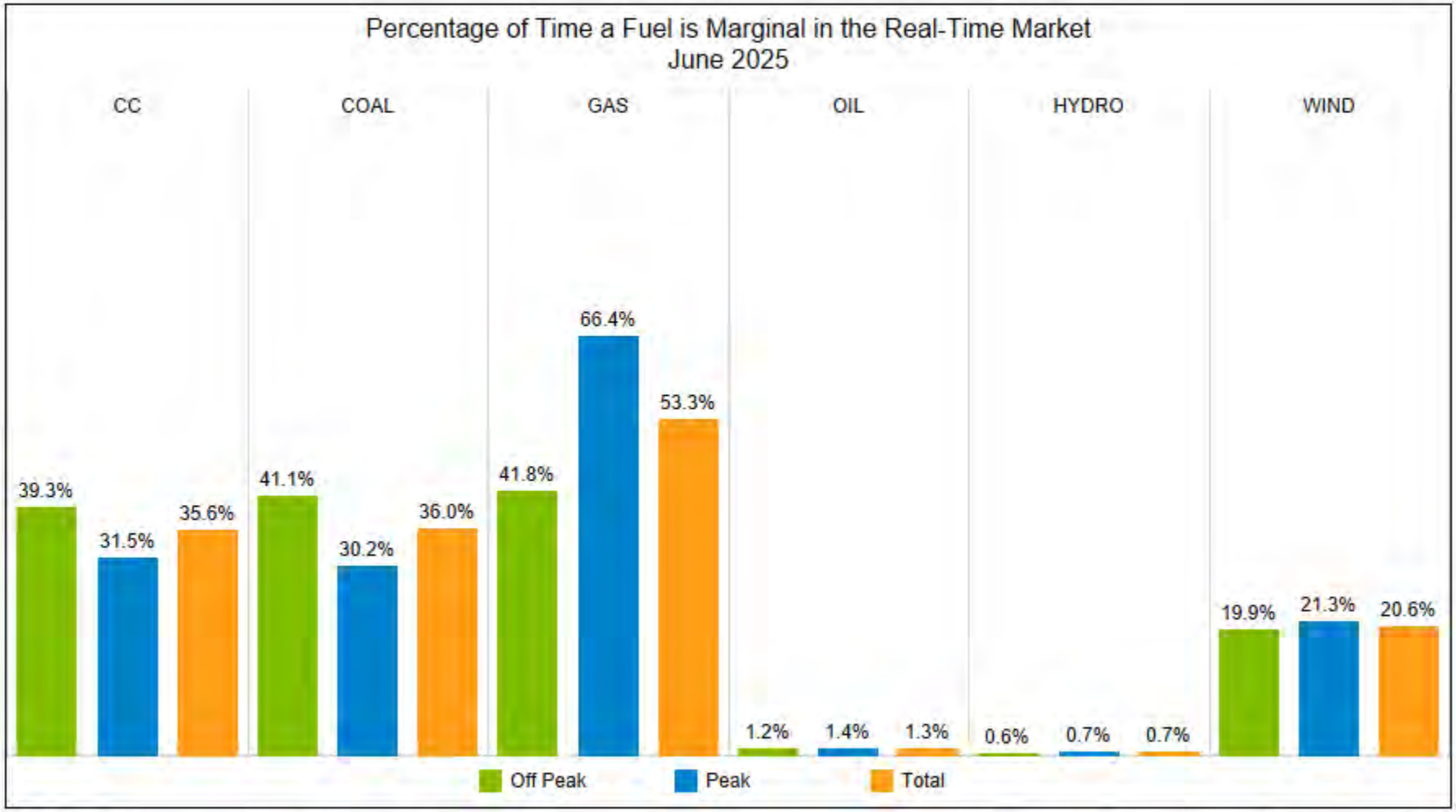
* Real-Time ICCP Load plus Real-Time Regulation Requirement plus Real-Time Spinning Requirement at the daily Peak hour.

** Other includes DRR, SER, pet coke, and waste units.

*** Gas excludes CC and CT.

*Source: MISO Market and Operations Analytics Department*

# Marginal Fuel




Note: Binding transmission constraints can produce instances where more than one unit is marginal in the system. Consequently, more than one fuel may be on the margin; and since each marginal unit is included in the analysis, the percentage may sum to more than 100%.



*Source: MISO Market and Operations Analytics Department*

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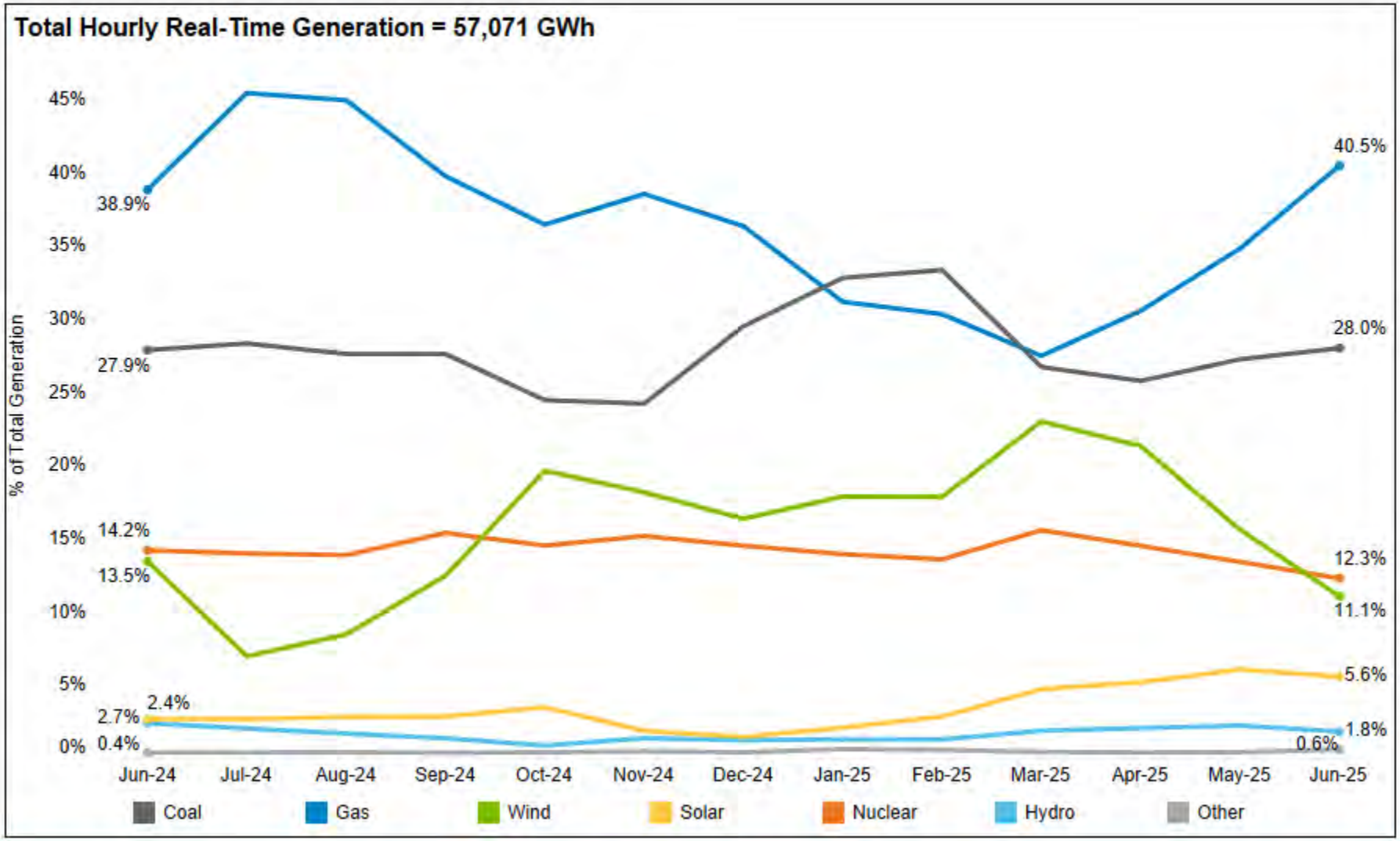
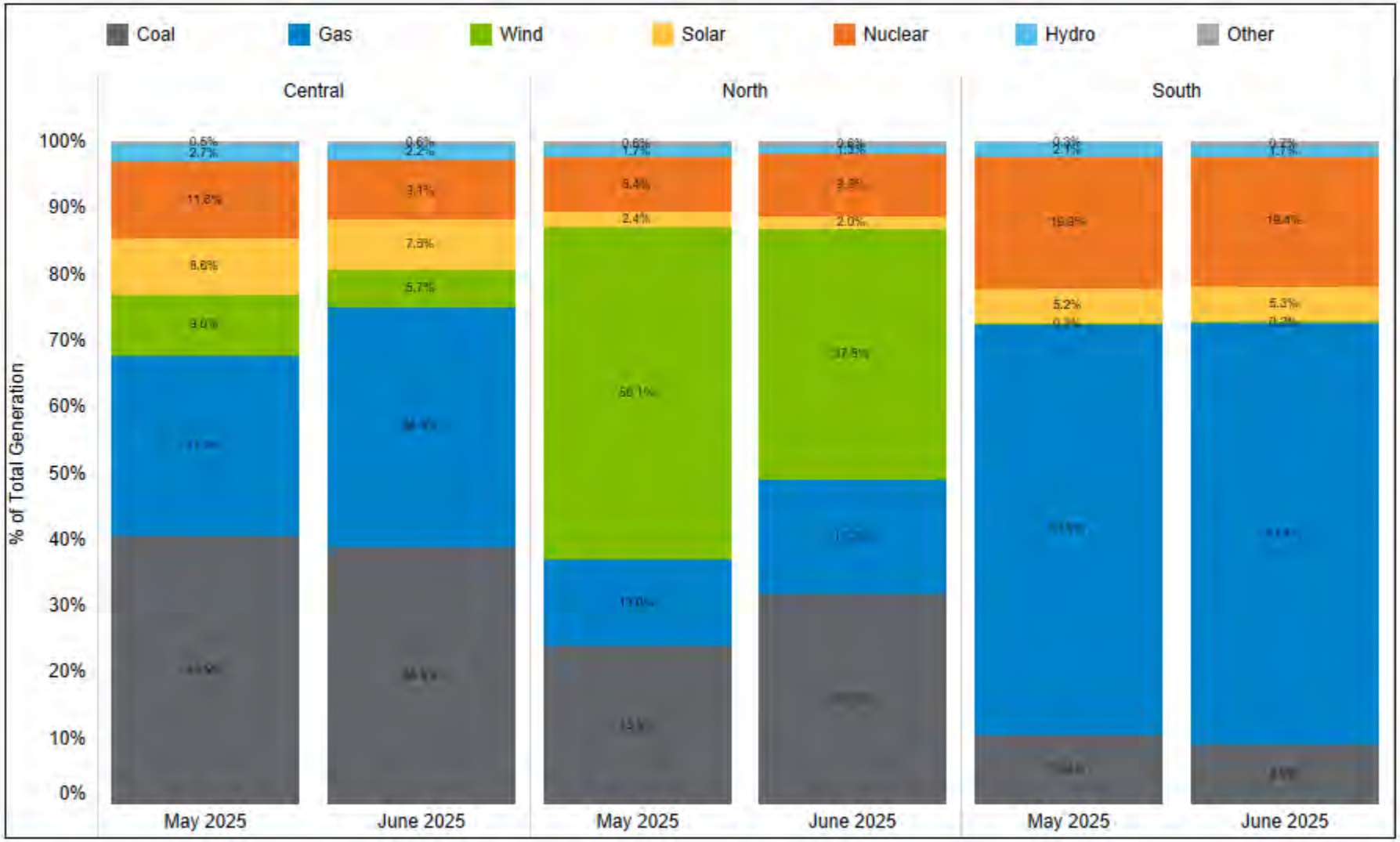
# Real-Time Generation Fuel Mix



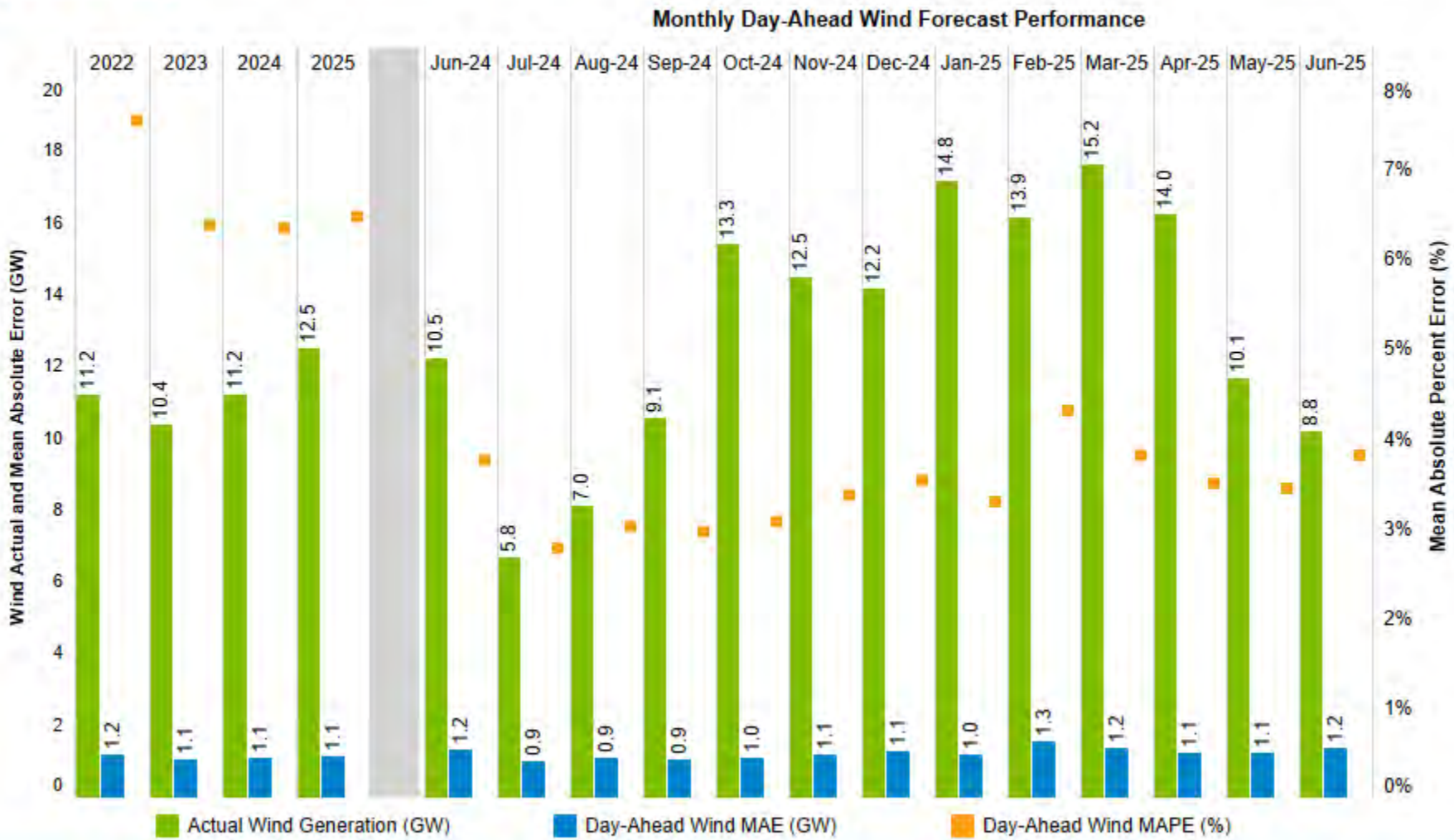

*Based on hourly unit level state estimator data*
**Other** includes: Battery, Oil, Pet Coke, Waste and Other fuels
*Source: MISO Market and Operations Analytics Department*

# Real-Time Generation Fuel Mix by Region



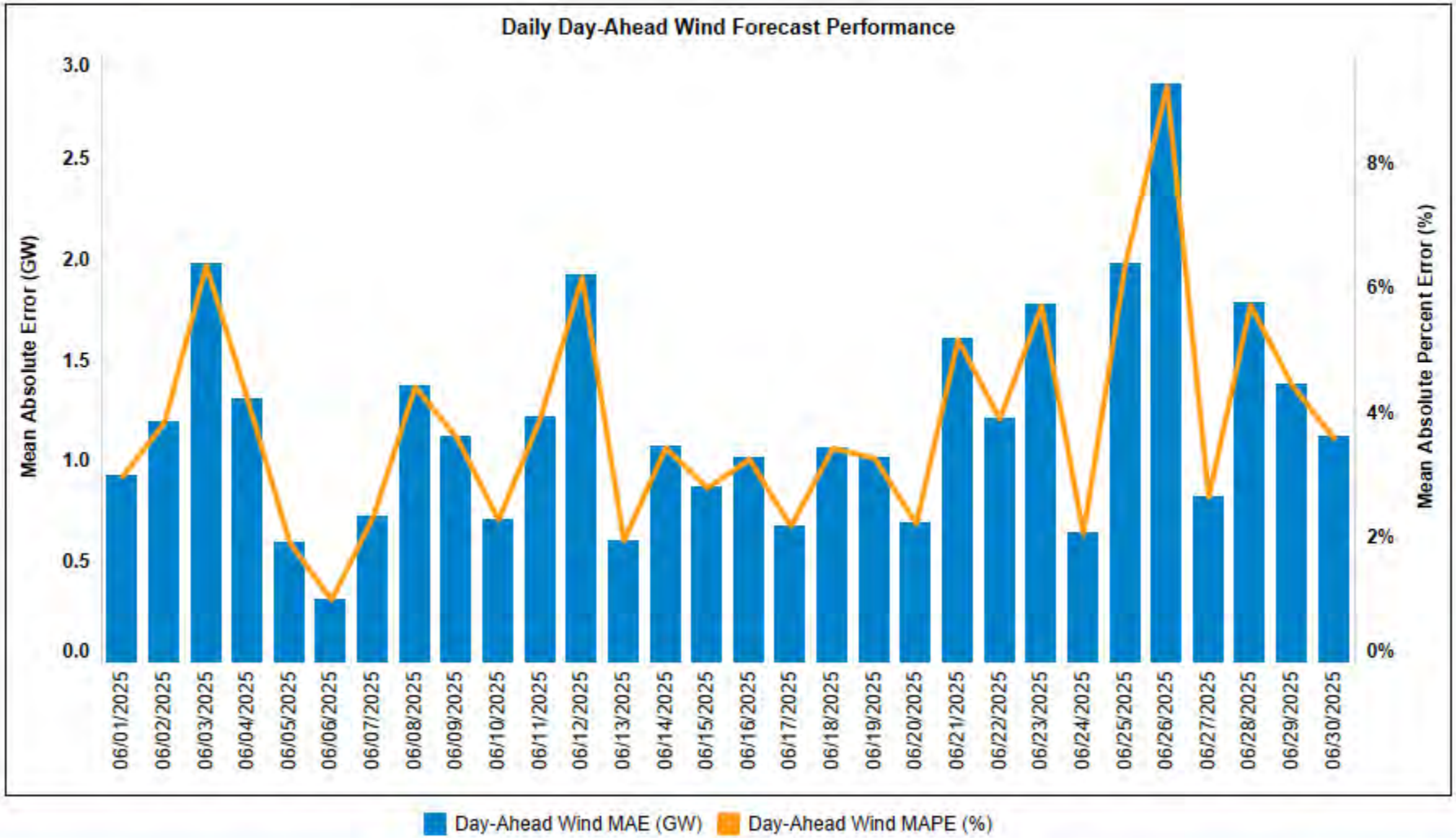

*Based on hourly unit level state estimator data*
**Other** includes: Battery, Oil, Pet Coke, Waste and Other fuels
*Source: MISO Market and Operations Analytics Department*

# Monthly Day-Ahead Wind Forecast Performance: Mean Absolute Error (MAE) and Mean Absolute Percent Error (MAPE)




*Source: MISO Operations Risk Management*

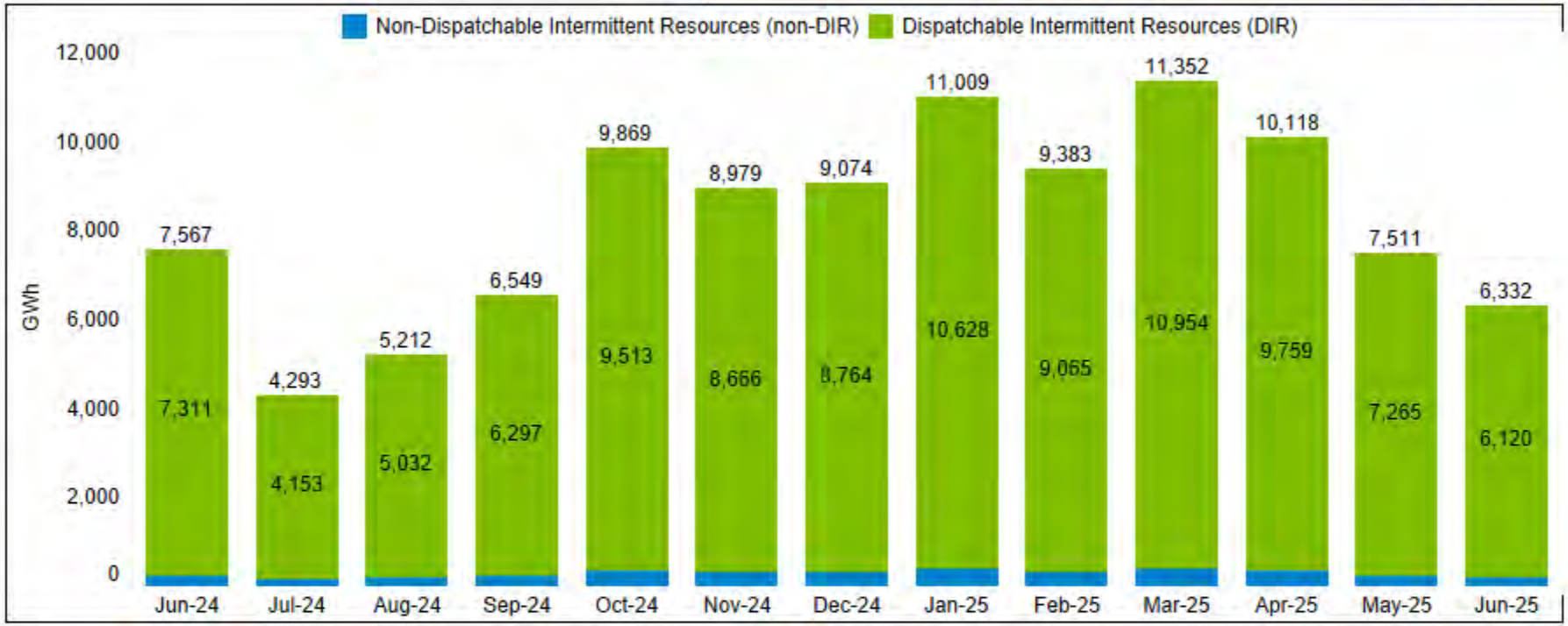
# Daily Day-Ahead Wind Forecast Performance: Mean Absolute Error (MAE) and Mean Absolute Percent Error (MAPE)




*Source: MISO Operations Risk Management*

# Monthly Wind Energy Generation

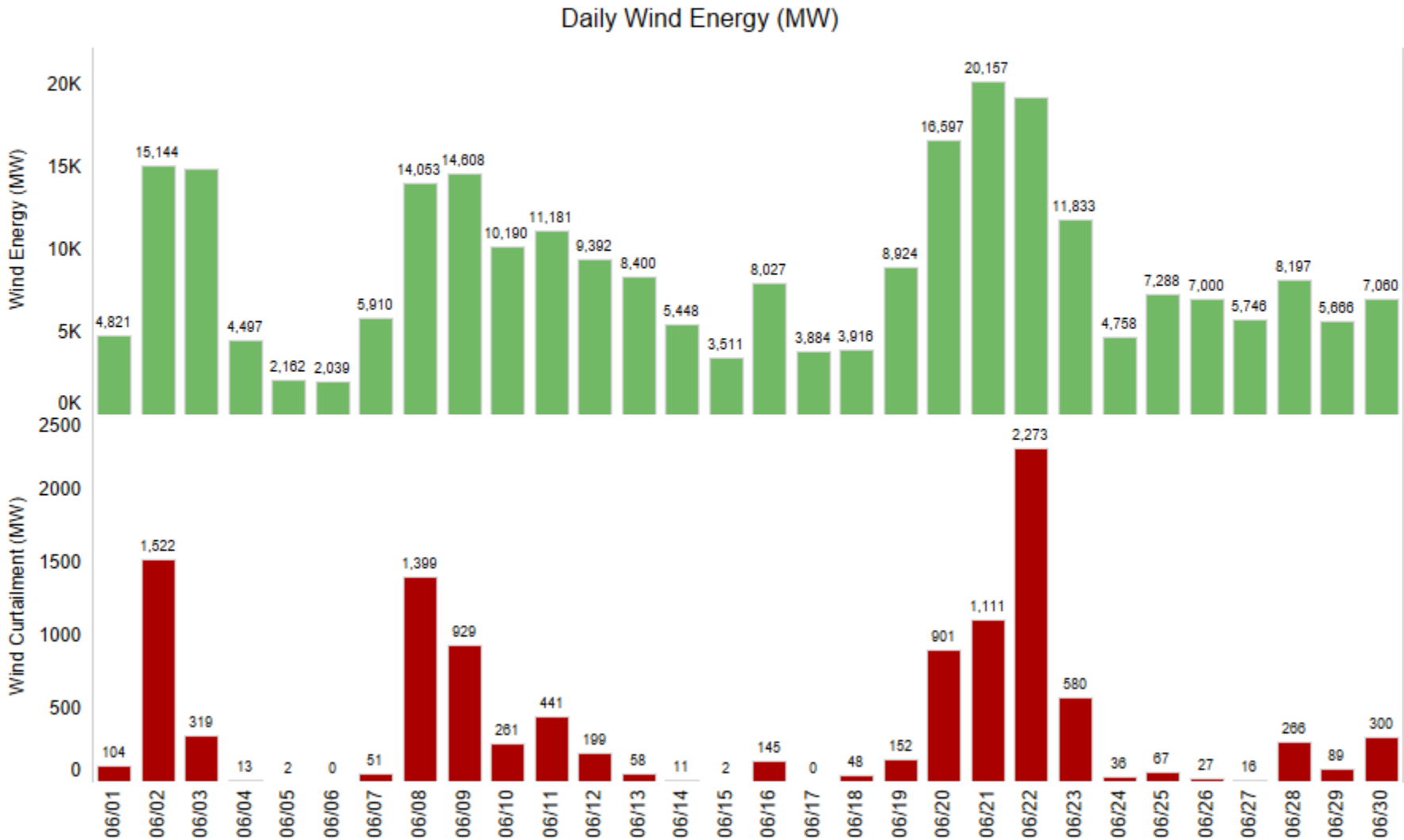
**As of 06/04/2025**
Registered Wind Capacity = 31,650 MW; Inservice Wind Capacity = 31,315 MW
Registered DIR Capacity = 30,122 MW; Inservice DIR Capacity = 29,787 MW




| | Jun-24 | Jul-24 | Aug-24 | Sep-24 | Oct-24 | Nov-24 | Dec-24 | Jan-25 | Feb-25 | Mar-25 | Apr-25 | May-25 | Jun-25 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Peak Wind Date and Hour Ending | 6/6 17 | 7/1 23 | 8/6 4 | 9/12 24 | 10/30 2 | 11/20 18 | 12/4 11 | 1/28 21 | 2/28 22 | 3/23 15 | 4/28 19 | 5/16 21 | 6/21 15 |
| Peak hourly wind output (MW) | 21,341 | 18,465 | 15,418 | 16,944 | 22,683 | 21,272 | 24,044 | 25,218 | 24,646 | 24,172 | 23,582 | 22,803 | 21,086 |
| Peak wind output as % of MISO load in that hour | 24.1% | 24.0% | 21.2% | 24.2% | 36.1% | 29.0% | 28.7% | 31.2% | 34.1% | 34.6% | 28.6% | 28.6% | 19.3% |
| Wind Energy as a percent of MISO Energy | 13.7% | 7.3% | 8.8% | 12.8% | 19.9% | 18.4% | 16.3% | 18.2% | 18.1% | 23.2% | 21.5% | 15.6% | 11.3% |
| DIR dispatch below Max as % of avail. DIR | 3.0% | 2.1% | 2.7% | 4.9% | 4.0% | 3.4% | 2.3% | 3.3% | 2.0% | 3.1% | 4.3% | 3.3% | 3.3% |

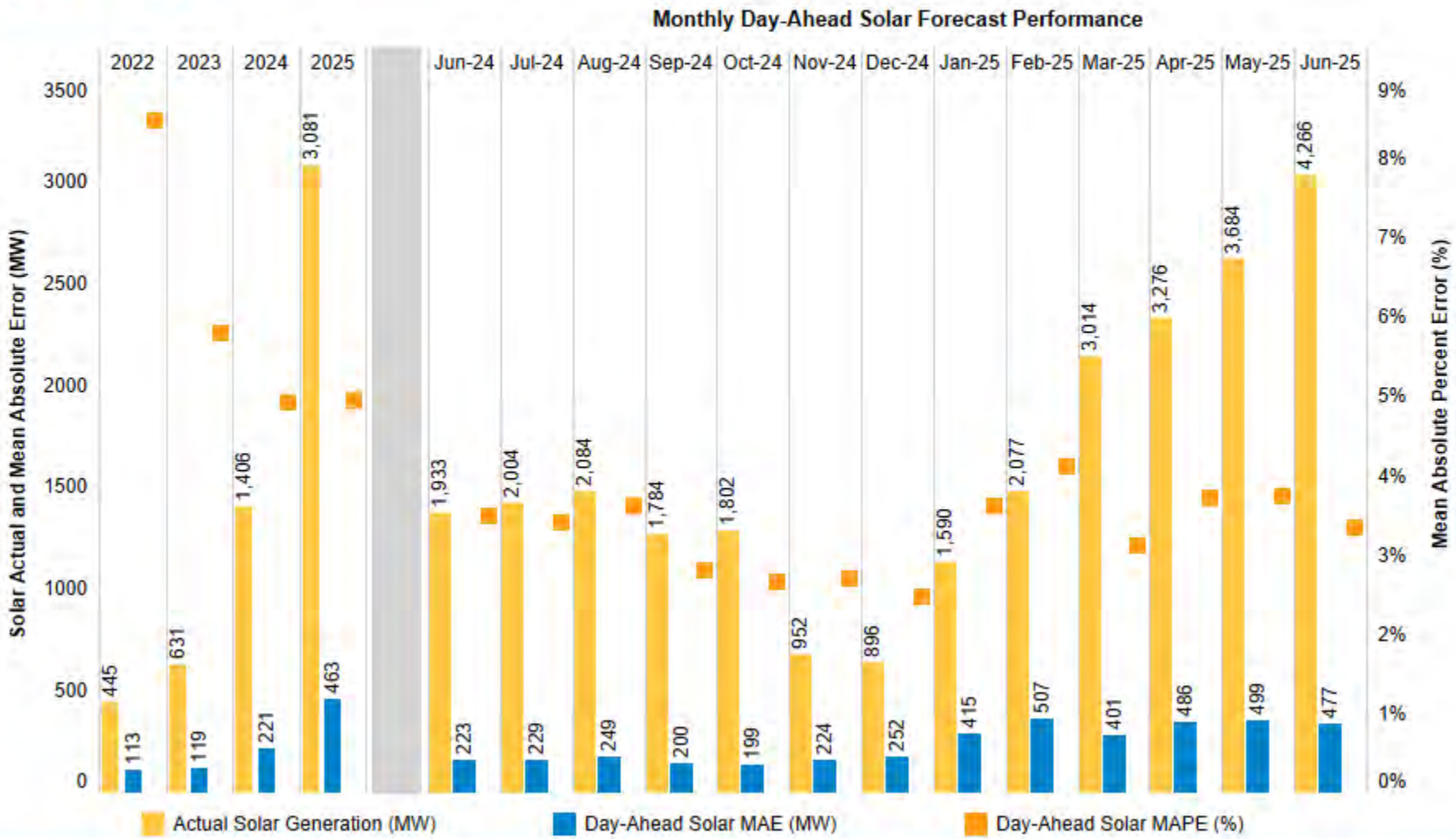
**Hourly State Estimator data*
*Source: MISO Market and Operations Analytics Department*

# Daily Average Wind Energy and Curtailment



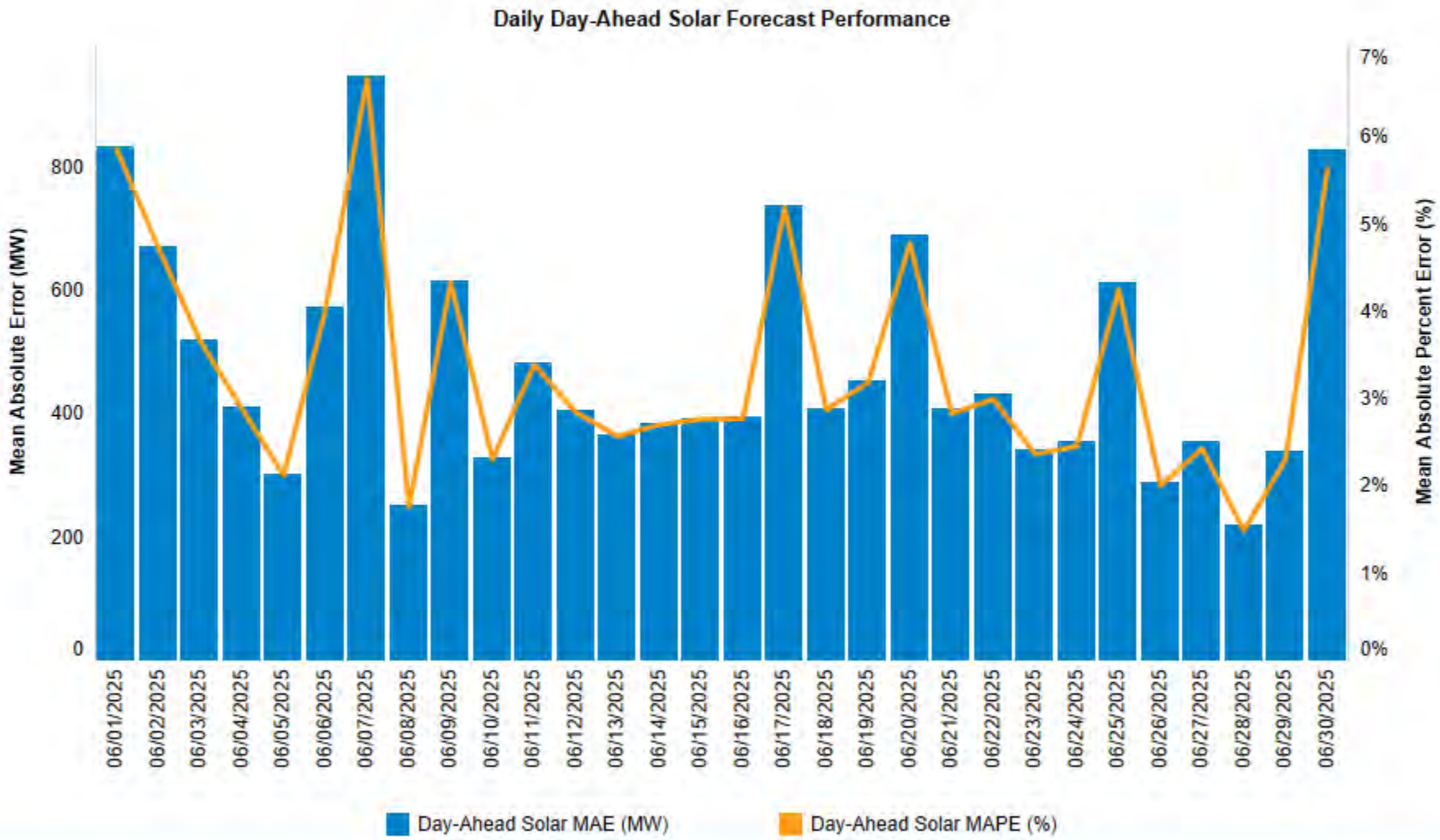

*Source: MISO Market and Operations Analytics Department*

# Monthly Day-Ahead Solar Forecast Performance: Mean Absolute Error (MAE) and Mean Absolute Percent Error (MAPE)




*Source: MISO Operations Risk Management*

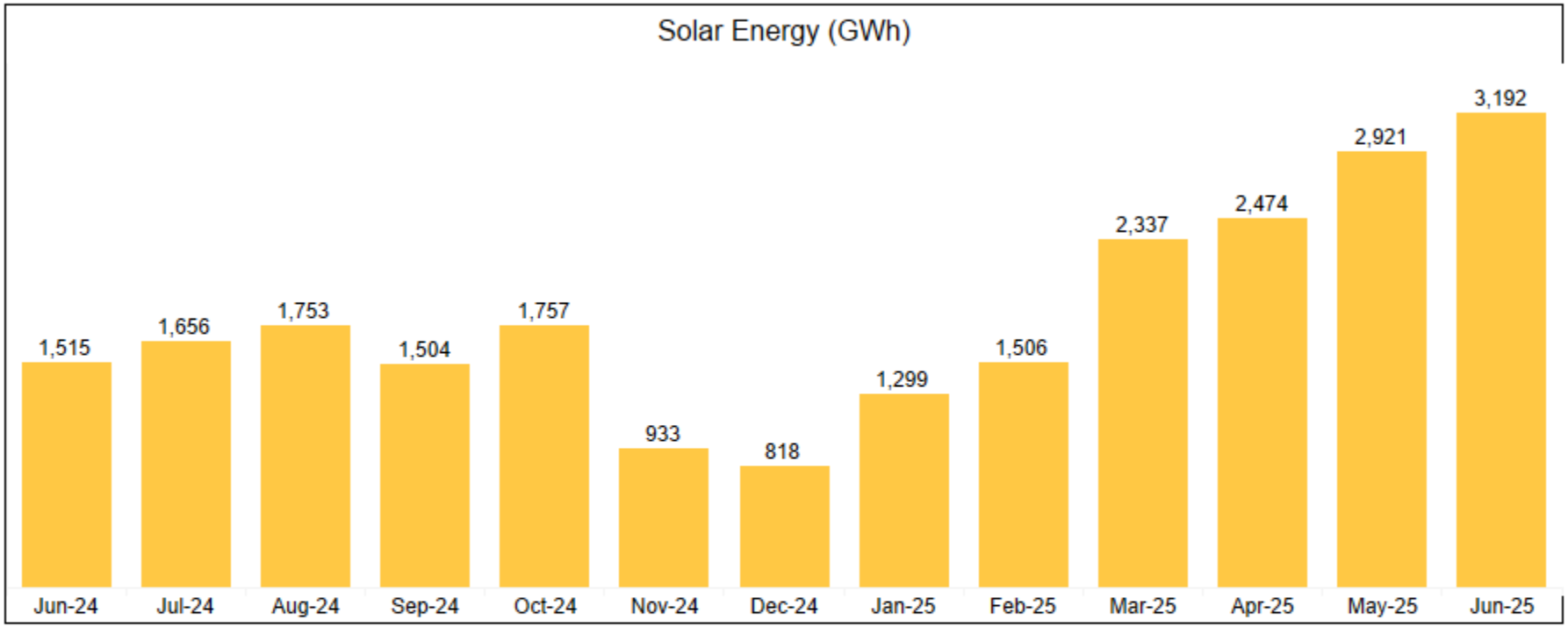
# Daily Day-Ahead Solar Forecast Performance: Mean Absolute Error (MAE) and Mean Absolute Percent Error (MAPE)




*Source: MISO Operations Risk Management*

# Monthly Solar Energy

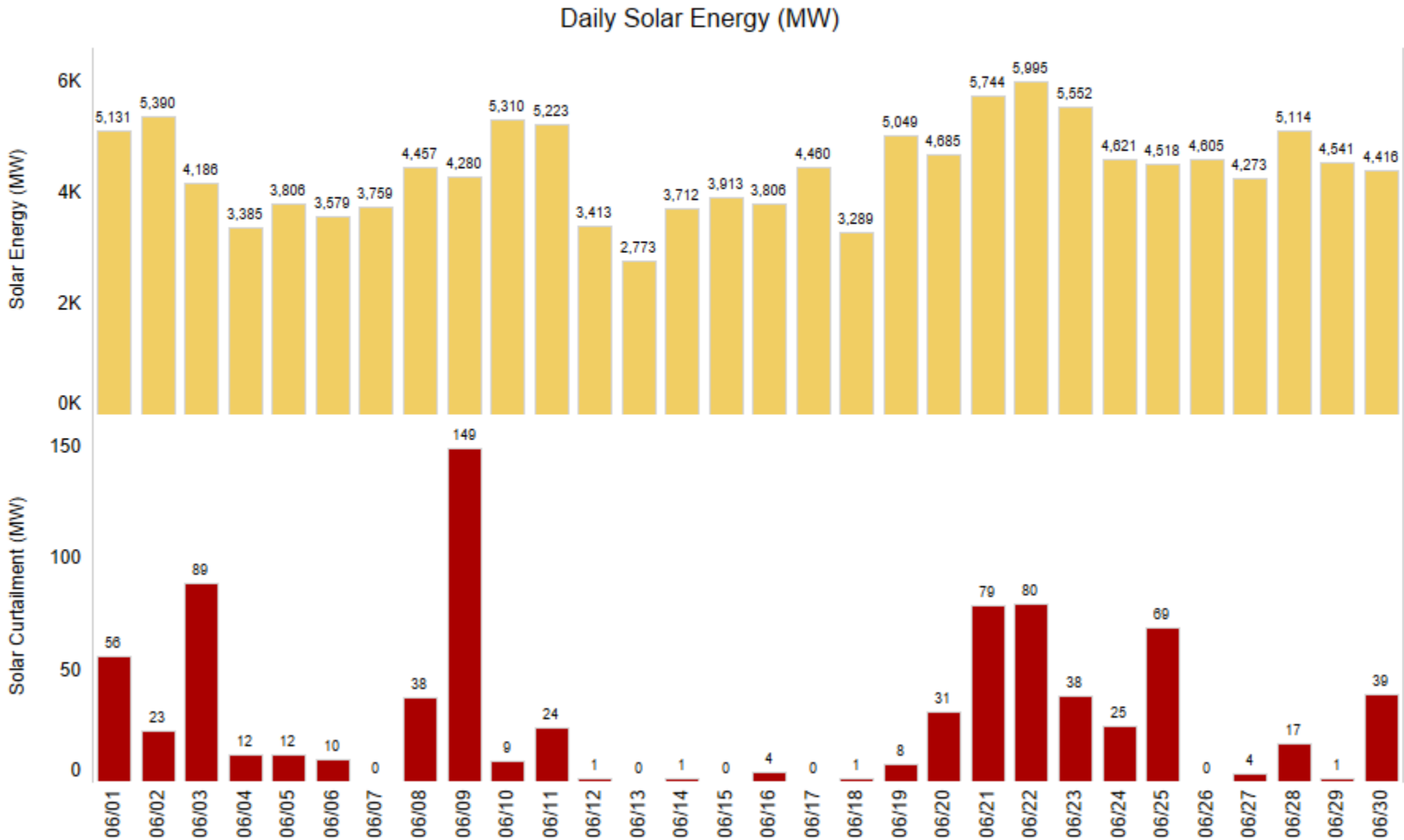
**As of 06/04/2025**
Registered Solar Capacity = 19,131 MW; Inservice Solar Capacity = 14,112 MW
Registered DIR Capacity = 18,959 MW; Inservice DIR Capacity = 13,940 MW




| Peak Solar Date and Hour Ending | Jun-24 | Jul-24 | Aug-24 | Sep-24 | Oct-24 | Nov-24 | Dec-24 | Jan-25 | Feb-25 | Mar-25 | Apr-25 | May-25 | Jun-25 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 6/14 11 | 7/13 12 | 8/22 12 | 9/26 12 | 10/16 16 | 11/12 16 | 12/21 12 | 1/20 12 | 2/21 12 | 3/22 15 | 4/16 14 | 5/31 13 | 6/22 11 |
| Peak Hour Solar Output (MW) | 6,016 | 6,168 | 6,835 | 7,054 | 7,919 | 6,813 | 6,898 | 8,308 | 11,360 | 12,061 | 12,342 | 13,366 | 12,872 |
| Peak Solar Output as a % of MISO Load in that hour | 6.9% | 6.5% | 8.3% | 9.1% | 11.5% | 9.6% | 8.7% | 8.4% | 12.4% | 18.8% | 18.0% | 19.2% | 12.9% |
| Solar Energy as a % of MISO Energy | 3.4% | 3.2% | 3.8% | 3.5% | 4.7% | 2.6% | 2.0% | 2.6% | 3.5% | 6.0% | 5.4% | 6.0% | 6.0% |
| DIR Dispatch below MAX as a % of avail. DIR | -0.1% | -0.5% | -0.5% | 0.4% | -0.3% | -0.6% | -3.1% | -1.9% | 0.1% | 1.1% | 0.5% | -0.1% | -0.1% |

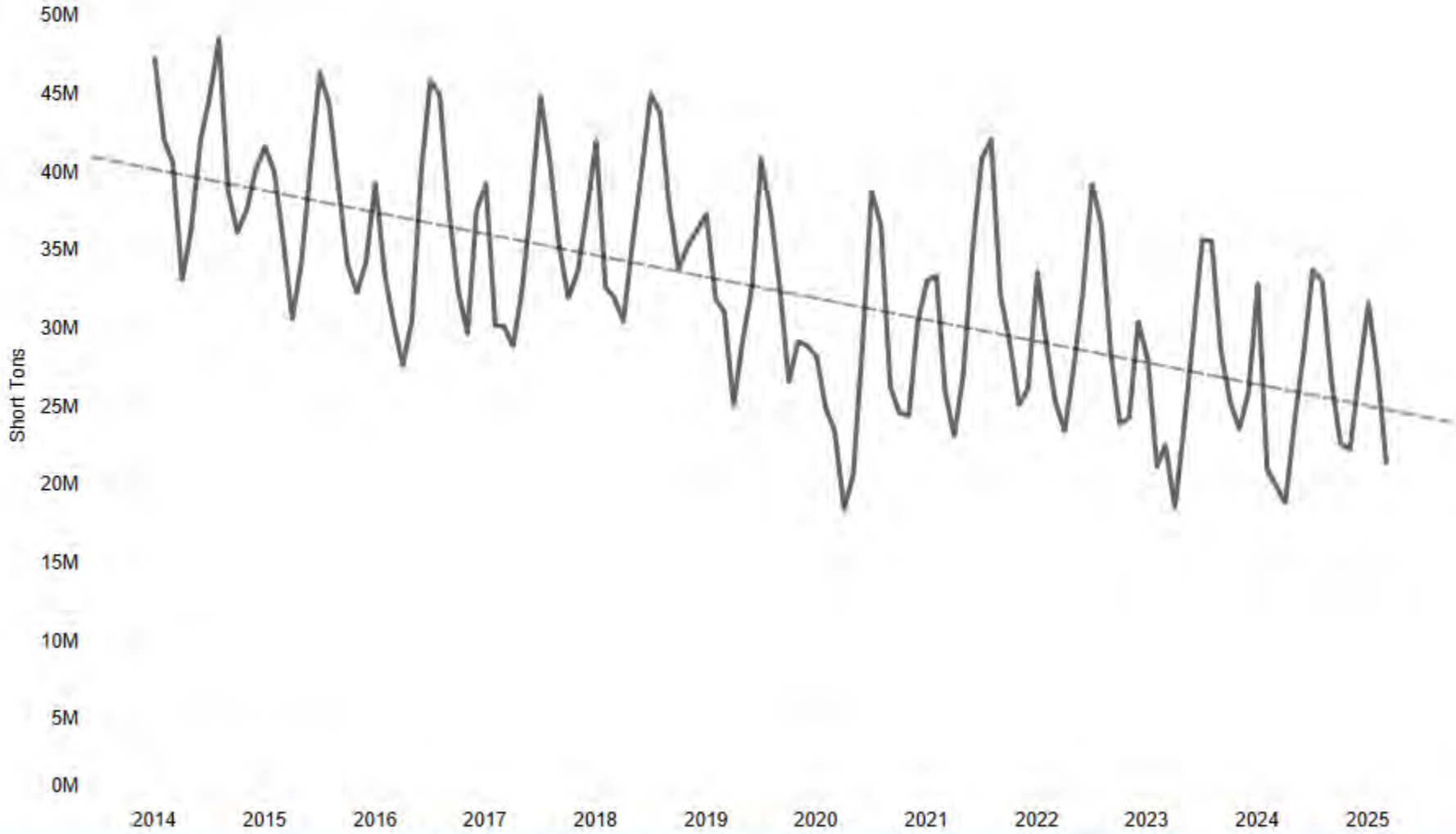
**Hourly State Estimator data*
*Source: MISO Forecast Department*

# Daily Average Solar Energy and Curtailment



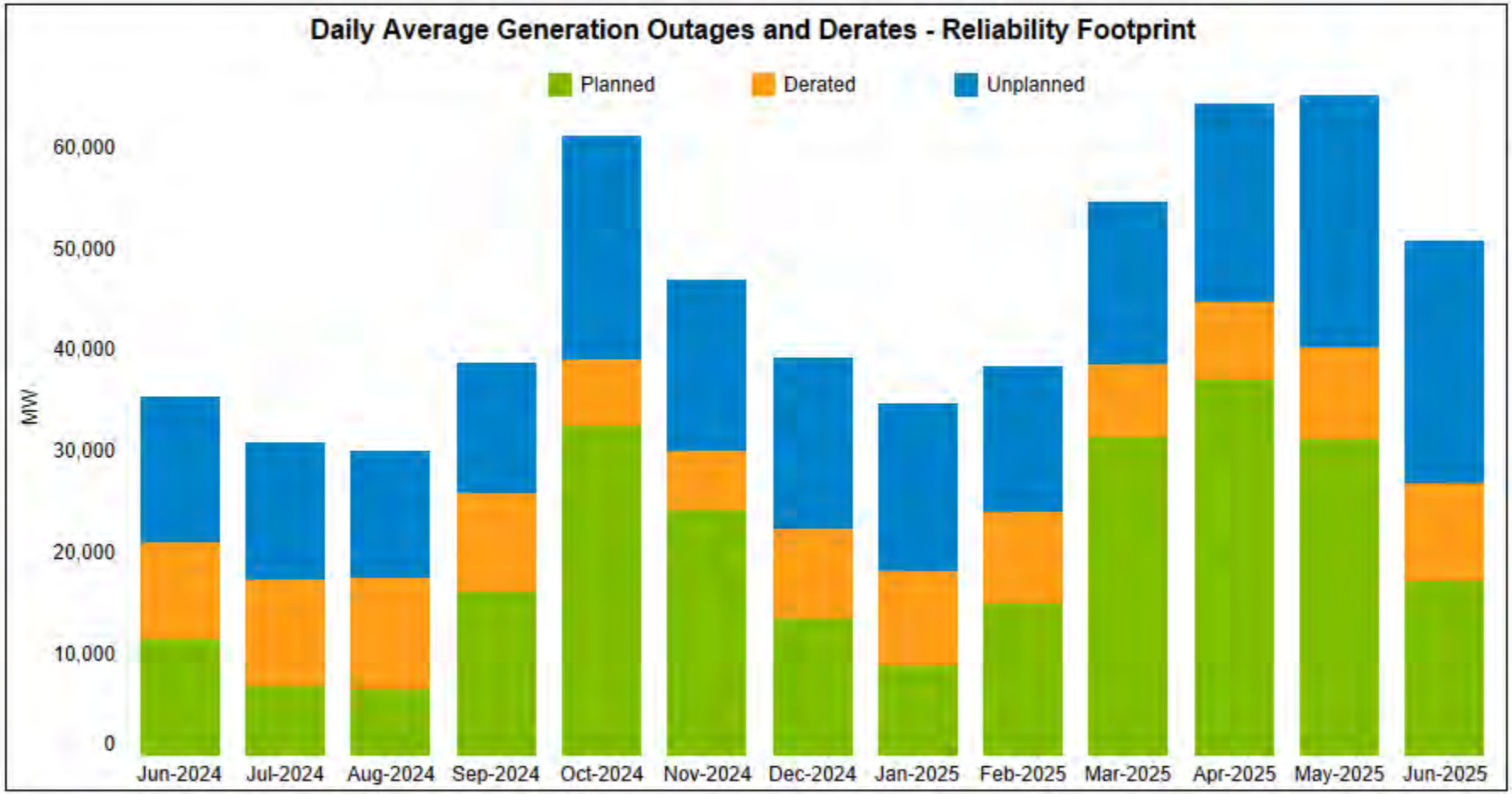

*Source: MISO Market and Operations Analytics Department*

# Carbon Emissions




*Data Source: EPA emissions through March 2025 and EPA EIA-860 2023*
*Emissions generated from MISO generators and does not account for volume of imports or exports*
*One Short Ton = 2000 lbs*

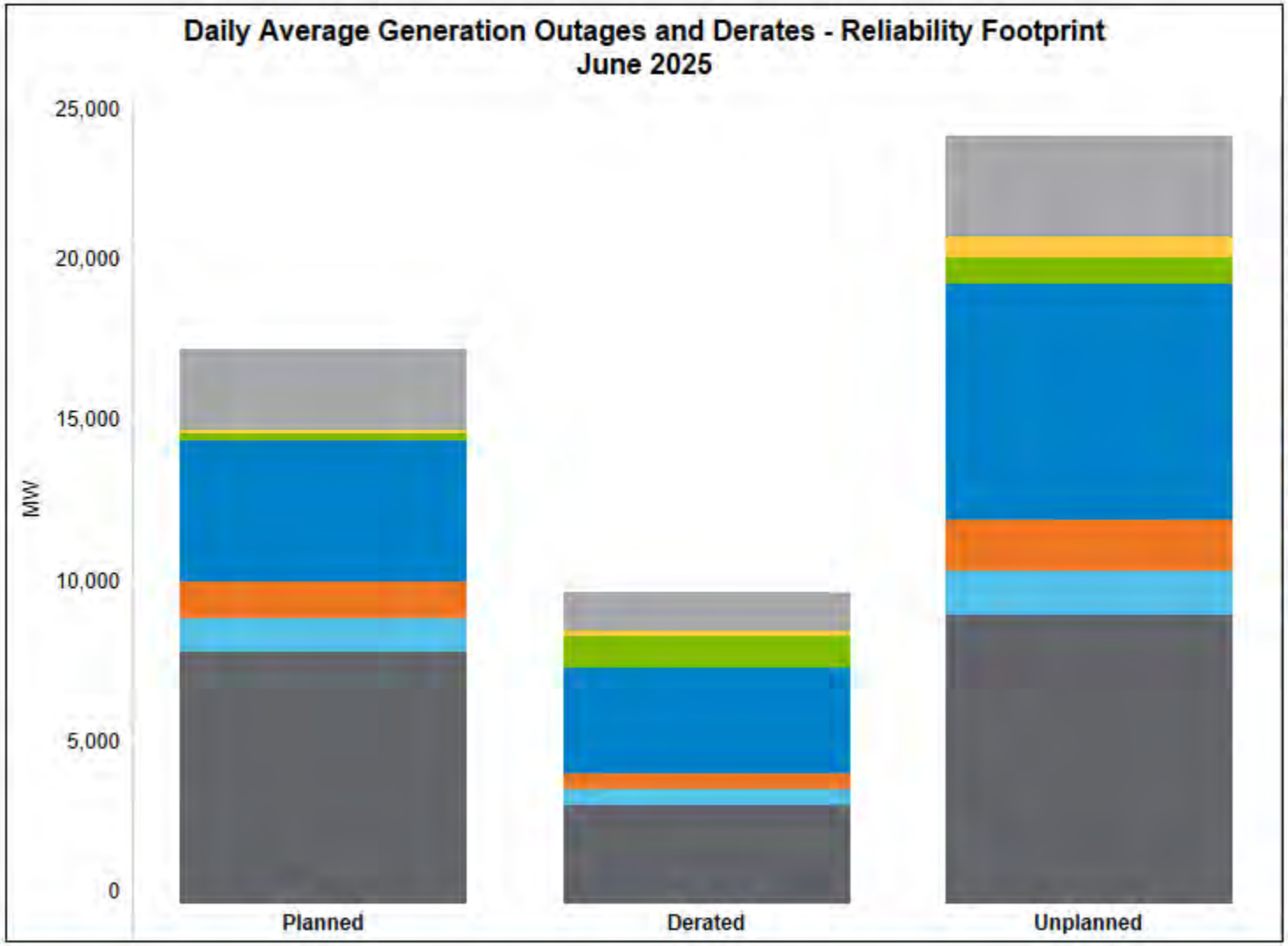
# Generation Outages and Derates




Notes:
- *Unplanned Outages include Emergency, Forced, and Urgent*
- *Planned Outages include Planned*
- *De-rates are based on limits observed in Real-Time and may not reflect normal seasonal de-rates or de-rates for maintenance or other operating conditions*

*Outage data is "point in time" and can change; the chart reflects the data as it resided in the system on the date of extraction*
*Source: MISO CROW Outage Scheduler*

# Generation Outages by Fuel

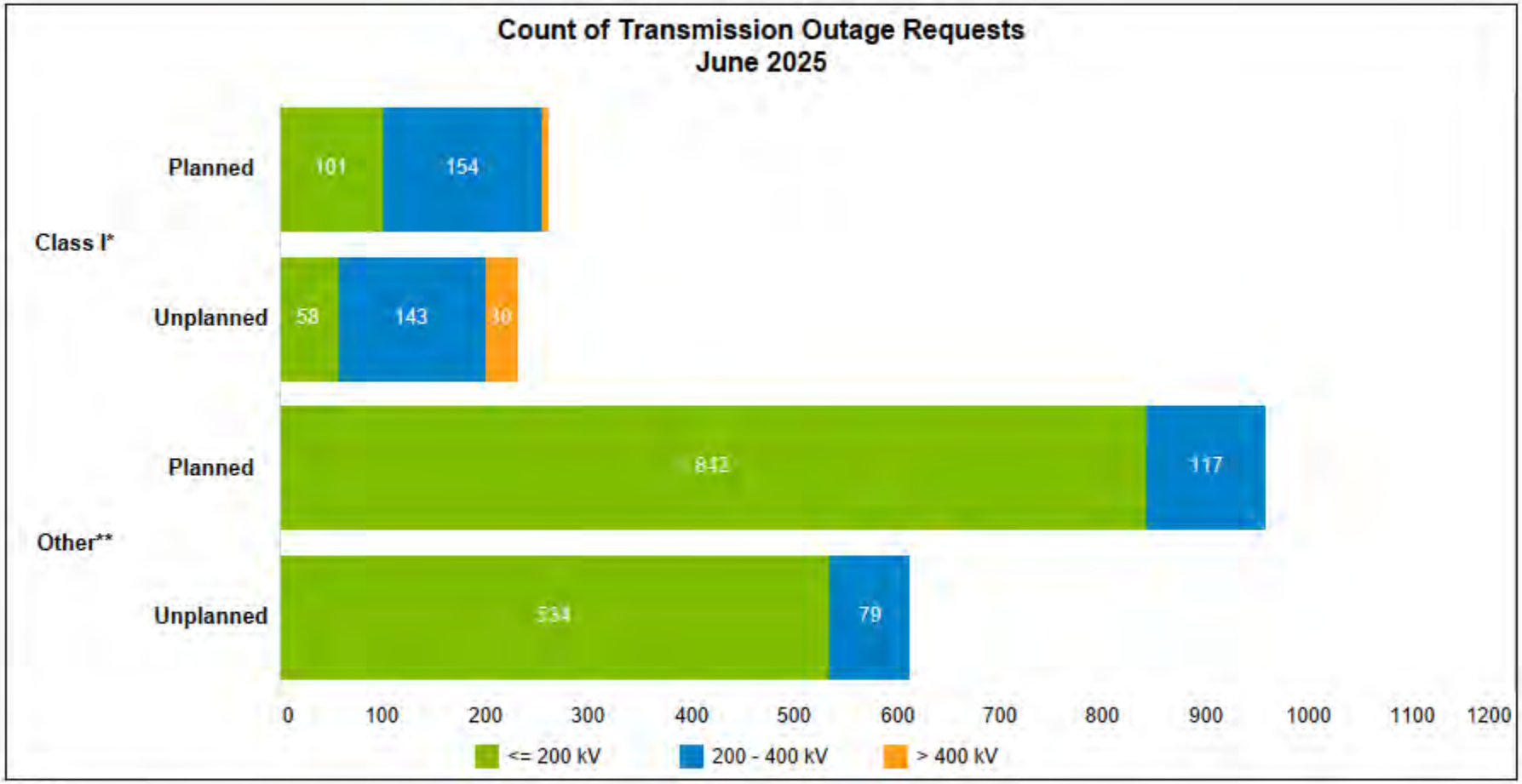



*Notes:*
- *Other includes Oil ,Hydro, Pet coke, Waste, BTMG, and units not in market footprint*
- *Unplanned Outages include Emergency, Forced, and Urgent*
- *Planned Outages include Planned*
- *De-rates are based on limits observed in Real-Time and may not reflect normal seasonal de-rates or de-rates for maintenance or other operating conditions*

Coal
Hydro
Nuclear
Gas
Wind
Solar
Other

*Outage data is "point in time" and can change; the chart reflects the data as it resided in the system on the date of extraction*
*Source: MISO CROW Outage Scheduler*

# Transmission Outages




Notes:
- *Class 1 is any facility which has a reliability or market impact on transmission system operations*
- *Other is any facility which does NOT have a reliability or market impact on transmission system operations*
- *Unplanned Outages include Emergency, Forced, Discretionary and Urgent*
- *Planned Outages include Planned, Opportunity*

*Outage data is "point in time" and can change; the chart reflects the data as it resided in the system on the date of extraction*
*Source: MISO CROW Outage Scheduler*

# MISO Inadvertent Balance

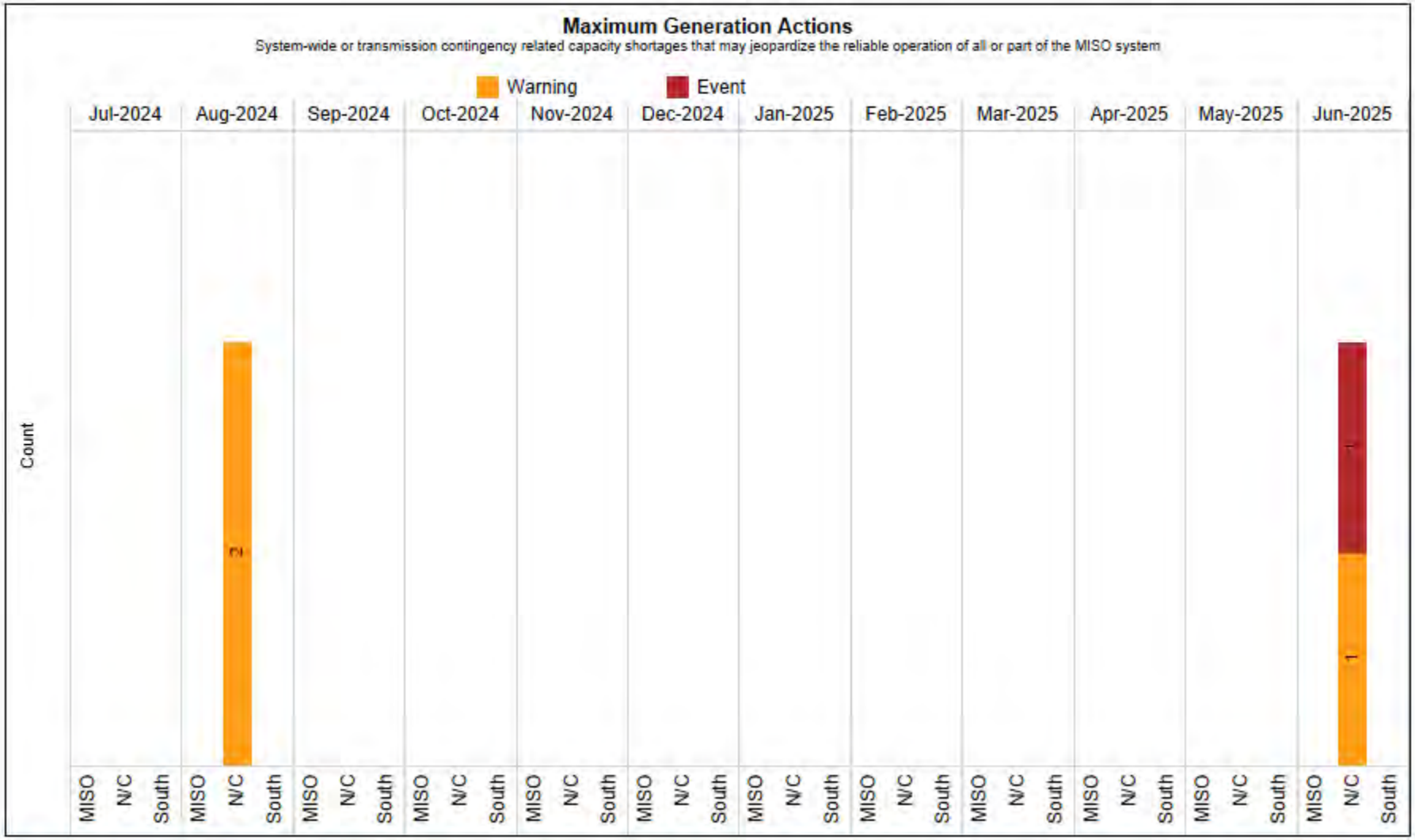
| Month/Year | Net | On-Peak | Off-Peak |
|---|---|---|---|
| 6/1/2024 | -21,123 | -10,382 | -10,741 |
| 7/1/2024 | -33,949 | -12,863 | -21,086 |
| 8/1/2024 | -39,602 | -15,448 | -24,154 |
| 9/1/2024 | -79,156 | -36,769 | -42,387 |
| 10/1/2024 | -37,833 | -17,446 | -20,387 |
| 11/1/2024 | -5,440 | -2,237 | -3,203 |
| 12/1/2024 | -1,006 | 624 | -1,630 |
| 1/1/2025 | 11,913 | 7,358 | 4,555 |
| 2/1/2025 | | | |
| 3/1/2025 | | | |
| 4/1/2025 | | | |
| 5/1/2025 | | | |
| 6/1/2025 | | | |
| Running Total from 2009 | -95,937 | -88,521 | -7,416 |

*Source: NERC Tool (As of May 10, 2025)*



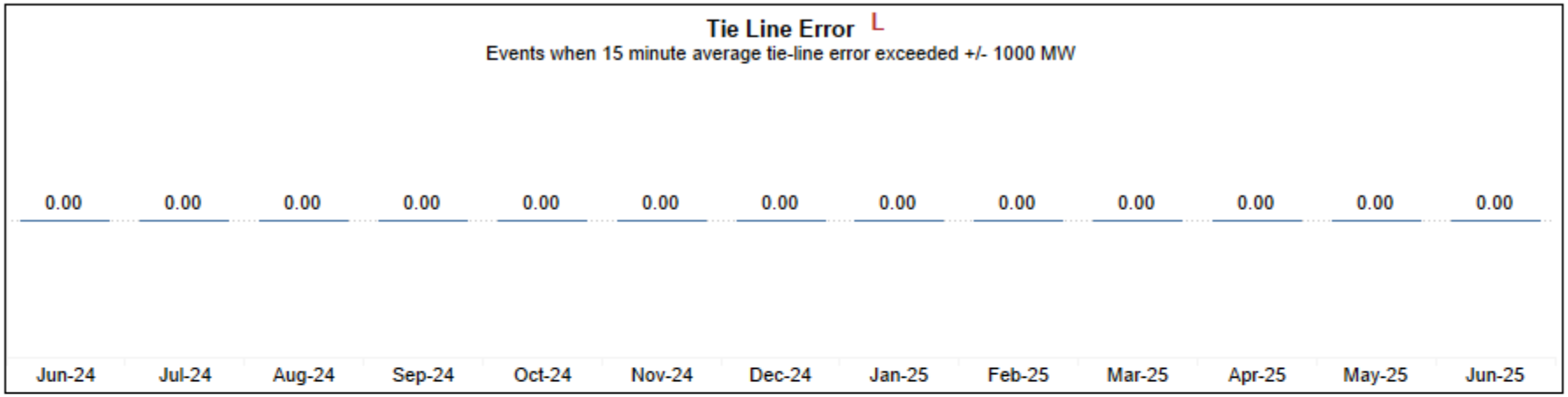
MISO

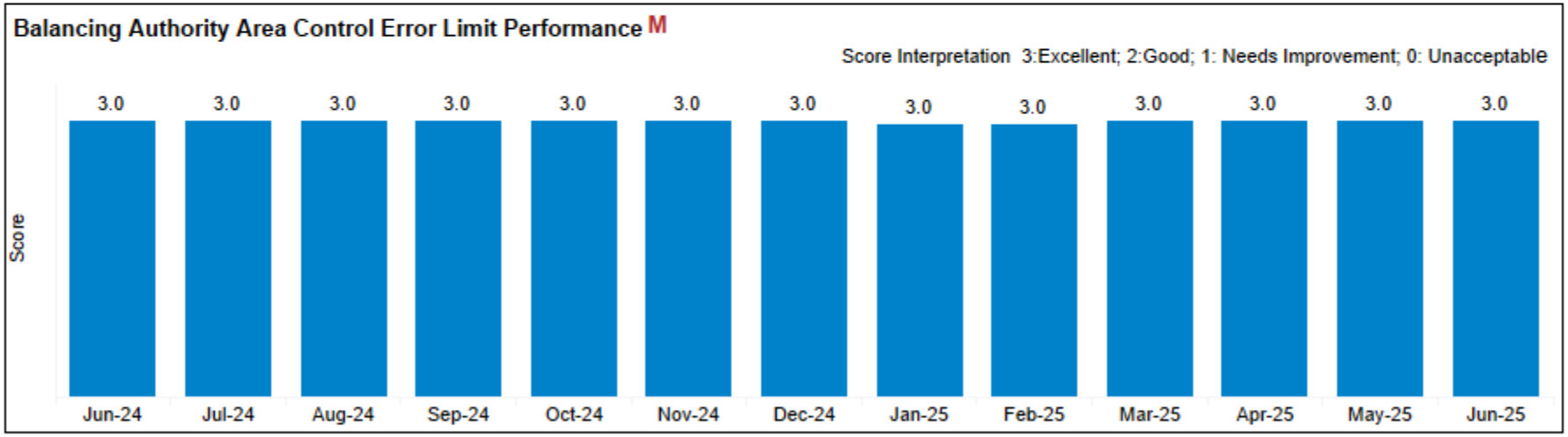
# Generation Notifications




* Alerts – forecasting specific emergency situations in a future time-frame
* Warnings – experiencing initial stages of an emergency situation and taking action
* Events – experiencing an emergency situation and taking action

# Tie Line and BAAL Performance



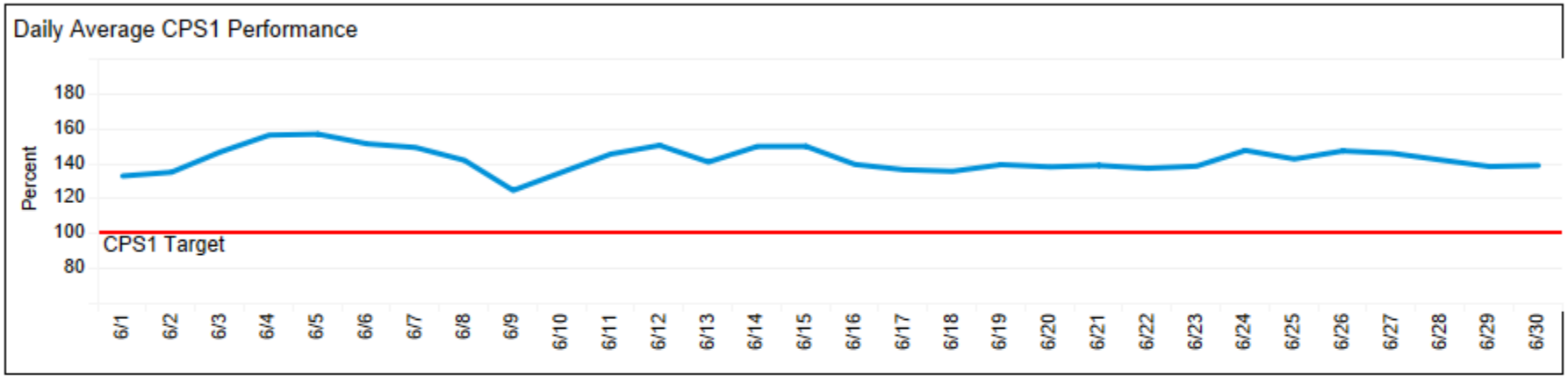

*The Balancing Authority Area Control Error Limit (BAAL) measures control performance over the short-term. Exceeding BAAL for a continuous time period greater than 30 minutes constitutes a non-compliant event. The daily MISO BAAL performance rating is the lowest scored incident of the day.*

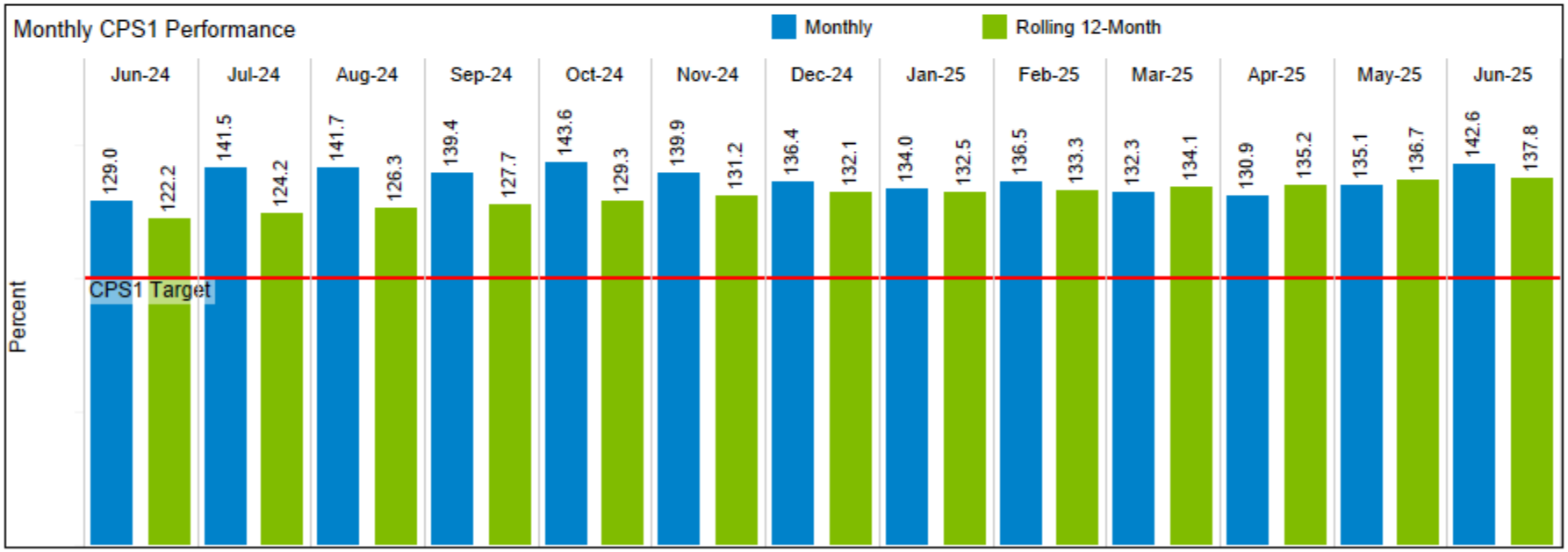


*Source: MISO Real-Time Operations Department*

# CPS1 Performance

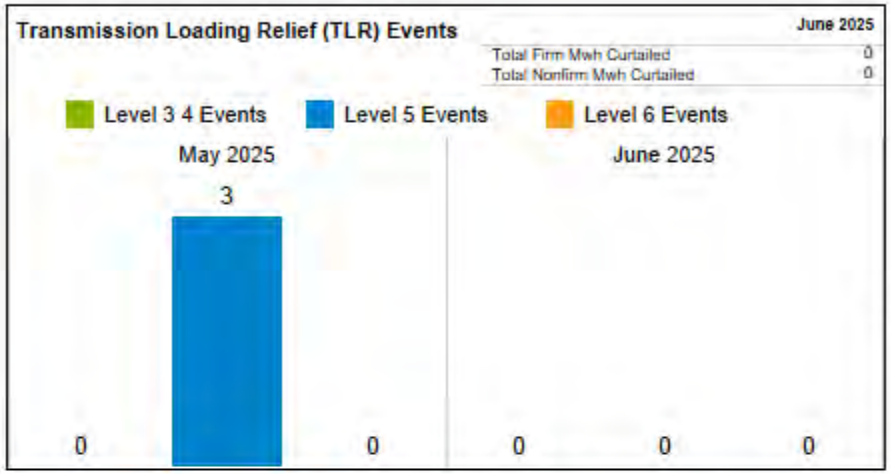
N

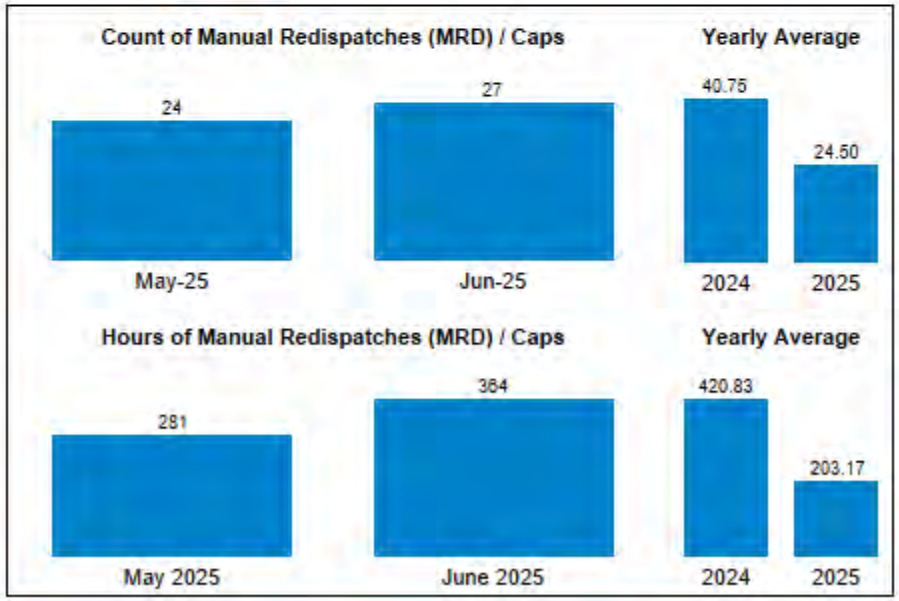


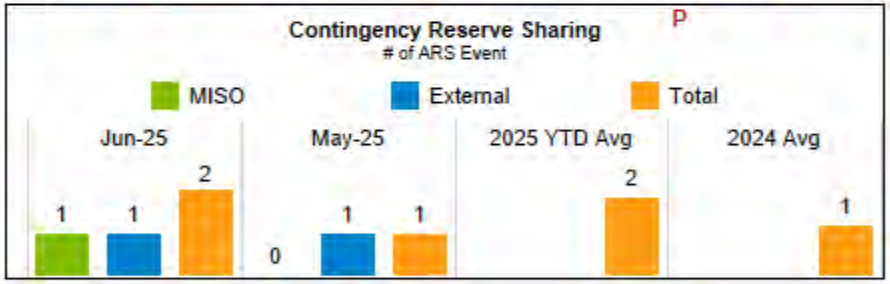




*Per NERC Standard BAL-001-0 and MISO OP-044, the MISO will monitor CPS 1 performance and implement actions to ensure the MISO's rolling 12-month CPS 1 performance exceeds 100%*
*Source: MISO Real-Time Operations Department*

# Reliability — Other Metrics





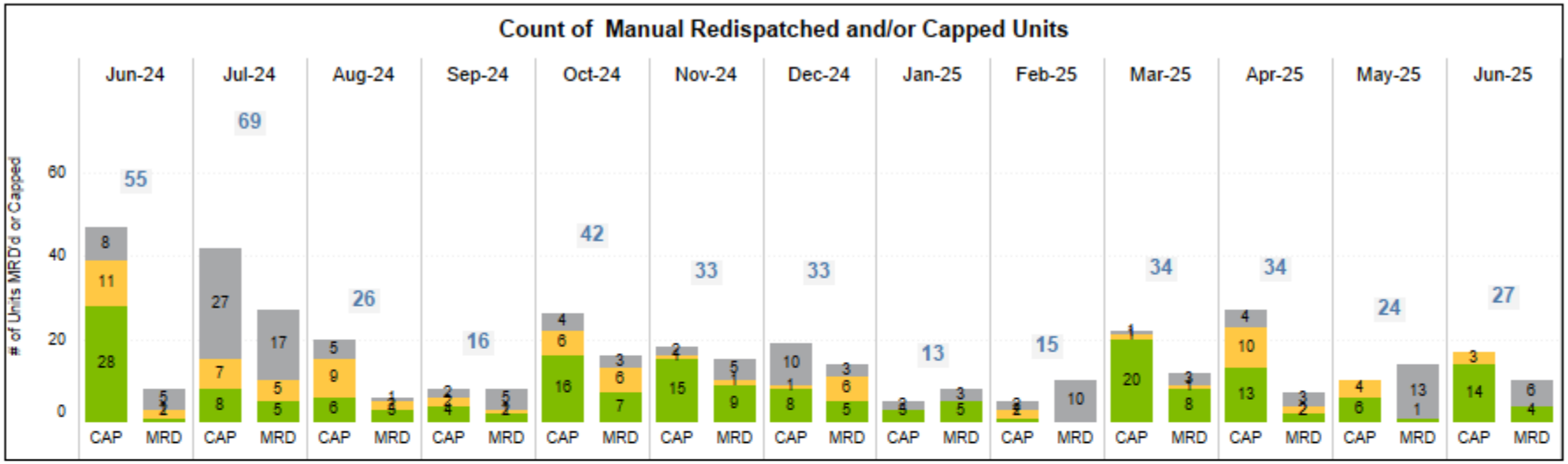

**MISO deployed Contingency Reserves ****

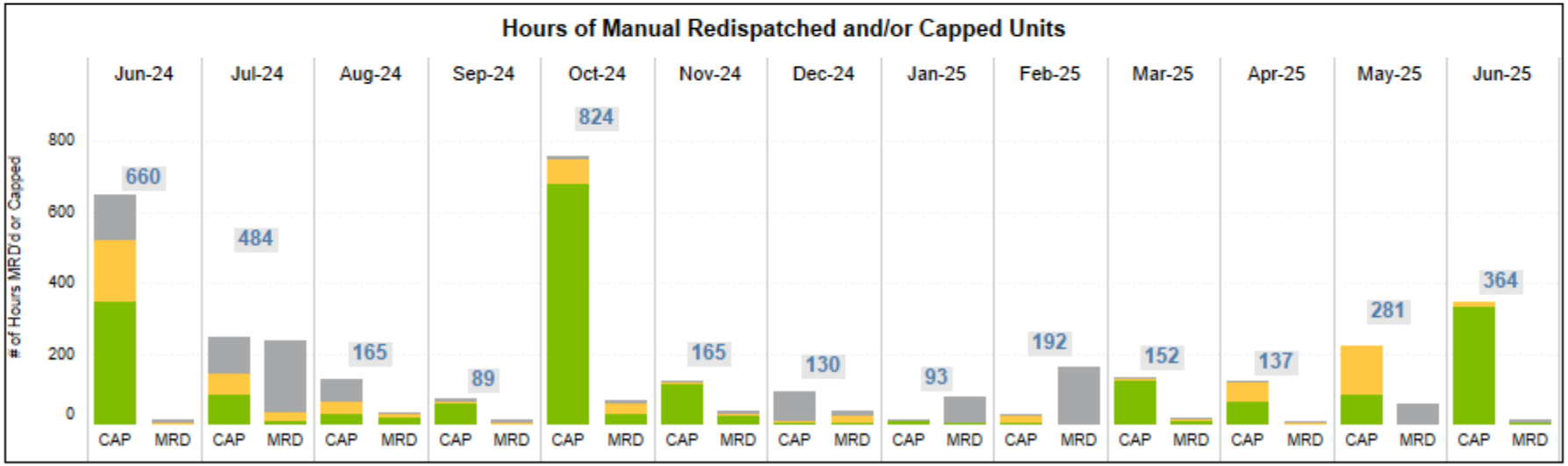
| Date | HE | Deployment Type | MW |
|---|---|---|---|
| 6/1/2025 | 19 | OFFLINE | 79 |
| | | ONLINE | 1,227 |
| 6/17/2025 | 5 | OFFLINE | 338 |
| | | ONLINE | 961 |
| 5/20/2025 | 9 | ONLINE | 512 |

*Source: MISO Real-Time Operations Department*

*Historical Contingency Deployment data located in *Related Documents* at https://cdn.misoenergy.org/202001-202103%20Additional%20Information%20Historical%20Contingency%20Deployment%20Data548321.pdf /

# Operator Actions - Manual Redispatch and Caps



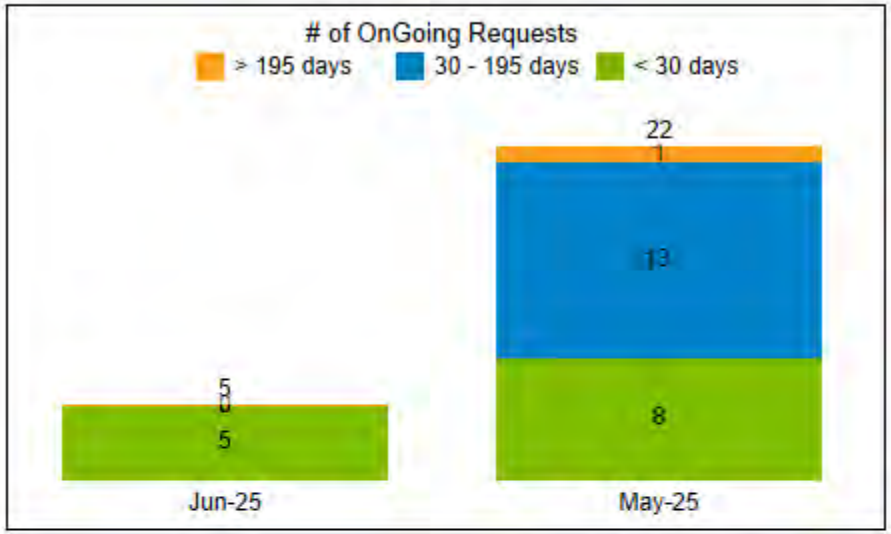



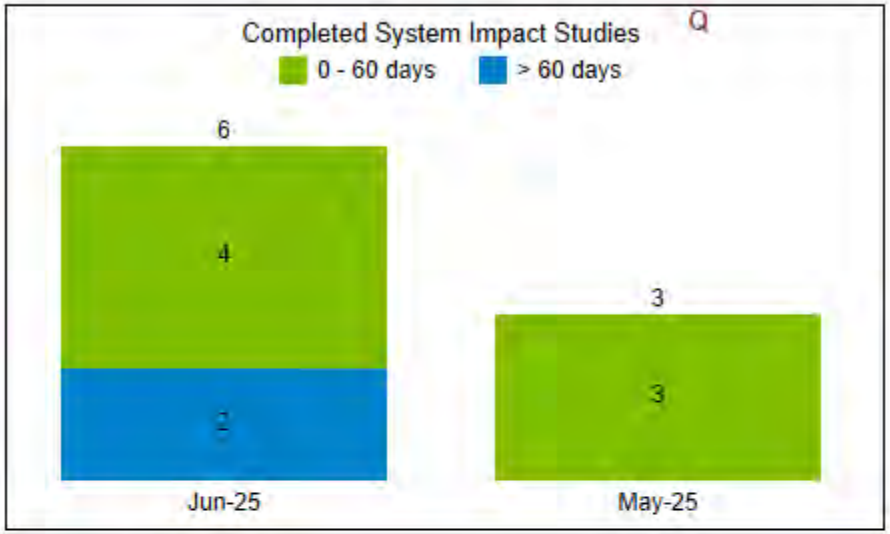

Wind Solar Non-Intermittent

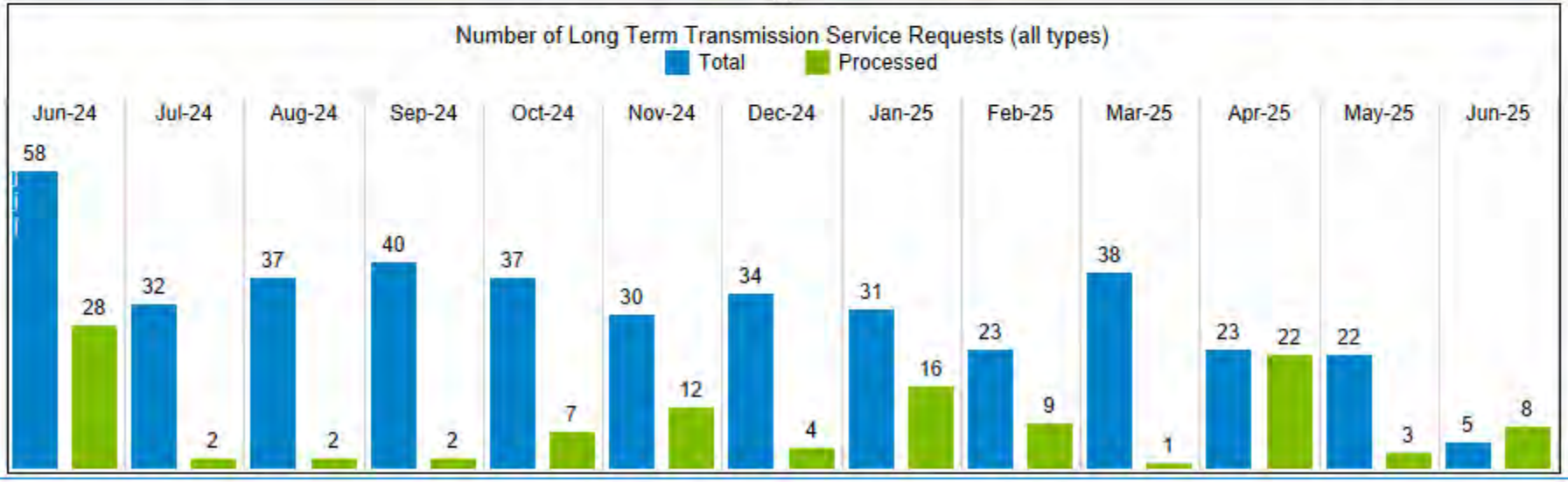


*Source: MISO Market and Operations Analytics Department*

# Transmission Service Request



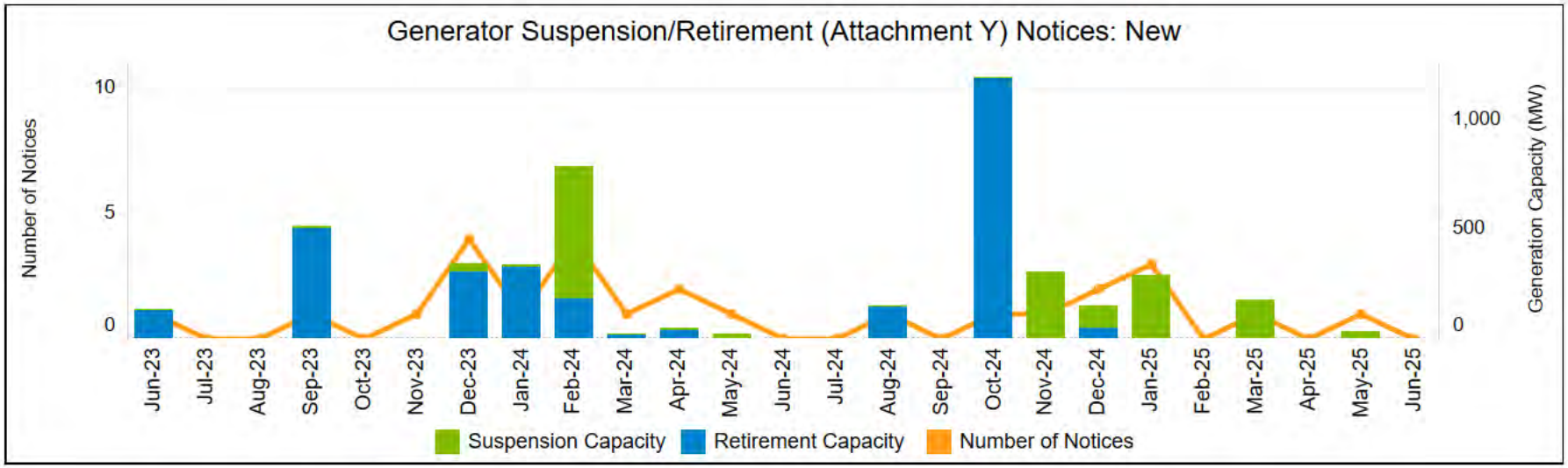



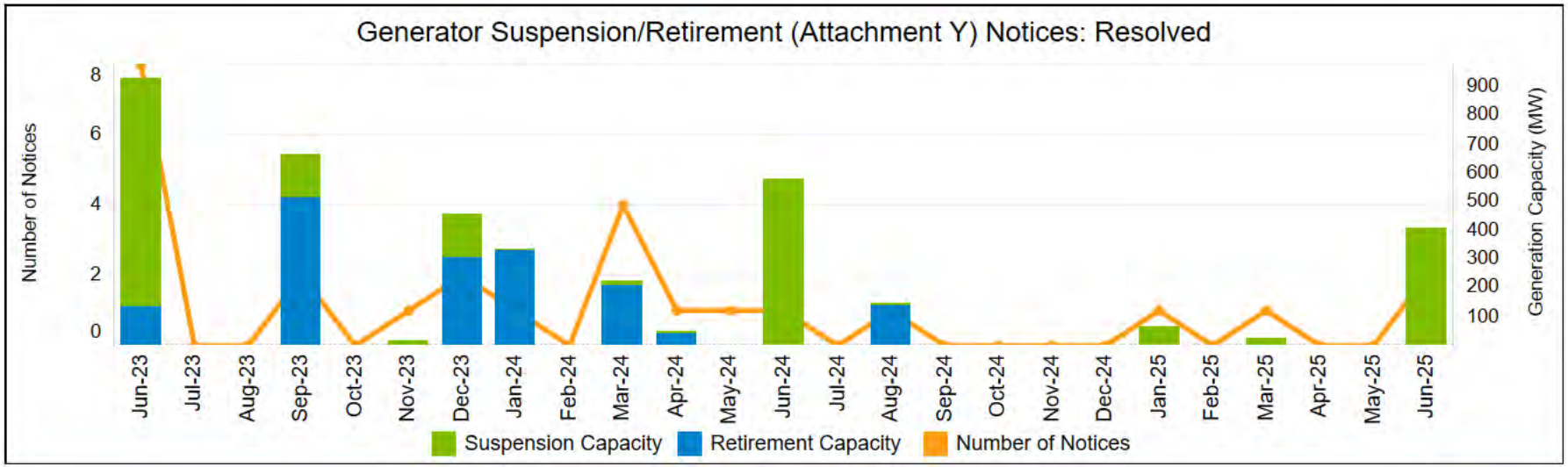




*Source: MISO Resource Utilization*

MISO

# Generator Suspension/Retirement - New and Resolved

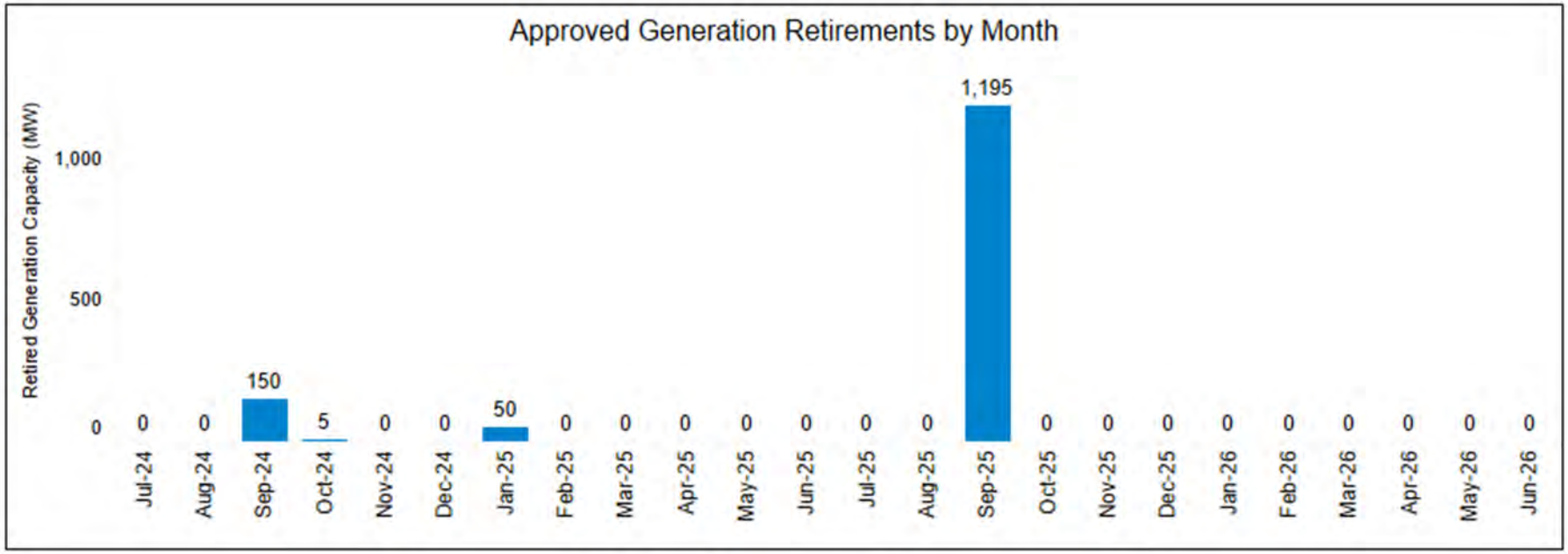


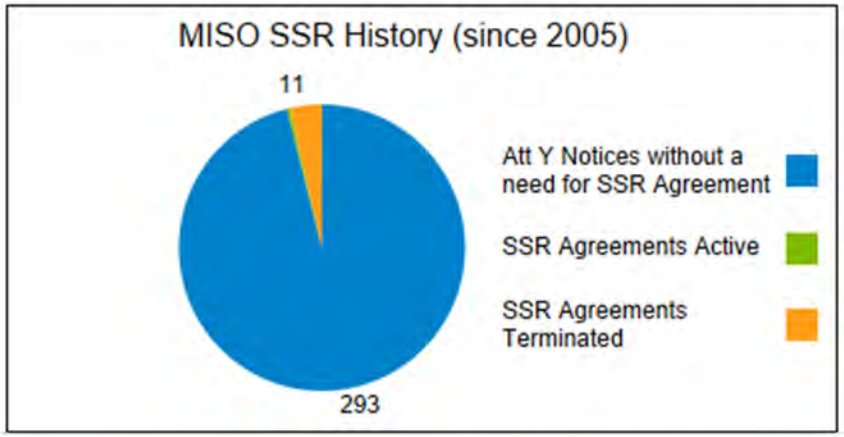




*Source: MISO Transmission Planning Department*

MISO

# Generator Suspension/Retirement - Overall

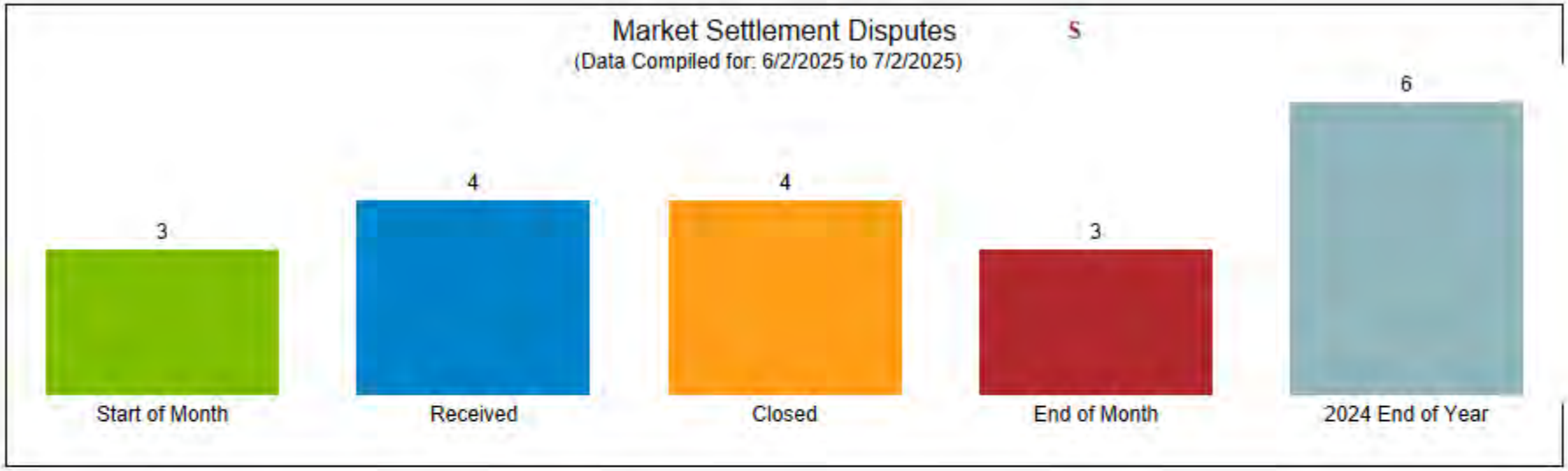


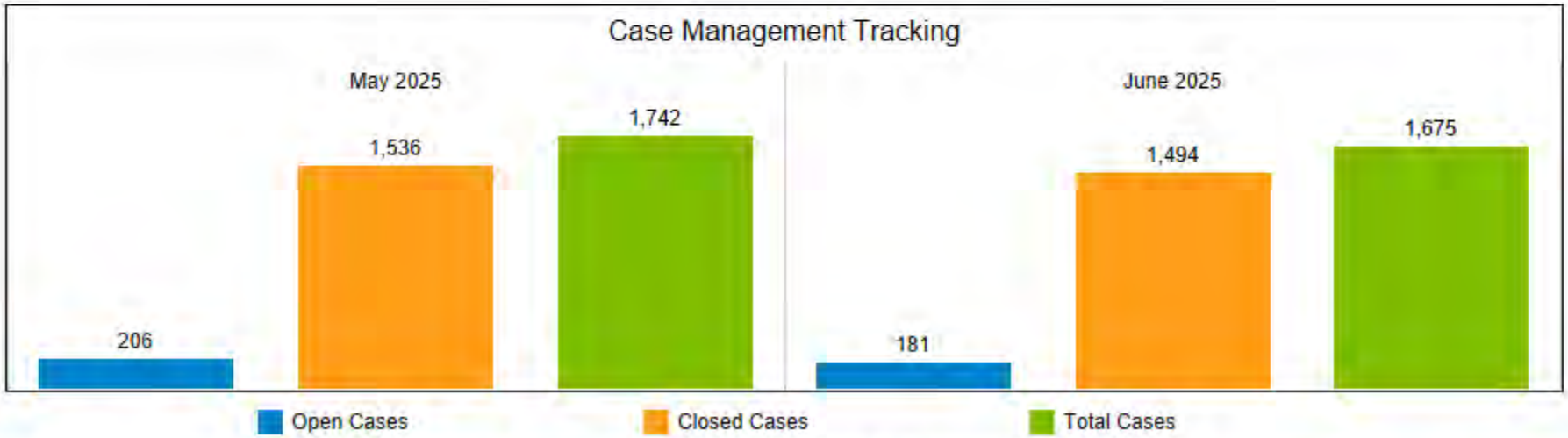




*Source - MISO Transmission Planning Department*

MISO

# Settlements/Client Services and Readiness




*Source: MISO Settlements and Client Services and Readiness Departments*
*Settlement values may change due to resettlement*
*Resource Adequacy, Tariff Pricing, Market Settlements, and Credit cases are included in Case Management Tracking data*

# MISO has set an even higher standard for its System Availability metrics in 2025, and while January and February had no downtime, a critical incident occurred in March that impacted STI

## January - April 2025

| Short-Term Incentive Metrics | JAN 25 | FEB 25 | MAR 25 | APR 25 | Trend * | YTD | Threshold \| Target \| Excellent |
|---|---|---|---|---|---|---|---|
| **Critical Systems Availability** (Downtime in Hours) | 0.0 | 0.0 | 1.5 | 0.0 | ↘ | **1.5** | 4 Hours \| 3 Hours \| 2 Hours |
| **Number of Critical System Incidents Exceeding 30 Minutes** | 0 | 0 | 1 | 0.0 | ↘ | **1** | 2 \| 1 \| 0 |

| Other Availability Metrics | JAN 25 | FEB 25 | MAR 25 | APR 25 | Trend * | Monthly Target |
|---|---|---|---|---|---|---|
| **ICCP**** (Availability %) | 100 | 100 | 100 | 100 | ↔ | 99.5 |
| **Customer Facing Applications – Portals** (Availability Index) | 10 | 10 | 10 | 10 | ↔ | 10 of 10 |
| **Markets** (Availability Index) | 4 | 4 | 4 | 4 | ↔ | 4 of 4 |
| **Reliability Targets** (Availability Index) | 3 | 3 | 3 | 3 | ↔ | 3 of 3 |

**Trend lines represent quarter-over-quarter performance*

***ICCP = Inter-Control Center Communications Protocol*

# 2025 Dashboard Metric Criteria (1 of 2)

**New or revised 2025 Metric;*

| Operational Excellence | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Metric | Chart | ● Expected | ■ Monitor | ▼ Review | Metric | Chart | ● Expected | ■ Monitor | ▼ Review |
| Percentage Price Deviation* | A | Absolute DA-RT price difference divided by DA LMP <=28.6% | Absolute DA-RT price difference divided by DA LMP is >28.6% but <=34.3% | Absolute DA-RT price difference divided by DA LMP >34.3% | Unit Commitment Efficiency* | H | >=93% | | <93% |
| Monthly Average Gross Virtual Profitability* | B | Within the standard deviation bands (threshold $0.44/MWh) | Outside the standard deviation bands | | Real-Time Obligation fulfilled by Day-Ahead Supply at the Peak Hour | I | >=95% | >=93% but <95% | <93% |
| FTR Funding | C | Monthly FTR Allocation % is >=92% and YTD FTR Allocation % is >=96% | Not in good status AND Monthly FTR Allocation % is >=87% AND Rolling 12-month FTR Allocation % is >=93% | Not in Good AND not in Monitor status | Day Ahead Wind Generation Forecast Error | K | # of days that the hourly average forecast error exceeds 10% <= 6 | # of days that the forecast error exceeds 10% >6 or Forecast error exceeds 15% in = 3 days | # of days that the forecast error exceeds 10% >8 or Forecast error exceeds 15% in > 3 days or Forecast error resulted in declaring 1 Real Time Event |
| Market Efficiency Metric | D | >= 95% | | <95% | Day Ahead Solar Generation Forecast Error | T | # of days that the hourly average forecast error exceeds 10% <= 6 | # of days that the forecast error exceeds 10% >6 or Forecast error exceeds 15% in = 3 days | # of days that the forecast error exceeds 10% >8 or Forecast error exceeds 15% in > 3 days or Forecast error resulted in declaring 1 Real Time Event |
| RSG per MWh to Energy Price* | E | <=0.38% | >0.38% and <=0.46% | >0.46% | Tie Line Error | L | <=1 | >1 but <=3 | >3 |
| Day Ahead Mid-Term Load Forecast** | F | # of days that forecast error exceeds 3% <=6 AND # days that forecast error exceeds 4% <=4 | # of days that forecast error exceeds 3% > 6 OR # days that forecast error exceeds 4%> 4 OR forecast error exceeds 6% on >= 1 day | # of days that forecast error exceeds 3% > 10 OR # days that forecast error exceeds 4%> 8 OR forecast error exceeds 7% on >= 1 day OR Forecast error resulted in declaring 1 Real Time Event | Control Performance – BAAL | M | Monthly performance score >=2 | Monthly performance score<2 but >=1 | Monthly performance score <1 |

*FTR YTD metric is applied beginning April*

*** Forecast errors observed in March, April, October and November will be measured by 1% lower thresholds*

# 2025 Dashboard Metric Criteria (2 of 2)

**New or revised 2025 Metric;*

| Operational Excellence | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Metric | Chart | ● Expected | ■ Monitor | ▼ Review | Metric | Chart | ● Expected | ■ Monitor | ▼ Review |
| Short-Term Load Forecast* | G | Forecast error exceeding the 95% percentile of forecast error for the past year <= 2 days | 3 days <= Forecast error exceeding the 95% percentile of forecast error for the past year <= 5 days | Forecast error exceeding the 95% percentile of forecast error for the past year > 5 days | Control Performance – CPS1 and CPS1 12-month rolling | N | >=100% | | <100% |
| | | | | | ARS Deployment | P | DCS monthly average % recovery (APR) = 100% | Analysis of event not yet complete | DCS monthly average % recovery (APR) confirmed <100% |
| **Customer Service** | | | | | | | | | |
| System Impact Study Performance | Q | Studies completed in less than 60 days >=85% | Studies completed in less than 60 days <85% but >=75% | Studies completed in less than 60 days <75% | Settlement Disputes | S | Increase of up to 20 disputes | Increase of between 20 and 50 disputes | Increase of more than 50 disputes |

*FTR YTD metric is applied beginning April*

*** Forecast errors observed in March, April, October and November will be measured by 1% lower thresholds*

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | |
|---|---|
| Federal Power Act Section 202(c) | ) |
| Emergency Order: Midcontinent | ) |
| Independent System Operator | ) |
| (MISO) | ) |
| | ) |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

# Exhibit 112

# Witmeier 2024 Queue Cap Testimony

TAB A

**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

| | | |
|---|---|---|
| **Midcontinent Independent System Operator, Inc.** | **)**<br>**)** | **Docket No. ER25-___-000** |

# PREPARED DIRECT TESTIMONY OF ANDREW WITMEIER

## ON BEHALF OF THE MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.

**November 21, 2024**

**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

| | | |
|---|---|---|
| **Midcontinent Independent System Operator, Inc.** | **)**<br>**)** | **Docket No. ER25-___-000** |

**PREPARED DIRECT TESTIMONY OF**
**ANDREW WITMEIER**

## I. PROFESSIONAL BACKGROUND AND QUALIFICATIONS

**Q. PLEASE STATE YOUR NAME, CURRENT POSITION AND YOUR BUSINESS ADDRESS.**

**A.** My name is Andrew Witmeier. I am the Director of Resource Utilization for the Midcontinent Independent System Operator, Inc. ("MISO"). My business address is: 720 City Center Drive, Carmel, IN 46032-7574.

**Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.**

**A**. I joined MISO in 2003 after graduating from Purdue University with a bachelor's degree in electrical engineering. I spent the first 17 years of my career in various positions in MISO Operations. During that time, I worked as a North American Electric Reliability Corporation ("NERC") certified system operator in scheduling, engineering, and as a reliability coordinator. I also led several groups within MISO Operations as a manager in engineering, reliability coordination, and seams administration. In January 2020, I was appointed to my current position.

**Q. PLEASE DESCRIBE YOUR JOB RESPONSIBILITIES WITH MISO AS THEY RELATE TO THIS FILING.**

**A.** As the Director of Resource Utilization, I am responsible for the administration of MISO's Generator Interconnection Procedures ("GIP"), which are set forth in Attachment X of MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff" or "MISO Tariff").[1] I oversee MISO's generation interconnection queue, including the negotiation and execution of Generator Interconnection Agreements ("GIAs"), which are based on MISO's *pro forma* GIA set forth in Appendix 6 of the GIP. I also oversee the group that manages and processes generation retirement, generator replacement, and Surplus Interconnection Service requests for generators connected to MISO's Transmission System. I have been directly involved in the preparation and development of the current proposals.

**Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN REGULATORY PROCEEDINGS?**

**A.** Yes. I submitted testimony at the Federal Energy Regulatory Commission ("FERC" or "Commission") in Docket No. ER22-661-000 on issues related to MISO's generator queue reform and resource utilization and Docket Nos. ER24-340-000 and ER24-341-000 on additional issues related to MISO's generator queue reform and management.

## II. OVERVIEW AND PURPOSE OF TESTIMONY

**Q. ARE YOU SUBMITTING YOUR TESTIMONY ON BEHALF OF MISO?**

**A.** Yes.

---

[1] Unless otherwise indicated in my Testimony, all capitalized terms used herein have the meaning as set forth in the Tariff or the proposed Tariff revisions, as applicable.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

**A**. My testimony supports the updated Tariff revisions that MISO is submitting in this docket to refile certain urgent quantity improvements to the GIP. As further discussed below, MISO's filing in this docket contains two severable proposals. While these proposals are separate from each other, both should be implemented as soon as possible to ensure that MISO's generator interconnection queue can continue to operate in a just and reasonable manner in the face of severe challenges precipitated by an ongoing and unprecedented increase in the number and volume of Interconnection Requests in MISO. The proposed changes will make MISO's administration of the queue more efficient and will improve MISO's compliance with the GIP timing requirements.

**Q. HOW WAS THIS NEW PROPOSAL DEVELOPED?**

**A.** MISO developed this updated proposal through a broad and inclusive stakeholder process. This filing incorporates the extensive stakeholder input we received in the past several months and reflects the lessons we learned from our previous queue reform efforts, including the Commission's guidance in Docket No. ER24-341-000. As discussed in more detail below, we have addressed the specific suggestions and concerns identified in the guidance order and have provided extensive opportunities for all interested parties to comment during the stakeholder review process. The final proposal that MISO is submitting today incorporates many of the comments and recommendations we have received in the process.

**Q. HOW IS THIS FILING DIFFERENT FROM THE NOVEMBER 2023 CAP PROPOSAL?**

**A.** MISO adjusted the formula for determining the cap, how exemptions will fit within the cap structure, and the types of exemptions presented in the current filing. With respect to the cap formula, the current proposal responds to the Commission's directives and opts for a more balanced, much simpler approach that relies on the MTEP power flow model to run the interconnection studies as the basis for the cap formula. The proposed cap formula will be 50% of the non-coincident summer peak values for each study region from the power flow model that will be used to perform the queue studies.[2] This percentage was chosen based on analysis performed by MISO that showed when queue volumes continue to rise above 50%, more Network Upgrades are required to mitigate congestion caused by new Interconnection Requests, offsetting substantially more existing generation. The purpose of a cap is to establish a more realistic dispatch that includes existing generation with new Interconnection Requests. This improved dispatch should result in less Network Upgrades, which reduces costs and reduces the need for additional facility studies and should therefore lead to faster processing and less dropouts. In light of the Commission's Order in Docket Nos. ER24-340-000 and ER24-341-000, MISO significantly modified the exemptions from its prior proposal. First, MISO removed the RERRA exemption. After special consideration of the comments and concerns brought forth by stakeholders and the Commission and the unique needs of RERRAs, MISO has committed to address RERRAs

[2] *Queue Improvements Cap Proposal* (October 16, 2024), https://cdn.misoenergy.org/20241016%20PAC%20Item%2006b%20Cap%20Proposal%20(PAC-2023-1)653144.pdf.

in a separate, newly proposed Expedited Resource Adequacy Study ("ERAS") process.[3] This new process will expedite the approval process of new generation needed to address state resource adequacy goals.[4] Second, addressing the Commission's earlier concerns regarding uncapped exemptions, MISO updated its queue cap formula to note that approved exemptions will be included in the number of Interconnection Requests needed to reach the 50% cap number. Put another way, approved exemptions will count towards the total MW queue cap of a given region. Third, any exemption must be elected at the time the interconnection application is submitted. This ensures the efficient implementation of the processing of the exemptions, less volatility in establishing the queue cap, and increases the levels of communication between MISO and stakeholders regarding when the queue cap is met. Finally, MISO is modifying the Provisional Generator Interconnection Agreement ("PGIA") exemption to stipulate that the PGIA exemption must be requested at the time of application. MISO determined that mandating an executed PGIA made it extremely difficult for Interconnection Customers to utilize this exemption for the reasons outlined above. Additionally, Interconnection Customers with a requested PGIA have assumed additional risks when their request for PGIA is made. While they are similarly situated to Replacement Generating Facilities or ERIS to NRIS conversions, MISO addressed PGIA specific concerns, such as when an Interconnection Customer can revert to non-provisional status.

---

[3] *See Expeditated Resource Adequacy Study (ERAS) Introduction* (November 13, 2024), https://cdn.misoenergy.org/20241113%20PAC%20Item%2009%20Expedited%20Resource%20Adequacy%20Study%20(ERAS)%20Introduction660245.pdf;.

[4] *See Expedited Resource Adequacy Study (ERAS) Workshop* (November 18, 2024), https://cdn.misoenergy.org/20241118%20Expedited%20Resource%20Adequacy%20Study%20(ERAS)%20Workshop661622.pdf.

**Q. PLEASE DESCRIBE WHY THE EXEMPTIONS, SITE CONTROL AND PAYMENTS ARE NOW REQUESTED WITH THE APPLICATION SUBMITTAL.**

**A.** Following the Commission's Order on its first proposal, MISO reanalyzed its internal processes on how it would validate Interconnection Requests. MISO determined it was administratively inefficient to allow Interconnection Customers to retroactively request priority project status. Retroactive requests undermine the assertion that a project is truly a priority project. Retroactive requests can also unfairly game the limitation on a queue cycle. For example, under MISO's previous proposal, if a project learns that it will not be under the queue cap, then it could retroactively propose to enter into a PGIA in order to gain access to the next queue cycle. Under the previous proposal, that same project could later revert to non-provisional status with no penalty. Stakeholders expressed similar concerns. By adjusting the requirements for when an exemption must be declared and the requirements to maintain that exemption, MISO levels the playing field for all projects. These changes will necessitate that Interconnection Customers who want to make use of the PGIA exemption evaluate its project's feasibility and viability earlier in the process to determine whether they are willing to be bound by the PGIA commitments that make these projects more certain and justify their priority inclusion. This approach will allow MISO to efficiently process and prepare for a given Definitive Planning Phase ("DPP") Cycle. Additionally, MISO modified its proposal to notify its Interconnection Customers of the queue cap earlier in the process.

**Q. PLEASE SUMMARIZE THE ADDITIONAL STAKHOLDER MEETINGS FOLLOWING THE ISSUES OF THE COMMISION'S REJECTION.**

**A.** MISO re-engaged with the stakeholders and revised its initial cap proposal. The revised proposal was posted for stakeholder review and discussed in the Interconnection Process Working Group ("IPWG") and Planning Advisory Committee ("PAC") on multiple occasions. During these discussions, an alternative proposal ("Savion VPE proposal") was presented and subsequently voted on by stakeholders at the IPWG. Ultimately, the alternative proposal didn't receive enough votes to pass.

**Q. PLEASE DESCRIBE THE BREAKDOWN OF THIS FILING.**

**A.** MISO views the Queue Cap Proposal and the Exemptions to the Queue Cap Proposal as being two separate, but related, proposals included together in one filing for administrative convenience and Tariff version control. The Queue Cap Proposal is necessary and appropriate to address the unsupportable number of Interconnection Requests that MISO must process. It is a complete proposal in and of itself and does not depend on the approval of any of the exemptions to be complete or reasonable rate. While the Exemptions to the Queue Cap Proposal will necessarily depend on the acceptance of the Queue Cap Proposal, it is severable and a complete proposal. The Exemptions to the Queue Cap Proposal is intended as a standalone set of enhancements to the Queue Cap Proposal. While it is not necessary to make the cap function, the exemptions add independent value. Specifically, they allow the historically limited number of projects that have used PGIAs, sought ERIS to NRIS conversions, or sought to add additional interconnection service to a replacement facility to proceed directly into the next queue cycle in acknowledgement of the facts that these types of projects have proven highly certain given the level of commitment undertaken or the existing facilities. Even if the Commission determines the Exemptions to the Queue Cap Proposal does not adequately address the open access concerns identified

in its previous order, the state of the queue still necessitates a backstop queue cap to properly function, and the cap can function without the exemptions. I note that neither I nor my staff made any promises regarding whether the exemptions should be included in the cap filing or made any compromises to secure stakeholder support for the Queue Cap Proposal based on these exemptions. MISO commits to making a subsequent filing with the Commission to update the Tariff sheets to reflect the most up-to-date versions of the then-current Tariff provisions and within sixty (60) days of an order on each proposal is

**Q. DID MISO ENGAGE THIRD PARTIES TO SUPPORT THE DEVELOPMENT OF THE PROPOSED REFORMS?**

**A.** Yes. MISO hired Charles River Associates ("CRA") in early 2023 to perform an analysis of the MISO generator interconnection queue and to recommend changes to the process that would improve the quality of projects entering the queue, as well as MISO's ability to provide timely and consistent study results. CRA provided its findings in the stakeholder process and their final report is included as Exhibit 1 to my testimony ("CRA Report").

**Q. DID MISO ADOPT ALL OF CRA'S RECOMMENDATIONS IN THIS PROPOSAL?**

**A.** MISO adopted a significant number of CRA recommendations, with some adjustments. MISO adjusted the Proposals based on guidance of the Commission's Order in Docket No. ER24-341-000. These final proposals reflect the collaborative input from MISO, its stakeholders, and the additional CRA analysis on the need for a cap. An example of the CRA recommendation that was not included was to consider an individual developer cap on proposed projects, in addition to the overall MW value cap. The intent of this CRA recommendation was to provide a protection mechanism such that smaller developers are

not crowded out of the process by larger developers. This concept potentially could be necessary at some point in the future, but at this time MISO believes there is insufficient evidence to support a per-developer cap in the Queue Cap Proposal as needed.

**Q. HOW DO THESE FILINGS RELATE TO MISO'S COMPLIANCE OBLIGATIONS UNDER ORDER NO. 2023/2023-A?**

**A.** At the time of this submission, MISO submitted its Order No. 2023-2023-A compliance filings pursuant to the independent entity variation requirements set forth in Order No. 2003.[5] If the Commission accepts the proposed revisions, they will become part of the MISO Tariff. The proposal is submitted as a necessary independent entity variation to MISO's compliance with Order No. 2023-2023-A.

## III. THE CURRENT STATE OF THE MISO QUEUE AND THE CONTINUED NEED FOR A CAP

**Q. PLEASE DESCRIBE MISO'S INTERCONNECTION QUEUE PROCESS.**

**A.** MISO's generator interconnection queue process generally follows the Commission's *pro forma* Large Generator Interconnection Procedures ("LGIP"), with changes and improvements adopted over the years pursuant to the Commission's independent entity variation. The current framework was put in effect in January 2017 as a result of extensive stakeholder driven reforms, which implemented a novel three-phase DPP structure to study Interconnection Requests, which since has been successfully adopted in some other regional transmission organizations ("RTOs"). MISO uses clusters to study

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[5] *See Standardization of Generator Interconnection Agreements and Procedures,* Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 552 U.S. 1230 (2008).

Interconnection Requests, with each calendar year producing one or two study clusters, known as "cycles." The clusters are studied on a subregional basis and, as I previously noted, MISO currently has five interconnection queue study regions.

**Q. PLEASE EXPLAIN HOW THE THREE-PHASE DPP PROCESS WORKS.**

**A.** The DPP structure provides for a sequential process to study Interconnection Requests in the queue. MISO conducts one System Impact Study ("SIS") in each of the three DPP Phases (*i.e.*, Preliminary SIS in DPP Phase I, Revised SIS in DPP Phase II, and Final SIS in DPP Phase III) to account for project withdrawals and to refine and update the analysis. Facilities Studies are conducted in DPP Phases II and III. The DPP process also includes three milestone payments—M2, M3, and M4, and provides for two designated off-ramps—Interconnection Customer Decision Points I and II ("Decision Points"). The first milestone payment, M2, is fixed at $8,000 per MW of Interconnection Service requested and is payable at entry into the queue. The second milestone, M3, is equal to the greater of twenty (20) percent of the amount of Network Upgrades identified in the Preliminary SIS less the amount previously posted as M2 or $1,000/MW. M3 is due at the end of Decision Point I. The third milestone, M4, is equal to 30 percent of the amount of Network Upgrades identified in the Revised SIS less than the amount previously posted as M2 and M3 payments. M4 is due at the end of Decision Point II. These milestones may be partially refundable upon withdrawal depending on the time of withdrawal and on whether they increase the Network Upgrade cost to other Interconnection Customers in the same cycle pursuant to a calculation of financial harm to other Interconnection Customers, as set forth in Section 7.8 of the GIP (*i.e.*, the "harm test"). The GIP also provides for penalty-free withdrawals in specified circumstances, as set forth in Section 7.6.2.4 of the GIP, less any

Automatic Withdrawal Penalty that was established in reforms approved by FERC in January 2024.6 The two off-ramps, Decision Points I and II, each last fifteen (15) Business Days and allow Interconnection Customers to review the study results from the most recent phase, pay the applicable milestone, and decide whether to proceed to the next DPP phase or withdraw from the queue.

**Q. PLEASE DESCRIBE THE CURRENT STATUS OF MISO'S GENERATOR INTERCONNECTION QUEUE.**

**A.** As of October 30, 2024, MISO's generator interconnection queue contained 1,706 active Interconnection Requests comprising of nearly 312 GW of proposed new generator interconnection capacity, which is a considerable backlog. This backlog is spread over all five queue study regions and includes queue cycles going back to 2019. It should be noted that when MISO previously made this cap filing in November of 2023, MISO's generator interconnection queue contained 1,371 active Interconnection Requests comprising nearly 236 GW of proposed new generator interconnection capacity. In contrast, MISO's peak load is only 127.1 GW and, as of December 2023, 191 GW of functioning total installed generation capacity already exists in the MISO Region.

**Q. HOW DOES THE CURRENT QUEUE SIZE COMPARE TO PRIOR YEARS?**

**A.** The current queue size is extraordinary and unprecedented. The most recent queue cycle, DPP-2023, alone is 124 GW. The two immediately preceding cycles, DPP-2022 and DPP-2021, were 170.8 GW and 76.8 GW, respectively. In contrast, the two cycles that started in 2017 following the implementation of the three-phase DPP process, DPP-2017-FEB and

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6 *Midcontinent Indep. Sys. Operator*, 186 FERC ¶ 61,054 (January 19, 2024).
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DPP-2017-AUG, were only 30.7 GW, which generally is in line with the average queue cycle size in 2014-2016. It is important to note that the queue reforms approved by FERC in January 2024 did result in lower number of submitted projects. DPP-2023 had 30% less Interconnection Requests submitted than the amount of DPP-2022. However, the 124 GW in DPP-2023 is still as large as MISO's typical summer peak load. This shows that the previous reforms were not enough to facilitate a more efficient queue, and a MW cap is still necessary.

**Q. WHAT IS THE CURRENT FUEL PROFILE OF THIS PROPOSED GENERATION?**

**A.** Virtually all the proposed generating capacity in the latest queue cycles involves intermittent and weather-dependent resources, with solar facilities accounting for the lion's share of those.

**Q. WHAT IS THE PERCENTAGE OF PROPOSED GENERATION IN THE MISO QUEUE THAT USUALLY GETS BUILT?**

**A.** The CRA Report analyzed queue withdrawals in the latest queue cycles. *See* Exhibit 1 at 7-10. In the most recent completed cycles at the time of the report, DPP-2017-FEB, DPP-2017-AUG, and DPP-2018-APR, nearly 70% of the total generation capacity that entered these cycles was eventually withdrawn. *Id*. at 8-9. The remaining approximately 30% got their GIAs, but the actual MWs of generating capacity that will be constructed and energized will be less than 30% due to financial and construction stage challenges. Some of these GIAs have already been terminated, and various delays impacting some of the remaining GIAs will reduce the number of projects that achieve commercial operation still further.

**Q. DO YOU EXPECT THE CURRENT QUEUE TRENDS TO CONTINUE?**

**A.** Yes. I expect the queue to continue to grow in the next several years, with the bulk of the new proposed generating resources continuing to be intermittent and weather dependent.

**Q. WHAT IS THE BASIS FOR YOUR EXPECTATION?**

**A.** I attribute this trend to growing customer demand for renewable generation, the considerable financial incentives for renewable generation implemented in the *Infrastructure Investment and Jobs Act of 2021* and the *Inflation Reduction Act of 2022*,[7] and the backbone transmission MISO has approved, and plans to approve, through our Long Range Transmission Planning ("LRTP") effort. In July 2022, the MISO Board of Directors approved the first tranche of LRTP projects worth an estimated $10.3 billion of regional transmission facilities, which will provide access to the MISO grid for many new renewable resources. MISO anticipates a second tranche of projects to be approved in December 2024, currently estimated at $21.8 billion and known as LRTP Tranche 2.1. These contributing factors make a growth in Interconnection Requests very likely, and it is critical to implement the proposed reforms to ensure that MISO can manage the continuing growth.

**Q. IF THE MAJORITY OF INTERCONNECTION REQUESTS IN THE QUEUE WITHDRAW, WHY IS THE CURRENT QUEUE GROWTH PROBLEMATIC?**

**A.** The increasing number and volume of speculative Interconnection Requests in the queue strains MISO's resources and ability to process Interconnection Requests in accordance with the Commission's timing requirements and causes delays in the completion of required Interconnection Studies. This leads to increasing withdrawals, less certain DPP

Phase I and II study results, and ultimately, uncertainty and delays for all Interconnection Customers in the queue. Currently, queue delays are one of the largest contributing factors that negatively impact Interconnection Customers' ability to timely execute a GIA and, potentially, receive timely capacity accreditation under MISO's Resource Adequacy construct. Although cluster studies allow for multiple Interconnection Requests to be studied together, many administrative tasks required to process the queue are performed on an individual Interconnection Request basis. Such tasks include application processing to review modeling data, Site Control, and financial security and certain other tasks. Also, each Interconnection Request usually has one POI that requires its own individual studies, and each GIA is negotiated and executed individually.

Furthermore, independent from these timing challenges, the growth of the interconnection queue jeopardizes the ability of Interconnection Customers to receive study results that reflect actual system impacts, and the costs needed to mitigate them, especially in earlier phases of the DPP. To capture the actual impact of an Interconnection Request on the Transmission System, MISO must study that Interconnection Request at its full output, according to fuel-based dispatch assumptions, to establish the Network Upgrades needed to accommodate that request. Because a project is allowed to operate up to the service levels specified in its GIA, failure to capture the impacts of operating at such a level would artificially understate the impact of that project. This, in turn, can lead to overloads and other reliability cost problems if not mitigated, and cause cost shifts if the mitigations are identified in later studies for other projects. Thus, it is important to capture the full impact of a proposed project in an Interconnection Study. However, this becomes increasingly challenging when the amount of generation proposed in a queue cycle begins to exceed

projected peak load. Proposed generating facilities do not exist in a vacuum on MISO's system. In addition to what is proposed in a given queue cycle, there is existing generation already in commercial operation on the Transmission System and higher queued projects whose output must be accounted for in studies for new Interconnection Requests. When the total of this generation far exceeds load, MISO must use assumptions in order to develop a valid mathematical solution that will allow for a model that studies new generation at its authorized output while still sinking that power in the MISO region. MISO has some limited flexibility in model building to address these problems. However, the larger the queue size, the more aggressively MISO must adjust its assumptions to allow the model to solve (*i.e.*, to balance generation and load). Past a certain point, these assumptions begin to diverge sufficiently from reality and the model is no longer modelling how MISO's Transmission System and generation resources are expected to behave. The results of a study built on such models have diminished value because some existing generation will continue to dispatch well above the artificially lowered assumptions resulting in reliability issues on the Transmission System that were not studied. This, in turn, will require new studies in the interconnection process or in annual transmission planning studies resulting in potential cost shifts to future Interconnection Requests or to load, which creates risks and cost uncertainty for both existing and future projects, can lead to reliability issues on the Transmission System, and ultimately delays in deploying new generation. In short, assumptions diverging from expected conditions is a necessary result of study clusters that are too large to study under realistic system conditions, particularly when populated with increasing numbers of speculative Interconnection Requests. And, while Interconnection Customers will receive some "results" from these studies, those

results have a diminished value and, will ultimately cause more risk to the Transmission System and Interconnection Customers than study results based on cluster sizes that allow for realistic assumptions to be used.

**Q. HAS MISO ATTEMPTED TO ADDRESS THESE CHALLENEGES WITHOUT LIMITING ITS QUEUE SIZE ?**

**A.** MISO is continuously striving to improve its GIP. Following the introduction of the three-phase DPP in 2017, MISO made several targeted efforts to improve various aspects of the DPP process, such as milestone and penalty provisions, Site Control requirements, expedited processing options and other improvements, as summarized in the transmittal letters accompanying the MISO filings in the dockets. Nonetheless, no material changes have been made to the milestone amounts and penalty-free withdrawal provisions since 2017. Accordingly, the new challenges that have recently arisen require an urgent response and change to those GIP requirements. Additionally, MISO submitted and received approval for a set of queue reforms in early 2024 regarding increased financial payments and penalties along with increased site control requirements.

## D. <u>TRANSITION PROVISIONS</u>

**Q. IS MISO PROPOSING ANY TRANSITION PROVISIONS FOR THE REFORMS INCLUDED IN THE GIP IMPROVEMENTS FILING?**

**A.** Yes, the transition provisions are included in proposed section 5.11 of the GIP. Generally, the proposed reforms will apply only to Interconnection Requests submitted in study cycles with application deadlines after the effective date of the reforms, starting with the DPP 2025 cycle. All preceding cycles will be exempt from the proposed changes.

## IV. THE NEW CAP FILING

**Q. PLEASE DESCRIBE THE UPDATED PERCENTAGE-BASED CAP MECHANISM.**

**A.** The percentage-based load nature of the cap ensures that the studies are appropriately scaled to consider existing generation, new Interconnection Requests, and the load MISO serves while still enabling competition. The new queue cap formula is noted below:

*MISO study region cap = 50% * study region non-coincident summer peak*

The proposed cap formula will be 50% of the non-coincident summer peak values for each study region from the power flow model that will be used to perform the queue studies. MISO will use the most recent available MTEP model series. Open access is maintained as Interconnection Requests that are included in the cap are based on the timing of their request. This formula will ensure more reasonable study volumes and subsequently result in more certain study outcomes. The new proposed cap formula differs in three ways from the rejected cap formula. First, the new proposed cap formula uses non-coincident summer peak values while the original cap formula used non-coincident shoulder peak values. Second, the old cap formula utilized the Pmin value as floor to which existing generation can be turned down to accommodate to generation. The new cap formula does not. Finally, the old cap formula adjusted for estimated withdrawals and exemptions. MISO will review the need for a queue cap after three (3) years.

**Q. WHY IS IT REASONABLE TO REQUIRE A 50% QUEUE CAP?**

**A.** The 50% queue cap is reasonable because it allows MISO to balance the appropriate level of the interconnection queue size to ensure that Interconnection Requests are processed efficiently, increasing certainty for active projects and reduces the risk of future cost shifts,

while also addressing the base load needs of each study region. After numerous rounds of internal analysis, MISO determined that 50% of the non-coincident peak best strikes that balance. The analysis entailed performing iterative model builds at a reduced non-coincident peak value until the model could be built and solved without the need for Backbone Network Upgrades or needing exports to neighboring systems. This threshold was met at 50%. Backbone Network Upgrades are an indication that the model, before taking any contingencies, is in such a state that the power flow can't be solved without the addition of Network Upgrade(s). Typically, this is an indication of voltage collapse. Similar, exports to neighbors are indication of further Affected System costs. The internal analysis recommended that the appropriate level of the queue cap as well would be 50%**.** This would balance out the backbone upgrades to a reasonable level where it is appropriate to obtain a usable model and run the DPP studies from. MISO provides the results below based on that internal analysis:

| **Power flow model** | **Total GW of Queue Projects** | **% of Non-Coincident Peak Load** | **Backbone Network Upgrades** | **Export to Neighbors (GW)** |
|---|---|---|---|---|
| 2022 Cycle test cases | 67.6 | 50% | 0 | 0 |
| 2022 Cycle test cases | 80.9 | 60% | 0 | 0 |
| 2022 Cycle test cases | 84.3 | 63% | 0 | 10.2 |
| 2022 Cycle test cases | 90.9 | 68% | 1 Transmission line | 12.2 |
| 2022 Cycle test cases | 95.9 | 72% | 1 Transmission line | 15.0 |

| | | | | |
|---|---|---|---|---|
| 2022 Cycle Kickoff | 142.0 | 106% | 21.5 GVAR of voltage support | 6.4 |
| 2022 Cycle Prescreen | 177.0 | 132% | 3 Transmission lines<br><br>42.5 GVAR of voltage support | 10.3 |

As noted in the chart, while the 60% test case did eliminate the need to make Backbone Network Upgrades under the previous formula, MISO also accounted for shoulder peak load and Pmin evaluation, which are no longer accounted for in the newly proposed queue cap formula. Based upon this evidence, MISO elected to move forward with the 50% cap value. This new formula represents a balance between MISO's need to efficiently manage the queue while also addressing regional load needs and open access concerns.

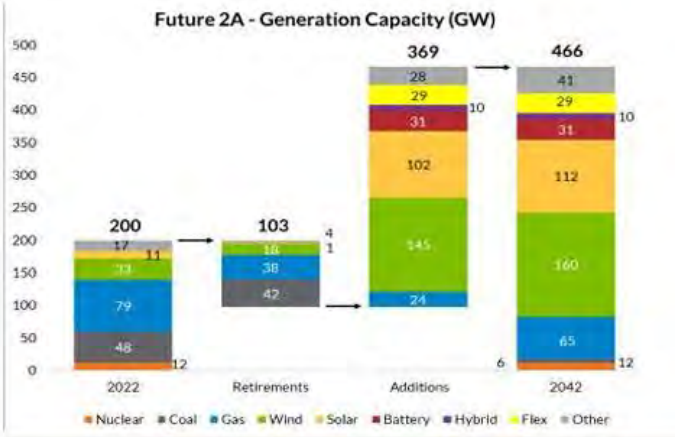
**Q. WHY ARE THE PROPOSED CAP CHANGES STILL NECESSARY AND URGENT GIVEN THE EARLIER APPROVED QUEUE REFORMS?**

**A.** While MISO noted that the increased GIP financial commitments and penalties along with updated site control evidence requirements that were approved in early 2024 resulted in a 30% reduction of "uncertain" interconnection applications from the previous cycle, it still represents a large number of projects for the team to study. Adding in the 2023 study cycle, MISO's current interconnection queue is sitting at roughly 312 GW. To put this into more context, MISO's all-time system peak load is 127 GW. Even with notable reductions of interconnection applications, the current interconnection service proposed in the queue is more than twice the all-time system peak load. This only further demonstrates purely qualitative improvements do not sufficiently increase in the queue size and ability to efficiently manage that queue. A MW limitation on individual interconnection queue

cycles will ensure that MISO can continue to produce more realistic resource dispatch, models, reduce queue timelines and produce lower Interconnection costs and therefore improving the success rate of the Queue, thereby increasing overall certainty in the interconnection queue. Additionally, MISO notes that the application portal is currently open and available for projects to be submitted into the next available study cycle; the cap is needed urgently to ensure that the appropriate balance of interconnection requests is processed in that study cycle.

**Q. PLEASE DESCRIBE HOW THIS NEW PROPOSED CAP ADDRESSES THE COMMISSIONS EARLIER CONCERNS REGARDING FUTURE RESOURCE ADEQUACY NEEDS?**

**A.** MISO re-engaged with its stakeholder to develop a proposal that would adequately address future adequacy needs. Per FERC's guidance, MISO reviewed the Future Planning Scenarios developed in conjunction with the Transmission Planning process("Futures"). MISO calls these scenarios "Futures," and they help MISO envision a set of possible resource adequacy outcomes up to twenty (20) years in the future. The scenarios establish a bookended range of economic, policy, and technological possibilities—such as load growth, electrification, decarbonization, renewable energy levels, generator retirements, fuel prices, and generation capital costs. The Futures hedge uncertainty by utilizing stakeholder information, policy direction, industry trends, and capacity expansion modeling to create the forecasts. Futures are updated with new or changing information. In reviewing the Futures 2A Planning Scenario, it was noted that 248 GW of Net Additions would be needed in the years 2025-2042 (17 years):




Taking this into account, MISO compared how the cap would impact this forecasted need.

| | |
|---|---|
| Active Interconnection Requests in the Queue8 | 321 GW |
| Assumed completion rate of 21% | 67.4 GW |
| Proposed Queue Cap | 68 GW |
| Per Year additions (21% completion rate) | 14.3 GW |

Per the CRA report, using a historical completion rate of 21%, MISO estimates per year additions of 14.3 GW. From 2025 to 2042 and adding to the existing active Interconnection Requests already in the queue, this equates to 310 GW. Based on this analysis MISO believes there will be adequate throughput even with the cap to meet our future Resource Adequacy needs even with a queue cap of 50% of the non-coincidental peak load.

**Q. PLEASE DESCRIBE HOW THIS NEW PROPOSED CAP FORMULA ADDRESSES THE COMMISSIONS EARLIER CONCERNS REGARDING EXEMPTIONS?**

**A.** While limited in use given their inherent nature that minimize their submittals, MISO has found that projects related to increases in replacements, ERIS to NRIS conversions and PGIAs tend to reflect a greater commitment of the Interconnection Customer to the project and a lower withdrawal rate, leading to a greater level of certainty, given they are comprised of instances where an Interconnection Customer seeks to add incremental new service to an existing generating facility or have committed to a higher level of financial commitment. Given this criterion of existing generation facilities, MISO anticipates the continued limited use of these exemptions based on the inherent practical nature of these products that have historically limited their submittals. Additionally, in rejecting MISO's initial cap filing, citing the RERRA exemption, FERC noted an "uncapped exemption" potential that might undermine the benefits of having a cap in place. MISO ultimately found that the RERRA exemption engendered strong criticism from the stakeholders and the Commission, and the filing was ultimately rejected. Under the current proposal, MISO is amending Section 4.1.2 of Attachment X to remove the RERRA exemption. MISO has recognized that this as a more distinct queue issue that should be addressed in a separate filing. MISO has committed to working on addressing the needs of RERRA entities through a newly proposed ERAS process that will expedite the approval process of new generation needed to address resource adequacy. Furthermore, MISO has updated the cap formula to note that approved exemptions will be included with all projects that are used to meet the cap limit.

**Q. DID CRA RECOMMEND A QUEUE CAP?**

**A.** Yes. In fact, the CRA Report recommends two separate caps: (1) a queue cap per cycle; and (2) a per developer cap. *See* Exhibit 1 at 17-18. The CRA Report views a queue cap as a critical remedy to address the challenges outlined in my testimony. CRA recommended that MISO determine the level of the queue cap as well as its application across study regions, queue cycles and potentially individual entities. *Id*. at 17. The CRA Report further suggested that the following criteria could be considered in designing an appropriate queue cap: (1) peak load and forecasted peak load, (2) installed capacity, guaranteed additions, and expected retirements, and (3) reliability and resource adequacy. *Id*. at 18.

**Q. WHAT ARE THE BENEFITS OF A STUDY CYCLE CAP?**

**A.** The proposed cap will ensure that Interconnection Study results are based on a more realistic dispatch, thereby removing the need for prohibitively expensive and unrealistic Network Upgrades. Currently, Interconnection Customers receive realistic and informative study results only after enough projects exit the queue to achieve a realistic dispatch. The proposed cap will ensure more realistic and informative study results at an earlier point in the study process, without the delays and uncertainty caused by withdrawals after studies are performed with unrealistic Network Upgrade assumptions. The cap benefits Interconnection Customers by providing better cost estimates and a timelier study process. As discussed above, the cap also will provide benefits to the engineers performing these studies by improving their ability to solve these complex models and will reduce the amount of unnecessary engineering analyses, which are performed on a study model using unrealistic assumptions.

**Q. WHERE WILL THIS CAP FORMULA BE STATED?**

**A.** MISO will put the queue cap formula in the Tariff. In addition, MISO will post a report to its website prior to each study cycle describing the cap calculation and results.

**Q. WILL MISO USE THE SAME FORMULA FOR POST-2025 QUEUE CYCLES?**

**A.** MISO will continue to work with stakeholders to determine if the calculation should be modified for future cycles. MISO purposely used a simple calculation that more than adequately meets regional load needs. MISO also has committed to revisiting its cap-related Tariff provisions in three (3) years. MISO is willing to either provide an informational report discussing the effectiveness of these provisions after the third cluster study cycle or propose changes in a subsequent FERC filing based on the accumulated experience.

**Q. HOW WILL MISO PROCESS APPLICATIONS ONCE THE CAP IS ESTABLISHED?**

**A.** Once the cap amount has been calculated and posted, MISO will process the applications using a serial "first-come, first-served" approach based on when the applications were queued during the open application window. MISO will subsequently review the interconnection applications until the cap amount is reached. This process will provide an incentive to submit an Interconnection Request earlier in the open application window as opposed to right up until the application deadline as is often the case today. In addition, this process will have the added effect of "flattening the curve" for application submittals, *i.e.*, the projects would enter the queue when they are ready rather than wait until the last moment, thereby allowing MISO to manage the study cycle more efficiently. Meaning we expect projects to enter the queue when they are ready and will meet all necessary

requirements to secure their spot. MISO recognizes that this flattening of the curve will not hold true for the 2023 cycle, as it is expected that most applications will be submitted on the first day that MISO opens the web-based application tool to accept new applications.

**Q. CAN YOU PLEASE EXPAND ON WHAT HAPPENS TO THOSE INTECONNECTION REQUESTS THAT FOUND TO BE "OVER THE CAP"?**

**A.** Interconnection Requests that are processed after the cap has been met will continue to be evaluated by MISO to ensure they are valid requests, including necessary items such as milestones, Site Control, and modeling data. Once approved as valid, these Interconnection Requests will remain in the queue and will be studied in the next available queue cycle. Therefore, all Interconnection Customers, even those that are "above the cap", have comparable access to the interconnection process. A subset of the Interconnection Requests, i.e., those submitted closest to the time when the cap was met, can potentially replace projects that withdraw up to 30 days before the start of the DPP process. If a project that was under the cap withdraws, then MISO will pull the first project in the next cycle forward. This will be done up until the model needs to be built for the pre-screening analysis, which is 30 days before the start of the DPP process. This will allow 15 days to develop the model and post the pre-screening results, and then another 15 days for Interconnection Customers to review the analysis and determine if they should withdraw or remain in the queue and be included in the DPP process. Any dropouts that occur between the window when the pre-screening model is being developed and the start of the DPP process will not be replaced.

**Q. CAN INTERCONNECTION REQUESTS IN THE QUEUE THAT ARE WAITING FOR THE NEXT CYCLE BE MODIFIED?**

**A.** Yes, these Interconnection Requests will be able to make all the modifications allowable per section 4.4 of the GIP, which could include, but are not limited to: POI changes, MW reduction, removal of one fuel source for hybrids. Once these Interconnection Requests are included in a DPP study cycle, any changes will be evaluated as a potential material modification per Section 4.4.

**Q. WILL DEVELOPERS KNOW THE MAXIMUM AMOUNT OF MEGAWATTS THAT CAN BE SUBMITTED IN A GIVEN QUEUE CYCLE?**

**A.** Yes, the MW value for each DPP study cycle will be posted on the MISO public website at least ten (10) Business Days prior to the application deadline of that Definitive Planning study cycle. Additionally, MISO will post an associated whitepaper to the MISO public website to inform stakeholders how the cap was developed and set. It should be noted that as part of this process, MISO will be re-evaluating the formula prior to each study cycle, including the cap amount and the associated margins. There will be no cap on the number of individual requests any Interconnection Customer can submit. All applications will be evaluated against the cap on a "first come, first served" basis. This could result in an Interconnection Customer having a higher percentage of projects within any given queue cycle than another. If MISO determines this could create an unfair advantage over other Interconnection Customers, then MISO will develop an individual cap per Interconnection Customer and will file that tariff change with FERC for future queue cycles.

**Q. IS MISO PROPOSING ANY EXEMPTIONS FROM THE QUEUE CAP?**

**A.** Yes. MISO recognized in the early stages of development of its queue reform proposals the importance for a narrow set of Interconnection Requests to be included in a cycle if they already have an existing Generating Facility or Interconnection Service in place or otherwise exhibit a high level of certainty. These proposed exemptions are set forth in Section 4.1.2 of the GIP and include: 1) Interconnection Requests involving an increase in the capacity of an approved Replacement Generating Facility; (2) Interconnection Requests involving a conversion of ERIS into NRIS; (3) Interconnection Requests involving a Generating Facility with a requirement to request a PGIA. MISO initially proposed that these projects be exempt from the queue size limitations and other aspects of the initial proposal. In consideration of the concerns highlighted by the Commission, these projects will no longer be exempt from the queue cap limitations. However, as described herein, these projects will be exempt from certain requirements that will allow these exemptions to receive first access to the cycle for which it applies. Exemption requests must be submitted with their application submittal.

**Q. PLEASE EXPLAIN THE REPLACEMENT FACILITY EXEMPTION.**

**A.** Under the Tariff, Replacement Generating Facility requests generally are processed outside the interconnection queue. One exception to this process is when a Replacement Generating Facility requires Interconnection Service (in MW) in excess of that of the Existing Generating Facility that is being replaced. In such instances, the Replacement Generating Facility is allowed to generate up to the existing Interconnection Service of the Existing Generating Facility. However, an Interconnection Request associated with the excess MW value must proceed through the regular DPP cycle procedures. The proposed

exemption is for such excess capacity requests. Such requests are highly valuable to the MISO Transmission System because they are certain: the Replacement Generating Facility was already approved through the replacement process and exists under an executed replacement GIA.

**Q. PLEASE EXPLAIN THE ERIS TO NRIS CONVERSION EXEMPTION.**

**A.** The Tariff allows Interconnection Customers to convert their ERIS to NRIS, which is a higher level of Interconnection Service. The conversion requires submission of an Interconnection Request and proceeding through the queue. MISO proposes to exempt such "NRIS conversion" Interconnection Requests from the cap. The rationale is similar to that for the Replacement Generating Facility exemption discussed above. The Interconnection Request seeking conversion already has an executed GIA and as such, are highly valuable to the MISO Transmission System.

**Q. PLEASE EXPLAIN THE PGIA EXEMPTION.**

**A.** MISO's Tariff currently includes a process that allows its Interconnection Customers to enter into a PGIA before the end of the DPP cycle. The PGIA allows limited operation, based upon the results of available studies. This option allows an Interconnection Customer with a ready project to connect to the MISO Transmission System and inject power into the grid before the completion of all studies. The potential downside of the PGIA is that Interconnection Customers assume the risk of interconnecting prior to the completion of Network Upgrades being identified through the DPP process. Because Interconnection Customers with a requested PGIA have assumed additional risks and commit to proceeding through the DPP cycle regardless of the potential costs of Network Upgrades, MISO views these types of Interconnection Requests are as certain as existing

generation—so long as the ability to revert is limited. Unlike MISO's current PGIA process, which allows reversion from provisional to non-provisional status, Interconnection Customers that claim this exemption will forfeit its ability to revert with no consequences. Any Interconnection Customer that elects to proceed under the PGIA exemption and reverts back to non-provisional status will lose all monies and will forfeit its queue position. This exemption is available to any Interconnection Customer willing to assume PGIA risks, thus allowing an exception for Interconnection Customers who are willing to make commitments that a reasonable developer would not undertake for an uncertain project.

**Q. PLEASE EXPLAIN WHY THE RERRA EXEMPTION WAS REMOVED FROM THIS UPDATED CAP FILING.**

**A.** In early 2024, MISO and its stakeholders embarked on a joint effort to address the challenges introduced with the RERRA exemption. MISO engaged in discussions with stakeholders to identify the challenges associated with the implementation of the RERRA exemption for the cap. MISO identified several concerns with the original RERRA exemption process. First, MISO was concerned with how to limit the size of RERRA exemptions. The RERRA exemptions, unlike the included exemptions, posed a particular risk to diminishing the value of the cap. Second, multiple stakeholders brought forth comments regarding the standardization of format and processing of the RERRA exemptions. Third. MISO further recognized this as a more distinct queue issue that should be addressed in a separate process. There is a fundamental necessity for a short-term generator interconnector product to handle direct urgent resource adequacy needs for the states within the MISO system. Due to these challenges, MISO removed the RERRA

exemption from the current filing. However, the importance of RERRAs to the MISO Transmission System is not lost on MISO. To better respond to the unique needs of RERRAs, MISO will work with stakeholders on a separate, concentrated effort to address the unique resource adequacy needs of a RERRA. MISO has committed to working on addressing the needs of RERRA entities through a new ERAS process that is being developed with stakeholders now and will more comprehensively address the approval process of new generation needed to address resource adequacy.

## VI. STAKEHOLDER PROCESS

**Q. PLEASE DESCRIBE THE STAKEHOLDER PROCESS USED TO DEVELOP THIS PROPOSAL.**

**A.** MISO engaged in an extensive stakeholder process throughout the development of its updated queue cap proposal. MISO obtained feedback through the PAC and the IPWG, conducted dozens of calls with stakeholders across the MISO sectors, and receiving multiple rounds of formal and informal written feedback. During the stakeholder process, MISO considered the advantages and disadvantages of multiple approaches for addressing the identified challenges and risks, collaborating with stakeholders on identifying areas where flexibility could be increased. MISO revised its initial proposal considerably, incorporating the input received.

The key milestones of the stakeholder process were as follows:

- January 30, 2024: MISO provided an update to the IPWG regarding FERC's response on MISO's GIP Improvements and Cap filings, along with next steps.
- July 23, 2024: MISO presented several updates to the cap proposal to address FERC concerns with the original filing at the IPWG

- September 3, 2024: MISO provided refined proposal and responded to feedback at the IPWG.
- September 30, 2024: MISO held a special IPWG workshop to review the current proposal and answer stakeholder questions
- October 16, 2024: MISO presented a final package of reforms at the PAC. MISO also introduced its Expedited Resource Adequacy Study proposal.[9]

**Q. WHAT WAS MISO'S RESPONSE TO CONCERNS AND RECOMMENDATIONS FROM STAKEHOLDERS?**

**A.** Stakeholders asked MISO to justify a rationale for the 50% limitation, with some expressing concern that this cap would "arbitrarily" reduce the number of projects that can compete. MISO understands these concerns but notes that the rationale for selecting 50% is to ensure a balance of supply to demand while also addressing the queue administration difficulties MISO faces due to the volume of Interconnection Requests. Without limiting the amount of Interconnection Requests, the interconnection queue will continue to grow at an unsustainable rate, slowing study processes and making results less accurate. MISO supports many of the objectives of the alternative Savion VPE Proposal and is committed to working with stakeholders to incorporate elements of that proposal to meet those objectives.

**Q. IS MISO STILL CONINUING TO IMPROVE QUEUE COORDINATION WITH INTERCONNECTION CUSTOMERS AND TRANSMISSION OWNERS?**

**A.** Yes. In addition to the proposed Tariff changes, MISO has multiple efforts underway to enhance the queue experience. These transparent initiatives will facilitate enhanced

9 ERAS Workshop Citation

Interconnection Customer workflow throughout Interconnection Request lifecycle. MISO is coordinating the development of these enhancements through the stakeholder process.

## VII. CONCLUSION

**Q. IN YOUR OPINION, ARE MISO'S FILINGS JUST AND REASONABLE?**

**A.** Yes. This updated cap Filing address certain specific needs that MISO, the Commission and the stakeholder process identified. To ensure that MISO is on the right track to resolving its interconnection backlog, MISO requests that the Commission approve this updated proposal. The proposed new Tariff revisions address the Commissions earlier concerns and will significantly enhance the GIP by reducing queue delays and by improving the precision and timeliness of Interconnection Studies and will enable MISO to take the necessary steps to manage the size of individual cluster studies performed during the interconnection queue process.

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

**A.** Yes, it does.

**Affidavit of Andrew Witmeier**

COUNTY OF HAMILTON )

)

STATE OF INDIANA )

Andrew Witmeier, being duly sworn, deposes and states that he prepared the Prepared Direct Testimony of Andrew Witmeier, and the statements contained therein are true and correct to the best of his knowledge and belief.

Andrew Witmeier

SUBSCRIBED AND SWORN BEFORE ME, this 7th day of November, 2024.

Jennifer L. Miller
Notary Public, State of Indiana
Boone County
Commission Number 697079
My Commission Expires
February 22, 2025

EXHIBIT 1
TO
PREPARED DIRECT TESTIMONY OF
ANDREW WITMEIER

**Prepared for:**
Midcontinent Independent System Operator
720 City Center Drive
Carmel, IN 46032

# MISO Generator Interconnection Queue: M2, M3, and M4 Security Deposits and Return Procedures

## Evaluation and Suggested Adjustments

**Prepared by:**
Charles River Associates
200 Clarendon Street
Boston, MA 02116

Date: September 27, 2023

## CONFIDENTIAL MATERIAL

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# 1. BACKGROUND

The Midcontinent Independent System Operator (MISO) generator interconnection queue has experienced significant growth, leading to a substantial backlog of projects that is negatively impacting MISO stakeholders and interconnection customers. Recognizing this challenge, MISO has undertaken efforts to improve the efficiency of the interconnection queue process and reduce the backlog.

In pursuit of these objectives, MISO has enlisted the expertise of Charles River Associates (CRA) to provide an independent review of current rules for entry to and exit from the interconnection queue. Within the review, we evaluate the security deposits required within the MISO Definitive Planning study process, with a specific focus on the M2, M3, and M4 deposit amounts. The analysis conducted by CRA has relied upon data from the 2017-2022 study cycles, which forms the basis for the charts and recommendations presented in this report.

CRA's historical analysis has concentrated on the volume of interconnection requests, the magnitude of network upgrade costs assessed at different stages of the queue process, and withdrawal rates. These analyses have provided insights into how deposit amounts, policies, and the overall study process can be restructured to enhance the efficiency of the interconnection queue.

# 2. STATE OF THE QUEUE

A prevailing trend observed with respect to the interconnection queue studies published in recent years[1] is the consistent rise in queue sizes, accompanied by prolonged wait times and elevated withdrawal rates.

## 2.1. QUEUE SIZE

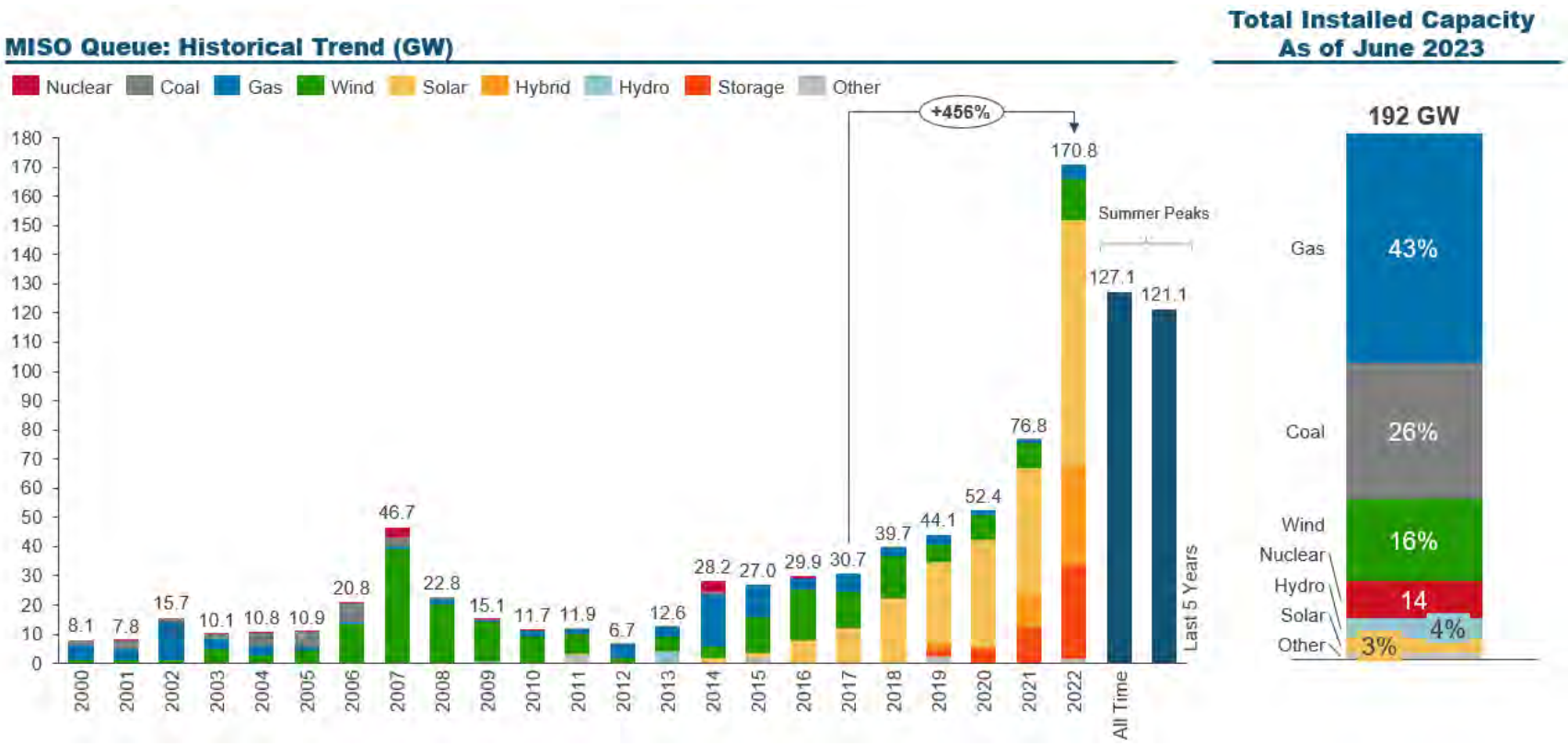
Figure 1 illustrates a concerning trend in the MISO queue. For years, the queue remained relatively stable but has inflated significantly in recent years to increasingly unmanageable levels. Comparing the 2022 queue size to the 2017 cycle, the queue has grown by 4.5 times. Moreover, the 2022 queue size, which stands at 170.8 GW, surpasses the all-time MISO summer peak demand of 127.1 GW and approaches the total MISO installed capacity of 192 GW.

The analysis of the 2022 interconnection queue, as presented in Figure 1, examines the costs associated with bringing all submitted capacity online as installed capacity. Results will likely show that significant costs are required, in the form of network upgrade and affected system costs, to bring all submitted capacity online. This data has been examined to give context to the proposed reforms outlined in this report and to help quantify the suggested magnitudes of deposits required and deposits at risk of forfeiture.

[1] For example, “Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection” published by Berkeley Lab https://emp.lbl.gov/queues

As a practical matter, a significant portion of the queued generation will not ultimately be placed in service and much of the study effort will, arguably, be wasted.

**Figure 1. MISO Queue: Historical Trend (GW)**




Source: MISO

## 2.2. Queue Phases, Milestones, and Timing [2]

The MISO interconnection queue study process is structured into distinct phases and incorporates milestone payments. In the pre-queue phase, interconnection customers (ICs) submit interconnection requests and MISO carries out essential preliminary tasks before commencing a formal study. These tasks include a set of initial screenings and a scoping meeting. A completed application includes an M2 milestone payment of $4,000 per MW studied.

The MISO Definitive Planning Phase (DPP) follows the pre-queue phase. During this phase, detailed studies and planning activities are conducted to assess the feasibility and impact of the proposed project on the MISO transmission system. The DPP consists of three phases: DPP Phase 1 (DPP 1), DPP Phase 2 (DPP 2), and DPP Phase 3 (DPP 3).

In the initial phase of the Definitive Planning Phase (DPP 1), the interconnection customer receives a comprehensive preliminary analysis of their request's impact on the reliability of the transmission system. During this phase, MISO conducts the initial Model Building and Review, followed by the preliminary System Impact Study (SIS). After completing the analysis, interconnection customers reach Decision Point I, where they have two options: (1) withdraw their request and potentially be subject to harm calculations (i.e., calculations to determine whether withdrawal shifted cost from the withdrawn project to other projects), with a potential to lose up to 50% of the M2 deposit, or (2) choose to proceed further in the queue process by paying an additional security deposit (M3). The M3 security deposit equals 10 percent of the network upgrade cost, as assessed in DPP 1, minus the M2 deposit.

DPP 2 is designed to provide the interconnection customer with a revised and more detailed analysis of the interconnection project's impact on the reliability of the transmission system after incorporating updated generation assumptions resulting from the withdrawal of interconnection requests during DPP 1. Once the revised SIS and affected system analysis are completed, inclusive of estimated upgrade costs, the interconnection customer enters Decision Point 2. Here, if the interconnection customer decides to withdraw, 100% of the M2 deposit becomes at risk (subject to harm calculations), and 100% of M3 is returned. If the project meets penalty-free withdrawal criteria,[3] 100% of the M2 deposit is returned. If the interconnection customer decides to continue in the queue, they are required to submit an M4 deposit. The M4 deposit equals 20% of the network upgrade cost calculated in DPP 2, minus the M3 and M2 deposits.

DPP Phase 3 is designed to provide ICs with a final, detailed analysis of their interconnection project's impact on the reliability of the transmission system after incorporating updated generation assumptions due to the withdrawals of interconnection requests during Decision Point 2. All milestone deposits (M2, M3, and M4) become at risk and subject to harm calculations upon entry into Phase 3. However, all three deposits may be returned in full upon withdrawal in DPP 3 if the project meets penalty-free withdrawal criteria.

[2] Information in this section is based on MISO's Generation Interconnection Business Practices Manual PM-015-r25

[3] Section 7.6.2.4 Withdrawal and refund due to increase in network upgrade costs of Generator Interconnection Procedures

The Generation Interconnection Agreement (GIA) Execution Phase follows DPP 3. For more detail, see MISO's Generator Interconnection Procedures, and Generation Interconnection Business Practices Manual.

We find that in our sample, the average length of the pre-kick off phase is 305 days and the average length of the DPP1 is 298 days, see Figure 2 below.

**Figure 2. Days spent in each queue cycle (2017-2022)**

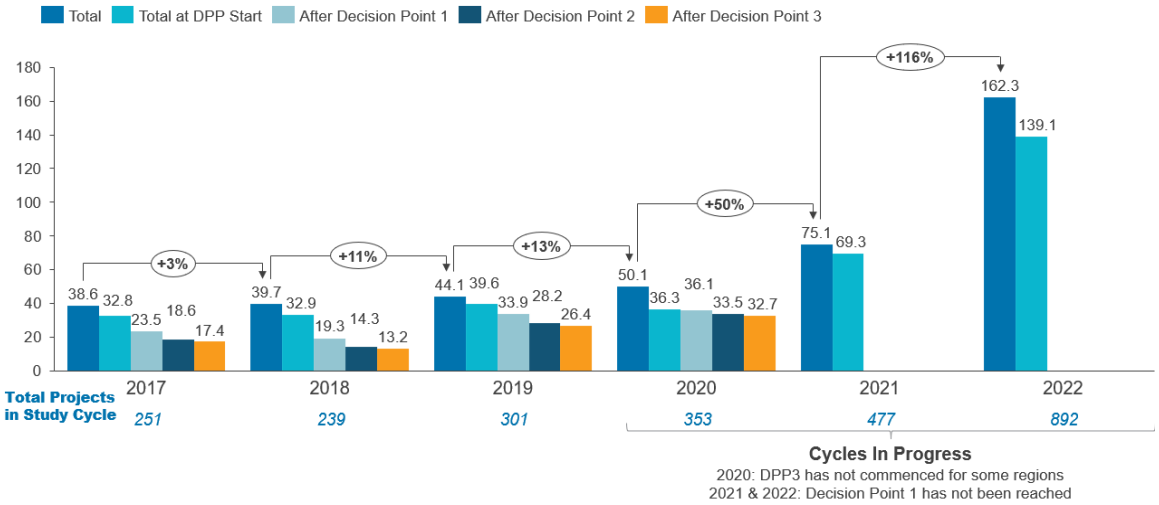
| Queue Phase | Average # days in phase |
|---|---|
| Pre-Kick-Off | 305 |
| DPP 1 | 298 |
| DPP 2 | 200 |
| DPP 3 | 187 |
| GIA Execution | 142 |

Source: MISO

## 2.3. WITHDRAWALS

Figure 3 further illustrates the year-over-year percentage increase in the size of the interconnection queue along with the dynamics of withdrawals. The queue size has experienced significant growth, with the steepest increase occurring between the 2021 and 2022 cycles, where the queue expanded by 116%. The withdrawals are significant and occur at every stage.

**Figure 3. MISO Queue Withdrawals by Cycle (GW)**




Source: MISO. Note: This figure does not include withdrawals without a specified date.

**Table 1. MISO Queue Withdrawals by Cycle, percentages based on MW withdrawn**

| Status | Withdrawal Phase | DPP-2017-AUG | DPP-2017-FEB | DPP-2018-APR | DPP-2019-Cycle | DPP-2020-Cycle | DPP-2021-Cycle | DPP-2022-Cycle |
|---|---|---|---|---|---|---|---|---|
| Active | | 2% | 0% | 0% | 13% | 53% | 88% | 86% |
| Done | | 35% | 26% | 32% | 44% | 6% | 0% | 0% |
| Withdrawn | | | | | | | | |
| | Pre Kick-off | 19% | 1% | 17% | 10% | 28% | 8% | 14% |
| | Decision Point 1 (DPP 1) | 22% | 34% | 34% | 13% | 0% | 2% | 0% |
| | Decision Point 2 (DPP 2) | 11% | 17% | 13% | 13% | 5% | 0% | 0% |
| | During DPP Phase 3 | 1% | 11% | 3% | 4% | 2% | 0% | 0% |
| | During GIA Execution Phase | 8% | 0% | 0% | 0% | 1% | 0% | 0% |
| | Post GIA | 2% | 11% | 1% | 0% | 0% | 0% | 0% |
| | Withdrawn (Other) | 0% | 0% | 0% | 2% | 6% | 2% | 0% |
| Withdrawn Total | | 63% | 74% | 68% | 43% | 41% | 12% | 14% |

Source: MISO.

Table 1 provides an overview of the percentage of total MW in the queue that has been withdrawn at various stages, including Active and Done[4] . Note that as of now, the 2019-2022 queue cycles remain active. Looking at the fully completed cycles in our sample (2017-2018

[4] Done means the project has completed the interconnection queue process.

cycles), nearly 70% of the total generation capacity that entered these cycles was eventually withdrawn. We observe that a considerable percentage of capacity is withdrawn during the Pre-Kick-off phase. The 2022 Cycle for example, which has not yet reached the DPP Phase, has already had 14% of the initially entered capacity withdrawn. This raises concerns about whether some projects are being entered into the queue speculatively without undergoing proper due diligence. Most of the withdrawn projects exit either before the DPP Start or at Decision Point 1, which highlights the need to incentivize more careful project assessment before entry into the queue.

Next, we examine the withdrawal dynamics based on the relative portion of the queue that each participant holds. The company size is determined by considering the total MW of projects within our sample. Table 2 illustrates the overall share of projects and the withdrawal pattern for the top developers in MISO territory.

According to the data in Table 2, the top 3 companies (as defined by requests to enter into the queue) collectively accounted for 30% of the capacity entered into the 2017 - 2022 interconnection queues. Of all applications submitted by these top 3 companies, 72% were eventually withdrawn. As we expand our analysis to include more companies, the overall percentage of withdrawn applications decreases. In comparison, when considering all companies in the sample, the withdrawal rate was 53%. This observation may imply a greater likelihood of speculative entry among the most active companies.

**Table 2. MISO Queue Withdrawals by Top Interconnection Customers**

| | Withdrawn MW 2017 – 2020 Cycles | | Point of Withdrawal | | | |
|---|---|---|---|---|---|---|
| | MW submitted into queue as % of all projects | Out of submitted, % withdrawn | % Withdrawn before DPP Start | % Withdrawn at DPP1 | % Withdrawn at DPP2 | % Withdrawn Phase 3 and after |
| Top 3 Companies | 30% | 72% | 32.5% | 37.8% | 22.6% | 5.5% |
| Top 5 Companies | 34% | 69% | 36.3% | 34.8% | 21.6% | 5.9% |
| Top 10 Companies | 40% | 68% | 38.4% | 32.1% | 20.9% | 7.4% |
| Top 15 Companies | 43% | 67% | 37.0% | 33.4% | 20.2% | 6.9% |
| Top 20 Companies | 46% | 66% | 38.0% | 33.2% | 19.3% | 7.1% |
| Top 25 Companies | 49% | 67% | 36.4% | 32.8% | 19.3% | 8.6% |
| **All Companies** | **100%** | **53%** | **33.6%** | **31.4%** | **19.7%** | **11.0%** |

Source: MISO. Note: figures by row may not sum to 100% due to missing withdrawal dates for some projects.

When we consider the timing of withdrawals, the top companies' withdrawal patterns differ from the broader pool of companies in the sample. The top developers are more likely to withdraw in the initial stages of the process and less likely to withdraw in Phase 3 or beyond. This finding suggests that top companies might have greater resources enabling follow-through and

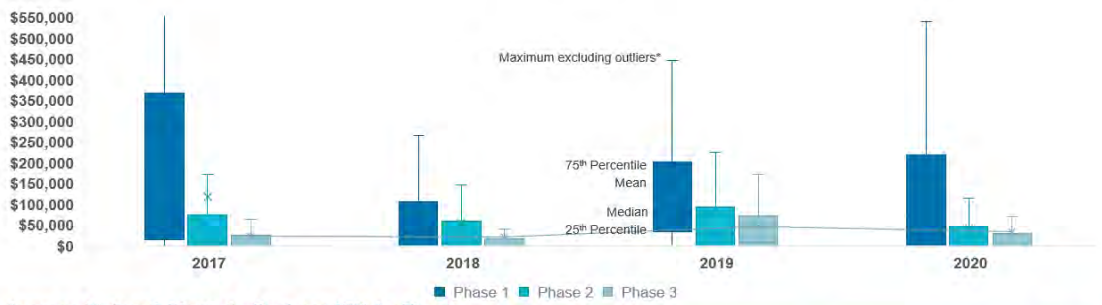
commitment, which explains the lower withdrawal rates at later phases as compared to other companies in the sample.

## 2.4. Network Upgrade Costs

In this section, we analyze the network upgrade costs per MW. As previously discussed in Section 2.2, the network upgrade costs are initially calculated in DPP 1, followed by DPP 2, and ultimately finalized in DPP 3. For a comprehensive overview, Figure 4 illustrates the network upgrade costs for the cycles spanning from 2017 to 2020, allowing for a comparison of average costs across the three DPP phases.

The average network upgrade costs in DPP 1 are notably higher compared to those in DPP 2 and DPP 3. This outcome is not surprising, considering the larger size of the initial queue. As projects progress through the phases, many drop out, leading to a more manageable number of projects being analyzed and, consequently, more realistic network upgrade costs. Additionally, the projects with the highest network upgrade costs are expected to drop out first.

**Figure 4. Network Upgrade Cost per MW, by DPP Phase[5]**




**Average Network Upgrade Cost per MW, by Phase**

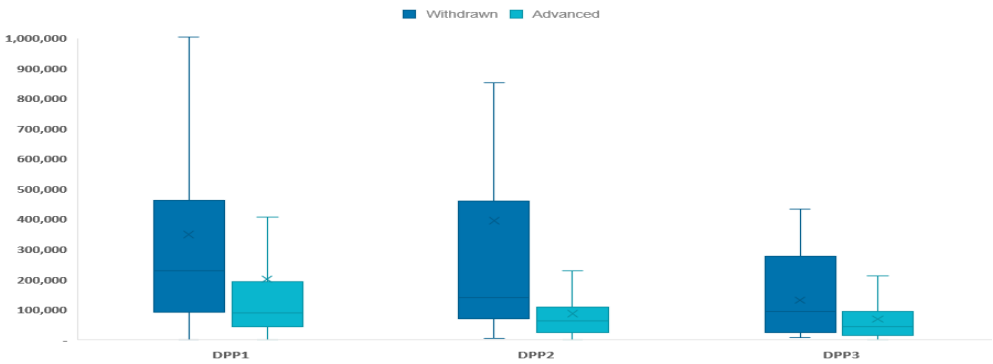
| | 2017 | 2018 | 2019 | 2020 | Average |
|---|---|---|---|---|---|
| Phase 1 | $341,916 | $101,703 | $170,781 | $297,694 | $232,051 |
| Phase 2 | $216,525 | $100,492 | $122,008 | $112,098 | $138,353 |
| Phase 3 | $53,518 | $56,483 | $82,037 | $94,279 | $72,514 |

Source: MISO.

[5] A box plot consists of a rectangular "box" that represents the interquartile range (IQR) of the data, (25th to 75Th percentile), and the "whiskers" show the range of the data. Any data points beyond the whiskers are considered outliers and are not shown on this chart.

We observe that the sample mean (marked as 'x') consistently exceeds the median (denoted by a line). This suggests that most of the projects within each plotted distribution have network upgrade costs lower than the average.

**Figure 5. Network Upgrade Cost per MW, by Phase and Status**




**Average Network Upgrade Cost per MW, by Phase and Status**

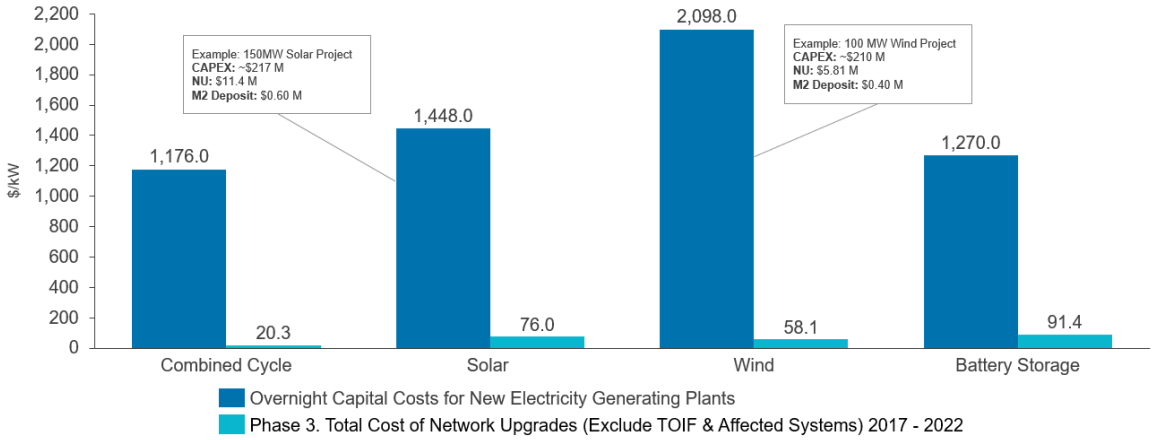
| | DPP1 | DPP2 | DPP3 |
|---|---|---|---|
| Withdrawn | $349,601 | $395,560 | $132,849 |
| Advanced | $201,878 | $87,747 | $70,059 |

Source: MISO.

Figure 5 presents the aggregate data for the 2017 – 2020 cycles. It illustrates the distinct cost distributions of network upgrades for projects that either proceeded to the subsequent DPP stage or were withdrawn at each respective DPP stage. At Decision Point 1, the average network upgrade cost per MW for a withdrawn project was $349,601, and projects that advanced to the next stage had an average network upgrade cost of $201,878. As anticipated, the projects that were advanced tend to, on average, have lower costs compared to those that were withdrawn.

The average network upgrade cost for projects that advanced beyond DPP 1 is notably higher than those advanced beyond DPP 2. This suggests that developers have an understanding that the network upgrade costs are likely to decrease in subsequent phases.

**Figure 6. Network Upgrade Cost per MW vs. CapEx**




Source: MISO (2017-2022 Cycles), EIA AEO (March 2023) Overnight Capital Costs for New Electricity Generating Plants

Figure 6 illustrates the comparison between the capital costs needed to construct a new generation facility and the average network upgrade costs that the same facility is anticipated to incur for securing interconnection in MISO. The network upgrade costs constitute only a fraction of the overall budget that developers are required to allocate.

This consideration plays a role when discussing incentives to deter speculative entry into the interconnection queue. The accepted economic deterrents for unwanted behavior are penalties. To be effective, penalties should be assessed within the context of overall costs and budgets.

# 3. RECOMMENDATIONS

This section presents our recommendations for MISO queue policies, aiming to achieve the dual goals of reducing the size of the interconnection queue and decreasing the withdrawal rate. Once these challenges are successfully addressed, study times will decrease, leading to enhanced efficiency within the MISO interconnection queue. This improvement will enable MISO to process more projects more quickly than the current situation allows and should result in customers receiving more dependable information with which to make business decisions regarding their projects.

## 3.1. DEFINITION OF HARM

The interconnection queue within MISO has reached a point where it has become unmanageable at entry, and modeling upgrade costs in the early phases has become unrealistic. Additionally, the frequent dropouts within the interconnection queue create significant uncertainty, making the results of studies unreliable and subject to significant change over the course of the study process. This constant fluctuation requires continual reevaluation, adding complexity to the process. We observed that interconnection requests are withdrawn at every stage, leading to changes in results and even more withdrawals.

Two behavioral aspects behind the problems identified above are (1) speculative entry and (2) frequent withdrawals. The two aspects are intertwined as projects that enter the queue without due diligence regarding readiness and feasibility are more likely to be withdrawn.

Effective preventive measures should be implemented to discourage these harmful behaviors. Creating and enforcing these measures establishes a more responsible environment, minimizing harm. To achieve this, harmful behavior must be clearly defined. Once appropriately defined, it becomes the basis for levying penalties where harmful behavior is proven to exist.

Withdrawals are unlikely to be penalized under the present definition of harm, which is narrowly focused on cost increases to remaining projects due to required Network Upgrades following a project's withdrawal. This definition accounts for situations where shares of required transmission upgrades are allocated to remaining projects after a re-study analysis. However, it may also result in less expensive required transmission upgrades and lower allocated shares, reflecting the stepped nature of upgrade costs as incremental generation capacity is accommodated. Such outcomes do not mean that the remaining projects are unharmed by the withdrawal. On the contrary, they suffer from the additional time required for necessary re-studies and the uncertainty engendered by the constantly changing queue.

Interdependencies among projects and shared information mean that withdrawals inevitably impact other projects through delays and increased uncertainty; these two impacts should be recognized as harmful:

> Delays: The study process is delayed when projects withdraw, and previously identified upgrades may no longer be applicable. This leads to more time required for analysis.
>
> Uncertainty: Projects in the queue rely on network upgrade estimates for crucial business decisions, and these decisions are undermined when projects are withdrawn.

Regardless of why a project is withdrawn from the interconnection queue, such withdrawal invariably inflicts some harm on remaining projects. This harm might be quantifiable in monetary terms but is often intangible and can only be described qualitatively.

Besides the measurable harm of increased upgrade costs, the delays and uncertainty inherent in the process argue for a harm penalty. This penalty, even when the harm isn't directly measurable, should escalate with each stage of the process to encourage early decision-making regarding non-viable projects. The presence of such a penalty recognizes that harm extends beyond mere dollars and cents, encompassing broader impacts on the queue's efficiency and reliability.

### 3.2. PENALTY FREE WITHDRAWAL ADJUSTMENT

Penalty-free withdrawal should be eligible only for projects facing a significant increase in total costs. Current MISO rules that allow for penalty-free withdrawal are outlined in Section 7.6.2 Refunds of Definitive Planning Phase Milestones (M2, M3, M4) of the Generator Interconnection Procedures (GIP). Figure 7 below summarizes our analysis of the penalty-free withdrawal rules.

**Figure 7. Penalty-free withdrawal rules application**

**Under current rules:**
Out of projects that reached DPP2, **42%** are eligible for penalty free withdrawal
Out of projects that reached DPP3, **37%** are eligible for penalty free withdrawal

| Status and Withdrawal Phase | DPP-2017-AUG | DPP-2017-FEB | DPP-2019-APR | DPP-2019-Cycle | DPP-2020-Cycle | DPP-2021-Cycle | DPP-2022-Cycle |
|---|---|---|---|---|---|---|---|
| Active | 2 | | 2 | 30 | 179 | 413 | 762 |
| Done | 64 | 17 | 80 | 131 | 17 | | |
| Withdrawn: Pre Kick off | 29 | 1 | 39 | 33 | 98 | 46 | 128 |
| Withdrawn: Decision Point 1 (DPP 1) | 51 | 23 | 81 | 52 | 3 | 12 | 2 |
| Withdrawn: Decision Point 2 (DPP 2) | 24 | 13 | 20 | 10 | 22 | | |
| Withdrawn: During DPP Phase 3 | 2 | 1 | 7 | 9 | 10 | | |
| Withdrawn: During GIA Execution Phase | 11 | | 1 | 2 | 5 | | |
| Withdrawn: Post GIA | 7 | 6 | 1 | 1 | | | |
| Withdrawn: Withdrawn - Pending Cure | | | | 1 | | | |
| Withdrawn: Withdrawn - No Date | | | | 2 | 19 | 6 | |
| Withdrawn Total | 124 | 44 | 157 | 140 | 157 | 64 | 130 |
| Total Project | 190 | 61 | 239 | 301 | 353 | 477 | 892 |

**127** projects withdrew at DPP 2; data available to evaluate **83** for penalty-free withdrawal eligibility.

| | > 25% NU Cost Increase | > 10,000 per MW Cost Increase | >10,000 Affected System upgrade costs increase | Eligible for Penalty-free withdrawal |
|---|---|---|---|---|
| Number of projects that qualify | 36 | 30 | 19* | 61 |
| % of total that qualify | 43% | 36% | 23% | 73% |

**29** projects withdrew at DPP 3; data available to evaluate **23** for penalty-free withdrawal eligibility.

| P2 to P3 | | | P1 to P2 | | | |
|---|---|---|---|---|---|---|
| > 35% NU Cost Increase | > 15,000 per MW Cost increase | > 40% Affected System upgrade costs increase | >$15,000 Affected System upgrade costs increase | > 50% NU Cost Increase | > 20,000 per MW Cost increase | Eligible for Penalty-free withdrawal |
| 9 | 8 | 3 | 7 | 9 | 6 | 17 |
| 39% | 35% | 13% | 30% | 39% | 26% | 74% |

*Only 2 projects had non-zero Affected System Upgrade costs in P1.

Source: MISO

The penalty-free withdrawal procedure is based on a comparison between the previously estimated network upgrade cost within the same cycle and the new estimates. As such, this procedure is only applicable at Decision Point 2 and when the DPP3 cost estimates become available.

Current rules allow for a broad set of circumstances to qualify. For example, projects that experience a significant decrease in network upgrade costs may still qualify if affected systems costs increase. This is one of the key reasons why penalty-free withdrawals apply to a large number of projects in the queue. For example, 42% of all projects that reached DPP2 are eligible for penalty-free withdrawal, and 37% of all projects that received network upgrade costs in phase 3 are eligible for penalty-free withdrawal in that phase.

Simple and efficient rules ensure that only projects facing significant increases in overall costs qualify for penalty-free withdrawal. We suggest streamlining the rules and applying only a percentage increase in combined network upgrade and affected systems costs from DPP1 to DPP2 or DPP2 to DPP3. That is, streamline rules to allow penalty-free withdrawal if:

Combined NU + AS cost increased by 50% from P1 and P2 (1)

Combined NU + AS cost increased by 35% from P2 and P3 (2)

The suggested thresholds of 50% and 35% are selected using data in Table 3 below. First column in Table 3 is the threshold, second shows the % of projects that reached DPP2 that would be eligible for penalty free withdrawal under (1) above, and the third column shows the % of projects that reached DPP3 eligible for withdrawal penalty-free withdrawal under (2) above.

At the suggested threshold of 50% cost increase from P1 to P2, 30% of all projects that reached DPP2 would be eligible for penalty-free withdrawal. At the suggested threshold of 35% cost increase from P2 to P3, 20% of all projects that reached DPP3 would be eligible for penalty-free withdrawal.

**Table 3. Sensitivity of Withdrawal Eligibility to NU + AS Threshold**

| Combined NU + AS % Increase Threshold | P2 to P1: % of Projects that Reached DPP2 Eligible for Withdrawal | P3 to P2: % of Projects that Reached DPP3 Eligible for Withdrawal |
|---|---|---|
| 10% | 43% | 27% |
| 20% | 37% | 22% |
| 25% | 36% | 21% |
| **30%** | **34%** | 20% |
| 35% | 33% | 20% |
| **40%** | 31% | **18%** |
| 45% | 31% | 16% |
| 50% | 30% | 15% |
| 55% | 29% | 14% |
| 60% | 29% | 13% |
| 65% | 27% | 13% |

Source: MISO

## 3.3. M2, M3 AND M4 ADJUSTMENTS

We recommend that MISO adjusts M2, M3, and M4 deposits to better reflect potential harm caused by a withdrawal at each study phase.

In The M2 deposit should be more representative of the final NU payment and significant enough to discourage speculative behavior. To aid our analysis of the appropriate deposit we consider average per MW costs in each phase of DPP cycle. We consider a range of 15% to 25% of the average NU cost in Phase 3 to determine a reasonable value range for the M2 deposit amount.

**Table 4. Network Upgrade Costs[6]**

| Study Cycle | Average of NU Cost per MW, Phase 1 | Average of NU Cost per MW, Phase 2 | Average of NU Cost per MW, Phase 3 | 15% of NU Cost in Phase 3 | 20% of the NU Cost in Phase 3 | 25% of NU Cost in Phase 3 |
|---|---|---|---|---|---|---|
| DPP-2017-AUG | $177,999 | $118,107 | $53,583 | $8,038 | $10,717 | $13,396 |
| DPP-2017-FEB | $840,358 | $521,006 | $53,247 | $7,987 | $10,649 | $13,312 |
| DPP-2018-APR | $101,703 | $100,492 | $56,483 | $8,472 | $11,297 | $14,121 |
| DPP-2019-Cycle | $170,781 | $122,008 | $82,037 | $12,306 | $16,407 | $20,509 |
| DPP-2020-Cycle | $297,694 | $112,098 | $94,279 | $14,142 | $18,856 | $23,570 |
| **Total In-Sample Average** | **$232,051** | **$138,353** | **$72,514** | **$10,877** | **$14,503** | **$18,129** |
| **Total in-Sample Median** | **$80,624** | **$70,690** | **$48,420** | **$7,263** | **$9,684** | **$12,105** |

Source: MISO

We recommend an increase of the M2 amount from $4,000 / MW to a value in the range of $10,000 to $14,000 / MW.

Deposits should increase at each stage, reflecting harm that occurs with withdrawal at later stages in the study process. Additionally, we suggest that M3 and M4 deposits should never be negative. Negative or zero deposits are not representative of harm that occurs should a project withdraw. We suggest adjusting M3 and M4 formulas to:

$$M3 = \text{Max of } \$1{,}000 \text{ and } ((10\% * NU) - M2)$$

$$M4 = \text{Max of } \$1{,}000 \text{ and } ((20\% * NU) - M3 - M2)$$

We believe that this deposit structure more accurately aligns with the network upgrade costs that developers are likely to incur.

## 3.4. Fixed Penalty Schedule

To mitigate the issues of an unwieldy queue size and frequent withdrawals, it is essential to implement penalties for detrimental practices. As previously discussed, both entering the queue without adequate due diligence and exiting the queue by interconnection customers contribute to an unmanageable queue size and create significant uncertainty.

Penalties are a proven economic lever for curbing undesirable behavior. For such penalties to be effective, they must be both substantial and consistently applied when unwanted actions occur.

Requiring a deposit alone is not a sufficient deterrent unless it is integrated with a comprehensive penalty structure. We propose implementing a fixed penalty schedule in conjunction with the current penalties to address this. Specifically, the current total amounts at risk from the DPP1 and beyond will remain unchanged. However, a predetermined percentage of the M2 deposit will be forfeited at withdrawal, regardless of the specific harm calculations. This percentage should

[6] Similar table based on median values is included in the Appendix

escalate with each successive phase of the DPP. We recommend that this penalty be applied to every withdrawal, extending even to those that occur before the commencement of the DPP.

Table 5 illustrates the suggested penalty schedule with an example.

**Table 5. Current and Potential Penalties by DPP Cycle**

| Withdrawal Time/ Stage of the Cycle | Current Penalties: at risk subject to harm calculations | Suggested Penalty Schedule: Example | | |
|---|---|---|---|---|
| | | *Fixed Penalty Schedule* | *Harm Calculation* | *Penalty-Free withdrawal* |
| Before DPP Start | No penalty | 10% of M2 Deposit | Doesn't apply | Doesn't apply |
| Decision Point 1 | 50% of M2 at risk | 25% of M2 Deposit | Applies | Doesn't apply |
| Decision Point 2 | 100% of M2 at risk | 50% of M2 Deposit | Applies | Applies |
| During Phase 3 | M2, M3, and M4 at risk | 75% of M2 Deposit | Applies | Applies |
| GIA Execution Phase and beyond | M2, M3, and M4 at risk | 100% of M2 Deposit | Applies | Doesn't apply |

Source: MISO

We suggest distributing the collected penalties pro-rata to completed projects of the same cycle. This provides additional support for projects that go through the process and additional incentive for interconnection customers to complete projects.

## 3.5. QUEUE CAP PER CYCLE

Robust demand for generation interconnection has caused the MISO queue to grow to an unmanageable size, with interconnection requests exceeding what MISO can process in a single cycle, contributing to a substantial backlog.

To mitigate the negative impact of excessive requests on participants and the overall study process, establishing a queue cap might be a solution. The implementation of a queue cap not only limits these detrimental effects but also strengthens the case for withdrawal penalties at every stage, including pre-kick-off.

The excessive interconnection requests compromise other study cycle participants and the overall integrity of the study process. As previously shown, these excessive requests can artificially inflate the magnitude of network upgrade costs in the early stages of the study cycle, leading to escalating financial and manpower burdens on MISO and other stakeholders as the queue size surpasses reasonable limits. Moreover, dissatisfaction with the process could fuel more speculative requests, and projects forced to drop out may swell the number of requests seen in subsequent study cycles.

MISO should determine the level of the queue cap along with its application across study regions, cycles, and possibly entities. The cap should be designed considering certain criteria for MISO overall and by region. For example, the following could be considered:

- Peak load and forecasted peak load.
- Installed capacity, guaranteed additions, and expected retirements.
- Reliability and resource adequacy.

All applications in excess of the cycle queue cap should be entered into the next cycle.

To give a tangible example, the queue cap per cycle could be set as a percentage of the forecasted peak load and/or installed capacity.

### 3.6. PER DEVELOPER CAP

Implementing a per-developer cap can be an approach to ensuring fairness within the interconnection queue, though it may present challenges in execution. To prevent a single developer from having disproportionate control or excessively entering multiple projects, it is advisable to consider specific safeguards when putting an overall queue cap in place.

These safeguards should be designed to maintain a balanced playing field among developers. It's important to recognize that no specific threshold is universally accepted to spark antitrust concerns; rather, this depends on a variety of factors, including market concentration, the potential for market manipulation, barriers to entry, and the possibility of harm to competition.

If an overall queue cap is put in place, we recommend considering a per-developer cap as well, set at a level between 5% and 15% of the overall queue cap per cycle. The implementation of a per-developer cap would necessitate a robust administrative process, with certain key elements to be included. These could encompass:

- **Authentication**: Define the entity or organization that is subject to the cap. Clear procedures should be established to ensure that all branches or subsidiaries of the same organization are included under the same cap.
- **Monitoring and Reporting**: Establish a system to track the project entries of each developer.
- **Verification**: Develop processes to validate the reported information provided by developers.
- **Transfers**: Ensure that transfers do not result in cap violations.
- **Penalties**: Define penalties for developers who exceed the prescribed limits.
- **Appeals and Dispute Resolution**: Establish a process for developers to appeal decisions related to cap enforcement.
- **Regular Review and Adjustment**: Conduct regular reviews of the cap's effectiveness and consider adjustments if necessary.

## 4. SUMMARY

CRA’s analysis supports the argument that reform to generator interconnection queue rules for queue entry and exit could alleviate interconnection constraints. A key step to reform is an

adjustment to the definition of harm. The new definition should acknowledge that withdrawn projects harm those remaining in the queue beyond cost shifting via queue delay and uncertainty. One suggestion to reducing queue sizes is that MISO establish queue cap rules. These caps, either in the form of regional caps or developer caps per cycle, could limit excessive requests detrimental to other participants and the overall study process. Updating the monetary value placed on entering, remaining in, and withdrawing from the queue will prevent speculative projects from entering the interconnection process. CRA recommends increasing the M2 deposit to a value in the range of $10,000-$14,000/MW and adjusting the M3 and M4 deposit formulas to a minimum of $1,000 to reflect final costs better. CRA also recommends that MISO implement an escalating fixed penalty schedule, including a minimum pre-kick-off stage withdrawal penalty to support the queue cap implementation. The penalty-free withdrawal rules should be updated to consider the overall percentage increase in combined network upgrades and affected system costs. Penalty-free rules should not apply after phase 3.

# 5. APPENDIX

The table presented below is a revised version of Table 4 from the report, adjusted to reflect median values. We've incorporated this table in response to feedback from stakeholders.

The values in this table support our recommendation for the M2 deposit, particularly when greater emphasis is placed on values from the latest cycles. Giving more weight to values from recent studies offers a more accurate representation of the queue's current status.

**Table 6. Network Upgrade Costs, Median Values**

| Study Cycle | Median of NU Cost per MW, Phase 1 | Median of NU Cost per MW, Phase 2 | Median of NU Cost per MW, Phase 3 | 15% of Median NU Cost in Phase 3 | 20% of Median NU Cost in Phase 3 | 25% of Median NU Cost in Phase 3 |
|---|---|---|---|---|---|---|
| DPP-2017-AUG | $ 89,051 | $ 52,000 | $ 42,948 | $ 6,442 | $ 8,590 | $ 10,737 |
| DPP-2017-FEB | $ 655,871 | $ 111,467 | $ 35,815 | $ 5,372 | $ 7,163 | $ 8,954 |
| DPP-2018-APR | $ 67,918 | $ 55,860 | $ 36,524 | $ 5,479 | $ 7,305 | $ 9,131 |
| **DPP-2019-Cycle** | **$ 100,511** | **$ 75,228** | **$ 56,814** | **$ 8,522** | **$ 11,363** | **$ 14,203** |
| **DPP-2020-Cycle** | **$ 135,621** | **$ 80,175** | **$ 65,872** | **$ 9,881** | **$ 13,174** | **$ 16,468** |
| Total in-Sample Median | $ 80,624 | $ 70,690 | $ 48,420 | $ 7,263 | $ 9,684 | $ 12,105 |

Source: MISO

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | |
|---|---|
| Federal Power Act Section 202(c) | ) |
| Emergency Order: Midcontinent | ) |
| Independent System Operator | ) |
| (MISO) | ) |
| | ) |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

# Exhibit 113

# Inst. Pol'y Integrity Report

# Enough Energy

## A Review of DOE's Resource Adequacy Methodology

Jennifer Danis
Christoph Graf, Ph.D.
Matthew Lifson

**July 2025**

Institute *for* Policy Integrity
NEW YORK UNIVERSITY SCHOOL OF LAW

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Institute for Policy Integrity
New York University School of Law
Wilf Hall, 139 MacDougal Street
New York, New York 10012

Jennifer Danis is the Federal Energy Policy Director at the Institute for Policy Integrity at NYU School of Law, where Christoph Graf, Ph.D. is a Senior Economist and Matthew Lifson is an Attorney.

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This report does not purport to present the views, if any, of NYU School of Law.

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# Executive Summary

On April 8, 2025, President Trump issued an Executive Order on Strengthening the Reliability and Security of the United States Electric Grid (the EO) requiring the Department of Energy (DOE) to (1) "identify current and anticipated regions with reserve margins below acceptable thresholds" and (2) "establish . . . a protocol to identify which generation resources within a region are critical to system reliability."[1] DOE responded on July 7, 2025 with its *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* (DOE Study).[2]

This report reviews best practices for analyzing whether a region is resource adequate and for identifying whether a particular resource is critical for resource adequacy. It next analyzes the DOE Study as compared to those best practices. Finally, it examines next steps for U.S. resource adequacy policy following the DOE Study, in light of different entities' respective authorities over the issue.

In Part 1, this report outlines a four-step process for evaluating whether a region is resource adequate and then identifying which resources are critical. Each step involves choices between traditional methods and best practices adapted to the evolving risks posed by the energy transition and the new conditions brought about by climate change.

- *Step 1*: *Set a Resource Adequacy Target*: Planners should define resource adequacy targets using a multi-metric approach that captures not just outage frequency but also magnitude and duration, possibly supplemented by metrics focused on tail risks instead of expected values. Targets should be region-specific and reflect a local cost-benefit analysis that weighs the incremental benefits and costs of achieving reduced outages.
- *Step 2: Conduct Resource Adequacy Modeling:* Rather than focusing narrowly on annual peak load, planners should assess whether a region achieves the target from Step 1 by modeling all 8,760 hours of the year in chronological order using probabilistic techniques that account for uncertainty like the Monte Carlo method. Best practices include incorporating weather-linked dependencies; climate-adjusted inputs; and realistic assumptions about retirements and additions, interregional imports, and storage and demand response dynamics. This modeling more accurately reflects the risks posed by variable generation and energy-limited resources.
- *Step 3: Establish Accreditation Values:* Resource accreditations—the specific contribution of a resource or resource type to resource adequacy—should be derived from Step 2's probabilistic modeling of a resource's ability to contribute during hours of highest risk.

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1 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521–22 (Apr. 14, 2025).

2 U.S. Dep't of Energy, Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid (2025), https://perma.cc/A587-S88S.

Effective Load Carrying Capability or related probabilistic methods should be applied to all resource types, including thermal plants, to accurately describe their contributions under a wide range of possible futures and hard-to-predict risk periods. Accreditation methods should be applied equally to thermal and variable resources to allow for technology-neutral comparisons.

- *Step 4: Calculate the Reference Margin Level and the Reserve Margin:* Using the resource adequacy modeling and accreditation values from Steps 2 and 3, planners should calculate a reference margin level—the amount of accredited capacity that corresponds to achieving the resource adequacy target. Comparing a region's actual resource fleet to this benchmark allows planners to determine whether the exit or entry of specific resources would affect achievement of the reference margin level and thus the resource adequacy target, given the resources' accreditations.

Part 2 compares the best practices from Part 1 to DOE's methodology in the DOE Study—in which DOE concluded that all transmission planning regions except ERCOT are currently resource adequate but that all regions except ISO-NE and NYISO will be resource inadequate in 2030. Across multiple dimensions, DOE's approach departs from best practices in ways that call these results into question.

- *Resource Adequacy Targets:* DOE's use of a multi-metric standard—2.4 hours of lost load per year and 0.002% normalized unserved energy—is consistent with best practices, but the choice of values is not. Neither value is appropriately justified based on a cost-benefit framework, and the use of a one-size-fits-all target for the entire country ignores regional differences. Additionally, DOE inappropriately attempts to label PJM as currently resource inadequate even though the region achieves DOE's own target according to DOE's modeling.

- *Resource Adequacy Modeling:* DOE models all 8,760 hours of the year chronologically but relies on a deterministic rather than probabilistic framework, limiting its ability to assess uncertainty or tail risks. This less accurate approach evaluates adequacy only under a fixed set of historical weather and load years. Further, DOE's truncated description of how its model decides whether an outage has been triggered makes this assumption impossible to fully evaluate, but DOE's limited explanation does suggest that it may have adopted an overly conservative approach that exaggerates resource adequacy risk. Finally, DOE's 2030 results are significantly shaped by unrealistic assumptions about additions, retirements, load, and possibly interregional imports.

- *Accreditation and Reference Margin Levels:* The DOE Study does not attempt to identify resources that are critical for any region's resource adequacy, and thus does not calculate accreditation values or reference margin levels. But DOE does estimate the amount of perfect capacity required to bring certain regions to the 0.002% NUSE target. DOE could build upon this approach in the future to calculate reference margin levels, but any future efforts should attend to all prongs of its multi-metric resource adequacy target. Additionally, DOE's perfect capacity additions inexplicably bring regions far beyond 0.002% NUSE, meaning that DOE overstates how difficult it would be to cure the purported resource adequacy shortfalls.

Part 3 answers what should happen next for U.S. resource adequacy policy now that DOE has published its study.

- Given how DOE's statutory authority under Section 202(c) of the Federal Power Act is limited to emergencies, DOE's own conclusion that most regions are not currently experiencing resource adequacy shortfalls suggests that DOE has limited legal authority to address potential problems in 2030. Moreover, the limitations of the DOE Study call into question the accuracy of DOE's forecasts.
- Instead of DOE, the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation could more appropriately—and less intrusively from the perspective of states, grid operators, and markets—support resource adequacy by issuing reliability standards that require best practices for regions' resource adequacy efforts. Rather than establishing a national resource adequacy target, these standards would govern how regions select resource adequacy targets, evaluate if they are achieving them, and measure the contributions of specific resources. This step would be in line with the Federal Energy Regulatory Commission's Order No. 747, which approved analytical guardrails for resource adequacy analysis for a portion of the U.S.

# Introduction

How does a regional electric grid operator know when its region has enough electricity to meet demand and whether any specific generation resource, like a particular coal plant, is essential for doing so? President Trump's Executive Order on Strengthening the Reliability and Security of the United States Electric Grid (the EO) implicates these questions: The EO directs the Department of Energy (DOE) to assess if each region of the United States has sufficient energy resources to meet current and future demand, and to identify and retain critical resources.[3] On July 7, 2025, DOE responded to the EO by publishing its *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* (DOE Study).[4]

This report addresses the EO and the DOE Study's fundamental concern: resource adequacy. Resource adequacy is one key aspect of a power system's reliability. It refers to a system's "ability . . . to generate and transmit adequate quantities of electricity to meet demand, taking into account scheduled and reasonably expected unscheduled system outages."[5] Resource adequacy thus concerns whether a system's supply of energy exceeds demand. Determining whether an area is resource adequate is, however, ultimately a policy question, rather than an engineering one, because it would be prohibitively expensive to build a system that serves 100% of demand under all conditions.[6] Deciding whether a region is resource adequate always explicitly or implicitly balances society's desire for reliable electricity with the cost of providing that reliability.

Starting from first principles, Part 1 examines how to determine whether a region meets its selected resource adequacy target and how a planner can know whether any one particular resource is critical for resource adequacy. Part 2 discusses whether the DOE Study reflects, rejects, or obscure these first principles. Part 3 explores next steps for U.S. resource adequacy policy following the publication of the DOE Study, considering the respective roles of the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC), DOE, grid operators, and states.

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3 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521 (Apr. 14, 2025).

4 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2.

5 Burçin Ünel & Avi Zevin, Inst. for Pol'y Integrity, Toward Resilience: Defining, Measuring, and Monetizing Resilience in the Electricity System 11 (2018), https://perma.cc/UDB5-DEEM (citing a NERC "Frequently Asked Questions" page that is no longer available).

6 Energy Sys. Integration Grp., New Resource Adequacy Criteria for the Energy Transition: Modernizing Reliability Requirements 38 (2024), https://perma.cc/NXU4-N4UG.

# Part 1: Best Practices for Resource Adequacy

The EO requires DOE to evaluate the sufficiency of regions' "reserve margins" and establish a resulting protocol to identify "critical" resources that should be retained.[7] To figure out what kind of buffer will ensure that a region achieves a given level of resource adequacy, and to label specific generators as essential for that resource adequacy, a planner would need to undertake a four-step process. At each step, the planner must pick between antiquated approaches and newer best practices.

First, the planner must make the policy choice of selecting a resource adequacy target for the region that, if achieved, would indicate resource adequacy. Second, it should use resource adequacy modeling to determine whether a region has achieved and will continue to achieve the selected target under foreseeable future conditions. Third, the planner should use its resource adequacy modeling with accurate data curation to derive how each generation and storage resource contributes to meeting the target (their "accreditation" values). Fourth, it should use the resource adequacy modeling plus resources' accreditation values to derive an acceptable reserve margin for the region (the "reference margin level"). At this fourth step, the planner can use the accreditation values to check whether the exit of a particular resource would cause a region to dip below the reference margin level.

These best practices have largely emerged to address the resource adequacy challenges caused by the energy transition and extreme weather events caused by climate change. Whereas traditional methods have focused on whether demand would exceed supply during peak load hours, system risk has shifted to *net* peak hours, i.e., when load minus variable generation is highest.[8] Measuring whether supply will meet demand has itself become more complicated. Increasingly, it has become important to perform modeling resource adequacy chronologically—each hour reflecting the conditions that came before it—to account for the dynamics of battery storage resources and demand response.[9] And policymakers now are also confronting the outdated idea that thermal resources are "perfect" capacity, given their weather-related vulnerabilities.[10]

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7 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521–22 (Apr. 14, 2025).

8 Juan Pablo Carvallo et al., Lawrence Berkeley Nat'l Lab'y, A Guide for Improved Resource Adequacy Assessments in Evolving Power Systems: Institutional and Technical Dimensions 13 (2023), https://perma.cc/5VLY-B7HF.

9 N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, Evolving Planning Criteria for a Sustainable Power Grid: A Workshop Report 9 (2024), https://perma.cc/KE8D-W6VX.

10 Nat'l Ass'n of Regul. Util. Comm'rs, Resource Adequacy for State Utility Regulators: Current Practices and Emerging Reforms 32–34 (Nov. 2023), https://perma.cc/K88X-2JCR.

## Step 1: Pick a Resource Adequacy Target

Before any analysis can determine if a system is resource adequate, policymakers must set a clear resource adequacy *target*.[11] This first step involves two distinct choices: (1) selecting one or more metrics to represent the variables by which resource adequacy will be judged, and (2) setting the numerical values for those chosen metrics to achieve the resource adequacy target.

Consider what it would take to set a target, not for resource adequacy, but for human health. First, you would pick the metrics that you think would best define whether a person is healthy, e.g., blood pressure, resting heart rate, or cholesterol levels. Using only one metric would not give you enough information. And paying attention to only each metric's average levels without also examining whether the metric ever reaches dangerous levels could obscure risk of a catastrophic health event. Second, you would pick a value for each metric, like a blood pressure of less than less than 120/80 mmHg. To pick that value, you would consider the best available evidence on what level is optimal.

Similarly, when it comes to resource adequacy, the best practice is to move beyond the standard approach of attending primarily to the *frequency* of outages and to also consider their *magnitude* and *duration*. Additionally, regions should consider metrics focused on the extremes of the probability distribution, rather than expected value metrics that could label a system as resource adequate when a low probability (but plausible) event would be catastrophic.

When selecting numerical values for the chosen resource adequacy metrics, the best practice is to consider the best available evidence on the tradeoff between the benefits and costs of additional resource adequacy. The optimal level of resource adequacy may be different in each region, depending on the local costs of the investments that would be needed to reduce shortfall events and the local consequences of a shortfall.[12] A resource adequacy target should ideally represent the level of resource adequacy that the system planner has identified as socially optimal because it balances costs and benefits.

### Metrics

Historically, U.S. policymakers have framed their resource adequacy targets in terms of loss of load expectation (LOLE),[13] and this metric remains widespread.[14] LOLE typically refers to the number of days per year in which an outage occurs and is largely a measure of frequency.[15]

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[11] *See* Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 2 tbl.1.

[12] *Id.* at 39, 41.

[13] Elec. Power Rsch. Inst., Metrics and Criteria: Insights from Case Studies and Recommendations and Considerations for Future Practice 31 (2024), https://perma.cc/W4VF-VQPD.

[14] Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 8 tbl.2.

[15] Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future 3, 8 (Apr. 2022), https://perma.cc/7G9V-CNWB. Technically, the number of days per year in which an outage occurs is "loss of load days" (LOLD), which is a special case of the broader concept of LOLE, which can be used with different event-periods. *Id.* at 7–8. In North America, however, LOLE typically means LOLD. *Id.* at 7; *accord* Gord Stephen et al., *Clarifying the Interpretation and Use of the LOLE Resource Adequacy Metric* at 2, https://perma.cc/A9DJ-C3B5.

Frequency is an important characteristic to track because consumers prefer fewer outages.[16] LOLE coarsely accounts for duration, too, in that an outage that stretches multiple days will count as an additional event for each additional day.

LOLE does, however, obscure important aspects of resource adequacy. It will not differentiate between (1) a 10-hour event with 1 GWh of load shed that is followed by a second identical event within the same day and (2) a 30-minute event with 5 MWh of load shed. Customers are not indifferent, however, between these two situations.[17] Because damages depend on outages' frequency, magnitude, and duration, LOLE neglects key dimensions of resource adequacy affecting customers' wellbeing.[18] Attending to these characteristics when setting resource adequacy targets is more important than ever, because changes in the resource mix and extreme weather due to climate change mean that loss-of-load events have become less uniform and thus less interchangeable.[19]

### *The Multi-Metric Approach*

The best practice is to supplement the traditional LOLE metric (or a different frequency-focused metric like "loss of load events," which separately counts all events within a year and thus differentiates between events that occur during the same day[20]) with additional metrics that capture other dimensions of resource adequacy.[21] Both the Electric Reliability Council of Texas (ERCOT) and the Northwest Power and Conservation Council (NWPCC) have done exactly this, augmenting their LOLE-based targets to include magnitude and duration metrics.[22] Under a multi-metric approach, a system could be declared resource adequate if it achieves selected value targets for each and every metric,[23] or if it achieves some minimum number or combination of the metrics (e.g., any two of a system's three metrics).[24]

A leading magnitude metric that could be incorporated into a multi-metric approach is expected unserved energy (EUE): the amount of demand that the system will fail to serve during a period, typically a year.[25] A region's EUE can be contextualized by dividing it by the region's total annual load—this is called normalized unserved energy (NEUE).[26] Australia uses an annual unserved

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16 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 17.

17 *Id.* at 3.

18 *Id.* at 10.

19 *Id.* at 11, 15, 22.

20 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 8.

21 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 33–37; Elec. Power Rsch. Inst., Resource Adequacy Philosophy: A Guide to Resource Adequacy Concepts and Approaches 23 (2022), https://perma.cc/ZH4Y-ZD7J; Juan Pablo Carvallo et al., *supra* note 8, at 28–29; N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at vii.

22 Reliability Standard for the ERCOT Region, No. 54584, 2024 WL 4263493, at *24 (Tex. Pub. Utils. Comm'n Sept. 9, 2024); *Resource Adequacy*, Nw. Power & Conservation Council, https://perma.cc/39P6-VBNN.

23 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 35.

24 Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 31–32.

25 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 17.

26 *Id.* at 18.

energy metric,[27] as does NWPCC.[28] Planning around these magnitude metrics can help a region avoid catastrophic events associated with significant unserved energy.[29]

But, like LOLE, magnitude-focused metrics like EUE and NEUE are incomplete alone; they do not account for how the unserved energy is distributed throughout the year.[30] An alternative or complementary magnitude metric is "peak shortfall," defined as the largest expected outage of the period.[31] Peak shortfall is potentially useful because damages from a single outage increase nonlinearly with its scale.[32] Both ERCOT and NWPCC have versions of a peak shortfall metric (NWPCC's complements its EUE metric).[33]

For duration, a popular metric that could supplement frequency and magnitude metrics is loss of load hours (LOLH), which measures the number of hours per year in which an outage occurs.[34] LOLH fundamentally resembles LOLE, but is more granular because it analyzes each hour, rather than each day. As such, LOLH does a better job at expressing the aggregate duration of all shortfalls in a region.[35]

Many countries use LOLH as their sole resource adequacy metric,[36] but, in aggregating hours, it neglects the duration of individual events—even though damages increase nonlinearly with an outage's duration.[37] Supplemental metrics such as average shortfall duration[38] and the maximum shortfall length (used in Texas and NWPCC)[39] can capture this aspect of duration.

### *Accounting for Tail Risks*

Beyond questions of frequency, magnitude, and duration, a separate question when using any chosen metric is whether to look at the mean of the distribution, extremes, or both. Traditionally, regions have framed their LOLE, EUE, and LOLH goals in terms of their *mean* values.[40] But the energy transition and climate change have increased the risk of extremely damaging tail risks,[41]

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27 *Id.* at 9.

28 Nw. Power & Conservation Council, *supra* note 22.

29 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 19 tbl.4.

30 *Id.*

31 Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide 18 (2024), https://perma.cc/CB7Q-MXZM (using the equivalent phrase "MW Short").

32 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 3.

33 Reliability Standard for the ERCOT Region, No. 54584, 2024 WL 4263493, at *24 (Tex. Pub. Utils. Comm'n Sept. 9, 2024); *Resource Adequacy*, Nw. Power & Conservation Council, https://perma.cc/39P6-VBNN.

34 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 8.

35 *Id.* at 8.

36 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 8.

37 *Id.* at 3.

38 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 10.

39 Reliability Standard for the ERCOT Region, No. 54584, 2024 WL 4263493, at *24 (Tex. Pub. Utils. Comm'n Sept. 9, 2024); *Resource Adequacy*, Nw. Power & Conservation Council, https://perma.cc/39P6-VBNN.

40 Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment 4 (2023), https://perma.cc/M3A5-2WAL; Juan Pablo Carvallo et al., *supra* note 8, at 12.

41 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 22.

making it increasingly appropriate to factor these risks into regions' metrics.[42] When it comes to resource adequacy, customers care not just about how the how severe and common outages will be on average, but also about how bad the worst outages they will experience could be.

One option for assessing these potentially severe consequences is the "value at risk" method. This method defines the selected metric (whether it is focused on frequency, magnitude, or duration), not in terms of its expected value, but in terms of how bad some relatively unlikely but still plausible scenario would be.[43] For example, one of NWPCC's metrics is the maximum shortfall length, framed in terms of what the maximum shortfall length will be at the 97.5$^{th}$ percentile of the distribution, i.e., how long the shortfall would be if there were only a 2.5% chance that the shortfall could be longer.[44] Planners can also frame a metric both in terms of expected value *and* value at risk for the same system: Belgium previously had an LOLE metric that simultaneously required an expected value of less than 3 LOLH and required the 95$^{th}$ percentile of the distribution to be less than 20 LOLH.[45]

An alternative to the value at risk method is the "conditional value at risk" method, in which the metric is framed not in terms of the value at some percentile of the distribution, but in terms of the average value of the distribution beyond the percentile.[46] Policymakers' preference between these two options will depend on their risk tolerance, as the value at risk method will equally weight all tail events while the conditional value at risk method effectively places more weight on extreme events even within the tail.[47]

## Values

After picking resource adequacy metrics—whether singular or multi-valued, and based on expected values, tail risks, or a combination of the two—the second step for setting a resource adequacy target is picking the numerical value for the metric(s). In the U.S., the most common value for the LOLE metric is 0.1, i.e., outages should occur no more than 0.1 days per year.[48] Selecting a value inherently involves balancing customers' desire for resource adequacy with the cost of achieving it.[49]

Notwithstanding that tradeoff, U.S. resource adequacy planners have largely set these values without any economic analysis. The origin of the widespread 0.1 LOLE target is somewhat enigmatic, especially relative to its contemporary significance, but it appears to describe the

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42 *See* Juan Pablo Carvallo et al., *supra* note 8, at 29; Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 8; Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 10; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 26–27.

43 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 26–27.

44 Nw. Power & Conservation Council, Pacific Northwest Power Supply Adequacy Assessment for 2029 12 (2024), https://perma.cc/GZY2-PKY7.

45 Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 17.

46 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 26–27; Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 10.

47 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 27 fig.8.

48 *Id.* at 8.

49 *Id.* at 38.

level of resource adequacy that happened to exist in the 1940s.[50]

The values used in NERC's reports on regions' long-term resource adequacy similarly seem arbitrary. NERC uses a LOLH metric, labeling regions with greater than 2.4 LOLH as high risk, 0.1-2.4 as elevated risk, and less than 0.1 as normal risk. NERC does not explain the basis for these categories, but they appear to stem this from a common (but widely criticized) hourly conversion of the 0.1 LOLE standard.[51] And NERC's values for the NEUE metric—above 0.002% is high risk, less than 0.002% but above zero is elevated risk, negligible or zero is normal risk—is adapted from Australia's 0.002% NEUE target without considering the different national contexts.[52] Context matters because the U.S. and Australia may vary in terms of how damaging outages would be (e.g., how bad it would be to lose electric heating and cooling in light of the region's temperatures) and how expensive it would be to avert them (e.g., the country-specific cost of building a natural gas peaker plant).

A better practice would be to use economic principles to select a socially efficient resource adequacy target, i.e., to select the value at which the incremental costs of additional resource adequacy equal the incremental benefits of achieving it.[53] Where policymakers do estimate the *costs* of improving resource adequacy, they often turn to the concept of "cost of new entry" (CONE).[54] CONE, expressed in $/MWh, represents the marginal investment and fixed costs of adding additional capacity to the system to achieve a more stringent resource adequacy standard.[55] Historically, planners assumed the marginal resource was a combustion turbine, but today it is more accurate to assume a portfolio of diverse resources.[56] Considering CONE by itself, however, does not accurately capture the social marginal cost of achieving higher levels of resource adequacy, because adding capacity can have follow-on effects like reducing the cost of energy.[57] Accordingly, it is better to estimate total net CONE, which nets out potential system benefits such as reduced energy costs for loads and lower operating costs.[58]

To estimate the *benefits* of additional resource adequacy, planners typically rely on the value of lost load (VOLL).[59] The VOLL represents the societal cost of failing to serve a unit of energy

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50 Kevin Carden et al., Nat'l Regul. Rsch. Inst., The Economics of Resource Adequacy: Why Reserve Margins Are Not Just About Keeping the Lights On 2 (2011), https://perma.cc/LS2F-2EZR; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 6.

51 *See* N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment 11–12 (2024), https://perma.cc/GJB2-VCZQ; Juan Pablo Carvallo et al., *supra* note 8, at 11 ("The LOLE is typically used as a target setting metric and has historically taken a value of 1 event-day in 10 years, commonly (and incorrectly) interpreted as 2.4 hours per year.").

52 N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 141.

53 Kevin Carden et al., *supra* note 50, at 1; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 38–42; Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 35.

54 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 13, 41–42.

55 *Id.* at 42.

56 *Id.*

57 Christoph Graf et al., *Cost-Effective Capacity Markets* 29, https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4864513 (posted June 21, 2024); Kevin Carden et al., *supra* note 50, at 8–9.

58 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 42.

59 Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 35.

demanded by consumers and is denominated in $/MWh.[60] Estimates vary significantly across customer classes,[61] but modelers can capture this through averaging.[62] More challenging is capturing how the VOLL varies with an outage's particular characteristics. For relatively short outages, the first hour tends to the most expensive,[63] indicating that many frequent outages could be more socially disruptive than a consolidated one of equal length. Long-duration outages result in damages that increase nonlinearly (food spoilage, jeopardized medical care, and loss of access to safe drinking water).[64] Similarly, the VOLL can increase nonlinearly with magnitude: When the grid operator can no longer manage the situation through rotating outages, the resulting uncontrolled outage is much more damaging.[65] Accordingly, undertaking a cost-benefit analysis that allows VOLL to vary with duration and magnitude would produce a more accurate, cost-benefit-justified resource adequacy target.

Many jurisdictions use some version a cost-benefit analysis when setting their resource adequacy targets. In the European Union, countries solve for their specific LOLH targets by dividing a local CONE value by the local VOLL, which, in 2023, resulted in a range from 1 LOLH (Sweden) to 15 LOLH (Czechia).[66] The United Kingdom uses this same approach.[67] Australia periodically reviews its 0.002% NEUE target to ensure that the implied "value of customer reliability," which is akin the VOLL, is close to its estimated value.[68] Somewhat analogous to these examples, the administratively set, downward-sloping demand curves for capacity markets in U.S. regions like PJM embody the tradeoff between the benefits and costs of additional resource adequacy, because the curves dictate how much regions are willing to pay for each increment of additional capacity given the capacity's incremental benefits.[69] Technically, though, this cost-benefit thinking happens not when *setting* the resource adequacy target, but in deciding whether to under-, over-, or exactly *achieve* an already-determined target.

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60 Jennifer Danis et al., Inst. for Pol'y Integrity, Transmission Planning for the Energy Transition: Rethinking Modeling Approaches 6 (2023), https://perma.cc/5A6L-DJHL.

61 Michael J. Sullivan et al., Ernest Orlando Lawrence Berkeley Nat'l Lab'y, Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States xii, tbl.ES-1 (2015), https://perma.cc/CT53-8WEA.

62 *See* Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 35.

63 Michael J. Sullivan et al., *supra* note 61, at xii, tbl.ES-1.

64 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 23 fig.5.

65 *See, e.g.*, Joshua W. Busby et al., *Cascading Risks: Understanding the 2021 Winter Blackout in Texas*, 77 Energy Rsch. & Soc. Sci. (2021); Sergio Castellanos et al., *A Synthesis and Review of Exacerbated Inequities from the February 2021 Winter Storm (Uri) in Texas and the Risks Moving Forward*, 5 Progress in Energy (2023); Hassan Haes Alhelou et al., *A Survey on Power System Blackout and Cascading Events: Research Motivations and Challenges*, 12 Energies 1, 16–17 (2019).

66 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 39 fig.12, 40.

67 *Id.* at 40.

68 Reliability Panel AEMC, Final Report: Reliability Standard and Settings Review 2018 i, 14 (2018), https://perma.cc/TAN8-TPXZ.

69 *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331, at P 76 (2006) ("In addition, we agree with PJM that a downward-sloping demand curve provides a better indication of the incremental value of capacity at different capacity levels than the current vertical demand curve. Under a vertical demand curve, capacity above the Installed Reserve Margin is deemed to have no value. Incremental capacity above the Installed Reserve Margin is likely to provide additional reliability benefits, albeit at a declining level. This value is reflected in the positive (but declining) prices in the sloped demand curve to the right of the Installed Reserve Margin, but is not reflected in the current capacity market.").

## Step 2: Conduct Resource Adequacy Modeling

Once the policymaker sets a resource adequacy target, a resource adequacy model can predict whether a region is achieving it (and will continue to do so). Traditionally, modeling was limited to examining whether demand would exceed supply during one or a few peak load hours. But the energy transition, combined with extreme weather from climate change, requires planners to rethink prevailing resource adequacy modeling techniques. For most systems, it is now important to model all 8,760 hours of the year, in chronological order, to accurately capture the risk of load shed.

Along with improving models' temporal resolution, it has become important to make more sophisticated assumptions about modeling inputs. In particular, it has become critical to capture how supply and demand have become more dependent on the weather, which, in turn, has become more extreme. In general, a best practice is to use the Monte Carlo method, and run many (on the order of hundreds or thousands) simulations of grid operations, allowing the model to randomly pull from a distribution of possible values for every input.[70] Additionally, best practices exist for curating the data for each input and their interdependencies, such as representing the relationship between the weather and thermal outages.[71]

### Temporal Scope

Historically, resource adequacy modeling focused on the likelihood that supply would exceed demand during one (or a few) top demand hours, ignoring the risk of inadequate supply during the rest of the year.[72] This simplification was more plausible when the grid was dominated by dispatchable resources with relatively predicable outputs.[73]

Now, with the increased penetration of wind and solar, periods of resource adequacy risk have shifted from peak demand to "net peak" demand, defined as load minus energy from non-dispatchable resources.[74] In this new reality, the system is most likely to lack sufficient supply when there is high demand unserved by wind or solar. And, just as weather dictates the performance of these variable resources, it also affects outages at thermal generators (e.g., interruptions of natural gas supply) and load (not just by influencing customers' demand, but also by altering

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70 See Inputs, below, for a more detailed description of the Monte Carlo method.

71 For example, cold winter snaps have historically yielded correlated outages of thermal generators. Nick Wintermantel & Nick Simmons, Astrapé Consulting 8 (2022), https://perma.cc/6D7Y-QCZ2. Similarly, extreme hot weather can require both thermal and nuclear units to cease operations, if the unit can no longer use intake water bodies for cooling. *E.g., High French River Temperatures to Hit Nuclear Production Next Week*, Reuters (June 20, 2025), https://www.reuters.com/business/energy/high-french-river-temperatures-hit-nuclear-production-next-week-2025-06-20.

72 Juan Pablo Carvallo et al., *supra* note 8, at 9; N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 2.

73 N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 2; Juan Pablo Carvallo et al., *supra* note 8, at 1, 27.

74 Jill Moraski et al., Clean Air Task Force, Beyond LCOE: A Systems-Oriented Perspective for Evaluating Electricity Decarbonization Pathways 21 (2025), https://perma.cc/3A39-FQLW.

behind-the-meter generation that typically provides "negative" load).[75] Given this confluence of variables, the best practice is now to examine all 8,760 hours of the year when evaluating the likelihood and expected characteristics of shortfalls.[76]

The increased prevalence of energy-limited resources like battery storage and demand response have similarly complicated more traditional resource adequacy modeling assumptions. Battery storage's ability to avoid a resource adequacy shortfall will depend on its state of charge.[77] For example, a battery could have sufficient energy to prevent a shortfall in the morning and then, if it has no opportunity to recharge, be empty for a second event that same afternoon. Similarly, demand response participants have only a limited willingness to curtail or shift their demand; activating the program degrades its later effectiveness.[78] Accordingly, the best practice for resource adequacy modeling is to not just to consider all 8,760 hours, but to do so sequentially, capturing how storage and demand response used in one hour can affect their subsequent availability.[79]

### Inputs

To keep pace with the many uncertainties of contemporary resource adequacy analysis, planners have shifted to probabilistic modeling approaches like the Monte Carlo method.[80] Under this best practice, rather than assessing resource adequacy using specific expected values for each input, the user provides the model with a probability distribution for different inputs, and the model randomly samples from those distributions across hundreds or thousands of simulated scenarios.[81] The model will draw the load for each hour, along with potentially correlated variable generation, thermal resource availability, and transmission outages.[82]

While the Monte Carlo method can yield more accurate resource adequacy estimates than simpler methods, its accuracy depends on the user-provided probability distributions, as well as accurate specification of key interdependencies.[83] For weather data, the current best practice is to use as many years as are available, with hourly resolution and geographic granularity.[84] And, especially when forecasting longer-term resource adequacy, it has become important to account

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75 Juan Pablo Carvallo et al., *supra* note 8, at 27; Standard Authorization Request (SAR) Form, N. Am. Elec. Reliability Corp. at 2, https://perma.cc/Q8AU-9YWW.

76 Juan Pablo Carvallo et al., *supra* note 8, at 27; Standard Authorization Request (SAR) Form, N. Am. Elec. Reliability Corp. at 2, https://perma.cc/Q8AU-9YWW.

77 Energy Sys. Integration Grp., Ensuring Efficient Reliability: New Design Principles for Capacity Accreditation 11 (2023), https://perma.cc/4ETD-JQK2.

78 Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide, *supra* note 31, at 55–56.

79 N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 9; Juan Pablo Carvallo et al., *supra* note 8, at 9; Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 44.

80 Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide, *supra* note 31, at 9.

81 *Id.* at 10.

82 Juan Pablo Carvallo et al., *supra* note 8, at 13.

83 Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide, *supra* note 31, at 12.

84 Juan Pablo Carvallo et al., *supra* note 8, at 30.

for climate change projections,[85] including the increasing severity of extreme events.[86]

For load, the best practice is to capture its relationship to the weather, and to add a probabilistically determined amount of distributed generation as negative load.[87] Similarly, for generation, the best practice is to derive the relationship between weather and its output, while also accounting for how technological improvements will improve production profiles,[88] along with the possibility of other types of common mode failures.[89]

Other important considerations include realistic assumptions about electricity imports from neighboring regions (e.g., probabilistically modeling neighbors' operations during tight periods),[90] intraregional transmission constraints,[91] the impact of probabilistic intraregional transmission failures,[92] and for when the model decides that an outage has been triggered.[93]

Additionally, for forecasting longer-term resource adequacy, modelers need to make assumptions about which resources retire and come online. These assumptions will have a large bearing on model outputs. For retirements, modelers should include announced retirements while also forecasting unannounced retirements by accounting for likely retirements due to federal and state policy, age-based retirements, and retirements driven by economics.[94] For near-term new generation and storage, modelers should consider projects that have cleared or will soon clear the interconnection queue, along with expected build times.[95] To anticipate later-term resource additions, modelers should consider resource costs and trajectories, regulatory incentives and barriers, and other relevant drivers. As with other inputs, modelers can implement retirements and additions through a distribution of probabilities, rather than strict assumptions about what will occur.[96]

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85 *Id.*

86 Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 22.

87 Juan Pablo Carvallo et al., *supra* note 8, at 31.

88 *Id.* at 32.

89 Elec. Power Rsch. Inst., Modeling New and Existing Technologies and System Components in Resource Adequacy 17–18 (2023), https://perma.cc/3CWR-G5LM; Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 37–38; *How MISO Utilizes PLEXOS for Enhanced Resource Adequacy*, Energy Exemplar (Oct. 9, 2024), https://perma.cc/VQY8-WAVX.

90 Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 31; Adria E. Brooks et al., Grid Strategies LLC, Resource Adequacy Value of Interregional Transmission 31 (2025), https://perma.cc/77FQ-L94V; Sam Hostetter & Derek Stenclik, Analysis of Resource Adequacy Across the Eastern Interconnection 7, 16 (2025), https://perma.cc/LCU4-LBZF.

91 Elec. Power Rsch. Inst., Resource Adequacy Scenario Selection Guide 6, (2024), https://perma.cc/FZ5A-5G2M.

92 Juan Pablo Carvallo et al., *supra* note 8, at 13–14; Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 12.

93 Kevin Carden et al., *supra* note 50, at 7.

94 Inst. for Pol'y Integrity, Comments on Policy-Driven Retirements in the Context of Order No. 1920 at 4–6 (Oct. 18, 2024), https://perma.cc/GB4R-X55D.

95 *E.g.,* N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 137.

96 *See* Inst. for Pol'y Integrity, Comments, *supra* note 94, at 7–8.

## Step 3: Accreditation

After resource adequacy modeling, the next step is to derive how much credit each resource deserves for its contribution towards the system's resource adequacy—a process called "accreditation." A resource's accreditation, typically expressed as a fraction of its nameplate capacity, captures the resource's estimated availability during the periods when resource adequacy is most strained.[97]

If a planner is interested in determining only whether a system is achieving its resource adequacy target, this step is unnecessary because Step 2 will accomplish that.[98] Nor is this step strictly necessary to determine how the retirement of any particular resource would affect reaching the resource adequacy target; a planner can accomplish that by re-running Step 2 without the resource included.

But, as explained further in Step 4, accreditation is important to calculate a region's *reference reserve margin*, i.e., the resource adequacy cushion that, when obtained, suggests that the system will achieve its resource adequacy target. Accreditation is also valuable because, once a planner calculates the reference margin level, having these accreditation values can allow a policymaker to quickly estimate how the retirement or addition of particular resources would affect maintaining that margin, without needing to re-run the resource adequacy modeling. This kind of analysis could satisfy the EO's call for a protocol to "identify which generation resources within a region are critical to system reliability."[99]

Historically, planners accredited thermal resources at their full nameplate capacity—reflecting an assumption that they could always generate at maximum capacity during the moments of greatest resource adequacy risk—or accredited them based on their nameplate capacity discounted by their average forced outage rate.[100] Variable resources have often been accredited based on their historical performance during peak load hours.[101]

With the energy transition and climate change, however, the best practice is to derive a resource's accreditation from the resource adequacy modeling described in Step 2 using a probabilistic

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[97] An Pham et al., Nat'l Renewable Energy Lab'y, Average and Marginal Capacity Credit Values of Renewable Energy and Battery Storage in the United States Power System 5 (2024) (using the equivalent phrase "capacity credit"). These times have become increasingly decoupled with peak load events. Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 4.

[98] Juan Pablo Carvallo et al., *supra* note 8, at 36 ("Capacity accreditation is not inherent to resource adequacy assessments . . . ."); Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at vii ("While resource adequacy analysis assesses whether there are enough resources to serve load across the system, capacity accreditation measures the contribution of individual resources toward meeting that goal, both in terms of capacity and energy.").

[99] Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15522 (Apr. 14, 2025).

[100] Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 9, 37; Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 5.

[101] Juan Pablo Carvallo et al., *supra* note 8, at 36.

method.[102] Probabilistic methods like Effective Load Carrying Capability (ELCC) analyze how slight changes in the modeled resource inputs would affect resource adequacy outcomes.[103] They typically work by adding more of the studied resource to the model, beyond what exists in the base case, and then adding load until the model's base case resource adequacy outcome is restored.[104]

The benefit of probabilistic approaches like ELCC is that, when the modeling inputs from Step 2 are well-curated, the resulting accreditations will more accurately reflect a resource's contribution to resource adequacy during the true risk periods.[105] Additionally, these methods consider a wide range of possible futures, including the possibility of tail events, rather than assuming the future will resemble the past.[106]

The best practice is to apply these ELCC-style methodologies to both variable and thermal resources, storage, and transmission.[107] It is important to treat all resource types equally because capacity accreditation provides a technology-agnostic way of comparing resources' resource adequacy contributions.[108] That purpose is compromised when the resource adequacy value of variable resources is reduced to account for myriad factors affecting their output, without parallel reductions capturing thermal resources' weather dependency and common mode outages.[109] With increased saturation of natural gas resources—which are susceptible to fuel disruptions and extreme weather—it is more important than ever to accurately account for thermal generations' winter risks, especially the risk that a significant amount of thermal capacity will become unavailable at once.[110] Probabilistic methods are ideal for understanding the effect of these risks, including tail risks, in light of the complicated interdependencies of all the factors that dictate the timing of resource adequacy shortfalls.[111]

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[102] *Id.* at 36–37; N. Am. Elec. Reliability Corp., Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning 24–27 (2011), https://perma.cc/294F-25KU.

[103] Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 13.

[104] *Id.*

[105] Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 12–14; Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 15; Christoph Graf et al., *supra* note 57, at 30. As explained in Step 2 above, these risk periods are becoming harder to predict due to weather's increased influence on supply and demand, and because of increased energy-limited resources in the generation mix.

[106] Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 14.

[107] Juan Pablo Carvallo et al., *supra* note 8, at 37; N. Am. Elec. Reliability Corp., Methods to Model and Calculate Capacity Contributions, *supra* note 102, at 28; Adria E. Brooks et al., *supra* note 90, at 31.

[108] Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 32, 37.

[109] *Id.* at 37–38.

[110] Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 24; Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 40–41; Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide, *supra* note 31, at 30; Elec. Power Rsch. Inst., Resource Adequacy Philosophy, *supra* note 21, at 27.

[111] *See* Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 11 ("Increasingly, periods of risk are driven by correlation among many components that are often weather-related, including high load, low renewable resource availability, drought, and correlated outages and fuel supply disruptions from the fossil fuel generators."); N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 91 ("If resource performance were to occur at the levels expected during average winter days, the system should be able to serve these high loads. However, resource performance from thermal resources on very cold days, especially natural gas resources, is more likely to be poor. This, coupled with poor performance from solar

## Step 4: Calculating the Reference Margin Level and the Reserve Margin

Using Step 2's resource adequacy modeling and Step 3's accreditations, a planner can assess whether a region's fleet would achieve its appropriate reference margin level.[112] The reference margin level typically expresses the amount of accredited capacity that a region would need to achieve its resource adequacy target. The planner will conduct resource adequacy modeling, adding or subtracting additional capacity or load until the system reaches the resource adequacy target. The reference margin level is the sum of the accredited capacity needed to achieve the target.

Once the planner derives the reference margin level (how much total accredited capacity the system requires), it is also possible to answer whether any particular resource is critical to achieving the margin. To check this, the planner would subtract the accredited capacity of the resource in question from the total accredited capacity of the region, and check whether the difference exceeds the reference margin level.

### Reference Margin Levels

Historically, reference margin levels were—and, in some places, continue to be—resource adequacy targets in themselves (e.g., a target of accredited capacity that is 15% above peak load).[113] But setting a target framed entirely around the summed accredited capacity, even when informed by years of operating experience at different margin levels, yields a target that does not explicitly aim to achieve any particular outcome.[114] As explained in Step 1, targets are more typically expressed in terms of outcomes: the frequency, duration, and/or magnitude of shortfalls.

Yet the idea of a reference margin level has persisted, as planners often convert their outcome-focused targets into the equivalent reference margin levels.[115] For example, a region might have a 0.1 LOLE target and then determine that the 0.1 LOLE target is achieved when the region's installed capacity has an accreditation of at least 15% above peak load.[116] The same type of translation is possible for targets set using other metrics, like EUE or LOLH.[117]

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resources, results in very low total electricity supply and causes loss-of-load events in the ProbA analysis. The winter load-loss events tend to occur during morning and evening demand peaks and coincide with poor thermal performance and poor solar performance.").

112 This is also commonly referred to as a planning reserve margin, connoting that it includes resources that are in reserve and only be dispatched in highly constrained scenarios.

113 Elec. Power Rsch. Inst., Resource Adequacy Philosophy, *supra* note 21, at 24; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 8–9.

114 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 5–6; N. Am. Elec. Reliability Corp., Methods to Model and Calculate Capacity Contributions, *supra* note 102, at 29–30.

115 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 7; Juan Pablo Carvallo et al., *supra* note 8, at 37; N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 1.

116 Juan Pablo Carvallo et al., *supra* note 8, at 28.

117 N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 15; Juan Pablo Carvallo et al., *supra* note 8, at 29.

Given how resource adequacy risk has evolved, however, the best practice is to derive the reference margin level using the probabilistic resource adequacy modeling from Step 2 (itself conducted in accordance with best practices).[118] Doing this helps to ensure that the margin is calculated to comprehensively reflect year-round risks. Indeed, when resource adequacy risk shifts beyond peak load hours, the amount of accredited capacity necessary to achieve the resource adequacy target can become *lower* than peak load—because resources' accreditations will be based on their outputs during moments of greatest risk, which may be lower than their outputs at peak load.[119] Accordingly, calculating a reference margin level that matches accredited capacity to peak load would overestimate the necessary margin.

While there are multiple plausible ways to use probabilistic resource adequacy modeling to convert the resource adequacy target to a reference margin level, the general approach depends on whether the modeling reveals that the system is exactly achieving the target, underachieving it, or overachieving it. For the rare case in which the system happens to be exactly achieving the resource adequacy target, then the sum of the total accredited capacity installed on the system equals the reference margin level. It can be expressed as MW of accredited capacity, or in reference to some other amount, like a percentage of peak load.[120]

It is more likely, however, that the system is either above or below the resource adequacy target. In these instances, it is common to add or subtract accredited capacity in the model until the system achieves the target.[121] Then, the reference margin level will be the amount of accredited capacity on the modeled system when the target is achieved, again expressed as a quantity of MWs or as a percentage of peak load.

### Effect of Particular Resources

Once the reference margin level and accreditation values have been calculated, it becomes possible to test how the exit (or entry) of a particular resource would affect the region's resource adequacy.

An example is useful in understanding how. Imagine that the reference margin level for a region is 25 GW, and its resource mix has 26 GW of accredited capacity. As is, the region would be exceeding its reference margin level by 1 GW. If any resource with an accreditation greater than 1 GW were to exit the grid, that would cause the actual reserve margin to dip below the reference margin level. Because the reference margin level was calculated following Steps 1–3,

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[118] Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 6, 11; Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 95. *See also* N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 11.

[119] Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 18.

[120] *Id.*; N. Am. Elec. Reliability Corp., Methods to Model and Calculate Capacity Contributions, *supra* note 102, at 6.

[121] Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 95. *See also, e.g.*, MISO, Planning Year 2025–2026 Loss of Load Expectation Study Report 34–35, https://perma.cc/4VV5-4FHU; Western Power Pool, Western Resource Adequacy Program, 102 Forward Showing Reliability Metrics 14 (2024), https://perma.cc/7A6Q-A96E; NYISO, 2024 Reliability Needs Assessment 44 (2024), https://perma.cc/LD5E-RMV9; IESO, Annual Planning Outlook: Resource Adequacy and Energy Assessments Methodology 19 (2024), https://perma.cc/26N7-QC5J.

this dip would indicate that the region can no longer be expected to achieve the resource adequacy target (e.g., 0.1 LOLE) underlying the 25 GW reference margin level. In contrast, any resource with an accredited capacity of 1 GW or less could retire without causing the system to violate its resource adequacy target.

Importantly, this technique for evaluating individual resources' impact works only for relatively small changes to the system, such as the exit or entry of one or a few plants. When larger changes happen in the region's resource composition, the new mix will itself affect resources' accreditation values, because these values inherently depend on the entire fleet composition.[122] To calculate the resource adequacy effect of major changes to the fleet (e.g., the retirement of half of the coal capacity in a region), it would be necessary to re-run the modeling from Step 2 with different inputs.

Having reviewed resource adequacy terms, methodologies, and best practices, Part 2 next uses this understanding to discuss DOE's recent resource adequacy modeling endeavor.

[122] Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 30.

# Part 2: DOE's *Resource Adequacy Report*

On July 7, 2025, DOE published its *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* (DOE Study), responding to the EO's request for a "uniform methodology to identify at-risk region(s) and guide reliability interventions."[123] The report does not fulfill the EO's separate request for a "a protocol to identify which generation resources within a region are critical to system reliability."[124]

The DOE Study generally examines the resource adequacy of two time periods: today and 2030. According to the study, today, only ERCOT currently fails to achieve DOE's selected resource adequacy targets.[125] Under DOE's assumptions about load growth (including load growth from data centers), resource additions, and retirements, its modeling shows that all transmission planning regions will be resource inadequate in 2030 except ISO-NE and NYISO.[126] When reporting that a region is or would be resource inadequate, DOE sometimes calculates the amount of perfect capacity that could restore the region to resource adequacy.[127]

The DOE Study borrows heavily from NERC's recent Interregional Transfer Capability Study, which analyzed interregional transmission capacity and evaluated how additional interregional capacity could improve resource adequacy.[128] In contrast to NERC's Interregional Transfer Capability Study, the DOE Study does not consider how shortfalls could be mitigated through additional interregional transmission, which can be an alternative to new generation.[129]

Building on Part 1's discussion of how a resource adequacy model's metrics, values, and input assumptions drive its results, this Part evaluates DOE's resource adequacy methodology, including its input choices for load growth, resource additions, and retirements. At each step, it discusses the assumptions embedded in DOE's modeling choices, and reviews why those assumptions provide a weak basis for commanding specific, aging resources to continue serving load at consumers' expense and outside of existing market structures.

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[123] U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at vi.

[124] Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521 (Apr. 14, 2025).

[125] U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 7.

[126] *Id.* at 8.

[127] *Id.* at 5. The exact meaning of these perfect capacity quantities is unclear due to contradictions within the DOE Study. At times, DOE explains that these are the perfect capacity quantities that restore the system to 0.002% while assuming projected retirements. *Id.* At other points, though, DOE states that these quantities assume no retirements. *Id.* at 9.

[128] *Id.* at 2; N. Am. Elec. Reliability Corp., Interregional Transfer Capability Study vi, ix (2024), https://perma.cc/U7M3-L56J.

[129] *See generally* Adria E. Brooks et al., *supra* note 90.

## Resource Adequacy Targets

The DOE Study uses a multi-metric resource adequacy target of 2.4 LOLH and 0.002% normalized unserved energy (NUSE), which is the deterministic equivalent to NEUE.[130] DOE's decision to use a multi-metric target aligns with best practices, and its decision to use LOLH and NEUE together is reasonable. But DOE's value selections for these metrics are problematic.

For LOLH, DOE indicated that it picked 2.4 because that value "translates into one day of lost load in ten years," i.e., the traditional 0.1 LOLE standard.[131] This decision does not align with best practices for two reasons. First, it seeks to unquestioningly replicate the already arbitrary 0.1 LOLE standard (which merely captures the level of resource adequacy that happened to exist in the 1940s).[132] DOE's choice thus does not reflect any meaningful cost-benefit analysis.

Second, DOE's conversion of 0.1 LOLE to 2.4 LOLH is inaccurate.[133] A region with 0.1 LOLE will experience only one day with an outage—of any length—across ten years, which will be 24 hours in only the most extreme case. A region with 2.4 LOLH will have 24 hours of outages across the decade, across any combination of hours. DOE's selection of 2.4 LOLH metric would therefore, in the vast majority of cases, permit a greater duration and frequency of outages.[134] Although this 2.4 LOLH target might indicate that, all else being equal, DOE's methodology is too permissive, DOE's inputs and assumptions likely dominate its analysis and lead DOE to overestimate potential shortfalls.

Turning to NUSE, DOE reports that it selected 0.002% because NERC uses that same value in its long-term resource adequacy assessments.[135] But, as discussed in Part 2, NERC adopted that value from Australia without any consideration of how the costs and benefits of resource adequacy differ in the U.S. context.[136] In contrast, DOE previously used 0.001% in the National Transmission Planning Study.[137]

Moreover, contrary to best practices, for both LOLH and NUSE, DOE imposes the same resource adequacy target across the entire continental United States, without considering regional differences. As noted in Part 1, when it comes to averting outages, regions face different costs and benefits with regard to resource adequacy and thus different socially optimal levels of resource adequacy.

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130 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 4, 14 ("This study does not employ common probabilistic industry metrics such as EUE or LOLE due to their reliance on probabilistic modeling. Instead, deterministic equivalents are used.").

131 *Id.* at 4.

132 Kevin Carden et al., *supra* note 50, at 2; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 6.

133 Juan Pablo Carvallo et al., *supra* note 8, at 11 ("The LOLE is typically used as a target setting metric and has historically taken a value of 1 event-day in 10 years, commonly (and incorrectly) interpreted as 2.4 hours per year.").

134 Gord Stephen et al., *supra* note 15, at 3, https://perma.cc/A9DJ-C3B5.

135 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 4 n.10.

136 N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 141.

137 U.S. Dep't of Energy, National Transmission Planning Study: Chapter 2: Long-Term U.S. Transmission Planning Scenarios 4, 82 (2024), https://perma.cc/R8RA-23E2.

Finally, at times, the DOE Study appears to struggle with the very meaning of a resource adequacy standard: It questions both PJM's and SPP's resource adequacy, even though each satisfies the metrics DOE's itself picked for its analysis. For PJM in particular, DOE notes that the region currently satisfies both prongs of the resource adequacy metric, but not for the particular weather year that includes Winter Storm Elliot.[138] Seemingly for this reason, DOE concludes that PJM needs 2.4 GW of additional perfect capacity to be resource adequate now.[139] But DOE's resource adequacy targets are, in DOE's own words, "average indicators" to be achieved across all modeled scenarios, not a requirement that must be achieved in each and every scenario.[140] PJM is resource adequate today according to DOE's targets.

Of course, as discussed in Part 1, it may be reasonable for a system planner to set a resource adequacy target that depends, in part, on each region's performance during tail risks. But DOE has not done so here.

## Resource Adequacy Modeling

DOE's resource adequacy modeling is inconsistent with best practices. DOE's high-level decisions about the study's overall modeling approach and data input decisions both diverge from the best practices described in Part 1.

### Deterministic Model

While the DOE Study appropriately examines all 8,760 hours of the year in chronological order,[141] DOE departs from best practices by using deterministic modeling rather than a probabilistic approach (like the Monte Carlo method), perhaps because of the EO's relatively short timeline.[142] Rather than randomly sampling probability distributions for each input to construct hundreds or thousands of plausible scenarios, DOE "evaluates whether a power system has sufficient resources . . . under a pre-defined set of conditions which correspond to the past few years of real-world events."[143] DOE uses twelve years of data (2007–2013 and 2019–2023) for weather, load, and generation.[144]

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138 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 7, 9, 27.

139 *Id.* at 9.

140 *Id.* at 7.

141 *See* U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 10, 12–13.

142 *Id.* at 2. The EO provided an extremely accelerated deadline of 90-days for DOE to produce results. *See* Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521 (Apr. 14, 2025). The DOE Study itself provides additional evidence for this conclusion, with its acknowledgement that "[p]robabilistic approaches incorporate data and advanced modeling techniques to represent uncertainty" but "require more computing power." U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 2 n.2.

143 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 10.

144 *Id.* at 11. While DOE uses historical data for the years 2019–2023, it uses "synthetic" data for 2007–2013. *Id.* "The synthetic approach used historical weather data to estimate load and resource availability if those same weather conditions were to occur again in the future. The historic approach used historical measured data for load, as well as wind and solar resource output, from recent years and scaled it appropriately to represent future conditions." N. Am. Elec. Reliability Corp., Interregional Transfer Capability Study, *supra* note 128, at 74.

By examining whether regions would be resource adequate only under conditions that resemble the recent past, DOE's study does not sufficiently account for uncertainty. Indeed, in the Interregional Transfer Capability Study, from which DOE borrowed, NERC itself explains the limitations of this same deterministic approach and same data: Some regions may look resource adequate because they happened to do well during the twelve years of data, while others look resource inadequate but be unlikely to perform as poorly in the future.[145] Addressing the deterministic vs. probabilistic distinction, NERC cautions that, because a "[p]robabilistic resource adequacy analysis was not conducted[,] . . . . the [Interregional Transfer Capability Study] should not be considered a North American resource adequacy assessment."[146]

DOE grounds its use of a deterministic model in "transparency" and an interest in "model[ing] detailed historic system conditions."[147] Neither is a reason to step away from best practices: DOE could document a probabilistic approach in a transparent way, and relying on a small sample of historic years is less accurate than a probabilistic approach. Given the high stakes associated with resource adequacy planning, any future DOE resource adequacy assessment should prioritize accuracy over expediency.

## Outage Threshold

Another modeling choice is the threshold for determining when a shortfall event has occurred. DOE projects a shortfall if "the remaining capacity after transmission and demand response falls below the 6 percent or 3 percent needed for error forecasting and ancillary services, depending on the scenario."[148] This choice means that DOE identifies shortfall events in the hours when, after exhausting imports and demand response, a region's excess energy falls below 6% or 3% of hourly load—but it is not clear when DOE uses 6% versus 3%. DOE states that more details are available in a section of the study's appendix entitled "Outputs," but, as of publication of this report, no such section appears to be available.[149]

NERC uses a 3% threshold in its Interregional Transfer Capability Study, using 6% only in a sensitivity analysis.[150] According to NERC, the 3% value "was established based on an evaluation of average reserve requirements where load shed may occur" and reflects how "a Balancing Authority will continue to hold reserves even if involuntary load shed is underway to safeguard the system from cascading or widespread outages."[151] It is impossible to tell from the DOE Study when DOE used 6% versus 3%, but the fact that DOE listed 6% first may suggest that 6% was not limited to a sensitivity analysis.

If DOE's model instead identifies shortage events even when a region still has 6% of load available as spare capacity, then DOE's results depart from NERC's practice and may overstate

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145 *Id.* at 138.
146 *Id.* at 4.
147 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 2 n.2.
148 *Id.* at 12.
149 *Id.*
150 N. Am. Elec. Reliability Corp., Interregional Transfer Capability Study, *supra* note 128, at 84.
151 *Id.* at 91 n.90, 85.

the extent of expected outages. In NERC's Interregional Transfer Capability Study, this change alone *significantly* altered the existence and extent of predicted outages in many regions, such as producing a 690% increase in the size of the maximum outage event in SERC-Florida.[152] Under the 6% sensitivity, NERC also recommended 58 GW of transmission additions to address resource adequacy instead of 35 GW, illustrating the sizable influence of shifting this assumption from 3% to 6%.[153]

## Inputs

DOE's prediction that most regions will experience resource inadequacy by 2030 depends heavily on its assumptions about resource additions, retirements, load growth, and interregional imports. In each instance, DOE makes choices that raise significant questions about the validity of its modeling results.

### *Additions*

DOE assumes that the only resource additions by 2030 will be those NERC currently categorizes as "Tier 1."[154] To be a Tier 1 resource, the resource must have achieved at least one milestone from a NERC list that signifies the unit is "very mature in the development pipeline."[155] This assumption is very conservative: The study itself admits that "[t]his results in minimal capacity additions beyond 2026."[156] In other words, DOE's finding of widespread resource inadequacy in 2030 rests on the assumption that very little will be built from 2027–2030. For example, NERC identifies 17,047 MW of Tier 1 resources slated to come online in PJM throughout 2025 and 2026, but only 1,108 MW from 2027–2030.[157]

The drop-off in Tier 1 resources after 2026 is not due to a shortage of projects in development, but rather because NERC currently classifies much of the capacity that will come online between 2027 and 2030 as "Tier 2."[158] Tier 2 resources occupy a wide range of positions in the interconnection queue, from the earliest stages (e.g., those having completed a feasibility study) to the very end

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[152] *Id.* at 105 tbl.8.4

[153] *Id.*

[154] U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 4.

[155] *Id.* at A-5. More specifically, the resource must have finished construction, be under construction, have a signed/approved interconnection service agreement, have a signed/approved power purchase agreement, have a signed/approved construction service agreement, have a signed/approved wholesale market participant agreement, or (if it is in the footprint of a vertically integrated utility) be included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement. N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 137.

[156] U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at A-5. *See also* Ric O'Connell, *GridLab Analysis: Department of Energy Resource Adequacy Report*, GridLab (July 11, 2025), https://perma.cc/B3GC-T7GA ("The report assumes just 22 GW of new 'firm' capacity (narrowly defined as gas) is added which is based on NERC LTRA 'Tier 1' – projects with a very high likelihood of success. The report assumes no projects are built post 2026, which is not realistic for a report forecasting to 2030. A more reasonable assumption for capacity additions is the EIA 860 released in June, which has 35 GW of gas additions, and another 53 GW of batteries – **88 GW of firm additions by 2030**.") (bolded text in original).

[157] N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 89.

[158] *See id.* at 137.

of the process (e.g., those that have requested an interconnection service agreement).[159]

In recent years, the median project has taken approximately 55 months (4.58 years) to go from entering the queue to commercial operation.[160] Extrapolating from this historical trend reveals that a large number of Tier 2 resources will likely be operating by 2030. DOE should have anticipated some of them in the 2030 resource mix, and it departed from best practices by excluding all Tier 2 resources.[161] To do this forecasting accurately, DOE should have examined historical statistics of interconnection queue time by region, resource type, and resource size, along with differentiated queue withdrawal rates, estimating Tier 2 resource additions for each region.[162]

And applying historical statistics for time spent in a region's interconnection queue would itself be a conservative methodology for DOE to use, as FERC Order 2023 and related regional interconnection queue updates are set to speed up waiting times.[163] For example, the DOE Study found a 10.5 GW resource adequacy deficit for PJM in 2030 but failed to consider the almost 12 GW of nameplate capacity—mostly gas—that PJM is fast-tracking through its Reliability Resource Initiative.[164] PJM expects that 90% of this capacity will be online by 2030.[165] PJM is simultaneously pursuing other resource adequacy interventions, including a FERC-approved change to surplus interconnection service (to allow new generators to come online faster by taking advantage of underutilized transmission capacity),[166] and a FERC-pending proposal to expedite the process to transfer capacity interconnection rights from retiring generators to new resources.[167]

Finally, recently "retired" resources represent another potential source of fast additions.[168]

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159 *Id.*

160 Joseph Rand et al., Lawrence Berkeley Nat'l Lab'y, Queued Up: 2024 Edition: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2023 41 (2024), https://perma.cc/5DE4-XNK6.

161 *See* N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 23 fig.2.

162 *See generally* Joseph Rand et al., Lawrence Berkeley Nat'l Lab'y, Queued Up: 2024 Edition: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2023 (2024), https://perma.cc/5DE4-XNK6.

163 *Improvements to Generator Interconnection Procedures and Agreements*, 184 FERC ¶ 61,054 (2023).

164 Donnie Bielak, PJM, Reliability Resource Initiative: Additional Summaries 2 (2025), https://perma.cc/Y2AB-3CEM; Donnie Bielak, PJM, Reliability Resource Initiative: Results Summary 6 (2025), https://perma.cc/MYQ8-Y53G. *See also* Ric O'Connell, *supra* note 156 ("The study ignores both utility plans for meeting increased load growth and how markets will respond. In fact, markets and utilities have already responded with plans to add new capacity and fast track new resources. These include PJM's Reliability Resource Initiative, which plans on adding 11 GW of new firm resources by 2030. SPP and MISO both have proposals at FERC (called ERAS) that will likely add another 30 GW of firm resources. Those three regional efforts alone would add roughly twice what the DOE assumed for the entire nation.").

165 *PJM Chooses 51 Generation Resource Projects To Address Near-Term Electricity Demand Growth*, PJM Inside Lines (May 2, 2025), https://perma.cc/8EW2-G2XZ.

166 *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,083 (2025).

167 Proposed Revisions to PJM's Open Access Transmission Tariff, PJM, Docket No. ER25-____-000 (Jan. 31, 2025), https://perma.cc/J9T3-MCGL.

168 *E.g.*, Francisco "A.J." Camacho & Daviel Schulman, *Mothballed Nuclear Plant on Brink of Revival*, EnergyWire (July 15, 2025), https://subscriber.politicopro.com/article/eenews/2025/07/15/mothablled-nuclear-plant-on-brink-of-revival-00445239.

### *Retirements*

DOE's assumption that 104 GW of nameplate capacity will retire by 2030 likely overestimates retirements.[169] This number includes both "confirmed" retirements—resources that have notified their system operators of their impending retirements and begun the retirement process—and "announced" retirements—which are publicly stated but not officially noticed.[170] These data come from NERC's Long-Term Reliability Assessment 2024 model.[171] In turn, NERC receives reports of confirmed retirements directly from each region, while announced retirements come from multiple sources, including Energy Information Agency Form 860 data, trade press, and utility integrated resource plans.[172]

These data likely overestimate retirements.[173] First, the economics of energy production have changed since 2024. The combined effect of new demand from data centers and the elimination of federal tax credits for new wind and solar resources improves the financial outlook for thermal resources.[174] Second, federal environmental regulations that would have required thermal resources to make investments reducing their pollution or else retire were projected to result in significant retirements before 2030.[175] But the Trump Administration has begun to rescind or reexamine these rules, which could cause resources to delay their retirements.[176]

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[169] *See* U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 5.

[170] *Id.* at 12.

[171] *Id.*

[172] N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 28 n.19.

[173] Ric O'Connell, *supra* note 156 ("The report assumed 104 GW of retirements by 2030, with 3/4 of this coal and 1/4 gas. But the most recent data from the U.S. Energy Information Administration released in June (the EIA 860) has just **half** of this capacity retiring. In the report, the DOE assumed these 50 GW of likely retirements, but included another 50 GW of *announced* retirements, inconsistent with their assumption around capacity additions. Most likely many plants will choose not to retire due to the changing regulatory and economic landscape, driven by the administration's policies.") (bolded text in original).

[174] Aurora Energy Research, Impact of Reform to Clean Energy Tax Credits on Investment, Jobs and Consumer Bills 10 (2025), https://perma.cc/VHR5-UEGP; ("Most demand is made up through more production from existing plants (35%), meaning these plants are running for longer hours and/or at higher output levels. Some projects that retired in the base case scenario see longer lifetimes in Tax Credit Removal scenario because of more favorable economics due to clean energy decline (making up 17% of lost generation), and the rest is made up for by new build thermal plants (29%)."); Energy Innovation Pol'y & Tech. LLC, Federal Clean Energy Tax Credits Make Energy More Affordable—A Meta-Analysis (2025) https://perma.cc/QH2E-7PLL ("The research is clear—repealing technology-neutral energy tax credits would raise annual energy bills up to $140–$220 per year nationally, and over $500 per year in some states."). *See also* Ethan Howland, *PJM Capacity Prices Hit Record Highs, Sending Build Signal to Generators*, Utility Dive (July 31, 2024), https://perma.cc/UC6U-QHYT ("Prices in the PJM Interconnection's latest capacity auction hit record highs, which should provide incentives for power plant companies to build new generating resources and keep existing ones operating, according to the grid operator."); Ethan Howland, *MISO Summer Capacity Prices Jump to $666.50/MW-day as Power Supplies Shrink*, Utility Dive (Apr. 29, 2025), https://perma.cc/A6S5-4A4U ("Capacity prices for the upcoming summer season jumped to $666.50/MW-day from $30/MW-day last year across the Midcontinent Independent System Operator's footprint—driven in part by declining surplus capacity, according to the results of its latest planning resource auction released Monday.").

[175] PJM, Energy Transition in PJM: Resource Retirements, Replacements & Risks 8 (2023), https://perma.cc/7J3A-FL8U.

[176] *EPA Launches Biggest Deregulatory Action in U.S. History*, EPA (Mar. 12, 2025), https://perma.cc/55MN-2SUB.

### *Load*

The DOE Study assumes 50 GW of growth in data center load and 51 GW of additional non-data center load.[177] DOE does not account for the possibility that this data center load could be flexible, even as one study suggests that 76 GW of additional data center load could be accommodated today if it could be curtailed only 0.25% of the time, and relevant corporations have confirmed flexibility potential.[178]

In June 2025, Texas enacted a law that allows ERCOT to curtail certain new loads over 75 MW during emergencies.[179] DOE assumes an additional 8 GW of data center load in ERCOT by 2030 and finds a reliability shortfall of 10.5 GW (which is likely an overestimate for the reasons discussed elsewhere in this Part, including how this 10.5 GW brings ERCOT to 0.0008% NUSE instead of 0.002% NUSE).[180] Accordingly, Texas's new law could go a long way towards avoiding the DOE-identified resource adequacy problem. Other regions like PJM are considering strategies to soften the resource adequacy impact of data centers, including ways to better encourage their participation in demand response programs.[181] DOE should have considered the possibility that some of the projected data center load would be flexible, especially in ERCOT.

Additionally, how DOE chose to distribute the projected 50 GW of data center load across regions is questionable. The DOE Study explains it used state-level growth ratios to perform this allocation.[182] But it is unlikely that all the computing demand needs to be processed close to load centers (i.e., proportional to a region's current electric load). In fact, some computing demand

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[177] U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 2–3.

[178] Tyler H. Norris et al., Nicholas Inst. for Energy, Env't & Sustainability, Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems 2 (2025), https://perma.cc/6693-3HZU; *EPRI Launches Initiative to Enhance Data Center Flexibility and Grid Reliability,* Elec. Power Rsch. Inst. (Oct. 29, 2024), https://perma.cc/75LY-PSP5 ("Led by EPRI, DCFlex will coordinate real-world demonstrations of flexibility in a variety of existing and planned data centers and electricity markets, creating reference architectures and providing shared learnings to enable broader adoption of flexible operations that benefit all electricity consumers. Specifically, DCFlex will establish five to ten flexibility hubs, demonstrating innovative data center and power supplier strategies that enable operational and deployment flexibility, streamline grid integration, and transition backup power solutions to grid assets. Demonstration deployment will begin in the first half of 2025, and testing could run through 2027."); Anuja Ratnayake, *Unlocking AI Potential with Data Center Flexibility*, EnergyCentral (June 12, 2025), https://www.energycentral.com/intelligent-utility/post/unlocking-ai-potential-with-data-center-flexibility-PtPoXIAuRMzs5Ff ("In a preliminary test of the depth of computational flexibility possible in an AI data center, the Arizona demonstration site experienced some early success. It showcased the potential for an AI data center to provide grid relief during a peak system event—such as a hot summer day with high power demand—by temporarily and precisely ramping down its electricity consumption without compromising data center performance."). *See also* Ric O'Connell, *supra* note 156 ("It does not address flexibility of this load, however, which was recently demonstrated in a report from Duke University to allow for 100 GW of large load additions today with minimal grid impact.").

[179] S.B. No. 6 § 4, 89th Legislature (Tex. 2025) (to be enacted at Tex. Util. Code § 39.170), https://perma.cc/4Z7H-9XKQ; Brian Martucci, *Texas Law Gives Grid Operator Power to Disconnect Data Centers During Crisis*, Utility Dive (June 25, 2025), https://perma.cc/SYK3-V4XX; Waleed Aslam & Robin Hytowitz, Elec. Power Rsch. Inst., Texas SB6 Explained: Addressing Large Load Impacts (2025), https://perma.cc/QD8S-3M5C.

[180] U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 40.

[181] Tim Horger, PJM, Large Load Additions Workshop 28 (2025), https://perma.cc/4HSN-CW4W.

[182] U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 17.

may be served from other regions if it will be cheaper to integrate the data center elsewhere. Given the scale of DOE's projected data center load compared to the relatively small resource adequacy shortfalls that the study identifies, these assumptions may have made the difference between whether a region achieves DOE's resource adequacy targets.[183]

### *Interregional Imports*

The DOE Study states that it has adopted the interregional transfer capacities from NERC's Interregional Transfer Capability Study but also notes that transfers are "available up to the *minimum* total transfer capacity."[184] NERC's values describe the available transmission capacity between regions, including sub-regions of larger transmission-constrained regions like PJM, SPP, and MISO.[185] NERC provides a summer value and a winter value for each interregional interface and for each direction of flow.[186]

It is unclear what DOE means when it says that transfers are allowed up to their "minimum." If DOE picked the lesser of the summer and winter transfer capacities and applied that annually, doing so would inaccurately underestimate the amount of interregional transfer capacity.

## Accreditation & Reference Margin Levels

While DOE issued its study in response to the EO's request for a "methodology to identify current and anticipated regions with reserve margins below acceptable thresholds,"[187] it does so through resource adequacy modeling, rather than by calculating accreditation values and using them to derive reference margin levels. As explained in Part 2, properly performed resource adequacy modeling is sufficient to determine whether a region is resource adequate.

In contrast, accreditations and reference margin levels are useful in combination to quickly evaluate how the loss or addition of a particular resource would affect whether a region achieves its resource adequacy target without re-running regional resource adequacy modeling. They are thus more applicable to EO Section 3(c)'s separate command to establish a "protocol to identify which generation resources within a region are critical to system reliability.[188] Thus far, DOE has not released a study implementing this provision. DOE may eventually supplement the DOE Study with additional accreditation and reference margin level analyses.

Nonetheless, while the DOE Study does not calculate accreditation values or reference margin levels, it does undertake the related exercise of evaluating how much additional perfect capacity would bring certain regions to resource adequacy.[189] (DOE calculated these perfect capacity

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[183] *See id.* at 9, 17.

[184] *Id.* at 18, 12, A-1 (emphasis added).

[185] N. Am. Elec. Reliability Corp., Interregional Transfer Capability Study, *supra* note 128, at 7, 9–10.

[186] *Id.* at 17–24.

[187] Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521 (Apr. 14, 2025).

[188] *Id.* at 15522.

[189] U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 5.

additions for only four of the seven regions that failed to achieve 0.002% NUSE in 2030: PJM, SPP, SERC, and ERCOT—not MISO, CAISO, or West Non-CAISO.[190]) More specifically, DOE asked how much perfect capacity it would take for regions to achieve the 0.002% NUSE resource adequacy standard in 2030.[191]

If, in the future, DOE were to also calculate the accredited capacity of a region's fleet and then add the solved-for perfect capacity, it could calculate the region's reference margin level. Similarly, although DOE did not perform any perfect capacity analysis for regions that achieve 0.002% NUSE, DOE could subtract perfect capacity from the accredited capacity of the regional fleets to solve for reference margin levels. Once DOE calculates a region's reference margin, it could look at the accredited capacity of any resource to evaluate how its exit or entry would affect achievement of the reference margin level.

In calculating any reference margin levels, DOE should attend to all prongs of its multi-metric resource adequacy target. Here, DOE Study's perfect capacity exercise focuses exclusively on 0.002% NUSE. But if a region achieves 0.002% NUSE and not 2.4 LOLH, it would be resource inadequate according to the terms of this DOE Study. Separate reference margin levels may apply to each prong, and a region would be resource adequate only when the highest reference margin level is achieved.

Additionally, going forward, DOE should better prioritize accuracy in any new studies with respect to calculating a region's need for perfect capacity additions/subtractions. Critically, while DOE asserted that it added the amount of perfect capacity needed to bring each region to 0.002% NUSE, the 10.5 GW that it added to PJM actually brought it to 0.0003% NUSE; the 500 MW added to SERC brought it to 0.0002% NUSE; the 1.5 GW added to SPP brought it to 0.0002% NUSE; and the 10.5 GW added to ERCOT brought it to 0.0008% NUSE.[192] All of these values indicate significantly greater resource adequacy that 0.002% NUSE, sometimes by an order of magnitude.

While DOE explains that its perfect capacity additions were done "by hand with a limited number of iterations (15)" such that the capacity additions "should not be considered the minimum possible capacity to accomplish these targets," that approach does not appear to explain why DOE brought these regions far beyond the 0.002% NUSE target.[193] Rather, this explanation suggests that, for each of the regions, DOE could have achieved these high levels of resource adequacy using less perfect capacity than it added. Accordingly, to achieve 0.002% NUSE, DOE likely could have added much less perfect capacity than it did. Identifying resources that meet these overestimated capacity levels could result in overpaying to achieve a different resource adequacy target than selected.

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[190] *Id.* at 20–42.
[191] Id. at 5.
[192] *Id.* at 27, 30, 32, 40.
[193] *Id.* at 19.

# Part 3: Next Steps

Having reviewed best practices for resource adequacy modeling and the DOE Study, this final section discusses next steps for U.S. resource adequacy policy considering the diverse actors in this space and their respective authorities.

The Federal Power Act (FPA) gives FERC, and FERC's designated "Electric Reliability Organization" (ERO), NERC, jurisdiction over and responsibility for ensuring "[e]lectric reliability" for the "bulk power system," i.e., the high-voltage transmission network and the energy that flows through it.[194] More specifically, the FPA requires NERC to "establish and enforce reliability standards," which take effect after FERC approves them.[195] Importantly, FERC can also order NERC to submit reliability standards on particular topics and can independently enforce reliability standards.[196] NERC's six regional entities (comprising the continental U.S. plus Canada) also have authority to propose reliability standards to NERC.[197]

Achieving reliability arguably requires that bulk power system be resource adequate because, as FERC explains, "[i]f resources cannot meet load, or are insufficient to provide a reserve margin above expected load, then instability, uncontrolled separation or cascading failures can result from the unanticipated loss of a system element."[198] But, although reliable grid operations depend in part on resource adequacy, the FPA does not put FERC and NERC in the driver's seat for this aspect of reliability. FERC lacks authority to *directly achieve* resource adequacy because it cannot order construction of electric generation facilities.[199] Rather, states retain their traditional authority "over facilities used for the generation of electric energy,"[200] which some exercise by requiring utilities to submit integrated resource plans describing their plans to meet future demand.[201] Other states fully or partially delegate this authority to the Regional Transmission Organizations (RTOs) that operate their regional grids, e.g., by relying on the RTOs to achieve resource adequacy through capacity markets.[202]

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194 16 U.S.C. § 824o(a).

195 16 U.S.C. § 824o(a)(2), (d). FERC does not have authority to create reliability standards directly. *See id.* at § 824o(d).

196 16 U.S.C. § 824o(d)(5), (e)(3).

197 16 U.S.C. § 824o(e)(4); *ERO Enterprise; Regional Entities,* N. Am. Elec. Reliability Corp., https://perma.cc/EQ9E-BXJW.

198 *Planning Resource Adequacy Assessment Reliability Standard*, 134 FERC ¶ 61,212, at P 25 (2011). Reliable operation also encompasses a second aspect of reliability not implicated by the EO—operational reliability—which refers to "ability of the electric system to withstand sudden disturbances while avoiding cascading blackouts." Burçin Ünel & Avi Zevin, *supra* note 5, at 11.

199 16 U.S.C. § 824o(a)(3). The FPA also prohibits FERC from directing utilities to build transmission, and states retain primary siting authority for transmission. *See id.*; *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, 187 FERC ¶ 61,068 at P258 (2024).

200 16 U.S.C. § 824(b)(1).

201 Coley Girouard, *Understanding IRPs: How Utilities Plan for the Future*, Advanced Energy United (Aug. 11, 2015), https://perma.cc/5MDN-26QY.

202 Dena Adler & Jennifer Danis, Inst. for Pol'y Integrity, Reducing Pollution Without Sacrificing Reliability 14–16

But FERC and NERC can still play an important role for resource adequacy: FERC and NERC, through reliability standards, can ensure grid operators are proactively conducting appropriate resource adequacy assessments and analyses. In Order No. 747, FERC approved a regional reliability standard for conducting resource adequacy assessments.[203] This enforceable reliability standard requires, at a minimum, that entities within the applicable footprint conduct an annual analysis of what reserve margin would be necessary to ensure no more than 0.1 LOLE, using specific inputs like the median load forecast and accounting for important factors like fuel availability.[204] This reliability standard does not require regions to actually achieve 0.1 LOLE, only to conduct the mandated analysis.[205] A future reliability standard could require regions to instead adopt best practices comparable to those described in Part 1.

Turning to DOE, the DOE Reorganization Act put emergency grid reliability powers in DOE's hands for addressing certain emergency situations. Section 202(c) of the FPA empowers DOE, upon the finding of an emergency, to require, among any things, "such generation . . . as in its judgment will best meet the emergency and serve the public interest."[206] Section 202(c) and its implementing regulations, along with the common understanding of the word "emergency," indicate that this authority is limited to unexpected events.[207] Additionally, DOE's implementing regulations indicate that a shortage caused by a resource's poor economics would not qualify as an emergency, unless the shortage is "imminent."[208] When promulgating these regulations, DOE noted that:

> DOE does not intend these regulations to replace prudent utility planning and system expansion. This intent has been reinforced in the final rule by expanding the "Definition of Emergency" to indicate that, while a utility may rely upon these regulations for assistance during a period of unexpected inadequate supply of electricity, it must solve long-term problems itself.[209]

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(2024), https://perma.cc/G6J3-9ZL4. These capacity markets are FERC-jurisdictional, and operate according to rules contained in tariffs filed with FERC, specifying particulars like demand curve type, resource accreditation, and formulas for calculating reserve margins. *See, e.g.*, *PJM Interconnection, L.L.C.*, 191 FERC ¶ 61,066, at P 8 (2025).

203 *Planning Resource Adequacy Assessment Reliability Standard*, 134 FERC ¶ 61,212, at P 1 (2011).

204 Standard BAL-502-RF-03, N. Am. Elec. Reliability Corp., https://perma.cc/9MB5-5H67.

205 *Planning Resource Adequacy Assessment Reliability Standard*, 134 FERC ¶ 61,212, at P 33 (2011) ("The only obligations under BAL-502-RFC-02 are analysis and documentation requirements. This regional Reliability Standard does not specify how the results of the analysis required in this standard are to be used. For example, BAL-502-RFC-02 does not require state commissions to use the resource assessment analysis resulting from BAL-502-RFC-02 for economic decisions regarding resource adequacy requirements.").

206 16 U.S.C. § 824a(c)(1).

207 16 U.S.C. § 824a(c)(1); 10 C.F.R. § 205.371; Burçin Ünel & Avi Zevin, *supra* note 5, at 37–38.

208 10 C.F.R. § 205.371 ("Situations where a shortage of electric energy is projected due solely to the failure of parties to agree to terms, conditions or other economic factors relating to service, generally will not be considered as emergencies unless the inability to supply electric service is imminent.").

209 Emergency Interconnection of Electric Facilities and the Transfer of Electricity to Alleviate an Emergency Shortage of Electric Power, 46 Fed. Reg. 39984, 39985 (Aug. 6, 1981) (codified at 10 C.F.R. pt. 205).

In a departure from prior practice,[210] DOE has now used this authority to prevent thermal plants from retiring.[211] These orders have already drawn challenges from multiple parties, including from a politically diverse coalition of utility regulators.[212] Parties argue, among other points, that the plants' retirements were not unexpected; that the regions would be resource adequate even without the plants; and that DOE's newly asserted authority over resource adequacy triggers the major questions doctrine.[213]

Having nationally set best practices and principles for determining resource adequacy in the face of rapidly escalating demand and the clean energy transition could be useful if they are well vetted and use appropriate legal constructs. The FPA in conjunction with the DOE Reorganization Act suggest that the appropriate course of action for the federal government to support resource adequacy would be for NERC and FERC to set national resource adequacy *planning* standards (not a national resource adequacy target) to help regions guard against potential resource adequacy risks that might materialize in the future, instead of allowing DOE to stretch its 202(c) emergency authorities.

The DOE study itself cautions, "the resource adequacy analysis that was performed in support of this study could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level."[214] Despite DOE's press statement asserting that the study's methodology can help guide "guide Federal reliability interventions,"[215] presumably to address the EO's mandate that DOE find a way to routinize further 202(c) emergency orders,[216] the study reports a fundamental limitation for doing so: It does not find any near-term reliability risk from current levels of resource adequacy.

The study itself states that, "one of the key takeaways from this study process is the underscored 'call to action' for strengthened regional engagement, collaboration, and robust data exchange which are critical to addressing the urgency of reliability and security concerns that underpin our

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[210] Cong. Rsch. Serv., Federal Power Act: The Department of Energy's Emergency Authority 4 (updated 2025), https://perma.cc/AU8L-VR55.

[211] *DOE's Use of Federal Power Act Emergency Authority*, U.S. Dep't of Energy, https://perma.cc/DPB9-6B74.

[212] Ethan Howland, *Groups Appeal DOE "Emergency" Order Keeping Michigan Plan Online*, Utility Dive (updated June 20, 2025), https://perma.cc/P9YZ-FNLK; Ethan Howland, *Eight Utility Regulators Challenge DOE Order Keeping Michigan Coal Plant* Open, Utility Dive (June 26, 2025), https://perma.cc/55FE-2RYR; Motion to Intervene and Request for Rehearing of the Joint Consumer Advocates, Dep't of Energy Order No. 202-25-4 (June 27, 2025), https://perma.cc/PD74-6CNC.

[213] Request for Rehearing by Michigan Attorney General Dana Nessel, Dep't of Energy Order No. 202-25-3, at 27–31, 35–36 (June 18, 2025); Motion to Intervene and Request for Rehearing and Stay of Sierra Club et al., Dep't of Energy Order No. 202-25-3, at 29–36 (June 18, 2025), https://perma.cc/4MYN-MHZC; Petition to Intervene and Request for Rehearing of the Organization of MISO States, Inc., Dep't of Energy Order No. 202-25-3, at 2–6 (June 23, 2025), https://perma.cc/D3PG-56H2. *See also* Brief of the Institute for Policy Integrity at 4–13, V.O.S. Selections, Inc. v. Trump, No. 25-00066-GSK-TMR-JAR (Ct. Int'l Trade May 8, 2025), https://perma.cc/5Z4T-8CHG (describing the major questions doctrine).

[214] U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at i.

[215] *Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security*, U.S. Dep't of Energy (July 7, 2025), https://perma.cc/942V-L7VB.

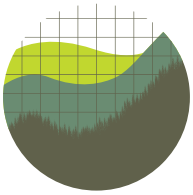
[216] *See* Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521–22 (Apr. 14, 2025).

collective economic and national security." And it presents a pathway to fulfill DOE's discussion of what will happen next: "The report will inform joint planning processes and help integrate modern metrics into national reliability assessment methodology."[217] FERC directing NERC to develop national resource adequacy planning metrics, protocols, and input parameters would fit neatly within this call to action.

[217] *Reliability*, U.S. Dep't of Energy, https://perma.cc/RSW3-FNN2.

# Conclusion

Given ever-increasing demand for electricity—proliferation of data centers for artificial intelligence; electrification of heating, cooling, and transportation; and pushes to onshore manufacturing—maintaining resource adequacy is essential. But there is no single answer to the question of when a system is resource adequate, or even what constitutes resource adequacy. Still, as this report explains, there are better and worse ways to pick resource adequacy targets, to evaluate whether the system has achieved and will maintain them, and to understand the resource adequacy impacts of a particular resource entering or exiting the system. The DOE Study uses some of these best practices but not other important ones, undermining the accuracy of its predictions. The DOE Study will hopefully focus additional attention on resource adequacy and speed up federal and state endeavors already underway to bolster resource adequacy. It does not, however, provide a rational basis for DOE to take action now to thwart ongoing plans for uneconomic, aging resources to retire. DOE's next best step would be to request that FERC open a proceeding eliciting proposals for nationwide, enforceable reliability standards mandating not a national resource adequacy target, but best practices for grid planners to conduct resource adequacy assessments. Additionally, states and grid operators should continue working together to expedite resource permitting, better forecast what hyperscaler demand will materialize, engage in holistic transmission planning, and speed interconnection queues—all of which will support future resource adequacy.



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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | |
|---|---|
| Federal Power Act Section 202(c) | ) |
| Emergency Order: Midcontinent | ) |
| Independent System Operator | ) |
| (MISO) | ) |
| | ) |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

# Exhibit 114

# 2025 EPA MI Haze SIP Approval

PRA. This proposed action does not establish any new information collection requirements.

*D. Regulatory Flexibility Act (RFA)*

This rule is not subject to notice and comment requirements because the Agency has invoked the APA ''good cause'' exemption under 5 U.S.C. 553(b)(B).

*E. Unfunded Mandates Reform Act (UMRA)*

This action does not contain an unfunded mandate as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The action imposes no enforceable duty on any state, local or Tribal governments or the private sector.

*F. Executive Order 13132: Federalism*

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

*G. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments*

This action does not have Tribal implications as specified in Executive Order 13175. This action withdraws two rules impacting the State of Texas. No Tribe is subject to the requirement to submit an implementation plan under the findings of inadequacy relevant to this action. Thus, Executive Order 13175 does not apply to this action.

*H. Executive Order: 13045 Protection of Children From Environmental Health & Safety Risks*

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of ''covered regulatory action'' in section 2–202 of the Executive Order. This action is not subject to Executive Order 13045 because it withdraws two rules that are no longer applicable to the State of Texas and does not directly or disproportionately affect children

*I. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution or Use*

This action is not subject to Executive Order 13211, because it is not a significant regulatory action under Executive Order 12866.

*J. National Technology Transfer and Advancement Act*

This proposed action does not involve technical standards.

This action is subject to the Congressional Review Act (CRA), and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

Under section 307(b)(1) of the CAA, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by November 4, 2025. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this action for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action may not be challenged later in proceedings to enforce its requirements (see section 307(b)(2)).

**List of Subjects in 40 CFR Part 52**

Environmental protection, Air pollution control, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping requirements, Sulfur oxides.

Dated: August 26, 2025.

**Walter Mason,**

*Regional Administrator, Region 6.*

For the reasons stated in the preamble, the Environmental Protection Agency amends 40 CFR part 52 as follows:

## PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

■ 1. The authority citation for part 52 continues to read as follows:

**Authority:** 42 U.S.C. 7401 *et seq.*

## Subpart SS—Texas

### § 52.2277 [Amended]

■ 2. Amend § 52.2277 by removing and reserving paragraph (c).

[FR Doc. 2025–17029 Filed 9–4–25; 8:45 am]

BILLING CODE 6560–50–P

## ENVIRONMENTAL PROTECTION AGENCY

## 40 CFR Part 52

**[EPA–R05–OAR–2021–0577; FRL–12588–02–R5]**

## Air Plan Approval; Michigan; Second Period Regional Haze Plan

**AGENCY:** Environmental Protection Agency (EPA).

**ACTION:** Final rule.

**SUMMARY:** The Environmental Protection Agency (EPA) is approving the Regional Haze State Implementation Plan (SIP) revision submitted by the Michigan Department of Environment, Great Lakes, and Energy (EGLE) on August 23, 2021, and supplemented on July 24, 2025, as satisfying applicable requirements under the Clean Air Act (CAA) and EPA's Regional Haze Rule (RHR) for the program's second implementation period. EGLE's SIP submission addresses the requirement that States must periodically revise their long-term strategies for making reasonable progress towards the national goal of preventing any future, and remedying any existing, anthropogenic impairment of visibility, including regional haze, in mandatory Class I Federal areas. The SIP submission also addresses other applicable requirements for the second implementation period of the regional haze program. EPA is taking this action pursuant to sections 110 and 169A of the CAA.

**DATES:** This final rule is effective on October 6, 2025.

**ADDRESSES:** EPA has established a docket for this action under Docket ID No. EPA–R05–OAR–2021–0577. All documents in the docket are listed on the *https://www.regulations.gov* website. Although listed in the index, some information is not publicly available, *i.e.,* Confidential Business Information (CBI), Proprietary Business Information (PBI), or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy form. Publicly available docket materials are available either through *https://www.regulations.gov* or at the Environmental Protection Agency, Region 5, Air and Radiation Division, 77 West Jackson Boulevard, Chicago, Illinois 60604. This facility is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding Federal holidays. We recommend that you telephone Matt

Rau, at (312) 886–6524 before visiting the Region 5 office.

**FOR FURTHER INFORMATION CONTACT:** Matt Rau, Air and Radiation Division (AR–18J), Environmental Protection Agency, Region 5, 77 West Jackson Boulevard, Chicago, Illinois 60604, (312) 886–6524, *rau.matthew@epa.gov.*

**SUPPLEMENTARY INFORMATION:** Throughout this document whenever ''we,'' ''us,'' or ''our'' is used, we mean EPA.

This supplementary information section is arranged as follows:

I. Background
II. Public Comment Process
III. Summary of Public Comments and EPA's Responses
IV. What action is EPA taking?
V. Statutory and Executive Order Reviews

## I. Background

On August 23, 2021, EGLE submitted a revision to its SIP to address regional haze requirements for the second implementation period. On July 24, 2025, EGLE submitted a supplement (Supplement) to its original submission providing expanded source-specific analyses and emissions updates. EGLE made this SIP submission to satisfy the requirements of the CAA's regional haze program pursuant to CAA sections 169A and 169B and 40 CFR 51.308.

EPA proposed to approve EGLE's submission into the SIP on June 18, 2025. A full background, the specifics of the Michigan regional haze plan, and EPA's evaluation of the plan are given in the proposed rule and will not be restated in this rule. See 90 FR 25975 (June 18, 2025). EGLE submitted the Supplement in draft for parallel processing on April 3, 2025. Detail on parallel processing is provided in the proposed rule.

In this final action, EPA is affirming that it is now the Agency's policy that, where visibility conditions for a Class I Federal area impacted by a State are below the uniform rate of progress (URP) and the State has considered the four statutory factors, the State will have presumptively demonstrated reasonable progress for the second planning period for that area. EPA acknowledges that this final action reflects a change in policy as to how the URP should be used in the evaluation of regional haze second planning period SIPs but believes that this policy better aligns with the purpose of the statute and RHR: achieving ''reasonable'' progress towards natural visibility.

As described in the approval of West Virginia's regional haze plan (90 FR 29737, July 7, 2025), EPA has discretion and authority to change its policy. In *FCC* v. *Fox Television Stations, Inc.,* the U.S. Supreme Court plainly stated that an agency is free to change a prior policy and ''need not demonstrate . . . that the reasons for the new policy are better than the reasons for the old one; it suffices that the new policy is permissible under the statute, that there are good reasons for it, and that the agency believes it to be better.'' 566 U.S. 502, 515 (2009) (referencing Motor *Vehicle Mfrs. Ass'n of United States, Inc.* v. *State Farm Mut. Auto. Ins. Co.,* 463 U.S. 29 (1983)). *See also Perez* v. *Mortgage Bankers Assn.,* 135 S. Ct. 1199 (2015).

The Class I areas impacted by emissions from Michigan sources are all below the 2028 URP, and EGLE's SIP submission demonstrated that the State took into consideration the four reasonable progress factors listed in CAA 169A(g)(1) [1] with respect to an adequate number of emissions sources. Thus, EPA determines that EGLE's SIP revision is fully approvable.

In developing the regulations required by CAA section 169A(b), EPA established the concept of the URP for each Class I area. The URP is determined by drawing a straight line from the measured 2000 to 2004 baseline conditions (in deciviews) for the 20 percent most impaired days at each Class I area to the estimated natural conditions (in deciviews) for the 20 percent most impaired days in 2064. From this calculation, a URP value can be calculated for each year between 2004 and 2064. EPA developed the URP to address the diverse concerns of Eastern and Western States and account for the varying levels of visibility impairment in Class I areas around the country while ensuring an equitable approach nationwide. For each Class I area, States must calculate the URP for the end of each planning period (*e.g.,* in 2028 for the second planning period).[2] 40 CFR 51.308(f)(1)(vi)(A). States may also adjust the URP to account for impacts from anthropogenic sources outside the United States and/or impacts from certain wildland prescribed fires. 40 CFR 51.308(f)(1)(vi)(B). Then, for each Class I area, States must compare the reasonable progress goal (RPG) for the 20 percent most impaired days to the URP for the end of the planning period. If the RPG is above the URP, then an additional ''robust demonstration'' requirement is triggered for each State that contributes to that Class I area. 40 CFR 51.308(f)(3)(ii)(B).

In the 2017 RHR Revisions, EPA addressed the role of the URP as it relates to a State's development of its second planning period SIP. 82 FR 3078 (January 10, 2017). Specifically, in response to comments suggesting that the URP should be considered a ''safe harbor'' that relieve States of any obligation to consider the four statutory factors, EPA explained that the URP was not intended to be such a safe harbor. *Id.* at 3099. ''Some commenters stated a desire for corresponding rule text dealing with situations where RPGs are equal to (''on'') or better than (''below'') the URP or glidepath. Several commenters stated that the URP or glidepath should be a 'safe harbor,' opining that States should be permitted to analyze whether projected visibility conditions for the end of the implementation period will be on or below the glidepath based on on-the-books or on-the-way control measures, and that in such cases a four-factor analysis should not be required.'' *Id.*

Other comments indicated a similar approach, such as ''a somewhat narrower entrance to a 'safe harbor,' by suggesting that if current visibility conditions are already below the end-of-planning-period point on the URP line, a four-factor analysis should not be required.'' *Id.* EPA stated in its response that we did not agree with either of these recommendations. ''The CAA requires that each SIP revision contain long-term strategies for making reasonable progress, and that in determining reasonable progress States must consider the four statutory factors. Treating the URP as a safe harbor would be inconsistent with the statutory requirement that States assess the potential to make further reasonable progress towards natural visibility goal in every implementation period.'' *Id.*

Importantly, EPA's recently adopted policy does not make the URP a safe harbor. The policy merely creates a presumption that the State's second planning period SIP is making reasonable progress for a Class I Federal Area if the State has taken into consideration the four statutory factors

[1] The four statutory factors required to be taken into consideration in determining reasonable progress are: the costs of compliance, the time necessary for compliance, and the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any existing source subject to such requirements. CAA section 169(g)(1).

[2] We note that RPGs are a regulatory construct that we developed to address the statutory mandate in CAA section 169B(e)(1), which required our regulations to include ''criteria for measuring 'reasonable progress' toward the national goal.'' Under 40 CFR 51.308(f)(3)(ii), RPGs measure the progress that is projected to be achieved by the control measures a State has determined are necessary to make reasonable progress. Consistent with the 1999 RHR, the RPGs are unenforceable, though they create a benchmark that allows for analytical comparisons to the URP and mid-implementation-period course corrections if necessary. 82 FR 3091–92 (January 10, 2017).

of 169A(g)(1) and that area is below the URP. This is consistent with the CAA and RHR.

## II. Public Comment Process

The public comment period on EPA's proposed approval ended on July 18, 2025. During this period, EPA received three sets of comments. The Power Generators Air Coalition (PGen) and the Mid-Atlantic/Northeast Visibility Union (MANEVU) each submitted a set of comments. Four conservation groups, including the National Parks Conservation Association, the Sierra Club, the Environmental Law and Policy Center, and the Coalition to Protect America's National Parks, submitted a third set of comments and are collectively referred to as ''the Conservation Groups'' throughout this document.

## III. Summary of Public Comments and EPA's Responses

EPA has included all comments in the rulemaking docket for this action. The August 25, 2025, Response to Comments (RTC) document is included in the docket for this rulemaking under Docket ID No. EPA–R05–OAR–2021–0577 and provides full and detailed responses to all significant comments that further explain the basis for our final action.

EPA received comments on the proposed rule that covered several topics including, but not limited to, EPA's URP policy,[3] an ''Ask'' from a regional planning organization, source selection, analysis of effectively controlled sources, incorporation of measures into the SIP, four-factor analyses,[4] and the impact on local communities.

PGen's comments, summarized as Comment 1 in the RTC document, are supportive of the proposed approval and EPA's URP policy. EPA concurs with the supportive comments and acknowledges the comment on the URP policy.

MANEVU commented on EPA's URP policy and its ''Asks'' about the DTE- St. Clair Power Plant. MANEVU's comments and EPA's responses can be found in the RTC document at Comment 2a and 2b and Response 2a and 2b. EPA disagrees with MANEVU's comment as the URP policy is consistent with the statute for the reasons as detailed in Response 2a in the RTC document. EPA also disagrees with MANEVU's comment regarding DTE-St. Clair Power Plant since EGLE fully responded to MANEVU's ''Asks'' [5] in the Supplement, section 2.2. See Response 2b in the RTC document for more detail on how EGLE addressed the MANEVU ''Asks.''

The Conservation Groups commented on the economic, public health, and environmental benefits of reducing air pollution through Michigan's regional haze SIP. EPA notes, as explained in Response 3 of the RTC, that EGLE has made progress in reducing visibility-impairing pollution during the second implementation period as demonstrated in the monitoring data collected at the impacted Class I areas. EPA also notes that regional haze program is designed to address visibility concerns and that the National Ambient Air Quality Standards, required by the CAA, protect human health.

The Conservation Groups argue that EGLE's source selection process is arbitrary and capricious since EGLE did not select sources that the Conservation Groups previously recommended for selection. As explained in Response 4 of the RTC, EPA disagrees with the comment. EGLE addressed the requirements of 40 CFR 51.308(f)(2)(i) in its source selection process. EGLE provided information on its source selection process and the results in section 3.2.2 of its Supplement.

The Conservation Groups commented that EPA's proposal to approve EGLE's determination that no additional measures were necessary to make reasonable progress in the second implementation period is arbitrary and capricious. The Conservation Groups claim that EPA has no system to determine how current control technologies or past and potential ongoing emission reductions should be considered when evaluating whether additional measures are necessary. The Conservation Groups also assert that EPA failed to provide adequate public notice because the proposed approval did not provide a metric or an analysis to determine that no additional measures are necessary. See Comment and Response 5 in the RTC document for further details. EPA disagrees with the comment. EPA fully evaluated the information EGLE provided for the sources with current effective control technologies, as well as emission reductions achieved in the second implementation period. In the proposed rule, EPA articulated its rationale in determining how to weigh current effective control measures and emission reductions to approve EGLE's determination that no additional measures are necessary for reasonable progress, citing references to effective control demonstrations in section 3(f) of the 2019 Regional Haze Guidance. See 90 FR 25975 (June 18, 2025). The record in the docket for this rulemaking contains evidence of enforceable emission reductions, as well as EPA's evaluation of emissions reductions in the Technical Support Document (TSD) accompanying the proposed rule. Therefore, EPA disagrees with the Conservation Groups that consideration of these emission reductions was improper in EGLE's determination that no additional measures are necessary to make reasonable progress in the second implementation period. EPA's proposed approval was not arbitrary or capricious because of a lack of a metric and analysis and, as such, does not constitute a failure of public notice.

The Conservation Groups claim that EGLE inappropriately failed to perform four-factor analyses for seven facilities that were improperly determined to be effectively controlled. The Conservation Groups state that the plain language of the CAA and the RHR does not allow EGLE or EPA to eliminate sources from analysis based on assertions that the sources are effectively controlled, but rather requires that States consider the four statutory factors. The Conservation Groups comment that the seven facilities are not effectively controlled and that there are likely cost-effective controls available for each of the sources that would further reduce emissions. The Conservation Groups also commented on two sources that EGLE did not select for analysis, saying EPA did not address or analyze EGLE's decision. As explained in Response 6 of the RTC document, EPA disagrees with this comment. Neither CAA section 169A(b)(2), CAA section 169A(g)(1), nor the RHR prohibit States from forgoing a four-factor analysis based on a source being effectively controlled. As outlined in the 2017 RHR, ''the EPA has consistently interpreted the CAA to provide States with the flexibility to conduct four-factor analyses for specific sources, groups of sources or even entire source categories, depending on State policy preferences and the specific circumstances of each State.'' 82 FR 3088, January 10, 2017. EPA acknowledges that a State may reasonably decide not to select sources

[3] A change in Agency policy was introduced in the approval of West Virginia's regional haze plan. See the April 18, 2025, (90 FR 16478) proposed rule) and the July 7, 2025, (90 FR 29737) final rule.

[4] Under CAA 169A(g)(1), the four statutory factors are the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources. See also 40 CFR 51.308(f)(2)(i). An evaluation of potential control options for sources of visibility impairing pollutants based on applying the four statutory factors in CAA section 169A(g)(1) is referred to as a ''four-factor'' analysis.

[5] The August 25, 2017, and July 27, 2018, MANEVU ''Asks''.

that have recently installed effective controls. EPA notes that if a source's emissions are already well-controlled, it is unlikely that further cost-effective reductions are available. In this case, EGLE evaluated the seven units, including permit limitations, control efficiencies, regulations, actual emissions, past emission trends, and projected 2028 emissions to demonstrate that the existing level of control makes it reasonable to conclude that the controls are effective and that a full four-factor analysis would likely result in the conclusion that no further controls are necessary. EPA also disagrees with the comment regarding two sources EGLE did not select for evaluation of potential additional control measures. EGLE properly addressed the requirements of 40 CFR 51.308(f)(2)(i) in the source selection process it used.

The Conservation Groups commented that EGLE's analyses of existing effective controls are flawed and that EPA's TSD for the proposed rule does not support EPA's proposed approval of EGLE's Regional Haze SIP revision. The Conservation Groups also commented that EGLE did not perform four-factor analyses for specific sources. Detail on the general existing effective controls is given in Comment and Response 6 in the RTC document. Comment and Response 6a in the RTC document provide details on the TSD comment. More detail on the comments regarding the specific sources EGLE did not perform a four-factor analysis on and the responses are found in the RTC document under Comment and Response 6b: J. H. Campbell, Units 1, 2, and 3; Comment and Response 6c: Consumers Energy—Dan E. Karn Units 3 and 4; Comment and Response 6d: Tilden Mining Company Kiln 1; Comment and Response 6e: Belle River Power Plant Units 1 and 2; Comment and Response 6f: St. Mary's Cement—Charlevoix Plant; Comment and Response 6g: Holcim US Lafarge Alpena Plant; and Comment and Response 6h: Neenah Paper Michigan-Munising. EPA disagrees with the assertion that CAA sections 169A(b)(2), (g)(1), or the RHR require every source exceeding the source selection threshold to require a four-factor analysis. EPA disagrees with the commentors on what those portions of the CAA and the RHR require of selected sources. Specifically, States have the flexibility to determine that a source is effectively controlled. As detailed in Response 6 in the RTC document, CAA section 169A(b)(2) does not discuss which sources, types of sources, or groups of sources must be considered to determine reasonable progress. Reasonable progress is addressed in CAA section 169A(g)(1) in that States must ''take into consideration'' the four statutory factors. Similarly, the RHR does not give minimum source selection criteria. EPA disagrees that the TSD does not provide support for the proposed approval. As explained in the TSD and RTC, EPA's approval of the Michigan regional haze plan is based on the consideration of all evidence provided in EGLE's submission and additional information provided in the docket. EPA also disagrees with the notion that a four-factor analysis is required for each of the specific units that were identified by the Conservations Groups. In summary, EPA finds that EGLE reasonably concluded that the units are effectively controlled and that conducting a four-factor analysis would not likely result in additional measures being needed for reasonable progress.

The Conservation Groups also commented with concerns that two specific sources, Midland Cogeneration Venture and EES Coke Battery, were not selected for evaluation of possible additional control measures. Further information regarding these two sources is found in the RTC at Response 6i: Midland Cogeneration Venture and Response 6j: EES Coke Battery. EPA disagrees that Midland Cogeneration Venture and EES Coke Battery should have been selected for analysis and EPA finds that EGLE's source selection process was appropriate and well supported. EGLE sufficiently captured the State's sources with the greatest impact on visibility impairment.

The Conservation Groups expressed concerns about EPA's review of EGLE's four-factor analyses, arguing that EPA did not provide an evaluation of EGLE's analyses or a conclusion as to whether the State's determinations complied with the CAA and RHR. The Conservation Groups also made specific comments on the four-factor analyses for three facilities. A summary of this comment and EPA's full response can be found as Comment and Response 7 in the RTC document. The comments and responses on specific four-factor analyses for Tilden Mining Company LLC Kiln 2, Billerud—Escanaba LLC Power Boiler 11, and Graymont Western Lime Kiln 1 are detailed in the RTC document as Comments and Responses 7a, 7b, and 7c, respectively. EPA disagrees with this comment. As explained in the proposed rule, EPA carefully evaluated EGLE's entire SIP submission, including the Supplement, the comments from the FLM consultation and the State's responses to comments received during the State comment period. EGLE worked directly with the sources in evaluating potential measures and concluded that additional control measures are not necessary for reasonable progress during the second implementation period based on the four factors. EPA disagrees with the comments on these specific facilities. EGLE considered the four statutory factors, current effective control technologies, emission reductions that have already occurred during the second implementation period, and the projected 2028 visibility conditions for Class I areas influenced by emissions from Michigan sources. EPA therefore finds that EGLE reasonably concluded that no additional measures are necessary to make reasonable progress in the second implementation period for any of the three identified sources.

The Conservation Groups commented that EPA did not analyze the impact of haze-forming pollution from Michigan sources on the communities that surround these facilities. See Comment and Response 8 in the RTC document. The RHR does not require an analysis of health impacts. Instead, the National Ambient Air Quality Standards are established to separately protect human health.

The Conservation Groups argue that EPA's URP Policy violates the CAA's visibility provisions. The Conservation Groups comment on specific portions of the CAA and cite several cases. Those comments and EPA's responses are detailed in Comments and Responses 9, 9a, 9b, 9c, and 9d in the RTC document. EPA disagrees with the comments. EPA's URP policy is consistent with the CAA. Pursuant to CAA 169A(a)(4), Congress explicitly delegated the authority to EPA to promulgate regulations regarding reasonable progress towards meeting the national goal. In determining the measures necessary to make reasonable progress, Congress mandated ''tak[ing] into consideration the cost of compliance, the time necessary for compliance, and the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any existing source subject to such requirement.'' CAA 169A(g)(1). However, nothing in the statute defines what it means ''to take into consideration'' the four factors under CAA 169A(g)(1). Under this statutory framework, Congress has empowered EPA to give meaning to this statutory phrase. *Loper Bright Enters.* v. *Raimondo,* 603 U.S. 369, 395 (2024). The phrase ''to take into consideration'' implies a broader process not limited to the four statutory factors, allowing

States to weigh other factors, like visibility, to support their determination of whether additional measures are necessary to make reasonable progress at Class I areas. This follows from the fact that reasonable progress requires the improvement of visibility. CAA 169A(b)(2). As such, visibility improvement must be a fundamental part of determining the extent of progress that is considered reasonable. Being below the URP does not relieve a State of its obligations under the CAA and the RHR to make reasonable progress.

The Conservation Groups state that the URP policy is inconsistent with the RHR. The Conservation Groups comment that, ''EPA cannot square its new policy with the RHR.'' See Comment 10 and Response 10 in the RTC document for further detail. EPA disagrees with this comment. EPA's URP policy is consistent with the RHR. To meet the reasonable progress goal requirements under 40 CFR 51.308(f)(3), the reasonable progress goals established by a State must reflect the measures it deemed to be necessary to make reasonable progress within the applicable implementation period and must be projected to be achieved by the end of the applicable implementation period. Therefore, it is sufficient under 40 CFR 51.308(f)(3) that this SIP establishes reasonable progress goals that reflect visibility conditions that are projected to be achieved by the end of the second planning period.

The Conservation Groups commented that the URP policy violates the procedural requirements of the CAA. The Conservation Groups comment that the URP policy unlawfully departs from national policy, that the URP policy is inconsistent with actions across EPA Regions, that the URP policy effectively revises the RHR, and that EPA must determine if its URP policy has a nationwide scope. The comments and responses on each point are presented in detail as Comments and Responses 11a, 11b, 11c, and 11d in the RTC document. EPA disagrees with each comment. As for the comment noting that the URP policy was announced in a regional action and that this change violates the CAA requirements that SIP actions be consistent with national policy, EPA disagrees that our Regional Consistency regulations at 40 CFR part 56, and 40 CFR 56.5(b) in particular, are relevant to this action. The Conservation Groups mention other regional haze actions in commenting that the URP policy is inconsistent with actions across EPA Regions. EPA disagrees that its change in policy means that all of its actions on second planning period regional haze SIPs that pre-date its proposed approval of the West Virginia second planning period submittal are inconsistent with the URP policy. See 90 FR 29737 (July 7, 2025). The policy is consistent with EPA's long-standing position that the URP is not a ''safe harbor.'' EPA's policy establishes a presumption that the reasonable progress requirements of the CAA and the RHR are met if the State has taken into consideration the four statutory factors and the visibility impairment for each Class I Area is projected to be below the URP (*i.e.,* the ''glidepath'') at the end of the applicable planning period. Unlike treating the URP as a ''safe harbor,'' the policy does not exempt or allow a State to evade the requirements of the CAA or the RHR. Treating the URP as a ''safe harbor'' would exempt States from considering the four statutory factors and would allow States to exclude measures necessary for reasonable progress from the SIP. EPA disagrees with the comment that it must determine if the URP policy has a nationwide scope. EPA notes that this action applies to a SIP submission from one State—Michigan. EPA also states that the comment that EPA ''must'' publish a finding that this action is ''based on a determination of nationwide scope [or] effect'' is also unsupported and incorrect. Under CAA section 307(b)(1), 42 U.S.C. 7607(b)(1), a petition for review of an action that is ''locally or regionally applicable may be filed only in the United States Court of Appeals for the appropriate circuit,'' with one exception: if (i) the action ''is based on a determination of nationwide scope or effect'' and (ii) ''if in taking such action the Administrator finds and publishes that such action is based on such a determination,'' then any petition for review must be filed in the D.C. Circuit. The Administrator has not made and published a finding that this action is based on a determination of nationwide scope or effect. Accordingly, any petition for review of this action must be filed in the United States Court of Appeals for the appropriate regional circuit.

The Conservation Groups commented that EGLE's SIP Revision and Supplement do not meet EPA's URP policy for presumptive approval. The Conservation Groups commented on EGLE relying on the IMPROVE Network to satisfy the monitoring requirement of the RHR and EGLE's URP adjustments, as well as on EGLE not addressing additional Class I areas. As explained in Responses 12a, 12b, and 12c of the RTC document, EPA disagrees with these comments. The IMPROVE network was in operation up to the time EGLE submitted its SIP revision. EGLE continues to support and participate in the IMPROVE network. Concerns regarding the future funding of the IMPROVE network are speculative, out of the control of EGLE, and beyond the scope of the basis for our action on EGLE's second planning period SIP. As for the URP adjustments, the RHR at 40 CFR 51.308(f)(1) also provides the option for States to propose adjustments to the URP line for a Class I area to account for visibility impacts from anthropogenic sources outside the United States and the impacts from wildland prescribed fires that were conducted for certain, specified objectives. EGLE provided this analysis for its Class I areas. Under 40 CFR 51.308(f)(2)(ii)(B), States must consider and address the emissions reduction measures identified by other States for their sources as being necessary to make reasonable progress in the mandatory out-of-state Class I area. EGLE analyzed the Class I areas impacted by Michigan emissions using Lake Michigan Air Directors Consortium (LADCO) modeling, as the comment noted. EGLE identified 13 out-of-state Class I areas in addition to its own two Class I areas where Michigan sources contribute to total visibility impairment above 1 percent. EGLE also identified two additional Class I areas within the LADCO States, Voyageurs National Park and Boundary Waters Canoe Area Wilderness in Minnesota, even though Michigan sources contribute below 1 percent to total visibility impairment in each of those areas. The comment included several additional Class I areas. EGLE found no additional measures to be necessary to make reasonable progress in the out-of-state Class I areas. The contribution from Michigan sources would be even smaller at more distant Class I areas so there is no reason to expect that EGLE would find additional measures necessary to make reasonable progress for those distant Class I areas. EPA concludes that EGLE properly considered Michigan sources that are reasonably anticipated to contribute to visibility impairment Class I areas.

## IV. What action is EPA taking?

EPA is approving the Regional Haze SIP revision submitted by EGLE on August 23, 2021, and supplemented on July 24, 2025, as satisfying applicable requirements under the CAA and RHR for the program's second implementation period.

## V. Statutory and Executive Order Reviews

Under the CAA, the Administrator is required to approve a SIP submission that complies with the provisions of the CAA and applicable Federal regulations. 42 U.S.C. 7410(k); 40 CFR 52.02(a). Thus, in reviewing SIP submissions, EPA's role is to approve State choices, provided that they meet the criteria of the CAA. Accordingly, this action merely approves State law as meeting Federal requirements and does not impose additional requirements beyond those imposed by State law. For that reason, this action:

- Is not a significant regulatory action subject to review by the Office of Management and Budget under Executive Order 12866 (58 FR 51735, October 4, 1993);
- Is not subject to Executive Order 14192 (90 FR 9065, February 6, 2025) because SIP actions are exempt from review under Executive Order 12866;
- Does not impose an information collection burden under the provisions of the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*);
- Is certified as not having a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*);
- Does not contain any unfunded mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4);
- Does not have federalism implications as specified in Executive Order 13132 (64 FR 43255, August 10, 1999);
- Is not subject to Executive Order 13045 (62 FR 19885, April 23, 1997) because it approves a State program;
- Is not a significant regulatory action subject to Executive Order 13211 (66 FR 28355, May 22, 2001); and
- Is not subject to requirements of section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) because application of those requirements would be inconsistent with the CAA.

In addition, the SIP is not approved to apply on any Indian reservation land or in any other area where EPA or an Indian Tribe has demonstrated that a Tribe has jurisdiction. In those areas of Indian country, the rule does not have Tribal implications and will not impose substantial direct costs on Tribal governments or preempt Tribal law as specified by Executive Order 13175 (65 FR 67249, November 9, 2000).

This action is subject to the Congressional Review Act, and EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

Under section 307(b)(1) of the CAA, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by November 4, 2025. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this action for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action may not be challenged later in proceedings to enforce its requirements. (See section 307(b)(2).)

### List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference, Intergovernmental relations, Nitrogen oxides, Reporting and recordkeeping requirements, Sulfur oxides.

Dated: August 26, 2025.

**Anne Vogel,**

*Regional Administrator, Region 5.*

For the reasons stated in the preamble, title 40 CFR part 52 is amended as follows:

## PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

■ 1. The authority citation for part 52 continues to read as follows:

**Authority:** 42 U.S.C. 7401 *et seq.*

■ 2. In § 52.1170, the table in paragraph (e) is amended by adding an entry for ''Regional Haze Plan for the Second Implementation Plan'' after the entry for ''Regional Haze Progress Report'' to read as follows:

**§ 52.1170 Identification of plan.**

* * * * *

(e) * * *

EPA—APPROVED MICHIGAN NONREGULATORY AND QUASI-REGULATORY PROVISIONS

| Name of nonregulatory SIP provision | Applicable geographic or nonattainment area | State submittal date | EPA approval date | Comments |
|---|---|---|---|---|
| * * | * | * | * * | * |
| Regional Haze Plan for the Second Implementation Plan. | Statewide | 8/23/2021, 7/24/2025. | 9/5/2025, 90 FR [Insert **Federal Register** page where the document begins]. | Full Approval. |
| * * | * | * | * * | * |

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[FR Doc. 2025–17096 Filed 9–4–25; 8:45 am]

BILLING CODE 6560–50–P

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | |
|---|---|
| Federal Power Act Section 202(c) | ) |
| Emergency Order: Midcontinent | ) |
| Independent System Operator | ) |
| (MISO) | ) |
| | ) |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

# Exhibit 115

# Mar. 2025 MI SIP Supplement

STATE OF MICHIGAN
DEPARTMENT OF
ENVIRONMENT, GREAT LAKES, AND ENERGY
EXECUTIVE OFFICE

GRETCHEN WHITMER
GOVERNOR

PHILLIP D. ROOS
DIRECTOR

April 3, 2025

VIA ELECTRONIC SUBMISSION

Cheryl Newton, Acting Regional Administrator
United States Environmental Protection Agency, Region 5
77 West Jackson Boulevard, R-19J
Chicago, Illinois 60604-3507

Dear Acting Regional Administrator Newton:

SUBJECT: Formal Request for Parallel Processing of Michigan's Supplement to the August 2021 Regional Haze State Implementation Plan

**Request for Parallel Processing**

The Michigan Department of Environment, Great Lakes, and Energy (EGLE) submits to the United States Environmental Protection Agency (USEPA) this formal request to initiate parallel processing, as authorized under Appendix V to Part 51 of Title 40 of the Code of Federal Regulations, for Michigan's Public Notice Draft Supplement to the August 2021 Regional Haze State Implementation Plan ("Supplement").

**Schedule for Final Submission to the USEPA**

The 30-day public comment period for the Supplement began on March 10, 2025, and was initially scheduled to end on April 8, 2025; however, upon receiving a request for extension from the National Parks Conservation Association, Coalition to Protect America's National Parks, and Sierra Club, EGLE decided to extend the public comment period by 14 days. Due to the approved extension, the new deadline for the public comment period regarding the Supplement is set to end on April 22, 2025. Upon completion of the public comment period, Air Quality Division (AQD) staff will address all public comments received, initiate further review by AQD management, and provide it for my consideration for submittal to the USEPA. EGLE anticipates that it has the ability to submit the Supplement to the USEPA in May, which would provide the USEPA with three or four months to issue a proposed approval, disapproval, or partial approval/disapproval for Michigan's Supplement, initiate a federal public comment period on the proposal, and issue a final rulemaking.

Please find Michigan's Public Notice Draft Regional Haze Supplement enclosed with this letter (Attachment A), along with all associated appendices (Attachments B-D).

If you have any questions, please contact John Olson, SIP Development Unit, AQD, at 517-648-3551 or OlsonJ12@Michigan.gov; or you may contact me.

Sincerely,

Phillip D. Roos
Director
517-284-6700

Enclosures
cc/enc: John Mooney, USEPA, Region 5
Michael Langman, USEPA, Region 5
Aaron B. Keatley, Chief Deputy Director, EGLE
Annette Switzer, EGLE
Dr. Eduardo Olaguer, EGLE
Tom Shanley, EGLE
Robert Irvine, EGLE
John Olson, EGLE

# SUPPLEMENT TO
# MICHIGAN'S AUGUST 23, 2021,
# REGIONAL HAZE STATE IMPLEMENTATION PLAN REVISION
# FOR THE SECOND PLANNING PERIOD

MICHIGAN DEPARTMENT OF
ENVIRONMENT, GREAT LAKES, AND ENERGY

Michigan Department of Environment, Great Lakes, and Energy
Air Quality Division
P.O. Box 30260
Lansing, Michigan 48909-7760
*https://www.michigan.gov/air*

[Public Notice Draft for 30-day Public Comment Period]

March 2025

| Facility Name | Sector | Facility Unit ID | Retirement Date | 2016 Emissions (tpy) | | | |
|---|---|---|---|---|---|---|---|
| | | | | NH3 | $NO_X$ | $PM_{2.5}$ | $SO_2$ |
| | | Unit 3 | 6/1/2021 | | 1859.4 | 3.6 | 2805.7 |
| LBWL, Erickson Station | EGU | Unit 1 | 11/28/2022 | 0.1 | 1058.5 | 1.4 | 2588.5 |
| LBWL, Eckert Station | EGU | Unit 1 | 12/31/2020 | 0.1 | 785.5 | 12.4 | 1858 |
| | | Unit 3 | 12/31/2020 | | | | |
| | | Unit 4 | 5/31/2021 | | | | |
| | | Unit 5 | 12/31/2020 | | | | |
| | | Unit 6 | 12/31/2020 | | | | |
| Consumers Energy – J.C. Weadock Facility | EGU | Weadock 7 | 4/15/2016 | 0 | 510.5 | 30.9 | 1635.5 |
| | | Weadock 8 | 4/15/2016 | | | | |
| Consumers Energy – D.E. Karn Facility | | Karn 1 | 6/1/2023 | 0 | 213.8 | 12 | 283.9 |
| | | Karn 2 | 6/1/2023 | | | | |
| MARQUETTE BOARD OF LIGHT & POWER - Shiras | EGU | Boiler 3 | 4/29/2019 | 0 | 196.7 | 44.5 | 419 |
| Michigan Hub Plant | EGU | Unit 1 | 9/30/2017 | | 132.9 | 0.8 | 139.5 |
| DTE – Pontiac North LLC | | EUBHB9 | 1/10/2017 | 0 | 0 | 0 | 0 |
| Graphic Packing International, Inc. - Kalamazoo | | Unit BLR08 | 10/07/2024 | | 82.1 | 4.5 | 0.4 |
| J B Sims | | Unit 3 | 6/1/2020 | 0 | 459.4 | 9.5 | 364.9 |
| J R Whiting | | Unit 1 | 4/15/2016 | 0 | 217.4 | 18.8 | 484.7 |
| | | Unit 2 | 4/15/2016 | 0 | 178.3 | 6.1 | 440.6 |
| | | Unit 3 | 4/15/2016 | 14.4 | 589 | 7.3 | 527.5 |
| James De Young | | Unit 5 | 6/1/2017 | | 0.1 | 0 | 0 |
| Consumers Energy - Thetford | | Unit 2 | 6/1/2019 | | 0 | | 0.6 |
| | | Unit 3 | 4/1/2018 | | 0 | | 0.8 |
| | | Unit 4 | 6/1/2019 | | 0 | | 1.5 |
| Wyandotte | | Unit 8 | 6/30/2016 | | 0 | 0 | 0.0 |

In addition to the retirements that have already occurred, the following units will be retired in the future, although not all were selected for a possible four-factor analysis under Section 3.2.2.

- **Consumers Energy – J.H. Campbell Plant: Units 1, 2, and 3**

  Units 1, 2, and 3 are discussed in detail in Michigan's 2021 Regional Haze SIP submittal on pages 14, 20, and 21 (*See* Appendix 1). This SIP supplement provides further elaboration.

  Consumers Energy – J.H. Campbell Power Plant is subject to a settlement agreement approved by the Michigan Public Service Commission on April 20, 2020, which requires closure/retirement of coal-fired Units 1, 2, and 3 on or before May 31, 2025. *See* April 20, 2022, Settlement Agreement – Michigan Public Service Commission, Case No. U-21090 – In the Matter of the Application of Consumers Energy Company for Approval of and Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief. https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000002gLkGAAU (*See* Appendix 10).

  The settlement agreement was executed by Consumers Energy Company, the Michigan Public Service Commission staff, Michigan Environmental Council, the Natural Resources Defense Council, the Sierra Club, Attorney General Dana Nessel, Environmental Law and Policy Center, Vote Solar, Ecology Center, Union of Concerned

Scientists, Urban Core Collective, Citizens Utility Board of Michigan, Hemlock Semiconductor Operations LLC, Michigan Energy Innovation Business Council, Institute for Energy Innovation, Clean Grid Alliance, Michigan Electric Transmission Company LLC, and Great Lakes Renewable Energy Association.

The settlement agreement was affirmed in the State of Michigan Court of Appeals. *See* No. 362294 Public Service Commission, LC No. 00-021090, March 23, 2023. https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000007I2GEAA0 (*See* Appendix 11).

When retired sometime before May 31, 2025, the permanent shutdown of coal-fired Units 1, 2 and 3 at Consumers Energy – J.H. Campbell Power Plant will represent a reduction in emissions of 2,346 tpy $NO_X$ and 12,850 tpy $SO_2$ based on the 2016 inventory.

- **Consumers Energy – Dan E. Karn, Units 3 and 4**

Units 3 and 4 are discussed in detail in Michigan's 2021 Regional Haze SIP submittal on pages 14,15, 21, and 22 (*See* Appendix 1). This SIP supplement provides further elaboration.

Consumers Energy – Dan E. Karn Power Plant is subject to the same settlement agreement mentioned above for the J.H. Campbell Plant that was approved by the Michigan Public Service Commission on April 20, 2022. The settlement agreement requires closure/retirement of coal-fired Units 3 and 4 at Consumers Energy – Dan E. Karn on or before May 31, 2031. *See* April 20, 2022, Settlement Agreement - Michigan Public Service Commission, Case No. U-21090 (*See* Appendix 10). In 2023, Consumers Energy voluntarily converted Units 3 and 4 from coal to natural gas and fuel oil – approximately 8 years ahead of its 2031 retirement deadline. https://www.consumersenergy.com/news-releases/news-release-details/2023/06/14/15/30/consumers-energy-takes-next-step-to-clean-energy-future-by-closing-karn-coal-plants.

Although 2031 is beyond the end of the second implementation period in 2028, the 2019 Regional Haze Guidance states, "if a source is certain to close by December 31, 2028 (or soon thereafter), under an enforceable requirement, a state can reasonably consider that to be sufficient reason to remove the source from further analysis and reasonable progress consideration" (2019 Regional Haze Guidance, pg. 42).

Although Units 3 and 4 did not appear on LADCO's list in Table 8 because the Q/d for both units was below 1.0, the emission reductions are still noteworthy. When retired sometime before May 31, 2031, the permanent shutdown of coal-fired Units 3 and 4 at Consumers Energy – Dan E. Karn will represent a reduction in emissions of 40 tpy $NO_X$ and 58 tpy $SO_2$ based on the 2016 inventory.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | |
|---|---|
| Federal Power Act Section 202(c) | ) |
| Emergency Order: Midcontinent | ) |
| Independent System Operator | ) |
| (MISO) | ) |
| | ) |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

# Exhibit 116

# July 2025 MI SIP Supplement

# SUPPLEMENT TO
# MICHIGAN'S AUGUST 23, 2021,
# REGIONAL HAZE STATE IMPLEMENTATION PLAN REVISION
# FOR THE SECOND PLANNING PERIOD

MICHIGAN DEPARTMENT OF
ENVIRONMENT, GREAT LAKES, AND ENERGY

Michigan Department of Environment, Great Lakes, and Energy
Air Quality Division
P.O. Box 30260
Lansing, Michigan 48909-7760
*https://www.michigan.gov/air*

July 2025

| | |
|---|---|
| SRN: | State Registration Number |
| Sources: | See Table 8 Appendix 33 and 34<br><br>Michigan EGLE Air Permits System<br>https://www.egle.state.mi.us/aps/downloads/rop/pub_ntce/pub_ntce.shtml<br><br>List of Michigan EGLE Air Quality Division – Voided Renewable Operating Permits (ROPs)<br>https://www.egle.state.mi.us/aps/downloads/rop/ROPlist/APS_ROP_Sources_Void.pdf<br><br>Sources Subject to Michigan's Renewable Operating Permit Program<br>https://www.egle.state.mi.us/aps/downloads/rop/ROPlist/APS_ROP_Sources_by_Name.pdf |

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  The permanent shutdown of coal-fired Units 1, 2 and 3 at Consumers Energy – J.H. Campbell Power Plant, which is now scheduled to occur in August 2025, will represent a reduction in emissions of 2,346 tpy $NO_X$ and 12,850 tpy $SO_2$ based on the 2016

inventory. On May 23, 2025, the DOE issued an emergency order[3], pursuant to section 202(c) of the Federal Power Act, to Midcontinent Independent System Operator (MISO). The emergency order directs MISO, in coordination with Consumers Energy, to ensure that the J.H. Campbell Power Plant in West Olive, Michigan remains available for operation, minimizing any potential generation shortfall that could lead to unnecessary power outages. This Order has been written to expire on August 21, 2025, which EGLE anticipates will prompt the retirement of the three coal-fired units at the plant on, or shortly thereafter, that date.

- **Consumers Energy – Dan E. Karn, Units 3 and 4**

  Units 3 and 4 are discussed in detail in Michigan's 2021 Regional Haze SIP submittal on pages 14,15, 21, and 22 (see Appendix 1). This SIP supplement provides further elaboration.

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  Although 2031 is beyond the end of the second implementation period in 2028, the 2019 Regional Haze Guidance states, "if a source is certain to close by December 31, 2028 (or soon thereafter), under an enforceable requirement, a state can reasonably consider that to be sufficient reason to remove the source from further analysis and reasonable progress consideration" (2019 Regional Haze Guidance, pg. 42).

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### 3.3.2 Indefinitely Idled Source

- **Cleveland-Cliffs, Inc. – Empire Iron Mining Partnership**

  Empire Iron Mining Partnership was among the sources screened in using EGLE's revised Q/d analysis based on emissions from a 2016 base year; however, since 2016, the facility has been idled indefinitely. A recent January 17, 2024, on-site inspection report by EGLE's AQD documented the following conditions:

[3] https://www.energy.gov/sites/default/files/2025-05/Midcontinent%20Independent%20System%20Operator%20%28MISO%29%20202%28c%29%20Order_1.pdf

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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|---|---|
| Federal Power Act Section 202(c) | ) |
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| Independent System Operator | ) |
| (MISO) | ) |
| | ) |

Exhibit to
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Public Interest Organizations

# Exhibit 117

# RTO Insider Article on August 2025 Order

Consumers Energy's J.H. Campbell coal plant | *Newkirk Electric Associates*

Aug 21, 2025 | John Cropley and Amanda Durish Cook

The U.S. Department of Energy has ordered the J.H. Campbell Generating Plant to remain available another 90 days, saying its capacity is needed to maintain *MISO* grid reliability.

Consumers Energy had planned to retire the 1,420-MW coal-fired facility in southwest Michigan on May 31, but DOE on May 23 issued an emergency order (*202-25-3*) under Section 202(c) of the Federal Power Act ordering it to remain ready to operate because of a shortage of electricity and capacity to generate electricity. (See *DOE Orders Michigan Coal Plant to Reverse Retirement*.)

That order expired at midnight Eastern time Aug. 21.

Energy Secretary Chris Wright issued the follow-up order (*202-25-7*) at 8:50 p.m. Eastern time Aug. 20; it expires Nov. 19.

**Why This Matters**

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The order is another move by the Trump administration to use

aging fossil generation to shore up the grid.

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In his Aug. 20 order, Wright indicated the generation shortfall in MISO is likely to continue.

President Donald Trump *declared an energy emergency* on his first day in office, and his Cabinet agencies have been scrambling to rejigger energy policy toward the fossil fuels he favors.

One of their stated priorities has been halting retirement of aging fossil-burning plants.

*In a news release*, Wright cited seasonal outlooks by *NERC* and NOAA warning of high temperatures in the Midwest as well as resource adequacy projections by MISO itself.

“The United States continues to face an energy emergency, with some regions experiencing more capacity constraints than others. With electricity demand increasing, we must put an end to the dangerous energy subtraction policies embraced by politicians for too long,” he said.

“This order will help ensure millions of Americans can continue to access affordable, reliable and secure baseload power regardless of whether the wind is blowing or the sun is shining.”

Section 202(c) has been a lightly used provision historically. Just 11 orders were issued during the Biden administration, all of them weather-related. This compares with *nine by Wright since mid-May*, only one of which was weather-related.

The cost of halting the J.H. Campbell retirement has been a point of contention. (See *DOE Extension of Michigan Coal Plant Cost $29M in 1st Month* and *FERC Rules Costs of Mich. Coal Plant Extension Can be Split Among 11 States*.)

It also has been unpopular with environmental advocates.

Sierra Club Beyond Coal Campaign Director Laurie Williams *said Aug. 21*: “By illegally extending this sham emergency order, Donald Trump and Chis Wright are costing hardworking Americans more money every single day for a coal plant that is unnecessary, deadly and extremely expensive.”

Earthjustice Senior Attorney Michael Lenoff said: “Chris Wright is not a Soviet-era central planner, but his new order suggests he would fit right in. The order purports to override the considered judgment and careful work of many federal, state and regional bodies who actually have authority to keep the lights on. In their place, Secretary Wright blunders in.”

In a statement, MISO said it will “continue coordinating with Consumers Energy to comply with the order.”

But MISO again stressed that J.H. Campbell did not clear the planning resource auction and is unnecessary for resource adequacy in the 2025/26 planning year.

“MISO’s 2025-2026 Planning Resource Auction indicated adequate resources to meet anticipated demand. State regulators along with utilities have the responsibility of ensuring resource adequacy. MISO remains focused on reliably operating the grid using the resources our members provide, while working closely with stakeholders and regulatory partners, providing visibility into system needs and sending market signals to inform long-term resource planning,” MISO spokesperson Brandon Morris said in a statement to *RTO Insider*.

MISO leadership previously has said it might have to navigate similar future orders from the federal government to prop up retiring coal plants.

MISO Director Todd Raba said MISO might have to navigate similar edicts in the future, with about 30 coal plants in the footprint. At MISO’s June board meeting, he said it’s a “critical topic that will have huge implications in MISO.”

Lawmakers, health professionals and other officials *gathered* near the plant in West Olive, Mich., on Aug. 12 to protest its extension. On Aug. 18, a small crowd of community members marched to U.S. Rep. Bill Huizenga’s office in nearby Holland, Mich., to again protest continued operations.

Consumers Energy said it was evaluating the order extension and expects to “continue operating the plant as required by DOE.”

“We have worked closely with MISO and have been operating in compliance with the order and MISO’s dispatch requirements. All power generated by the Campbell plant and other Consumers generating plants is supplied to the MISO grid. Specific details on recent generation are not publicly available at this time,” spokesperson Brian Wheeler told *RTO Insider*.

Wheeler also said the utility was “pleased” with *FERC*’s approval of an allocation that’s set to disburse cost recovery of the plant among the 11 states or portions of states in MISO Midwest.

Consumers Energy declined to comment on the coal plant’s usefulness so far over the summer or how the plant will fit into the MISO market over the fall.

Data from power analytics company Yes Energy shows the 1.42-GW plant has been used consistently since the beginning of August, averaging an 84-88% hourly capacity factor.

COAL | RELIABILITY | RESOURCE ADEQUACY

KEYWORDS CHRIS WRIGHT | CONSUMERS ENERGY | FEDERAL POWER ACT SECTION 202 (C) | J.H. CAMPBELL PLANT | MIDCONTINENT INDEPENDENT SYSTEM OPERATOR (MISO) | U.S. DEPARTMENT OF ENERGY (DOE)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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|---|---|
| Federal Power Act Section 202(c) | ) |
| Emergency Order: Midcontinent | ) |
| Independent System Operator | ) |
| (MISO) | ) |
| | ) |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

# Exhibit 118

# RMI Analysis of Coal Plants' Threats to Reliability

# Reality Check: We Have What's Needed to Reliably Power the Data Center Boom, and It's Not Coal Plants

**A range of clean, resilient solutions can help us meet the electrical needs of our growing digital economy while saving Americans money.**

**August 12, 2025**

**By Gabriella Tosado, Ashtin Massie, Joe Daniel**

After decades of relatively flat electricity demand, the US power sector is expecting demand to grow due, in large part, to new data centers. These energy-intensive facilities are reshaping the grid, with some utilities now projecting over 20 percent load growth by 2035. In places like Virginia, which constitutes 13 percent of all reported data center capacity globally and 25 percent of the data center capacity in the United States, data centers already account for over a quarter of some utilities' total electric demand, and their footprint is only growing.

## The myth

Utilities are struggling to maintain accurate forecasts and identify resources that can meet this growth. There is a high-profile effort to keep coal plants that are set to retire online and run them at unprecedented levels, ostensibly for reasons of reliability. But the truth is, coal-fired power plants, far from being a reliable backbone for this new era of electricity demand, are a brittle, outmoded technology that threatens to undermine the very grid resilience they're being proposed to protect.

> Coal-fired power plants, far from being a reliable backbone for this new era of electricity demand, are a brittle, outmoded technology that threatens to undermine the very grid resilience they're being proposed to protect.
>
> Tweet

## Reality #1: Aging coal plants are failing to consistently deliver under stress

Coal plants face a fundamental constraint: they are aging and increasingly unreliable. Most of the coal fleet was built in the 1970s and 1980s, and years of wear and tear have led to a rise in unplanned outages. In many cases the sheer cost to maintain and modernize these plants did not make sense with the availability of more reliable and affordable alternatives – and that's still the case.

According to the Energy Systems Integration Group (ESIG) ***Ensuring Efficient Reliability*** report, a coal plant's capacity accreditation, or the amount of time it can contribute to peak demand, is only 83 percent when adjusted for real-world performance. PJM also has capacity accreditation of coal plants at 83 percent and some plants fare even worse. Gridlab's reliability study found Colstrip, a large regional coal plant in Montana, operating with a capacity accreditation of only 54 percent – meaning it's effectively unavailable nearly half the time it's needed.

Extreme weather exacerbates these vulnerabilities. Cold snaps, heat waves, and storms have all exposed coal's fragility during grid stress events. Reliability is not just about being dispatchable, it's about delivering performance under stress. Coal plants struggle to do that consistently. For coal plants to truly meet the constant demands of data centers, they would need to run at high-capacity factors and avoid major outages, all of which fly in the face of current performance trends. If a large coal plant trips offline while supporting a cluster of data centers,

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Electricity
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Third Derivative
Transportation
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US Policy

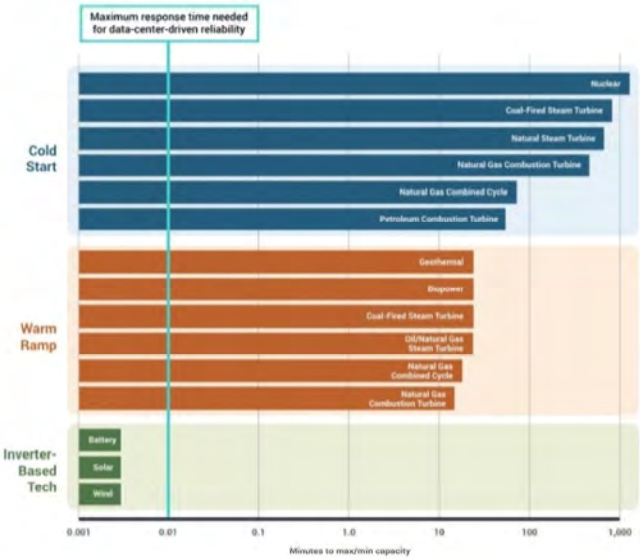
the sudden loss of supply could lead to cascading failures across the grid. This is because generation must equal load at all times, datacenter or no datacenter. As a result, relying on coal plants to support these high-density digital loads doesn't enhance reliability, it endangers it. And it's not a matter of *if* the coal plant will fail, but *when*.

## Reality #2: The inflexibility of coal plants risks grid stability

Coal boosters often point to the "always-on" nature of coal plants as evidence of their reliability. But that characteristic is a liability, not a strength, when it comes to supporting large, fast-changing loads like data centers. Coal units are inherently inflexible: they ramp slowly, respond poorly to sudden load shifts, and are difficult to turn on or off quickly. This rigidity is a poor match for the dynamic and often unpredictable nature of data center demand. Further, inflexible coal plants can worsen grid congestion; by occupying limited transmission capacity with inflexible generation, they prevent cheaper or cleaner resources from being delivered. This issue has already been flagged by independent market monitors in regions like MISO – which covers 15 US states and a Canadian province – where congestion-related market distortions have cost over $1 billion a year. Coal plants displace faster-responding resources that are better suited to follow load. And the stakes are high.

As noted by the North American Electric Reliability Corporation (NERC), large, voltage-sensitive loads like data centers require flexible, responsive grid solutions, not slow-ramping generators that can take 12 or more hours to come online. NERC's recent *Incident Review and Guidance on Voltage-Sensitive Large Load Integration* describes an event in 2024 where a transmission fault triggered a sudden disconnection of 1,500 megawatts of voltage-sensitive data center load, leading to sharp frequency and voltage spikes that required operator intervention. The incident exposes the system's vulnerability to instability when inflexible generation cannot respond to large load fluctuations.

**Minutes needed for a power plant to reach max/min capacity**




If a data center either loses access to load or goes offline rapidly, a grid's generation needs to respond at sub-second speeds. The average coal plant ramp rate is 4 percent per minute which translates to spending over 20 minutes to respond to a large load event. From a cold start, the average coal plant would take over 12 hours to reach max capacity. Coal plants simply can't respond fast enough to support the reliability needs of modern data centers. Whether it's the hours-long startup time from a cold state or sluggish ramp rates to turn off, these plants are too slow to provide the real-time flexibility required during sudden load changes or outages.

## Reality #3: Clean resources are available now that can better respond to and support data centers for less

Shares

The good news is that we don't need to rely on brittle coal plants to meet the needs of a digital economy. A range of cleaner, more resilient solutions is already available – and scalable. For example, we recently found that more than 95 percent of future demand can be met with fast, scalable, and clean solutions:

### Alternative near-term solutions to meet load growth

| Technology | Opportunity |
|---|---|
| Energy Efficiency | Over 50 GW of energy efficiency can be deployed – by both creating programs for new loads and expanding existing programs aligned with system needs. Energy efficiency can unlock benefits beyond system cost savings, improving comfort and resilience in homes. |

| | |
|---|---|
| Virtual Power Plants | 60 GW of virtual power plants can be deployed by 2030, with programs stood up and enrolled in under 6 months. Policymakers in Virginia recently passed a bill that requires 450 MW of VPPs deployed rapidly to meet growing demand. |
| Advanced Transmission Technologies | Grid enhancing technologies and reconductoring can unlock over 80 GW of incremental peak capacity by reducing transmission and interconnection constraints. Lawmakers in New Mexico passed a bill requiring utilities to assess the use these technologies in plans to get more out of the existing grid. |
| Clean Repowering | There is 14 GW of fossil-fuel generation expected to retire, that could serve as sites for quick addition of new renewable energy and storage while reducing system costs. Market operators like PJM are enabling clean repowering by updating rules to allow for surplus interconnection. |
| Power Couples | New load can be co-located with renewable energy at the site of existing, underutilized generators with approved interconnections—a strategy which we call "Power Couples." There is over 30 GW of opportunity to deploy Power Couples under $100/MWh, and over 50 GW of opportunity under $200/MWh. |

Coal plants are a legacy technology, not a solution for the future. Coal plants' operational characteristics make them less suited to meet the scale and speed of these new challenges. The path forward is not about discarding the past, but about building on it with cleaner, more adaptable resources that can reliably serve evolving grid needs.

Technologies like battery storage, demand flexibility, and clean energy portfolios offer practical, cost-effective options that align with modern load dynamics. As we noted in a recent article, by running coal plants only when it is economical to do so and using the extra transmission headroom that creates to reinvest with clean energy upgrades, our grid can support the next wave of economic growth with the flexibility it demands. There are reasons to manage the shift to new, clean resources thoughtfully and intentionally, but propping up coal plants that are not suited for the job is a step in the wrong direction.

## RECOMMENDED READING

### Gas Turbine Supply Constraints Threaten Grid Reliability; More Affordable Near-Term Solutions Can Help

June 18, 2025

Read More

### Reinvesting at Coal Plant Sites with Clean Energy Upgrades Supports both Reliability and Affordability

July 16, 2025

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**Solutions Can Help**
June 18, 2025
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**Affordability**
July 16, 2025
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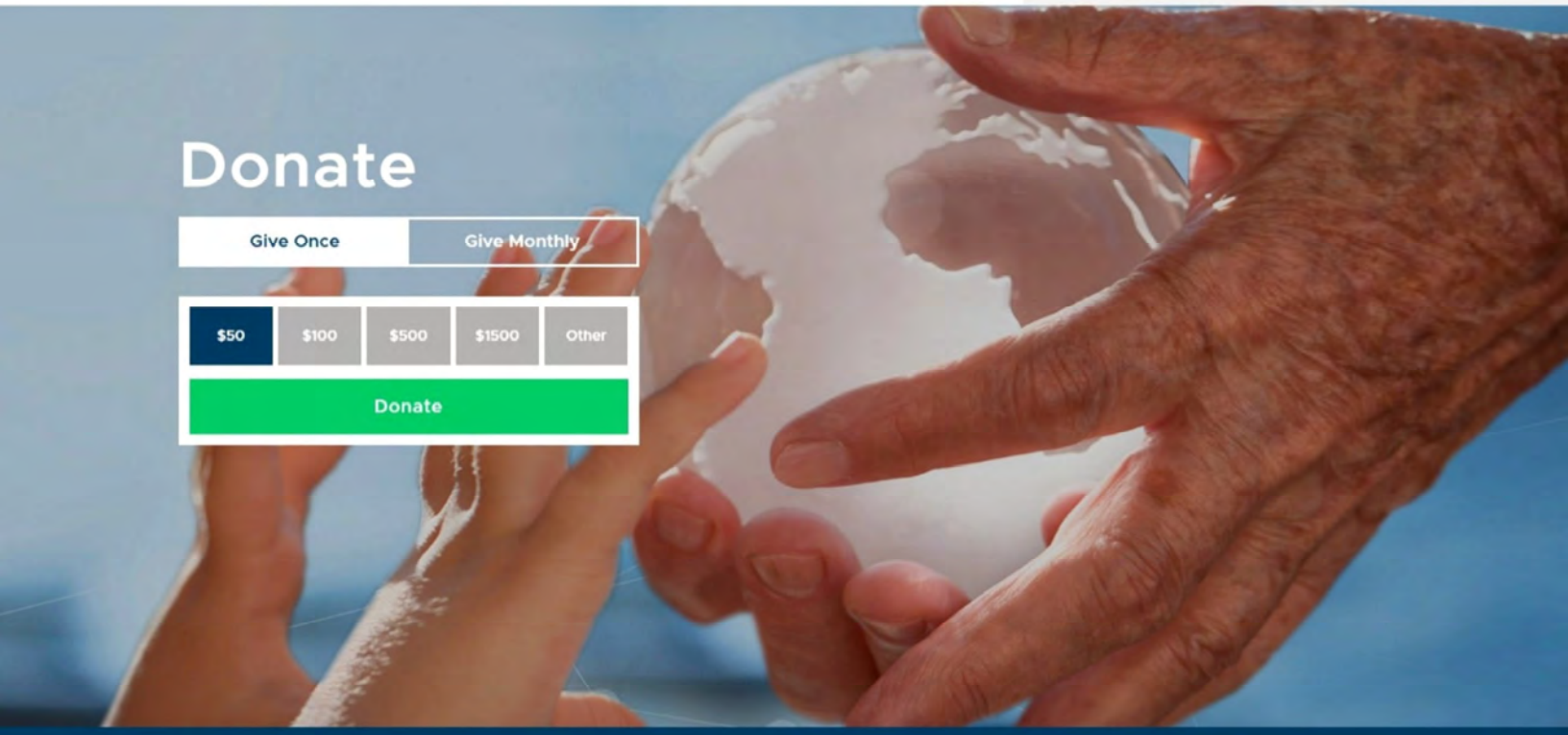

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Climate Finance
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Climate Intelligence
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India Program
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Technology & Innovation
Urban Transformation
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Public Interest Organizations

# Exhibit 119

# ZRC Replacement

# ZRC Replacement and instructions in the MECT

**RASC**

05/24/2023

Presentation updated as 7/11/2023
Updates are at the end of the deck Slides 12-17

Presentation updated as of 9/29/2023
Updates are on slides 14 & 17

# Purpose and Key Takeaways

## Purpose:

Provide Stakeholders with information and training on ZRC replacement in the MECT

## Key Takeaways:

- ZRC replacement uses, and process explained and clarified
- ZRC replacement does not impact settlements from the PRA
- ZRC replacement is used for suspension, retirement, Catastrophic Generator Outage or full or partial Generator Planned Outages that may exceed thirty-one (31) Days in the Season
- MECT User Guide has additional detail

# Reasons to use ZRC Replacement

- Generators that have cleared a season(s) in the PRA that go on suspension, retirement or Catastrophic Generator Outage
- Cleared ZRCs for resources with planned generator outages and/or derates in excess of 31 days in a season
- ZRC replacement must overlap the suspension, retirement, catastrophic outage or outages/derates of the cleared generation being replaced
- Resources ZRCs cannot be replaced other than for the reasons listed above



31-day rule Capacity Replacement Clarification

# ZRC Replacement FAQ

- ZRC replacement substitutes the Resource Adequacy Requirement (RAR) and Must Offer Obligation for the cleared resource

- Fully replaced resources (>95% cleared ZRC) will be granted Tier 1 & 2 exemptions during the replacement hours from Schedule 53 SAC calculation
  - Exemptions are for SAC calculations only, still subject to the capacity replacement rules and penalties
  - Exemptions for derates is still under discussion

- ZRC replacement does not impact settlements from the PRA, however resources that failed to meet the replacement requirement will incur non-compliance charges

# Process for ZRC Replacement

- Use the "Replacement Calculator" on the MECT
- Obtain the ZRCs used in the replacement
- Submit the replacement on the "Resource Substitution" screen in the MECT
  - ZRC replacement should be entered into the MECT at least 7 calendar days prior to the effective date of replacement
- Contact MISO with any issues through the MISO help center

# Use Replacement Calculator

- The Replacement Calculator is to verify that the prospective replacement ZRCs do not violate LCR, CIL or CEL for each zone when using ZRCs from another LRZ or ERZ

| Zonal Data | PRMR (Obligation) | Offers Cleared + FRAP | LCR | Import Level (CIL) | Export Level (CEL) | Auction Import | Auction Export | Replacement Import | Replacement Export | Import Available | Export Available |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 18374.9 | 18661.2 | 16588.7 | 3754.0 | 3373.2 | 0.0 | 286.3 | 0.0 | 0.0 | 4040.3 | 3086.9 |
| 2 | 13449.9 | 13536.9 | 13017.5 | 1714.0 | 978.7 | 0.0 | 87.0 | 48.1 | 22.0 | 1774.9 | 917.8 |
| 3 | 9882.0 | 10391.1 | 7960.2 | 2896.0 | 4589.7 | 0.0 | 509.1 | 0.0 | 0.4 | 3405.5 | 4080.2 |

CALCULATE RESET

| Calculator | Total MW needing replacement | Replacement ZRCs from the same zone | ZRCs from same zone after replacement | LCR test | Total Import Amount Needed | Amount Exported | Import Test | Export Test |
|---|---|---|---|---|---|---|---|---|
| 1 | 200 | 100 | 18661.2 | PASS | 100 | 0 | PASS | |
| 2 | 0 | 0 | 13470.8 | PASS | | 40 | | PASS |
| 3 | 0 | 0 | 10331.5 | PASS | | 60 | | PASS |
| 4 | 0 | 0 | | | | 0 | | |



More information can be found in the MECT User Guide in section 31 & 32

# Obtain the ZRCs

- Market Participants will need the un-cleared ZRCs to use in the ZRC replacement
  - This can be from their own un-cleared ZRCs
  - This can be from a ZRC Transaction
    - Non-MISO Bulletin can be utilized to find ZRCs from other Market Participants



More information can be found in the MECT User Guide in section 18

# ZRC Replacement in the MECT

- Navigate to the "Resource Substitution" screen in the MECT, fill in the form and submit

More information can be found in the MECT User Guide in section 30

# Next Steps

- MECT release at the end of May will include an “end date” for ZRC replacement”. When the replacement is completed the ZRCs will be repopulated to the resource

- Additional details and screenshots will be added to this presentation and the MECT user guide and both will be reposted



Bullet point 3 updated on 7/12/2023

# References

- MISO Resource Adequacy BPM-011-r27
  - Section 6.4, “Replacement Resources”
- MISO Tariff Module E-1
  - Section 69A.3.1.h, “Retirement, Suspension and Replacement of Planning Resources”
- MECT User Guide
  - Sections 18, 30, 31 and 32

https://help.misoenergy.org/support/

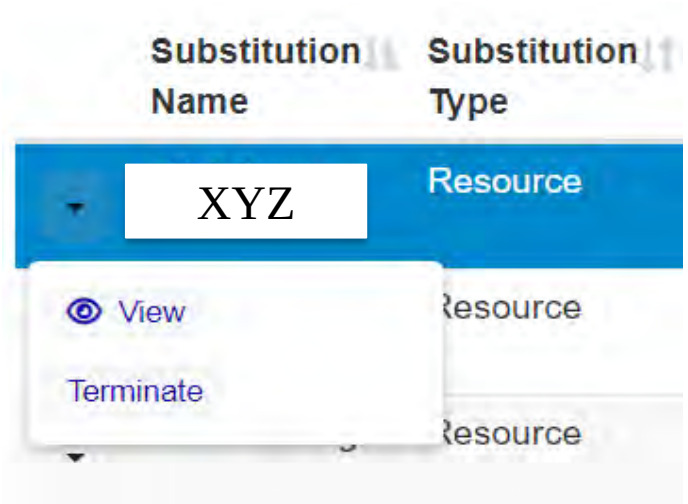
# Additional Content added as of 7/11/2023

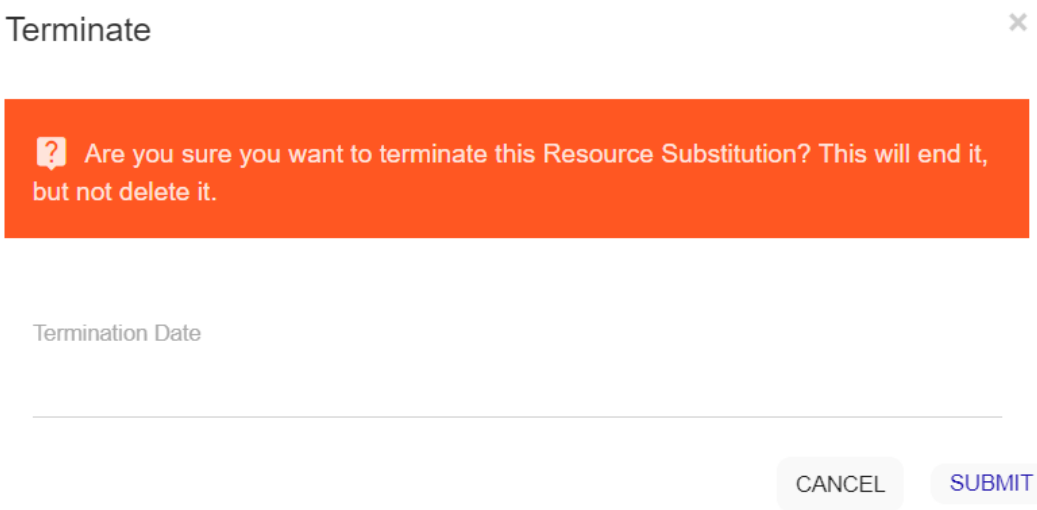
# BPM-011-r28 updated and posted to MISO website

- BPM-011-r28 has been posted to MISO website with clarification to sections 6.4.3 – 6.4.7
- Updates are limited to ZRC Replacement and implementation and assessment of the 31-day rule

# Updates to the MECT allowing ZRC Replacement Termination

- Resource Substitution defaults to the end of the season
  - Before the effective date, a new dropdown will allow MPs to delete the substitution
  - After the effective date, a new dropdown will allow MPs to terminate the ZRC replacement between the effective date and current date



# Scheduling 31+ day Generator Outages and participation in the PRA

- For resources that have anticipated planned outages that last longer than 31 days in the next Planning Year, the following options are available
  - Straddle seasons, if the resource has a planned 50-day outage, having 25 at the end of one season, continuing for the other 25 days into the subsequent season
  - If the outage is long enough, the resource could plan the outage during one season and not offer into the PRA for that season (requires working with the IMM). During the time the resource is available in the season, they could provide ZRC replacement for other resources
  - Work with the IMM to factor in the 31-day penalty price into the offer for the PRA, which can exceed the FSRL limit ~$25-30/MW-day

# 31-day Outage Rule (1 of 2)

- MISO's Control Room Operations Window (CROW) includes the following 4 categories of out of service (OOS) and derates: Planned, Urgent, Emergency and Forced. For purposes of calculating CRNCCs, MISO will use CROW outages prioritized as Planned. In addition, all outages not prioritized as Planned in CROW, but that were: (1) known or reasonably known at the time of the PRA, or (2) were determined by the IMM to be incorrectly prioritized in CROW shall be included in calculation of the CRNCC. See BPM-008 and the CROW users guide for outage prioritization codes and definitions. must replace ZRCs or incur a CRNCC penalty cost.
- Capacity non-compliance charge as stated in section 6.4.7 of BPM-011-r28 is equal to the # of days greater than 31 that did not properly replace * # of ZRCs * (seasonal ACP + daily Zonal CONE)
  - For example. A 100 MW resource in LRZ5 for Summer 2023 ($10 ACP) that was on a planned outage for 35 days and did not replace any ZRCs would incur the following charges
    - 4 days * 100MW * (10 + 300.2) = $124,080
- The ZRC replacement and penalties are assessed and applied to the Market Participant who converts SAC to ZRCs

# 31-day Outage Rule (2 of 2)

- The 31-day rule will be implemented on an hourly basis as laid out in section 6.4.7 of BPM-011-r28 (31 days * 24 hours = 744hours)
- CROW has 4 outage types

| | |
|---|---|
| Forced – already out at time of submission | Not counted |
| Emergency – 0 to 2 days in the future | Not counted |
| Urgent – 2 to 14 days in the future | Not counted* |
| Planned – 14 days + in the future | Counted |

- The hours of planned outages across the season per resource will be summed up from most ZRCs to least ZRCs, the 31 days will apply to the most severe planned outage days and the remaining hours will be counted towards the penalty
- The penalty is assessed on a daily basis so the hours will be converted back to days and rounded down to the nearest day

*IMM and MISO will continue to review Urgent, Emergency and Forced outages to determine if they were known or reasonably known at the time of the PRA and if they should be counted towards the 31-day outage rule

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | |
|---|---|
| Federal Power Act Section 202(c) | ) |
| Emergency Order: Midcontinent | ) |
| Independent System Operator | ) |
| (MISO) | ) |
| | ) |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

# Exhibit 120

# 2024 OMS-MISO Survey

# 2024 OMS-MISO Survey Results

*Furthering our joint commitment to regional resource adequacy, OMS and MISO are pleased to announce the results of the 2024 OMS-MISO Survey*

**CORRECTIONS**
**Reposted 6/20/2024**
**Slide 11 PRM% Updated**

June 20, 2024

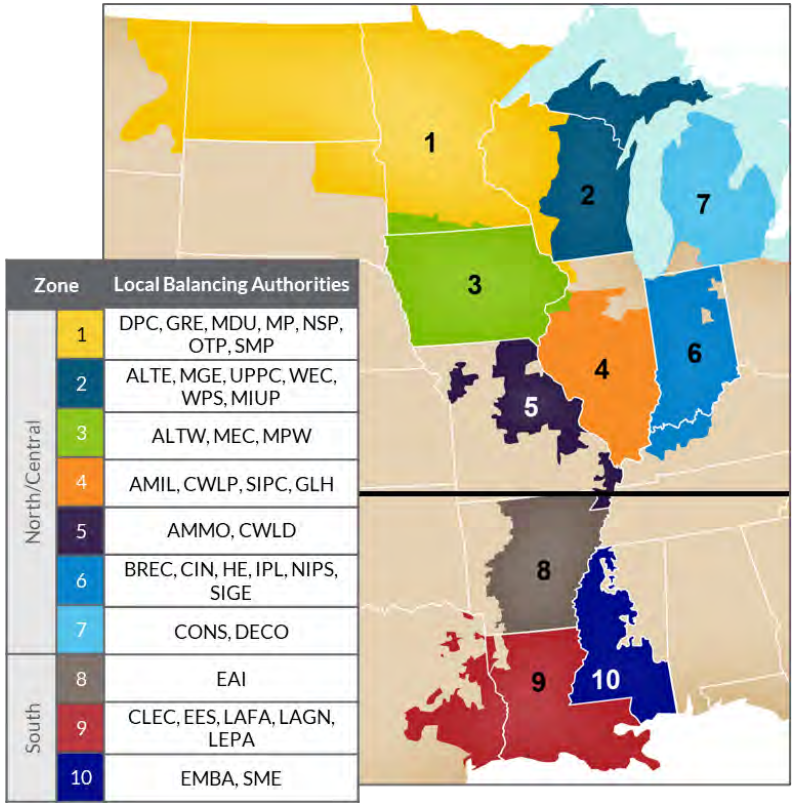
# The 2024 OMS-MISO Survey reinforces near-term risks and highlights key uncertainties impacting resource adequacy in the MISO region

- Results indicate a potential surplus of 1.1 GW to a deficit of 2.7 GW for the summer of PY2025/26, depending on critical, yet uncertain, drivers such as the pace and quantity of new resource additions and projected resource retirements.
- Resource Adequacy risks could grow over time across all seasons, absent increased new capacity additions and actions to delay capacity retirements.
- Significant economic development activities are spurring new, large spot-load additions (e.g., data centers, onshoring of manufacturing, new industrials) and increasing pressures on resource adequacy and requiring improved abilities for the timely addition of new resources.
- Recent reforms to MISO's resource adequacy construct will enhance MISO's ability to accurately assess the changing resource adequacy risks driven by extreme weather, the rapid growth of weather-dependent resources, and the retirement of dispatchable resources.
- Results highlight resource adequacy challenges in the MISO region and the need for continued collaboration between OMS, MISO, and its Members to maintain a reliable electricity system.

*All presentation references to capacity indicate Seasonal Accredited Capacity (SAC)*

# The OMS-MISO Survey provides a resource adequacy view over a five-year horizon based on currently available information

- The survey results indicate the degree to which expected capacity resources satisfy planning reserve margin requirements with either a surplus or a deficit.
- The survey considers that Load Serving Entities (LSEs) within each zone must have sufficient resources to meet load and required reserves.
- Surplus resources may be shared among LSEs with resource deficits to meet reserve requirements.




| | Zone | Local Balancing Authorities |
|---|---|---|
| North/Central | 1 | DPC, GRE, MDU, MP, NSP, OTP, SMP |
| | 2 | ALTE, MGE, UPPC, WEC, WPS, MIUP |
| | 3 | ALTW, MEC, MPW |
| | 4 | AMIL, CWLP, SIPC, GLH |
| | 5 | AMMO, CWLD |
| | 6 | BREC, CIN, HE, IPL, NIPS, SIGE |
| | 7 | CONS, DECO |
| South | 8 | EAI |
| | 9 | CLEC, EES, LAFA, LAGN, LEPA |
| | 10 | EMBA, SME |

*This year's survey includes an updated baseline methodology to reflect the changing pace of new resource additions. Various scenarios for projected capacity and anticipated large spot-load additions across the MISO region are also included to highlight the increasing uncertainty and evolving risk.*

*90% of existing generation capacity participated in OMS-MISO Survey in 2024.*

# Additional factors can impact projected deficits or surpluses that are observed in the survey

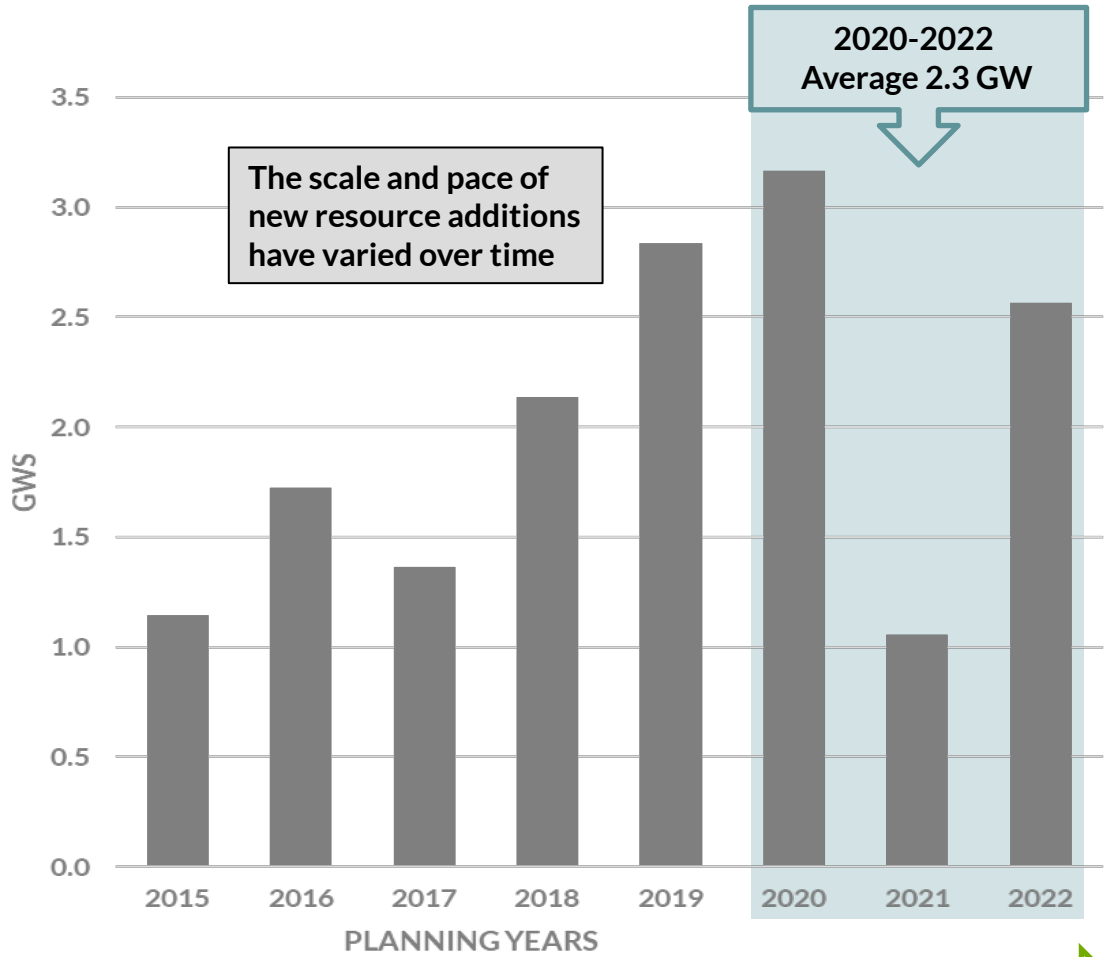
## Downside Risks

- Continuing rapid pace of resource retirements
- EPA regulations further accelerating resource retirements
- Ongoing delays to capacity additions due to supply chain bottlenecks, permitting delays, and commercial challenges
- Continued queue challenges due to exceptionally large accumulated backlog and expectations for high quantities of future applications
- Higher load growth due to economic development and new, large spot-load additions (e.g., data centers and onshoring of manufacturing/new industrials), absent an improved ability to concurrently add new resources

## Upside Possibilities

- Substantial new capacity enabled by the easing of supply chain bottlenecks, permitting constraints, and labor shortages
- Continued queue improvements to reduce speculative quantities and associated delays
- Market responses to local capacity deficits
- Improved price signals through market reforms, such as the Reliability Based Demand Curve, incentivizing additional capacity
- Improved ability to add new resources and support economic development and related new, large spot-load additions

# Trends and market pressures related to new capacity additions suggest refinements are needed to better reflect uncertainty




**Queue applications have grown to >300 GW & >50 GW signed GIAs**

In the past, it was reasonable to use probability-adjusted estimates applied to quantities of projects in various phases of queue development.

That's no longer applicable due to the larger queue and constraints faced by projects with signed generation interconnection agreements (GIAs). The 2024 survey uses a range of estimates for new resource additions:

1. **Three-Year Historical Average:** based on the historical rate of additions per planning year*
2. **Alternative Projection:** based on MISO's updated timing estimates from interconnection customers with GIAs*

*Note: 2023 data unavailable during time of analysis. Including 2023 projects would change the 3-year average to 2.2 GW.*
**Based on Historical averages defined on slide 6*

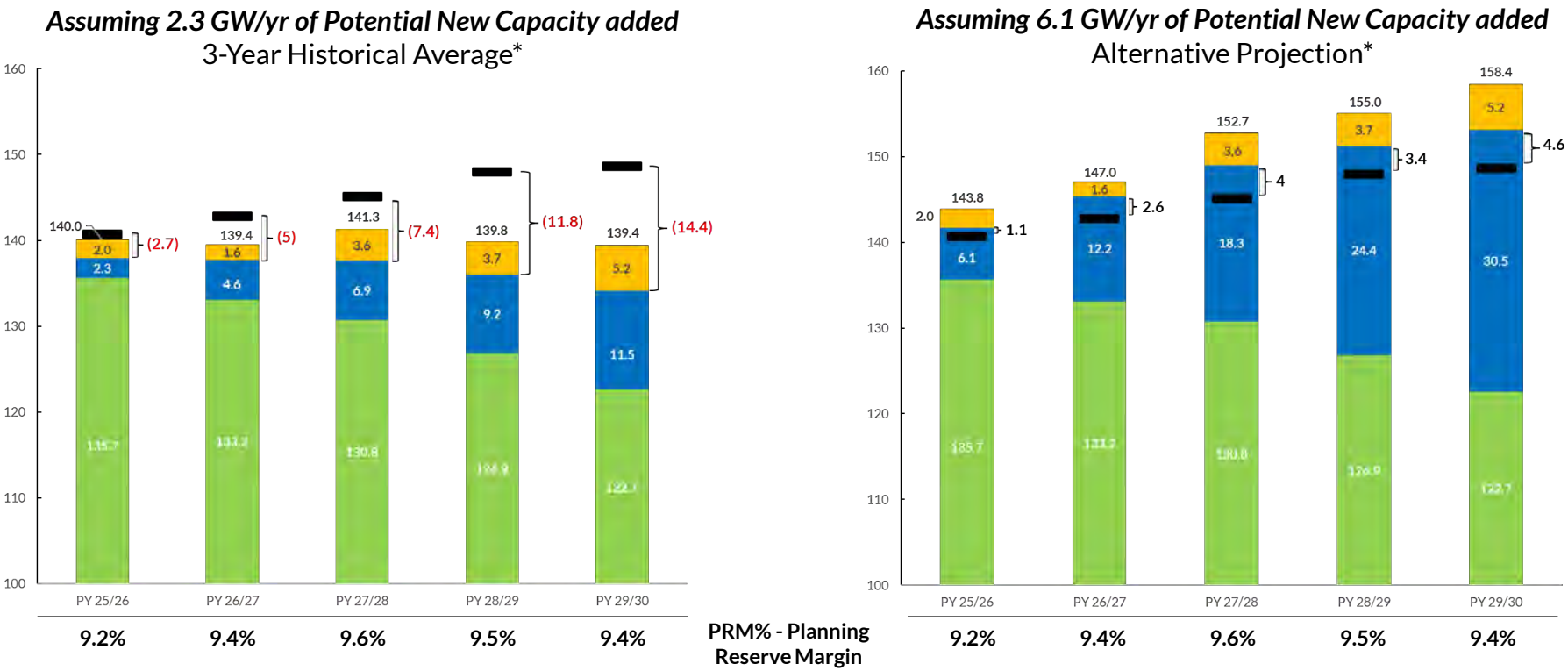
# Understanding Resource Categories

| Resource Category | Past Practice | 2024 Survey |
|---|---|---|
| **Committed Capacity**<br>*Resources committed to serving MISO's load* | • Existing generation resources<br>• Signed Generation Interconnection Agreement Projects<br>• External resources with firm contracts to MISO load<br>• Assumes resources will be used to meet PRMR | • **Same, except does not include signed Generation Interconnection Agreement (GIA) projects (Signed GIA projects moved to 'Potential New')** |
| **Potential New Capacity** | • Projects in the MISO Generator Interconnection Queue adjusted for queue phase and related probabilities for projects reaching commercial operations<br>• Assumes resources will **NOT** be used to meet PRMR | • **Using 3-Year Historical Average: Capacity addition based (2.3 GW/year) based on the average new capacity built in Planning Years 2020-2022**<br>• **Using Alternative Projection: Informed by timing estimates from interconnection customers with signed GIA projects* (6.1 GW/year)**<br>• **Assumes resources <u>WILL</u> be used to meet PRMR** |
| **Potentially Unavailable Resources**<br>*May be available to serve MISO's load but may not have firm commitments* | • Indicated as Low Certainty in survey results by Market Participants<br>• Includes potential retirements or suspensions<br>• Assumes resources will **NOT** be used to meet PRMR | • **No Changes** |

***MISO Alternative Projection**: Responses indicate 6.8GW can be built for PY 2025/26. MISO data shows 90% of GIAs get built.*
*PRMR: Planning Reserve Margin Requirement*

# The 2024 OMS-MISO Survey illustrates a strong sensitivity to the pace of new capacity additions, with PY 2025/26 showing a range from a 2.7 GW deficit to a 1.1 GW surplus and widening thereafter

## MISO Resource Adequacy Projection – Summer (GW)




Projected PRMR with LSE forecast
Potentially Unavailable Resources
Potential New Capacity
Committed Capacity

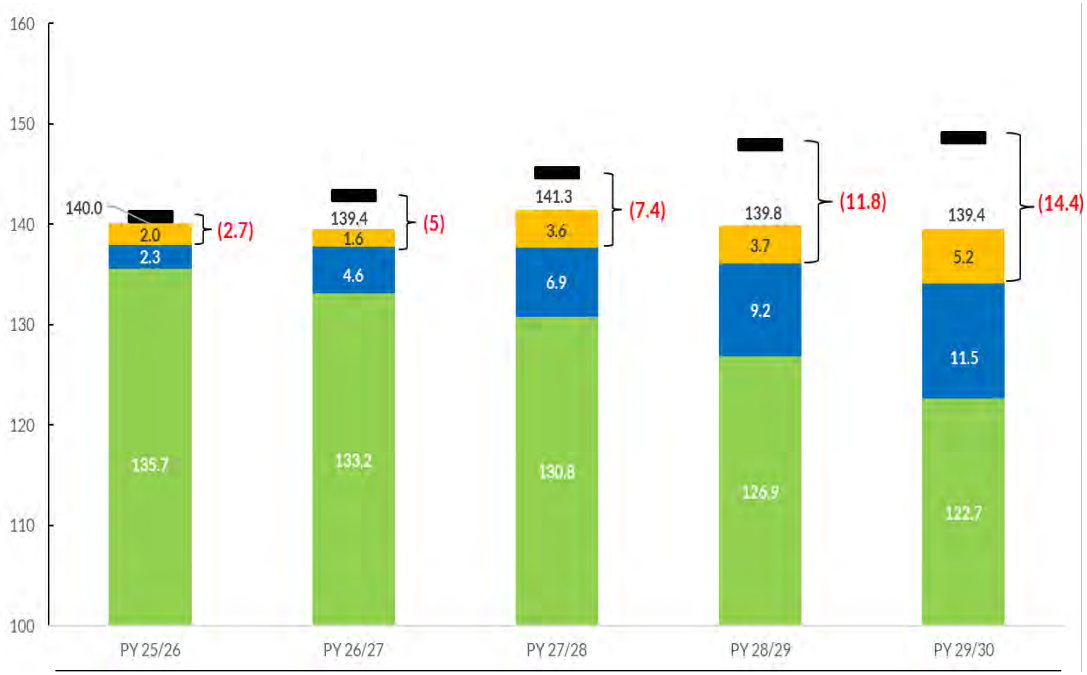
- Bracketed values indicate difference between Committed + Projected New Capacity and Projected PRMR with LSE forecast
- Capacity accreditation values and PRM projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

*Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency.*
*PRMR: Planning Reserve Margin Requirement*
**Using methods for potential New Capacity described on Slide 6*

# Continued pace of retirements and pressures on generation development could potentially result in deficits as early as PY 2025/26

## MISO Resource Adequacy Projection – Summer (GW)

*Assuming **2.3 GW/yr** of Potential New Capacity added*
3-Year Historical Average*




| PRM% - Planning Reserve Margin | PY 25/26 | PY 26/27 | PY 27/28 | PY 28/29 | PY 29/30 |
|---|---|---|---|---|---|
| | 9.2% | 9.4% | 9.6% | 9.5% | 9.4% |

Projected PRMR with LSE forecast
Potentially Unavailable Resources
Potential New Capacity
Committed Capacity

- Bracketed values indicate difference between Committed+ Projected New Capacity and Projected PRMR with LSE forecast
- Capacity accreditation values and PRM projections based on current practices
- Regional Directional Transfer (RDT) limit of 1,900 MW is reflected in this chart

**Projection of 2.3 GW of new capacity per year derived from:**

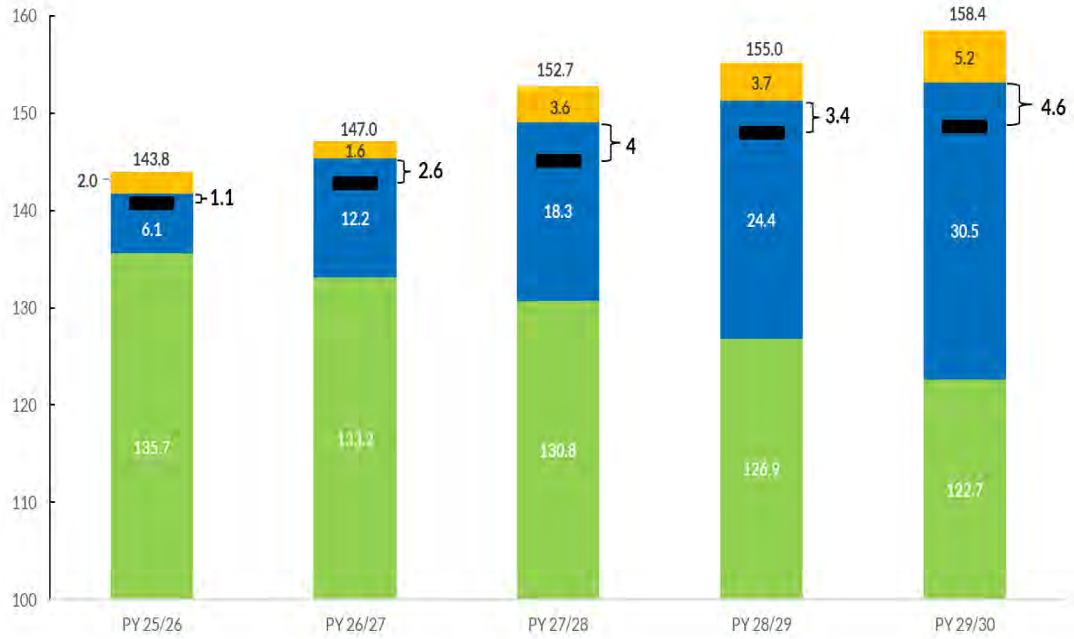
- Actual buildout over PYs 2020-2022
- Projected capacity buildout in line with historical rate
- Reflects impacts from COVID slowdown, such as continuing supply-chain bottlenecks, commercial uncertainty and permitting/labor delays

*Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency.*
*All references to capacity indicate Seasonal Accredited Capacity (SAC)*
**Using Potential New Capacity as described on slide 6*

# Favorable changes in development drivers could accelerate capacity additions necessary to cover projected growth

## MISO Resource Adequacy Projection – Summer (GW)

*Assuming **6.1 GW/yr** of Potential New Capacity added*
Alternative Projection*




| PRM% - Planning Reserve Margin | PY 25/26 | PY 26/27 | PY 27/28 | PY 28/29 | PY 29/30 |
|---|---|---|---|---|---|
| | 9.2% | 9.4% | 9.6% | 9.5% | 9.4% |

Projected PRMR with LSE forecast
Potentially Unavailable Resources
Potential New Capacity
Committed Capacity

- Bracketed values indicate difference between Committed+ Projected New Capacity and Projected PRMR with LSE forecast
- Capacity accreditation values and PRM projections based on current practices
- Regional Directional Transfer (RDT) limit of 1,900 MW is reflected in this chart

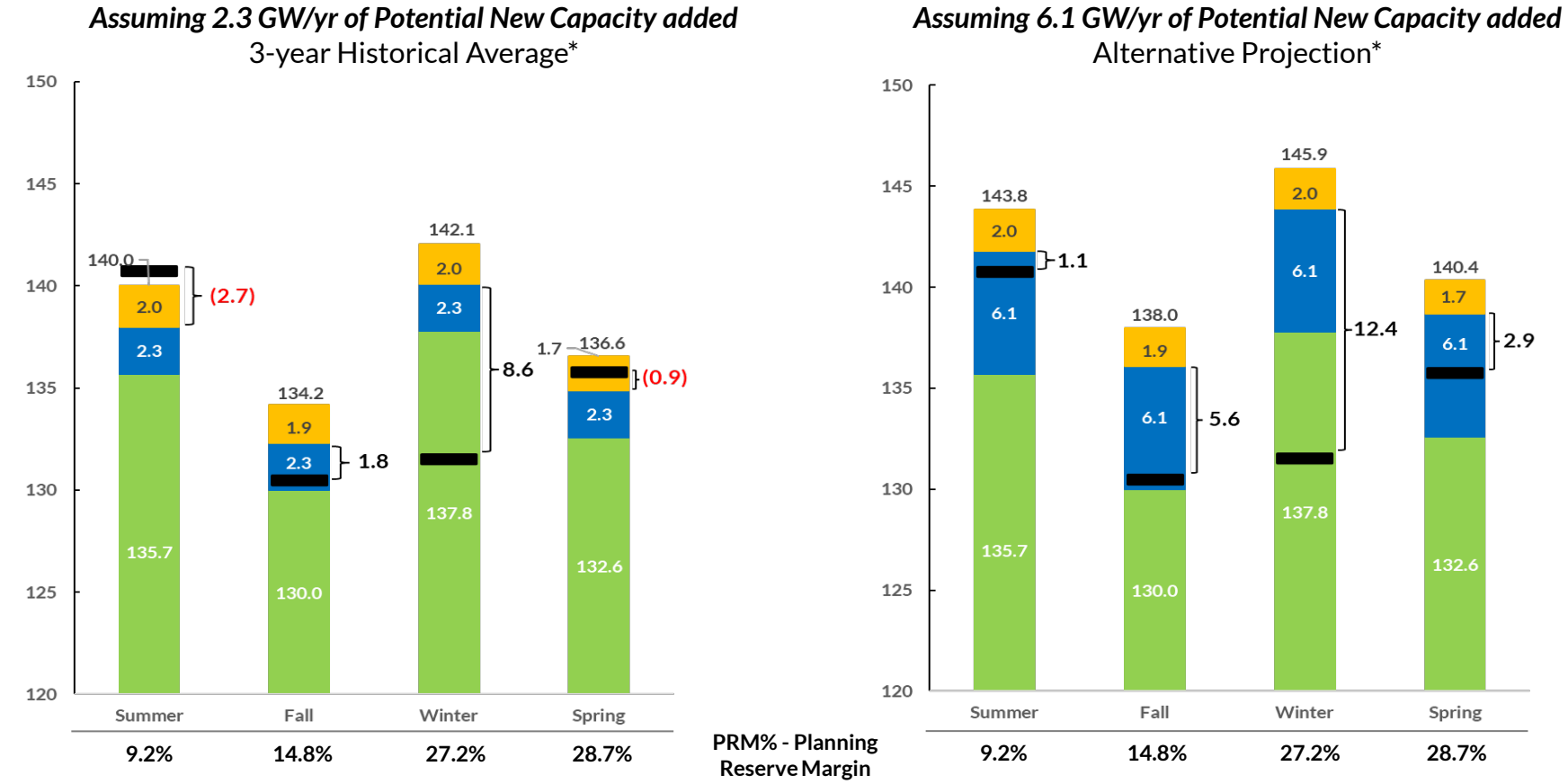
**Projection of 6.1 GW of new capacity per year dependent upon:**

- Easing of supply chain bottlenecks
- Reduced permitting-related delays
- Adequate supply of skilled labor
- Supportive commercial viability
- Continued queue improvements to reduce speculative quantities and associated delays

*Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency.*
*All references to capacity indicate Seasonal Accredited Capacity (SAC)*
**Using Potential New Capacity as described on slide 6*

# Seasonal comparison for PY 2025-26 shows the greatest risk in summer and spring

## MISO Resource Adequacy Projection 2025/26 (GW)

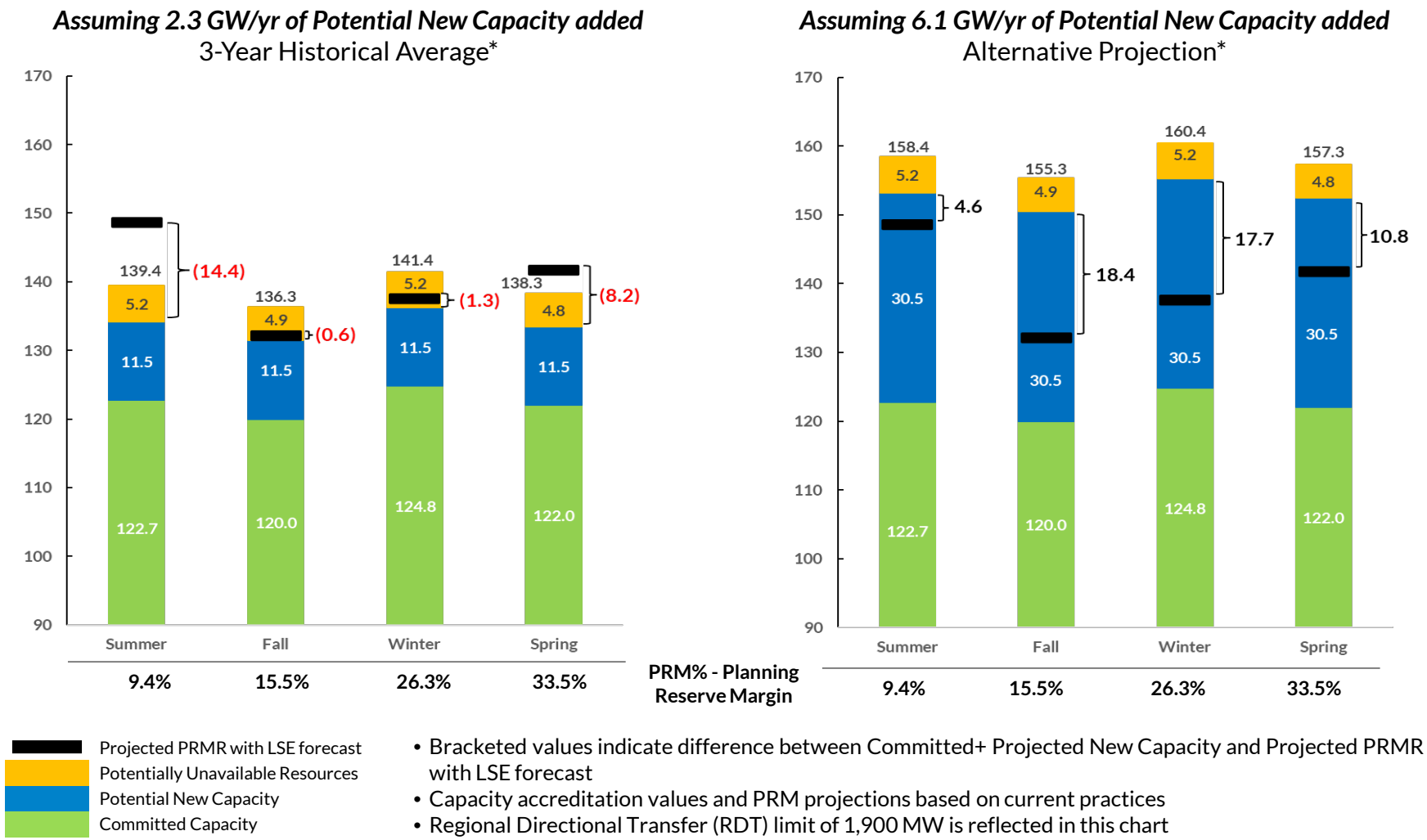



- Bracketed values indicate difference between Committed+ Projected New Capacity and Projected PRMR with LSE forecast
- Capacity accreditation values and PRM projections based on current practices
- Regional Directional Transfer (RDT) limit of 1,900 MW is reflected in this chart

*Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency.*
*PRMR: Planning Reserve Margin Requirement*
**Using Potential New Capacity as described on slide 6*

# Projections for PY 2029/30 show increased reliance on new resources to meet PRMR

## MISO Resource Adequacy Projection 2029/30 (GW)

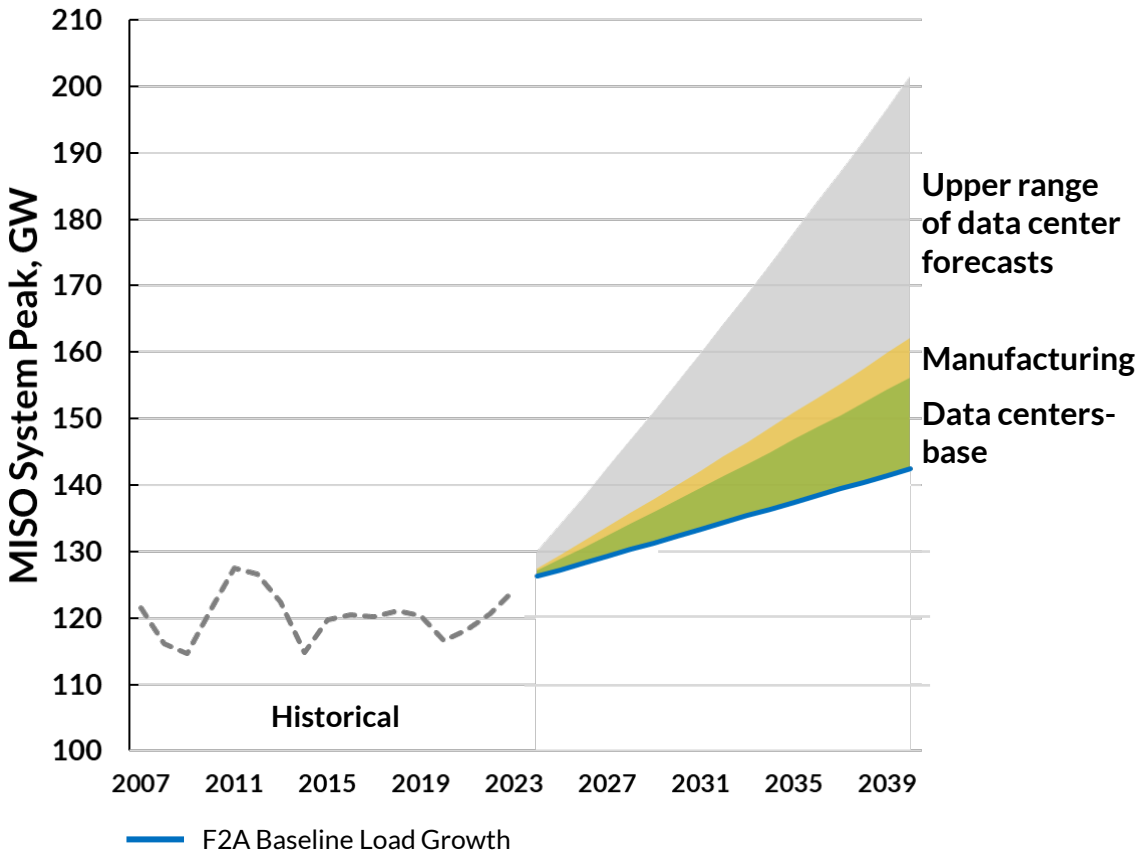



- Bracketed values indicate difference between Committed+ Projected New Capacity and Projected PRMR with LSE forecast
- Capacity accreditation values and PRM projections based on current practices
- Regional Directional Transfer (RDT) limit of 1,900 MW is reflected in this chart

*Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency.*
*PRMR: Planning Reserve Margin Requirement*
**Using Potential New Capacity as described on slide 6*

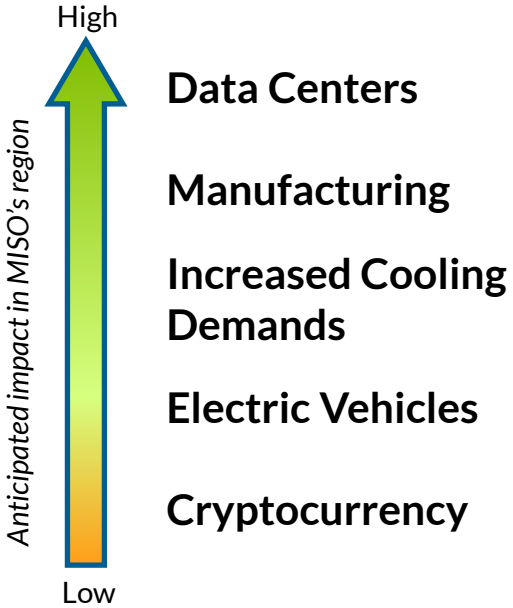
# MISO's future long-term load forecasts will account for emerging digital demands, industrial expansion and climate changes

**EPRI and Grid Strategies[1] anticipate manufacturing growth to favor MISO's service area**




***Note:*** *All figures shown are PRELIMINARY*

- Grid planners nearly *doubled* their 5-year peak load growth forecasts since last year
- MISO anticipates strong *long-term* load growth driven primarily by:




*See appendix slide 31 with load forecast updates of other grid operators, potential new data centers in MISO and other commentary*

1: https://www.epri.com/research/products/000000003002027930; https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf

# NEW: The 2024 OMS-MISO Survey includes sensitivities considering a range of new, large spot-load additions

*Illustrative Example: PY 2026/27 Using Three-Year Historical Average*

**PRMR based on a higher range of large spot-load additions**

- Uses MISO Future 2A as starting point[1]
- Models higher load-growth scenario using data from third-party consultants based on aggressive buildout of large load spot additions[2]

**PRMR considering large spot-load additions**

- Uses MISO Future 2A as starting point[1]
- Models increased demand based on public announcements for proposed data centers and manufacturing facilities within the MISO region[2]

**PRMR based on LSE submitted load forecast**

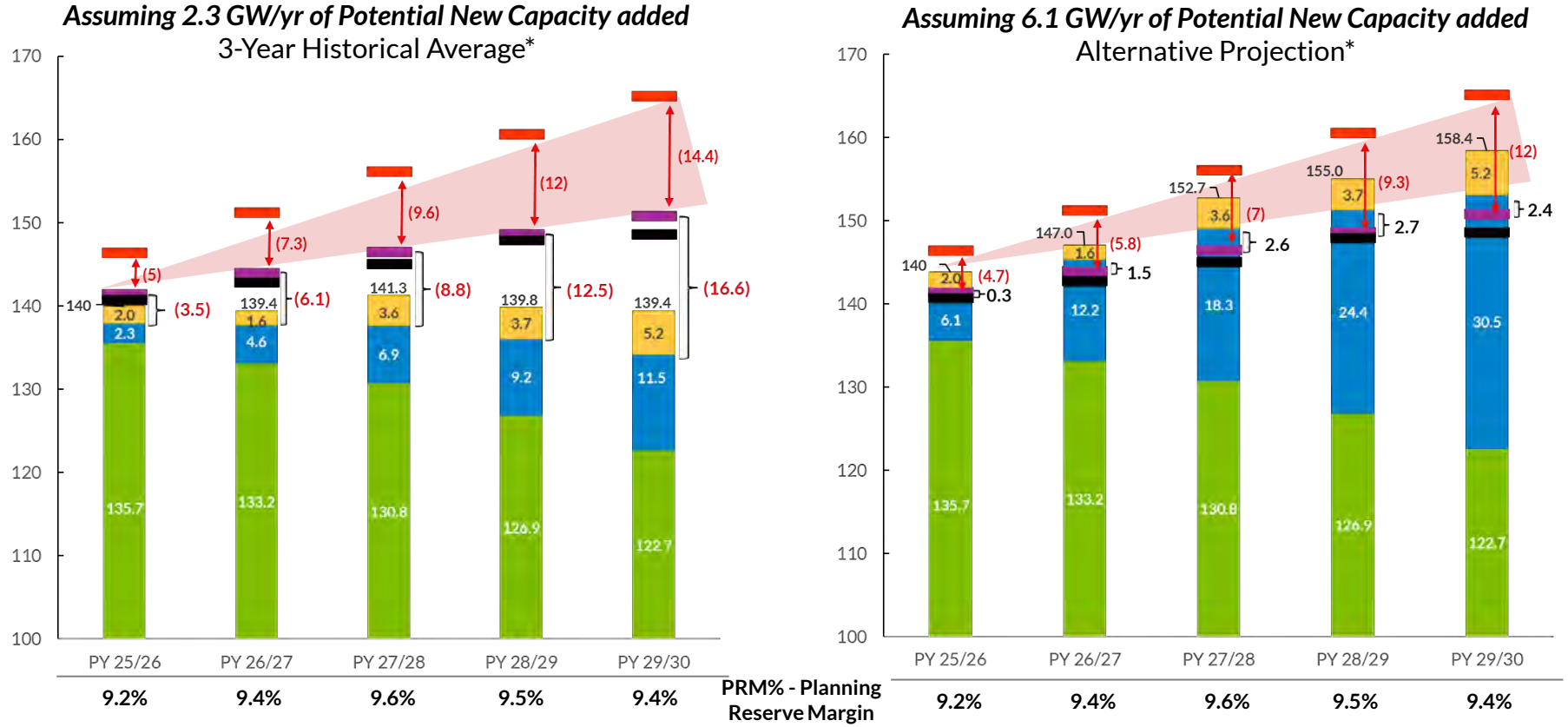
- LSE-submitted Non-Coincident Peak Forecast (NCPF) converted to Coincident Peak Forecast (CPF) using MISO posted Coincidence Factors
- Transmission losses added
- PRMR calculated using out year PRM% from PY 2024/25 LOLE Study

[1] *https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf*, [2] *See slides 12 & 31 for more information*

*PRMR: Planning Reserve Margin Requirement LSE: Load Serving Entity LOLE: Loss of Load Expectation*

# Capacity deficits continue to grow in the near and long term under a large spot-load additions scenario

## MISO Resource Adequacy Projection – Summer (GW)




- Projected PRMR for high range of Large Spot-Load Additions
- Projected PRMR with Large Load Spot Additions
- Projected PRMR with LSE forecast
- Potentially Unavailable Resources
- Potential New Capacity
- Committed Capacity

- Bracketed values indicate difference between Committed + Projected New Capacity and Projected PRMR with large spot-load additions
- Red arrow values indicate the additional potential deficit with high-range large load growth case
- Capacity accreditation values and PRM projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

*Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency.*
*PRMR: Planning Reserve Margin Requirement*
**Using Potential New Capacity as described on slide 6*

# MISO's existing accreditation methods can overstate a resource's capacity value during the highest risk periods, especially as the region's risk profile changes, leading to understated risk

- Increased reliance on wind, solar and storage, projected large-load additions and electrification, and frequent large-scale weather events are decoupling periods of risk from periods of high demand.
- These drivers are upending traditional methods for establishing reliability requirements and resource accreditation.
- MISO's proposed resource accreditation methodology* (Direct Loss of Load) will value a resource's marginal contribution to reliability during the highest risk periods.

*MISO's proposed accreditation reforms, on file at FERC and targeted for implementation in PY 2028/29, will better measure a resource's contribution to reliability.*

*See Resource Accreditation White Paper, published March 2024: https://cdn.misoenergy.org/Resource%20Accreditation%20White%20Paper%20Version%202.1630728.pdf

# The 2024 Survey shows that the near-term resource decisions made by utilities, regulators, MISO and its Members will determine whether the region's resources remain adequate

- Continued collaboration between OMS and MISO is necessary to maintain a reliable electricity system.
- The survey shows a range of potential resource adequacy outcomes, reinforcing near-term risks and illustrating key uncertainties impacting resource adequacy in the MISO region.
- Immediate actions are needed to expedite the addition of new capacity, coordinate resources for new load additions, and potentially moderate the pace of resource retirements.
- MISO's reforms under the Reliability Imperative are timely and responsive to the drivers contributing to resource adequacy challenges.
  - Implemented: Seasonal construct and thermal accreditation
  - Filed at FERC: 1) Reliability-Based Demand Curve, 2) resource accreditation
  - Ongoing reforms: 1) Load Modifying Resource accreditation, 2) Resource adequacy risk modeling improvements, 3) Attributes Roadmap, 4) LRTP, 5) JTIQ, 6) Queue Reforms

# Appendix

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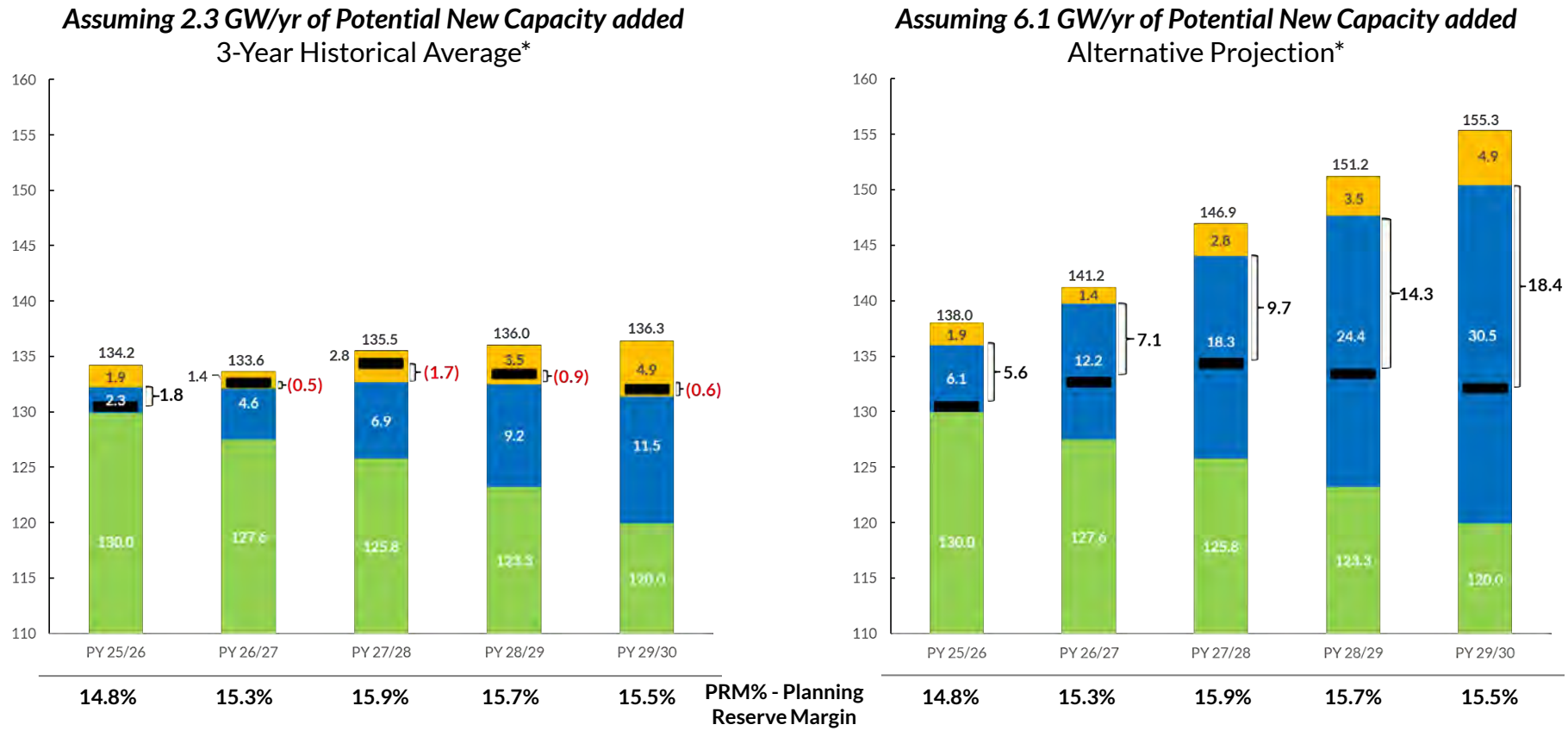
# Fall capacity ranges from 1.8 GWs to 5.6 GWs surplus in the prompt year

## MISO Resource Adequacy Projection – Fall (GW)




Projected PRMR with LSE forecast
Potentially Unavailable Resources
Potential New Capacity
Committed Capacity

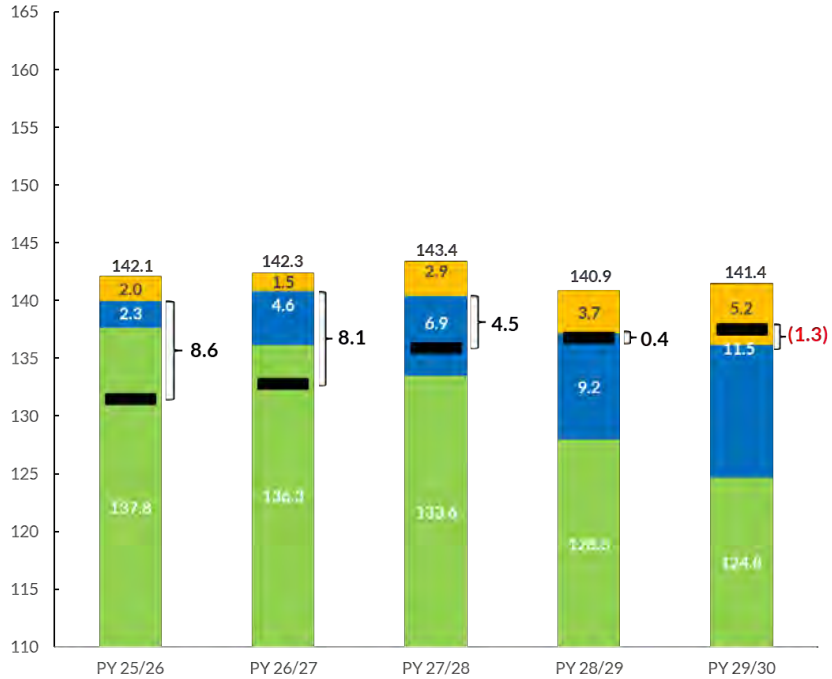
- Bracketed values indicate difference between Committed+ Projected New Capacity and Projected PRMR with LSE forecast
- Capacity accreditation values and PRM projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart
- Fall demand and PRMR calculated by using summer and winter demand forecast percent change seen year-over-year since out year Non- Coincident Peak Forecast (NCPF) is not submitted for out years for fall and spring

*Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency.*
*PRMR: Planning Reserve Margin Requirement*
**Using Potential New Capacity as described on slide 6*

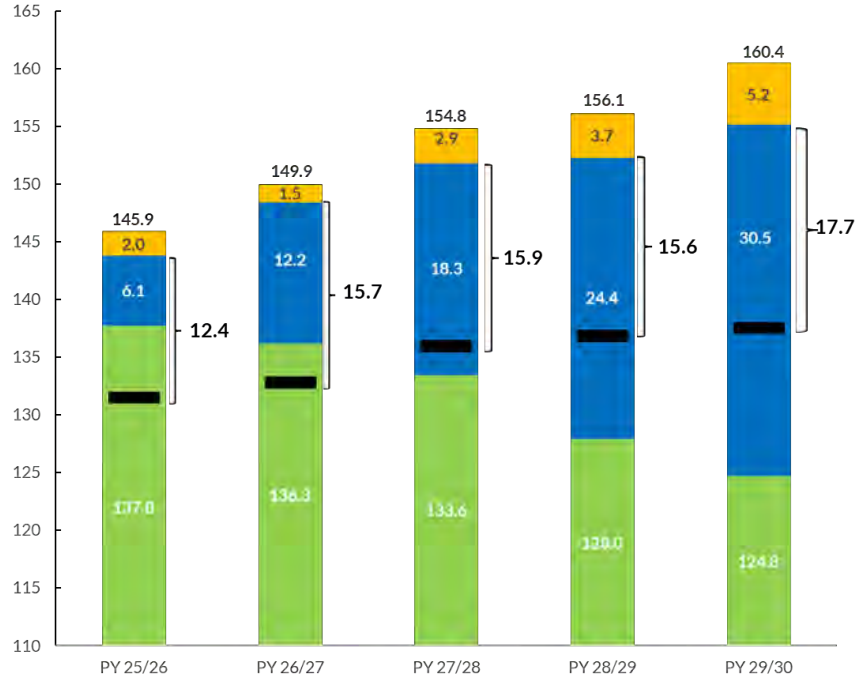
# Winter capacity ranges from 8.6 GWs to 12.4 GWs surplus in the prompt year

## MISO Resource Adequacy Projection – Winter (GW)

***Assuming 2.3 GW/yr of Potential New Capacity added***
3-Year Historical Average *




***Assuming 6.1 GW/yr of Potential New Capacity added***
Alternative Projection*




| | PY 25/26 | PY 26/27 | PY 27/28 | PY 28/29 | PY 29/30 |
|---|---|---|---|---|---|
| PRM% - Planning Reserve Margin (Winter) | 27.2% | 27% | 26.8% | 26.5% | 26.3% |
| PRM% - Planning Reserve Margin (Alternative Projection) | 27.2% | 27% | 26.8% | 26.5% | 26.3% |

- Projected PRMR with LSE forecast
- Potentially Unavailable Resources
- Potential New Capacity
- Committed Capacity

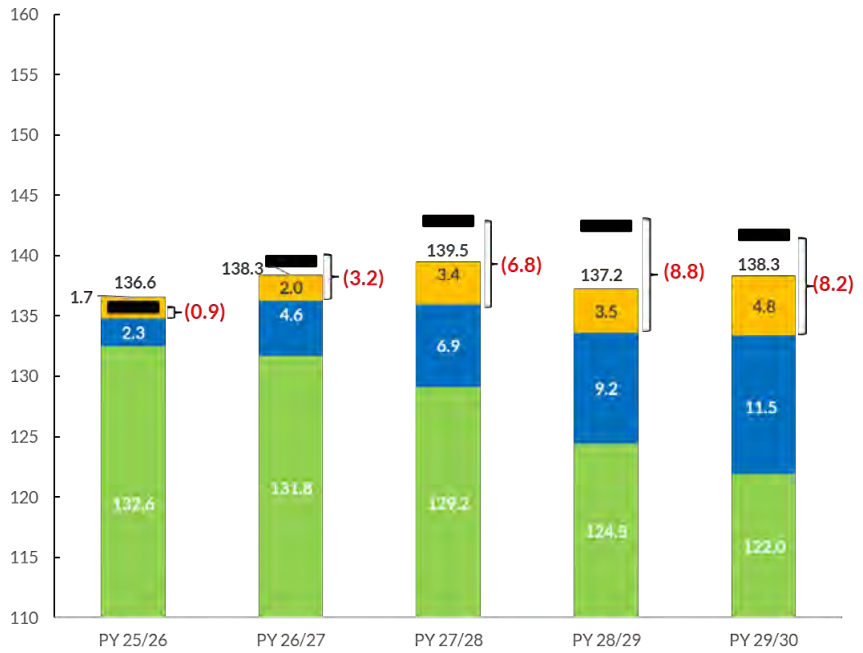
- Bracketed values indicate difference between Committed+ Projected New Capacity and Projected PRMR with LSE forecast
- Capacity accreditation values and PRM projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

*Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency.*
*PRMR: Planning Reserve Margin Requirement*
**Using Potential New Capacity as described on slide 6*

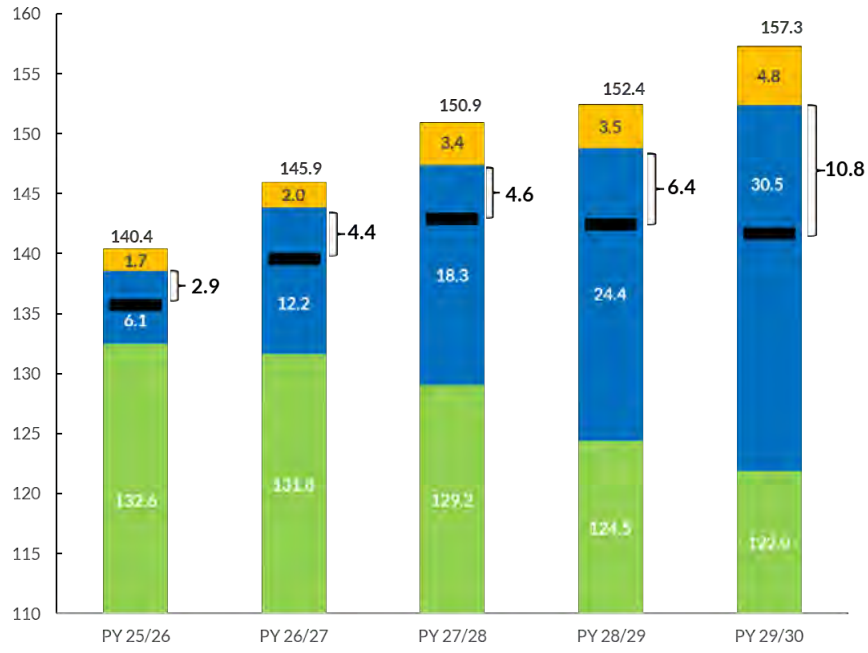
# Spring capacity ranges from 0.9 GWs deficit to 2.9 GWS surplus in the prompt year

## MISO Resource Adequacy Projection – Spring (GW)

***Assuming 2.3 GW/yr of Potential New Capacity added***
3-Year Historical Average *




***Assuming 6.1 GW/yr of Potential New Capacity added***
Alternative Projection*




| | PY 25/26 | PY 26/27 | PY 27/28 | PY 28/29 | PY 29/30 |
|---|---|---|---|---|---|
| PRM% - Planning Reserve Margin | 28.7% | 30.7% | 32.8% | 33.1% | 33.5% |
| | 28.7% | 30.7% | 32.8% | 33.1% | 33.5% |

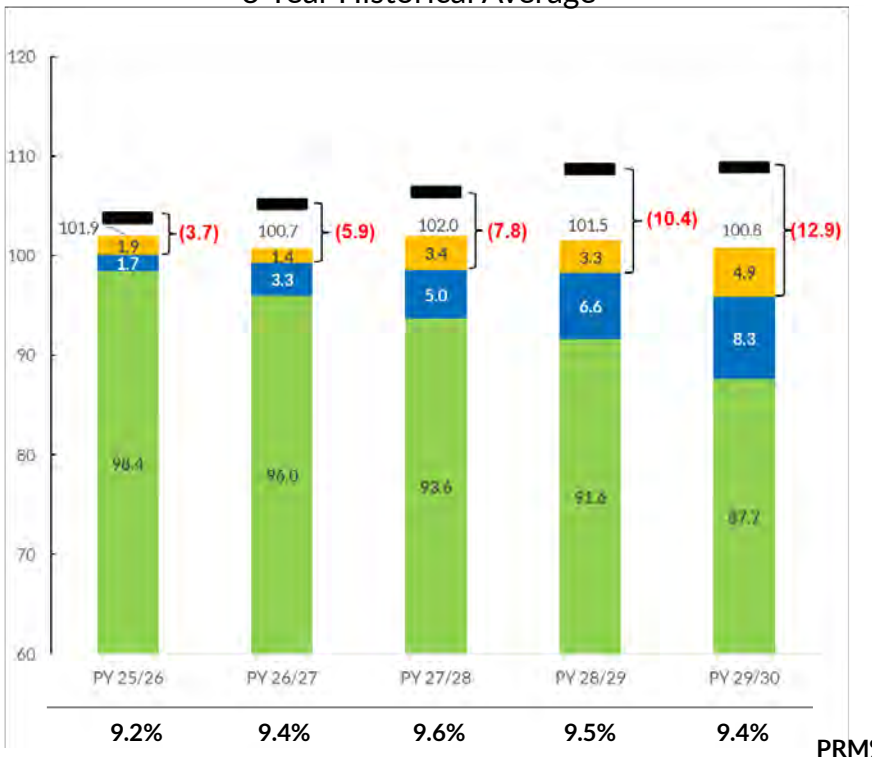
- Projected PRMR with LSE forecast
- Potentially Unavailable Resources
- Potential New Capacity
- Committed Capacity

- Bracketed values indicate difference between Committed+ Projected New Capacity and Projected PRMR with LSE forecast
- Capacity accreditation values and PRM projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart
- Spring demand and therefore PRMR is calculated by using Summer and Winter demand forecast percent change seen year over year since out year NCPF is not submitted for out years for Fall and Spring

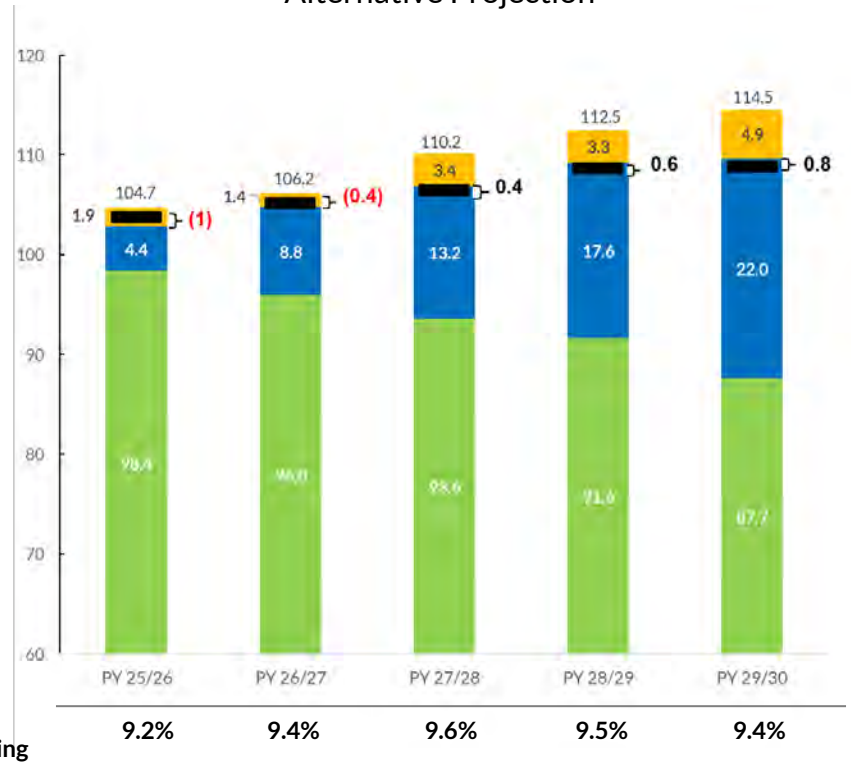
*Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency.*
*PRMR: Planning Reserve Margin Requirement*
**Using Potential New Capacity as described on slide 6*

# The North/Central subregion capacity for Summer ranges from 3.7 GWs to 1 GW deficit in the prompt year

***Assuming 2.3 GW/yr of Potential New Capacity added***
3-Year Historical Average *




***Assuming 6.1 GW/yr of Potential New Capacity added***
Alternative Projection*



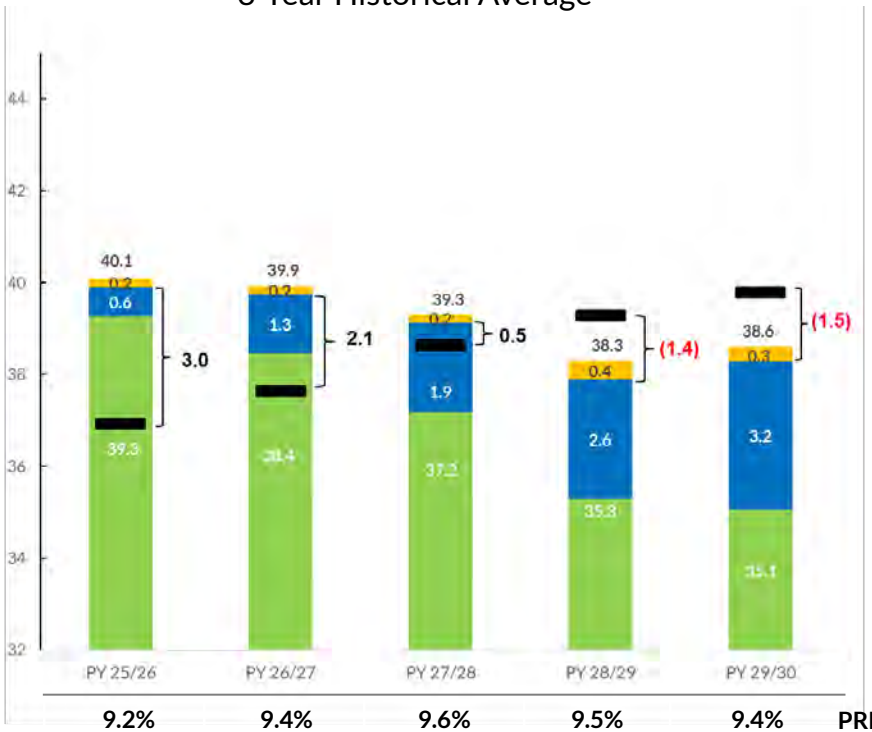

**PRM% - Planning Reserve Margin**

- Projected PRMR with LSE forecast
- Potentially Unavailable Resources
- Potential New Capacity
- Committed Capacity

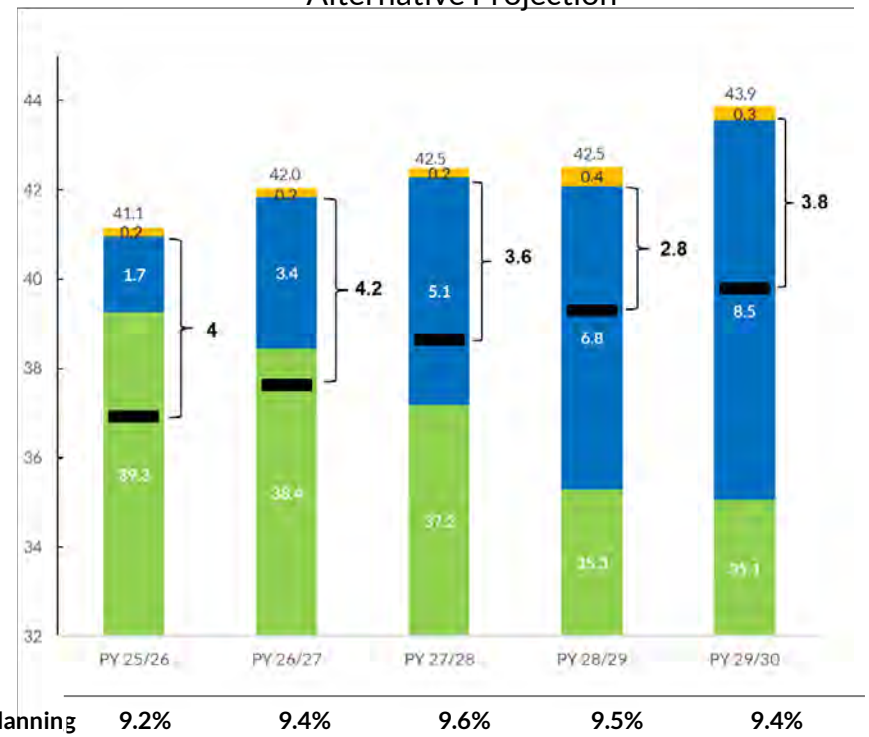
**Using Potential New Capacity as described on slide 6*
*Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency. While RDT is not reflected in these charts the limit is currently modeled at 1900 MW in Resource Adequacy. PRMR: Planning Reserve Margin Requirement.*

# The South subregion capacity for Summer ranges from 3 GWs to 4 GWs of surplus in the prompt year

***Assuming 2.3 GW/yr of Potential New Capacity added***
3-Year Historical Average *




***Assuming 6.1 GW/yr of Potential New Capacity added***
Alternative Projection*



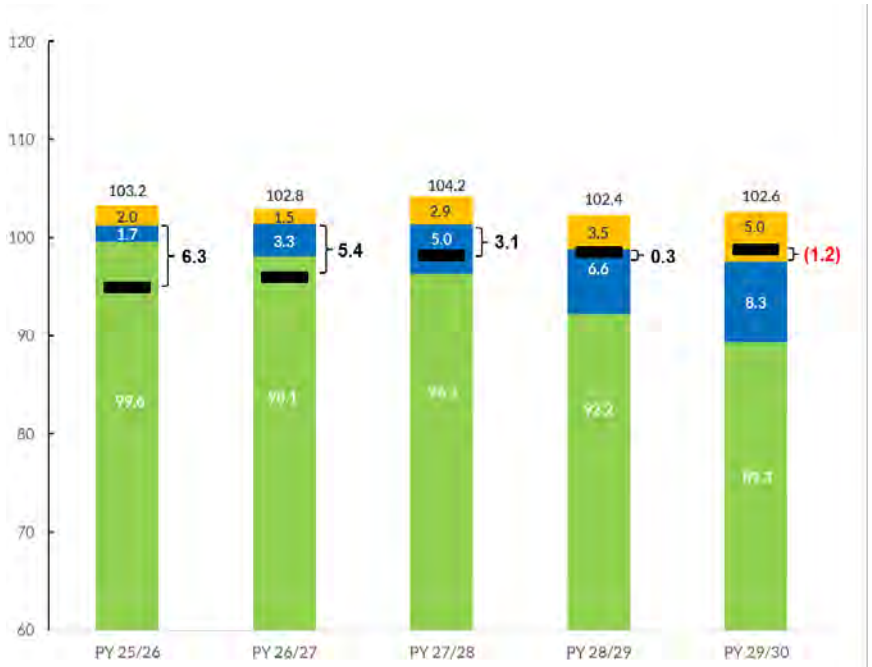

| | | | | | |
|---|---|---|---|---|---|
| **PRM% - Planning Reserve Margin** | **9.2%** | **9.4%** | **9.6%** | **9.5%** | **9.4%** |
| | **9.2%** | **9.4%** | **9.6%** | **9.5%** | **9.4%** |

- Projected PRMR with LSE forecast
- Potentially Unavailable Resources
- Potential New Capacity
- Committed Capacity

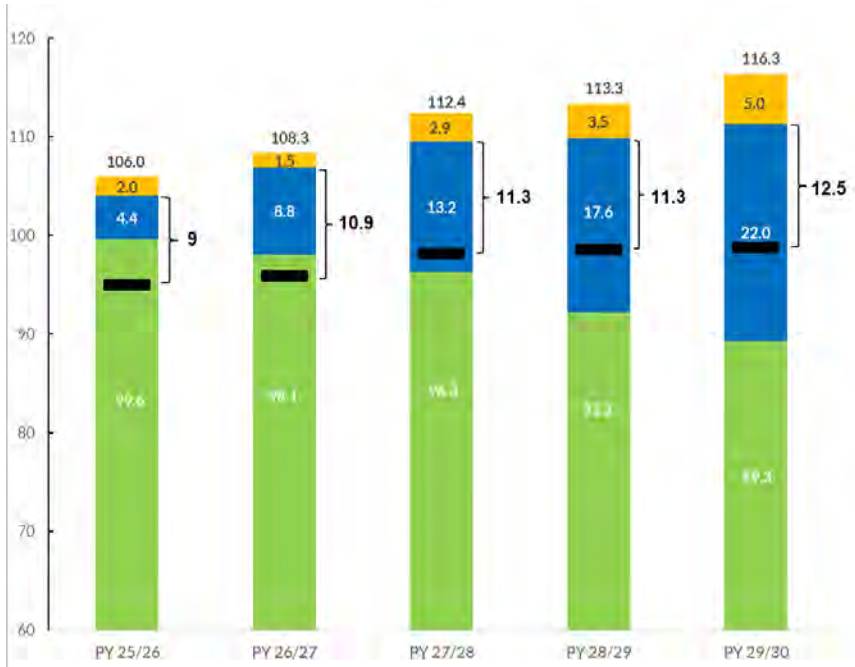
**Using Potential New Capacity as described on slide 6*
*Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency. While RDT is not reflected in these charts the limit is currently modeled at 1900 MW in Resource Adequacy. PRMR: Planning Reserve Margin Requirement.*

# The North/Central subregion capacity for Winter ranges from 6.3 GWs to 9 GWs of surplus in the prompt year

***Assuming 2.3 GW/yr of Potential New Capacity added***
3-Year Historical Average *




***Assuming 6.1 GW/yr of Potential New Capacity added***
Alternative Projection*



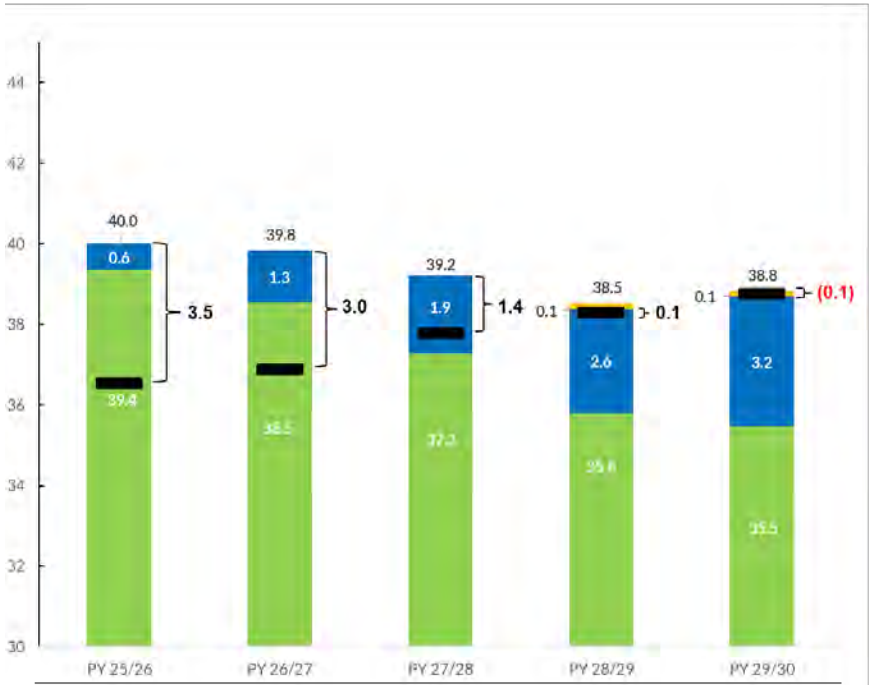

| | PY 25/26 | PY 26/27 | PY 27/28 | PY 28/29 | PY 29/30 |
|---|---|---|---|---|---|
| PRM% - Planning Reserve Margin (3-Year Historical Average) | 27.2% | 27% | 26.8% | 26.5% | 26.3% |
| PRM% - Planning Reserve Margin (Alternative Projection) | 27.2% | 27% | 26.8% | 26.5% | 26.3% |

- Projected PRMR with LSE forecast
- Potentially Unavailable Resources
- Potential New Capacity
- Committed Capacity

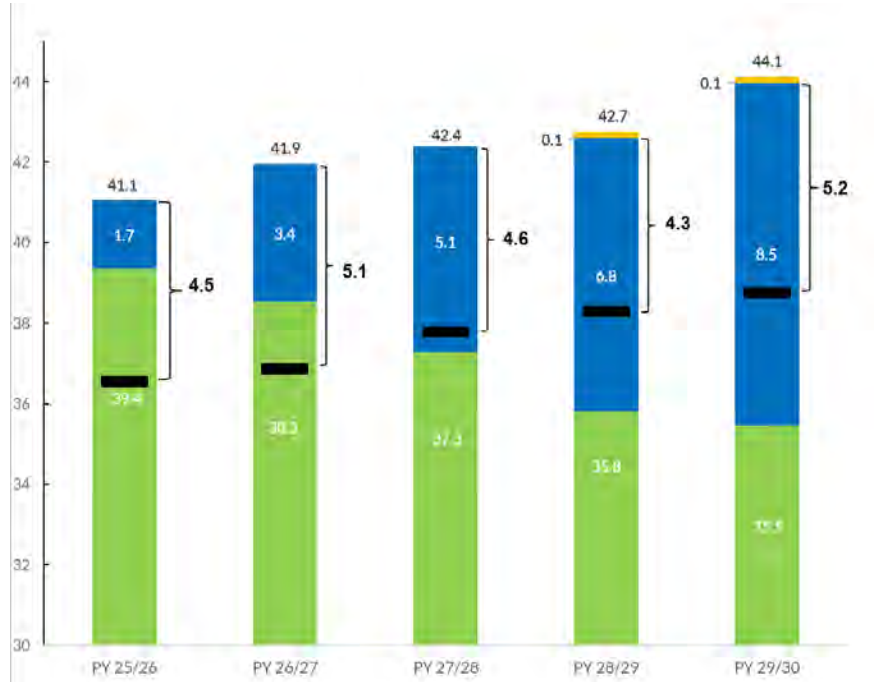
**Using Potential New Capacity as described on slide 6*
*Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency. While RDT is not reflected in these charts the limit is currently modeled at 1900 MW in Resource Adequacy. PRMR: Planning Reserve Margin Requirement.*

# The South subregion capacity for Winter ranges from 3.5 GWs to 4.5 GWs of surplus in the prompt year

***Assuming 2.3 GW/yr of Potential New Capacity added***
3-Year Historical Average *




***Assuming 6.1 GW/yr of Potential New Capacity added***
Alternative Projection*



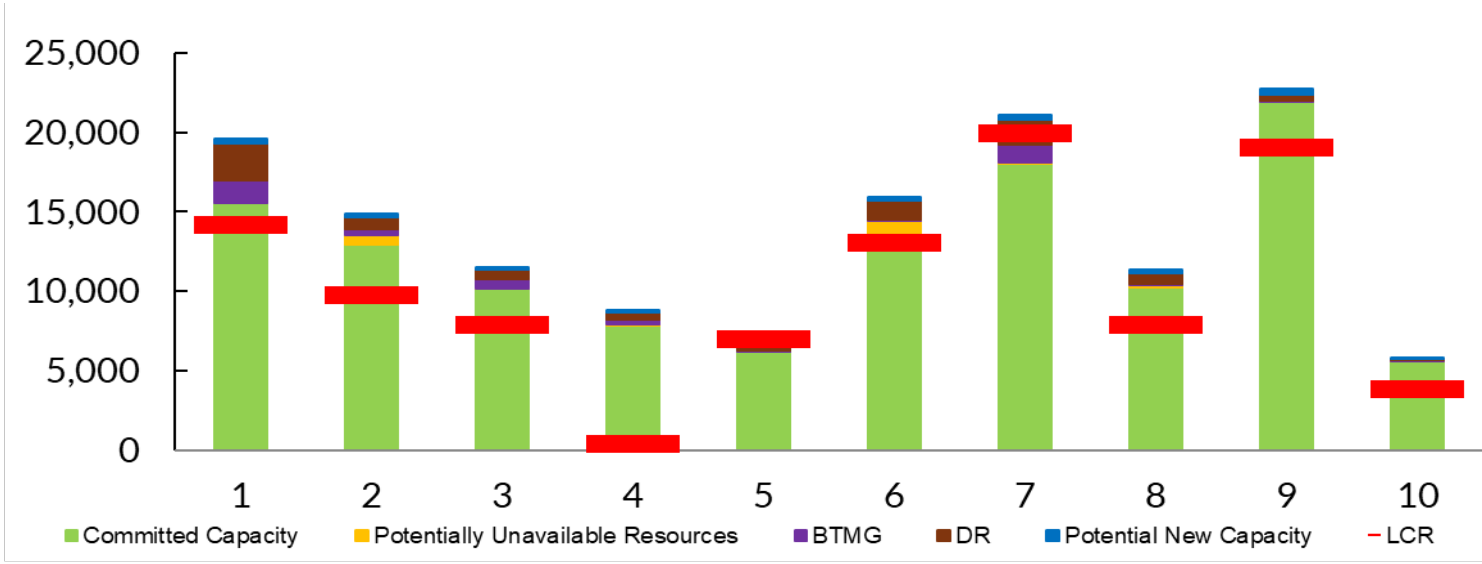

| | | | | | |
|---|---|---|---|---|---|
| 27.2% | 27% | 26.8% | 26.5% | 26.3% | PRM% - Planning Reserve Margin |
| 27.2% | 27% | 26.8% | 26.5% | 26.3% | |

- Projected PRMR with LSE forecast
- Potentially Unavailable Resources
- Potential New Capacity
- Committed Capacity

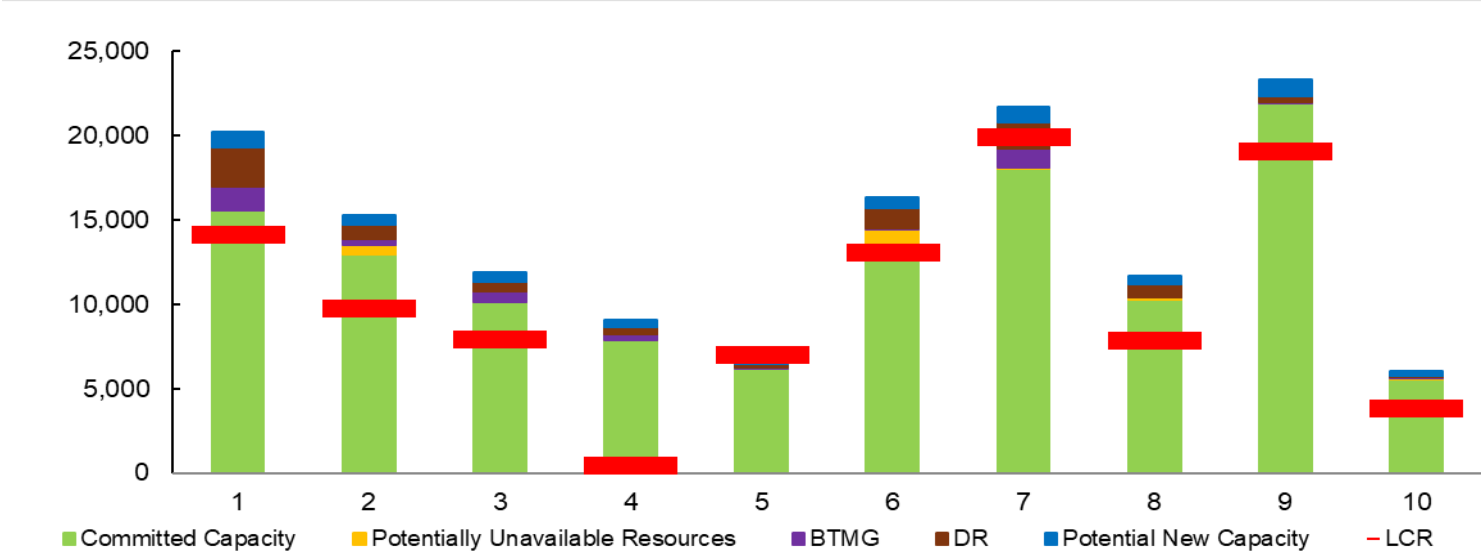
**Using Potential New Capacity as described on slide 6*
*Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency. While RDT is not reflected in these charts the limit is currently modeled at 1900 MW in Resource Adequacy. PRMR: Planning Reserve Margin Requirement.*

# Summer PY 2025/26 Load Clearing Requirement (LCR) by zone

PY 2025/26 Summer by Zone vs. LCR (MW) Using 3-Year Historical average for new capacity*



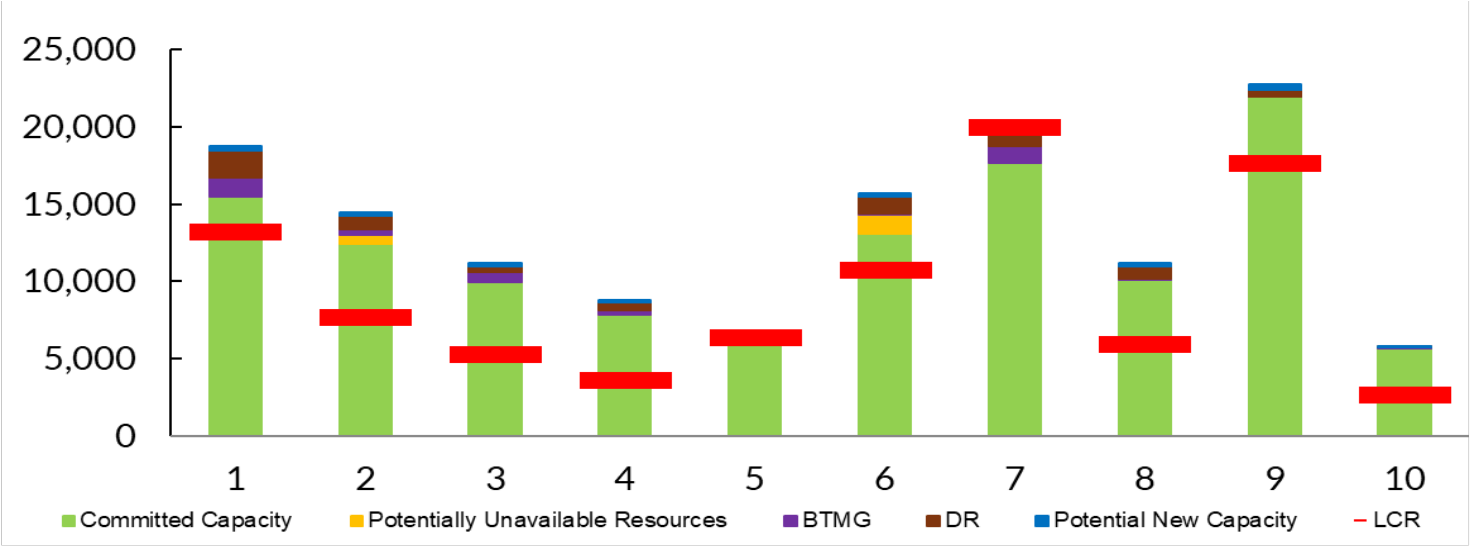

PY 2025/26 Summer by Zone vs. LCR (MW) Using Alternative Projection for new capacity*



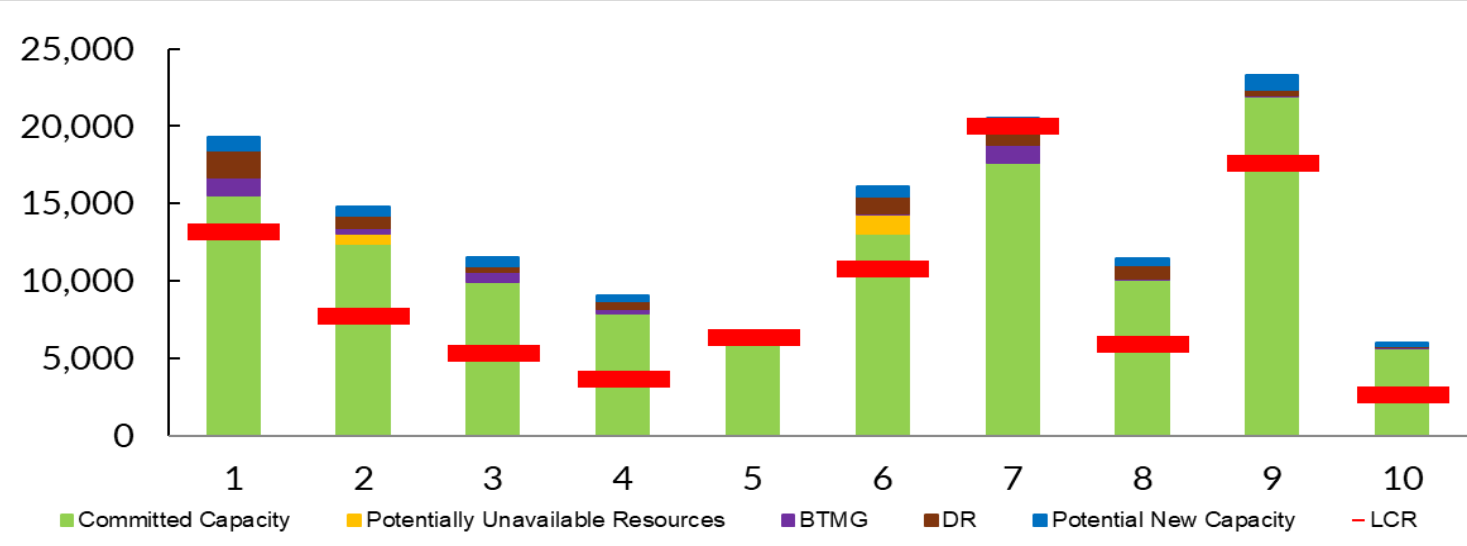

**Using Potential New Capacity as described on slide 6*
*Includes only projected capacity resources within the zone (not imports and interzonal transfers). Potential Capacity for each zone is the average actual installed New Capacity used in the MISO overview slide proportional to that zones existing generation.*

# Fall PY 25/26 Load Clearing Requirement (LCR) by Zone

PY 2025/26 Summer by Zone vs. LCR (MW) Using 3-Year Historical average for new capacity*




PY 2025/26 Summer by Zone vs. LCR (MW) Using Alternative Projection for new capacity*

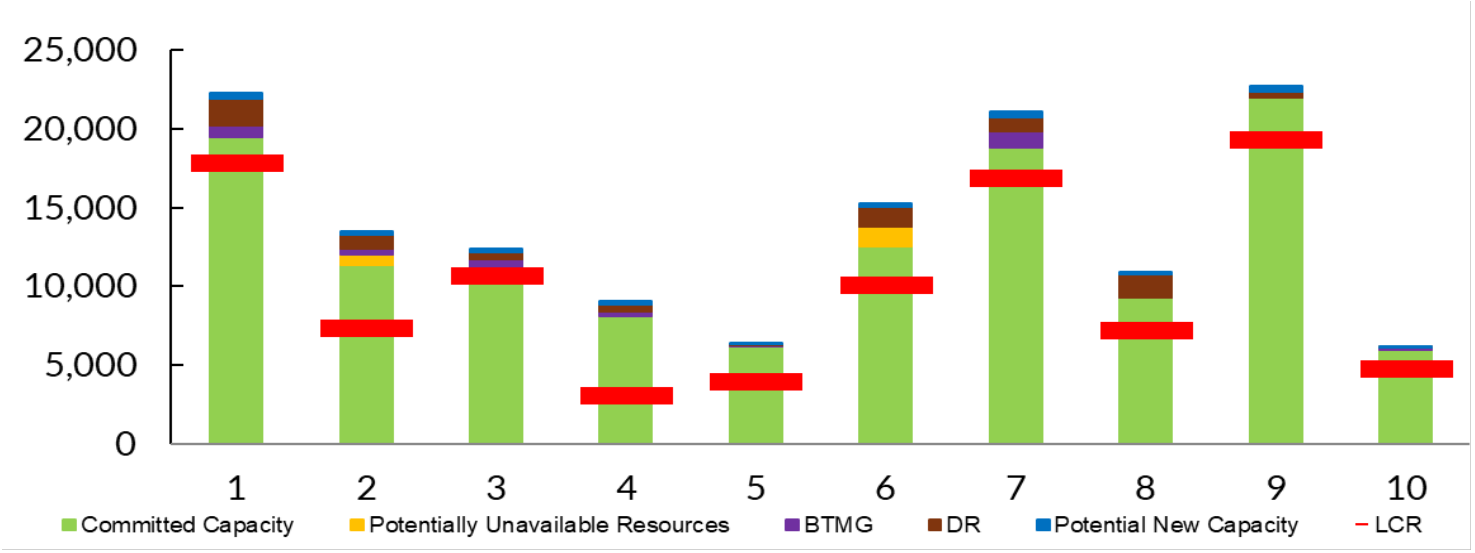



*Using Potential New Capacity as described on slide 6*

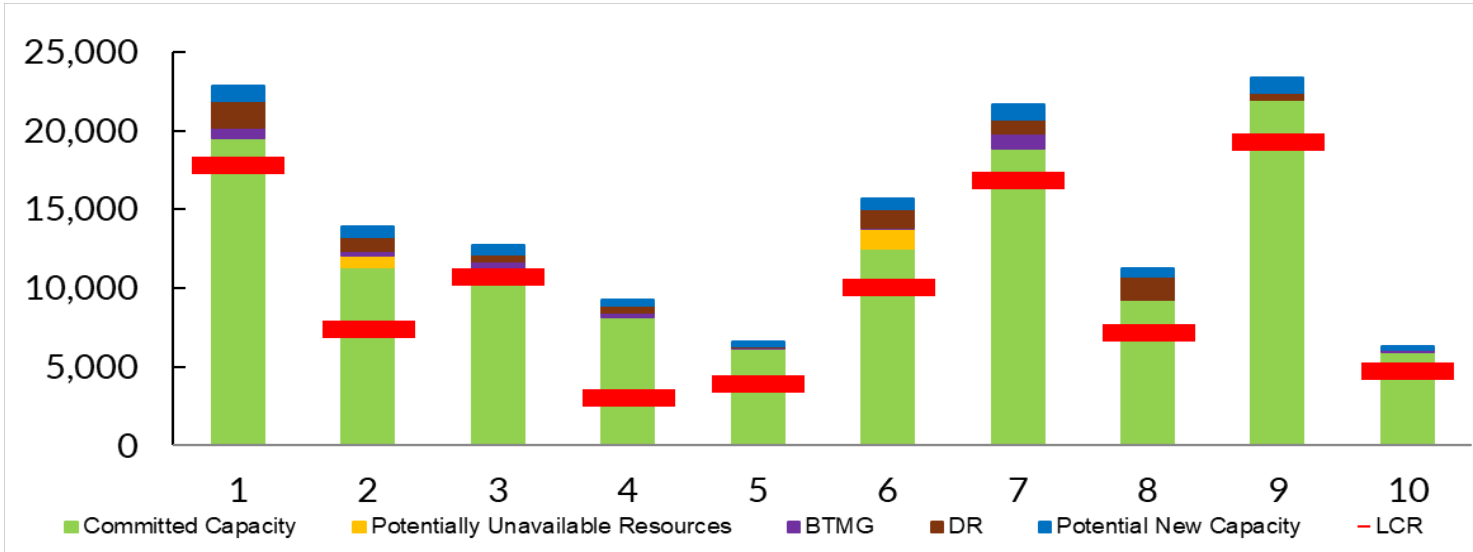
*Includes only projected capacity resources within the zone (not imports and interzonal transfers). Potential Capacity for each zone is the average actual installed New Capacity used in the MISO overview slide proportional to that zones existing generation.*

# Winter PY 25/26 Load Clearing Requirement (LCR) by Zone

PY 2025/26 Summer by Zone vs. LCR (MW) Using 3-Year Historical average for new capacity*




PY 2025/26 Summer by Zone vs. LCR (MW) Using Alternative Projection for new capacity*

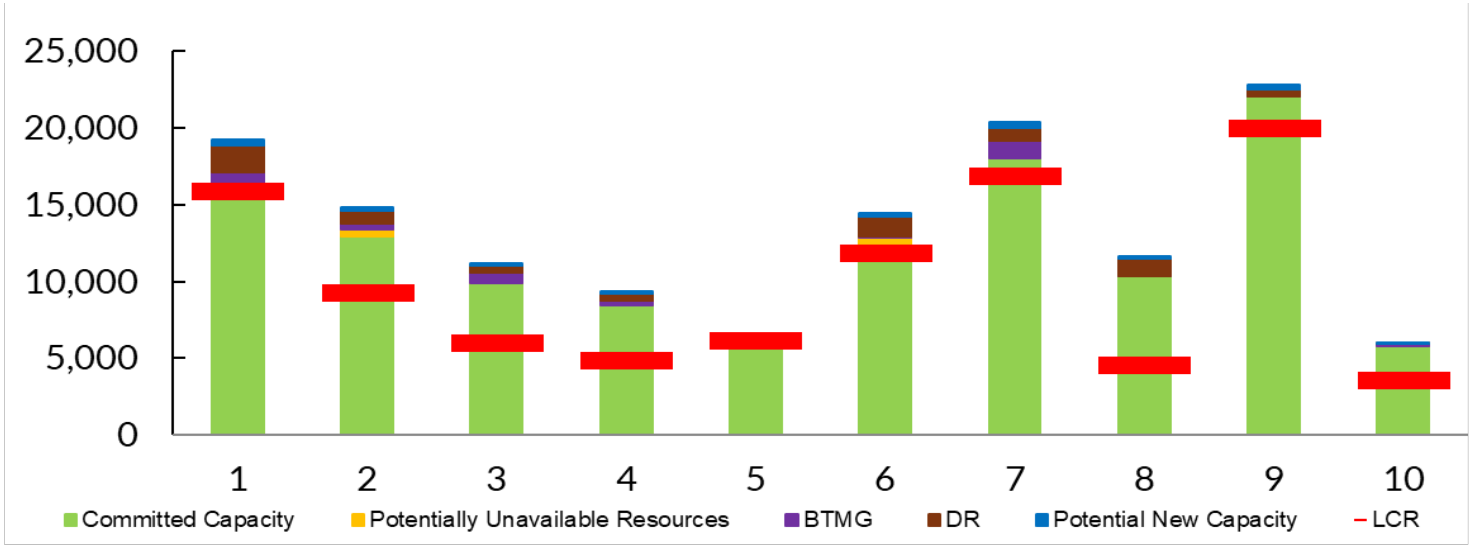



*Using Potential New Capacity as described on slide 6*

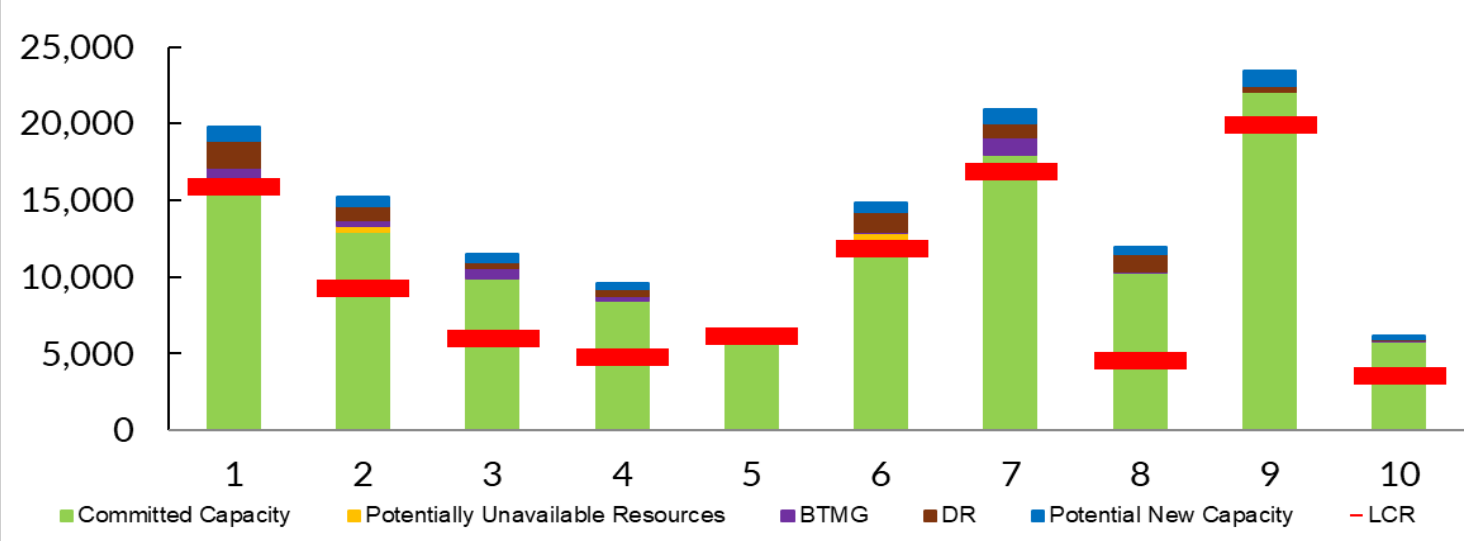
*Includes only projected capacity resources within the zone (not imports and interzonal transfers). Potential Capacity for each zone is the average actual installed New Capacity used in the MISO overview slide proportional to that zones existing generation.*

# Spring PY 25/26 Load Clearing Requirement (LCR) by Zone

PY 2025/26 Summer by Zone vs. LCR (MW) Using 3-Year Historical average for new capacity*




PY 2025/26 Summer by Zone vs. LCR (MW) Using Alternative Projection for new capacity*



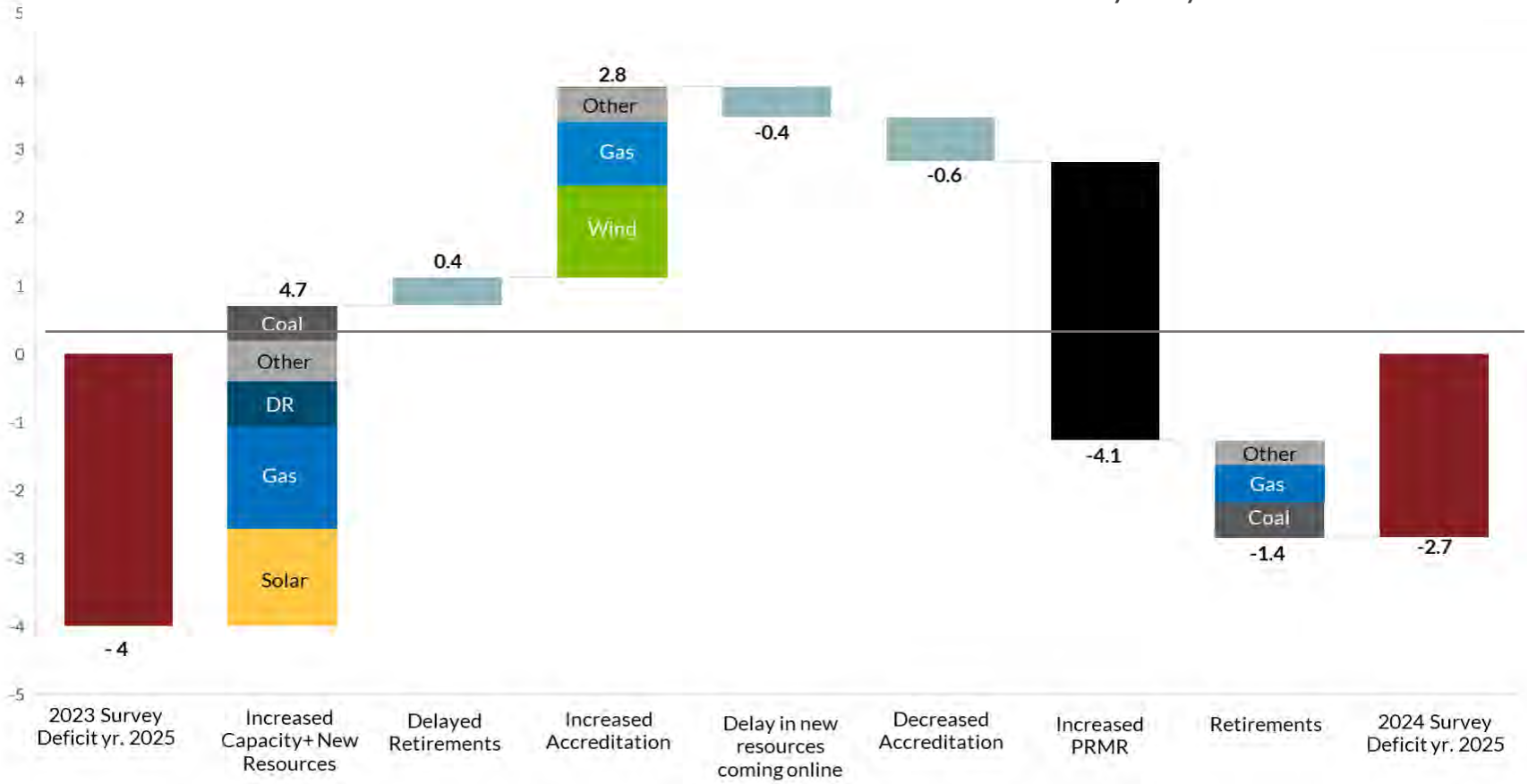

*Using Potential New Capacity as described on slide 6*

*Includes only projected capacity resources within the zone (not imports and interzonal transfers). Potential Capacity for each zone is the average actual installed New Capacity used in the MISO overview slide proportional to that zones existing generation.*

# Year-over-year, the OMS-MISO Survey results show a decreased deficit due to increased response/new resources and increased accreditation, but a deficit remains largely driven by an increased Planning Reserve Margin Requirement

## MISO 2025 SAC Projection (GW)

Reconciliation between 2023 & 2024 Summer OMS-MISO Survey for year 2025




*Higher load forecast included in 'Increased PRMR (Planning Reserve Margin Requirement)'*
*Other in 'Increased Response +New Resources': Wind, Battery, Hydro, and Oil*
*Other in 'Increased Accreditation' and Retirements: Other-Gas(CU ft), Water, Wood, Waste Heat*