BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-26-22

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

Exhibit 31

MISO 2025–26 Auction Results

Planning Resource Auction

Results for Planning Year 2025-26

April 2025

CORRECTIONS

Reposted 05/29/25

Slides Updated: 7, 11, 18-20, 23, 32-34

MISO met the planning year 2025/26 resource adequacy requirements, but pressure persists with reduced capacity surplus across the region and is reflected through improved price signals in this year's auction

Summer
$666.50
—
Fall
$91.60 (North/Central)
$74.09 (South)
—
Winter
$33.20
—
Spring
$69.88
—
Annualized
$217 (North/Central)
$212 (South)

- MISO's Reliability-Based Demand Curve (RBDC) improves price signals, reflecting the increased value of accredited capacity beyond the seasonal Planning Reserve Margin (PRM) target
    - For example, the auction cleared 1.9% above the 7.9% summer PRM target
- Summer price reflects the lowest available surplus capacity
    - Fall price varied slightly due to transfer limitations between the North and South
- Consistent with past years, most Load Service Entities (LSEs) self-supplied or secured capacity in advance and are hedged with respect to auction prices
- Surplus above the target PRM dropped 43% compared to last summer, despite the slightly lower PRM target (7.9% vs. 9.0% last year)
    - New capacity additions did not keep pace with reduced accreditation, suspensions/retirements and slightly reduced imports
- The results reinforce the need to increase capacity, as demand is expected to grow with new large load additions

Auction outcomes are consistent with the design intent of the Reliability-Based Demand Curve (RBDC), and MISO and its members can expect more stable and predictable capacity pricing, especially in surplus situations

In the 2025 PRA, the RBDC…

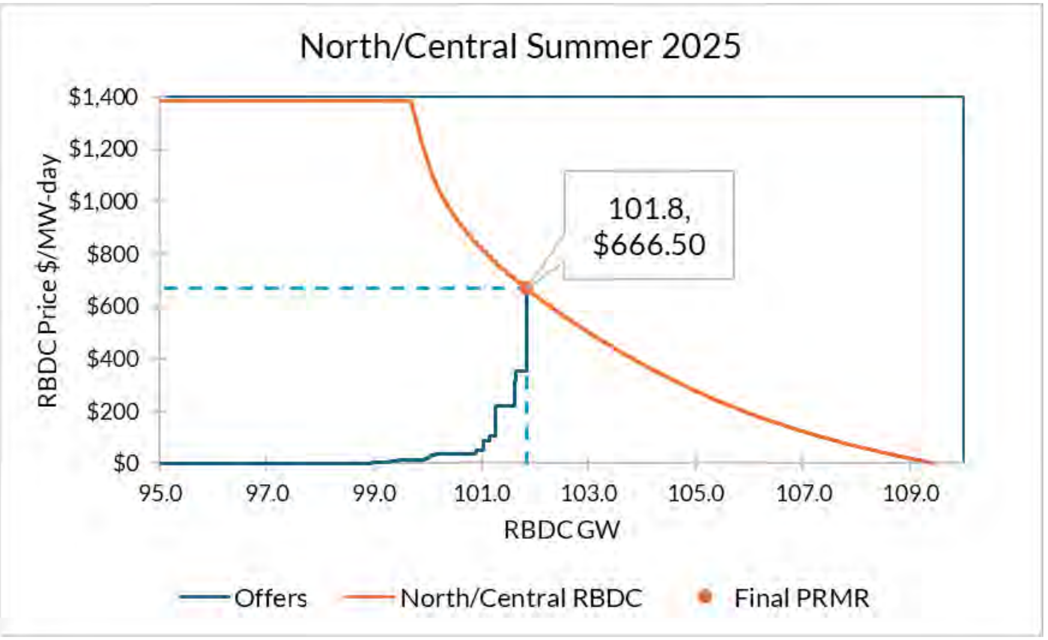
- Delivers competitive prices aligned with seasonal risks and tightening surplus
  - Prioritizes summer availability, the system's highest-risk season (based on 1-in-10 LOLE)
- Values incremental capacity above and below the LOLE target based on its reliability
  - Clears capacity above target Planning Reserve Margin based on its reliability value in each season
- Stabilizes prices in non-summer seasons, avoiding extreme volatility

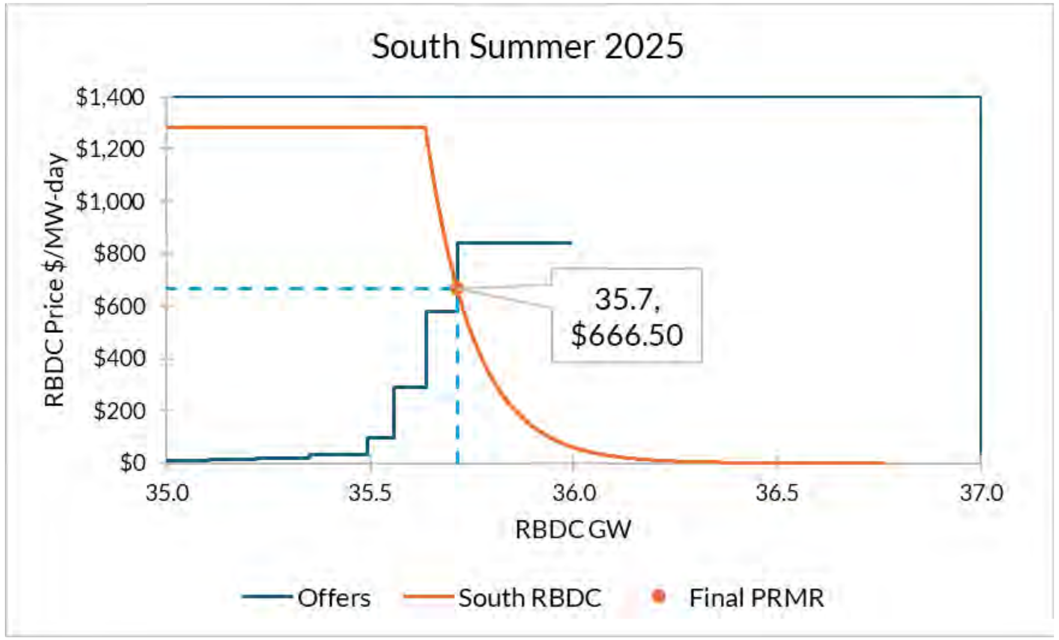
Why it Matters

- Sends clear and stable investment signals across the system, including to external resources
- Provides transparent value for capacity that exceeds the Planning Reserve Margin target
- Reflects subregional capacity needs and clears accordingly across all seasons

LOLE: Loss of Load Expectation

Auction pricing outcomes with the Reliability-Based Demand Curve (RBDC) better reflect value of capacity and resource adequacy risk across seasons





- Summer clearing of $666.50 reflects highest reliability risk and reducing surplus capacity year-over-year
  - Surplus capacity in the summer has reduced from approximately 6.5 GW in 2023, to 4.6 GW in 2024, to 2.6 GW in 2025
- Incremental capacity cleared beyond the target Planning Reserve Margin based on the value it adds to reliability (e.g., North/Central "effective" summer margin at 10.1% and South at 8.7% vs. target 7.9%)
  - A small quantity of capacity, that was offered at a price higher than the reliability value indicated through the demand curve, did not clear

LOLE: Loss of Load Expectation

MISO's Reliability-Based Demand Curve (RBDC) improves price signals, reflecting the increased value of accredited capacity beyond seasonal reliability targets

- Under RBDC, each season has an initial reliability target (PRM%)
- Auction cleared above seasonal final reliability target, representing additional reliability value at cost-competitive prices

	2025 Planning Resource Auction Initial Target vs. Final Cleared	Additional Reliability	Auction Clearing Price
Summer	Initial, 7.90% Cleared, 9.80%	+1.9%	$666.50
Fall	Initial, 14.90% Cleared, 17.50%	+2.6%	$91.60 N/C $74.09 S
Winter	Initial, 18.40% Cleared, 24.50%	+6.1%	$33.20
Spring	Initial, 25.30% Cleared, 26.80%	+1.5%	$69.88

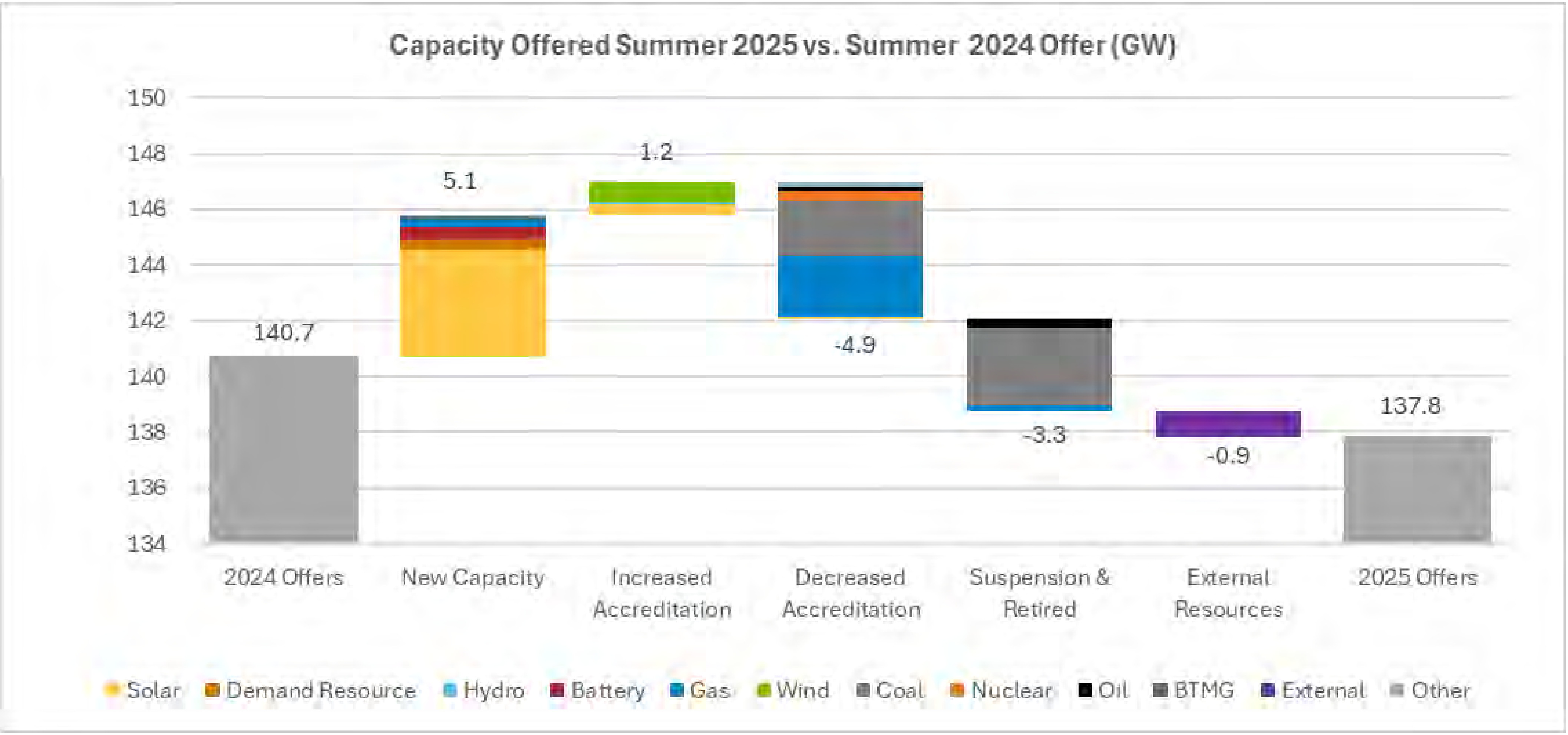
Annualized
$217 (North/Central)
$212 (South)

PRM: Planning Reserve Margin

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

MISO

New capacity additions did not keep pace with decreased accreditation, suspensions/ retirements and external resources



BTMG: Behind the Meter Generation | Capacity indicated is offered accredited value

MISO has taken action on many Reliability Imperative initiatives to address resource adequacy challenges, but there's more to be done

Ongoing Challenges

- Accelerating demand for electricity
- Rapid pace of generation retirements continue
- Loss of accredited capacity and reliability attributes
- Majority of new resources with variable, intermittent output and high weather correlation
- Delays of new resource additions
- More frequent extreme weather

Completed Initiatives

✓ Implemented Reliability-Based Demand Curve in 2025 PRA

✓ Non-emergency resource accreditation *(effective PY 2028/29)*

✓ Generation interconnection queue cap

✓ Improved generator interconnection queue process (*New application portal coming June 2025)*

✓ Approved over $30 billion in new transmission lines

Initiatives In Progress

- [ ] Implement Direct Loss of Load (DLOL)-based accreditation
- [ ] Enhance resource adequacy risk modeling
- [ ] Reduce queue cycle times through automation
- [ ] Implement interim Expedited Resource Addition Study (ERAS) process *(June 2025)*
- [ ] Demand Response and Emergency Resource reforms
- [ ] Enhance allocation of resource adequacy requirements

Next Steps

April 28

2025 PRA Results Posted

May 21

Zonal deliverability benefits available at the May RASC
—
MISO publishes cleared Load Modifying Resources to Operations tools

May 28

Posting of PRA masked offer data per Module E-1 69 A.7.4

June 1

2025 PRA prices go into affect
—
New Planning Year starts

Appendix

Table of Contents

Acronyms

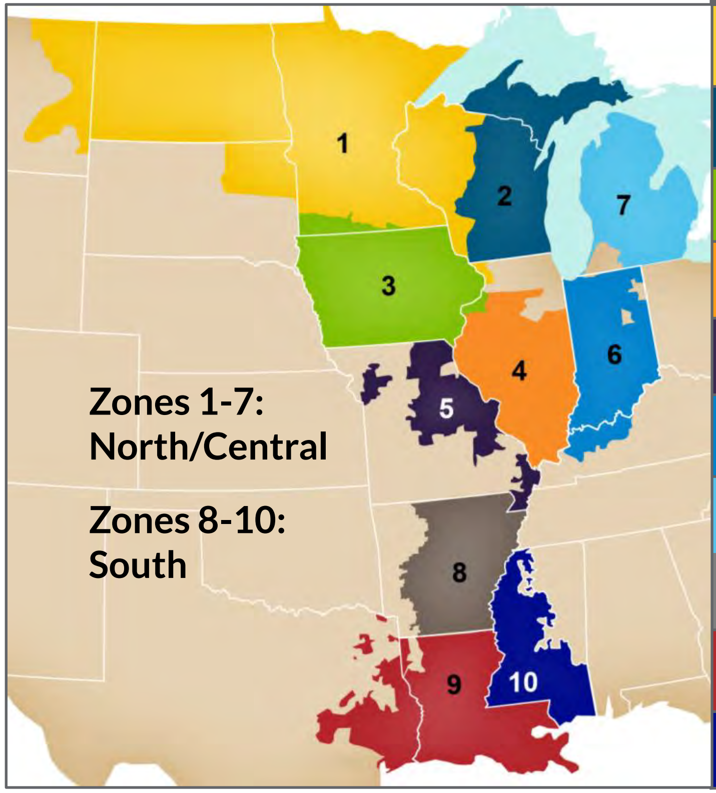
ACP: Auction Clearing Price
ARC: Aggregator of Retail Customers
BTMG: Behind the Meter Generator
CIL: Capacity Import Limit
CEL: Capacity Export Limit
CONE: Cost of New Entry
CPF: Coincident Peak Forecast
DLOL: Direct Loss-of-Load
DR: Demand Resource
ELCC: Effective Load Carrying Capability
EE: Energy Efficiency
ER: External Resource
ERAS: Expedited Resource Addition Study
ERZ: External Resource Zones

FRAP: Fixed Resource Adequacy Plan
ICAP: Installed Capacity
IMM: Independent Market Monitor
LBA: Load Balancing Authority
LCR: Local Clearing Requirement
LOLE: Loss of Load Expectation
LMR: Load Modifying Resource
LRR: Local Reliability Requirement
LRZ: Local Resource Zone
LSE: Load Serving Entity
OMS: Organization of MISO States
PO: Planned Outage
PRA: Planning Resource Auction
PRM: Planning Reserve Margin

PRMR: Planning Reserve Margin Requirement
RASC: Resource Adequacy Sub-Committee
RBDC: Reliability-Based Demand Curve
SAC: Seasonal Accredited Capacity
SREC: Sub-Regional Export Constraint
SRIC: Sub-Regional Import Constraint
SRPBC: Sub-Regional Power Balance Constraint
SS: Self Schedule
UCAP: Unforced Capacity
ZIA: Zonal Import Ability
ZRC: Zonal Resource Credit

The 2025 PRA demonstrated sufficient capacity at the regional, subregional and zonal levels, with the summer price reflecting the highest risk and a tighter supply-demand balance

MISO Resource Adequacy Zones



2025 PRA Results

<table>
<tr><th rowspan="2"></th><th colspan="4">Price/MW-Day</th></tr>
<tr><th>Summer</th><th>Fall</th><th>Winter</th><th>Spring</th></tr>
<tr><td>1</td><td rowspan="10">$666.50</td><td rowspan="7">$91.60</td><td rowspan="10">$33.20</td><td rowspan="10">$69.88</td></tr>
<tr><td>2</td></tr>
<tr><td>3</td></tr>
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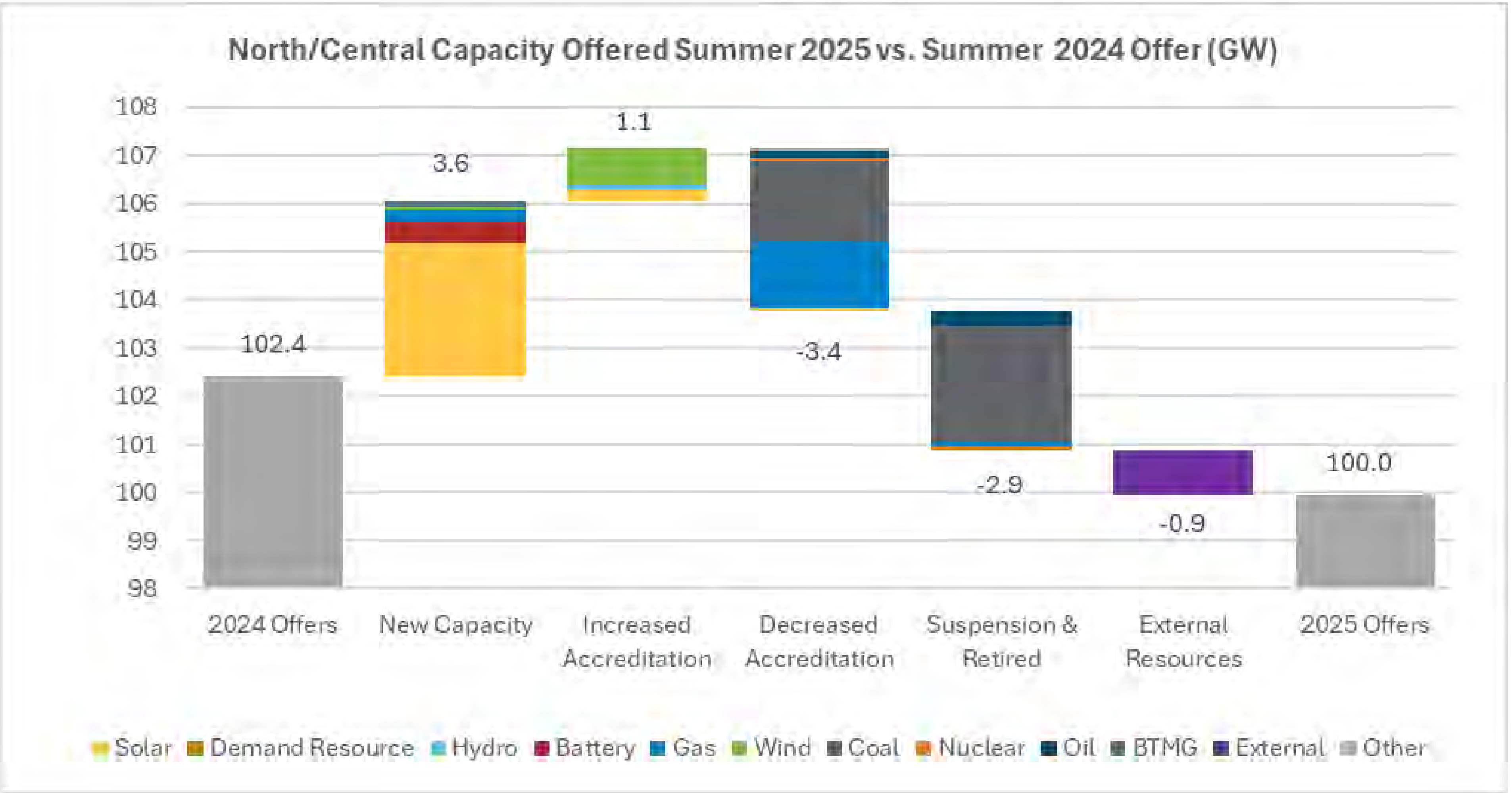
<tr><td>5</td></tr>
<tr><td>6</td></tr>
<tr><td>7</td></tr>
<tr><td>8</td><td rowspan="3">$74.09</td></tr>
<tr><td>9</td></tr>
<tr><td>10</td></tr>
</table>

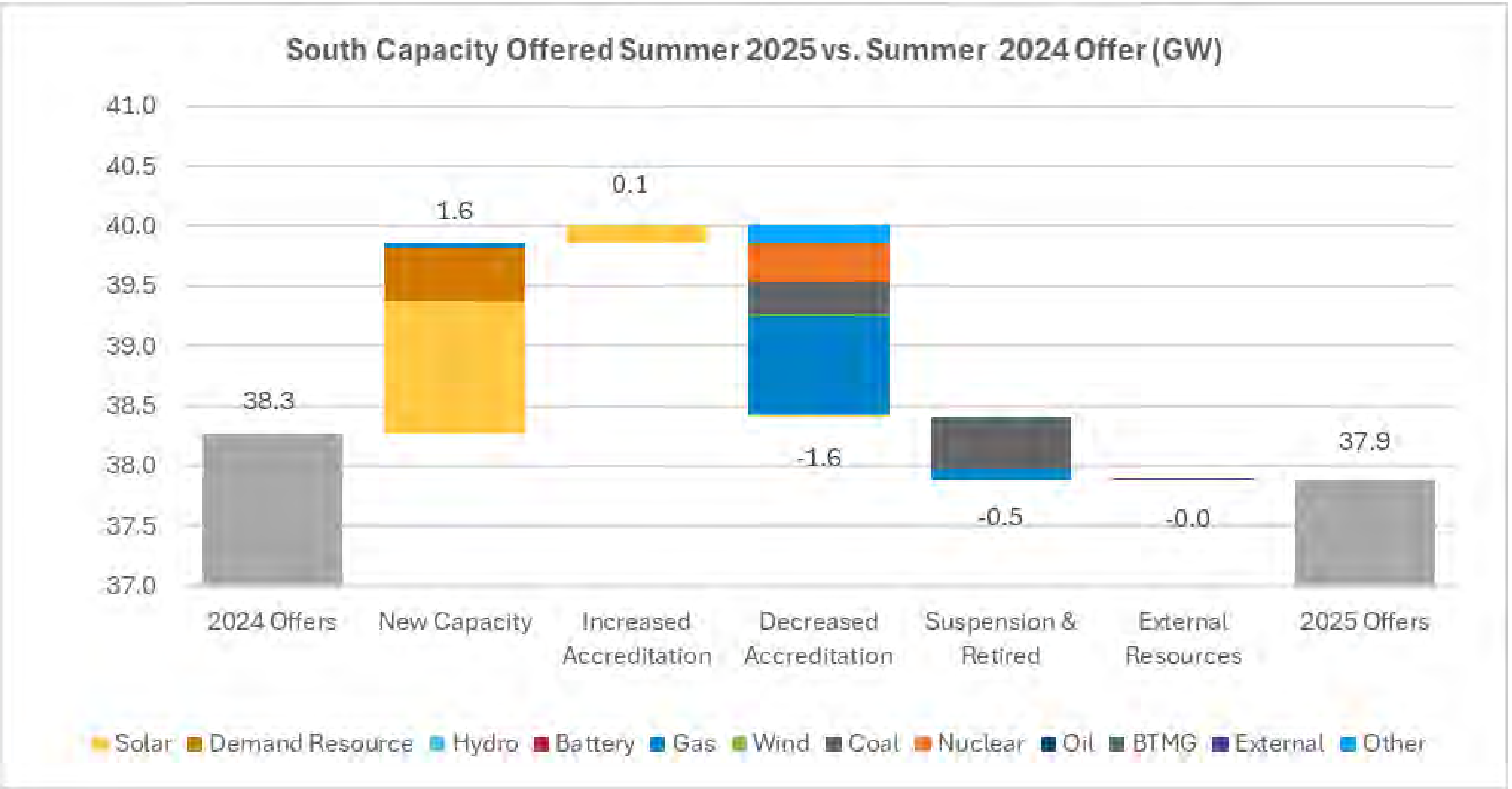
Annualized
$217 (North/Central)
$212 (South)

For North/Central, new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources



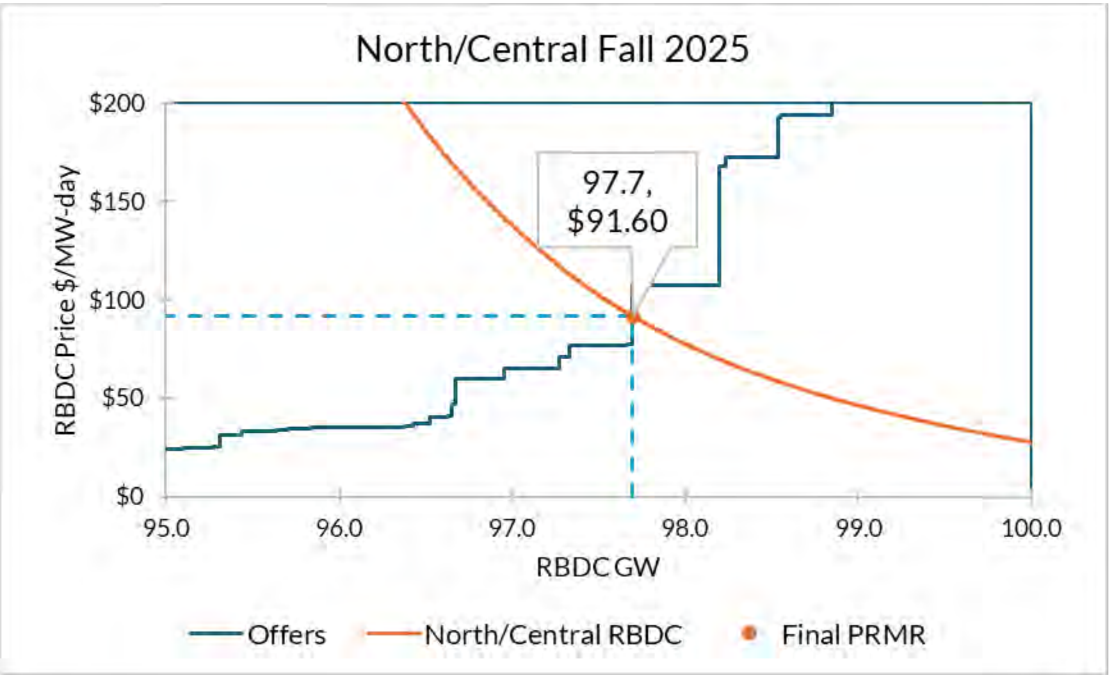
BTMG: Behind the Meter Generation | Capacity indicated is offered accredited value

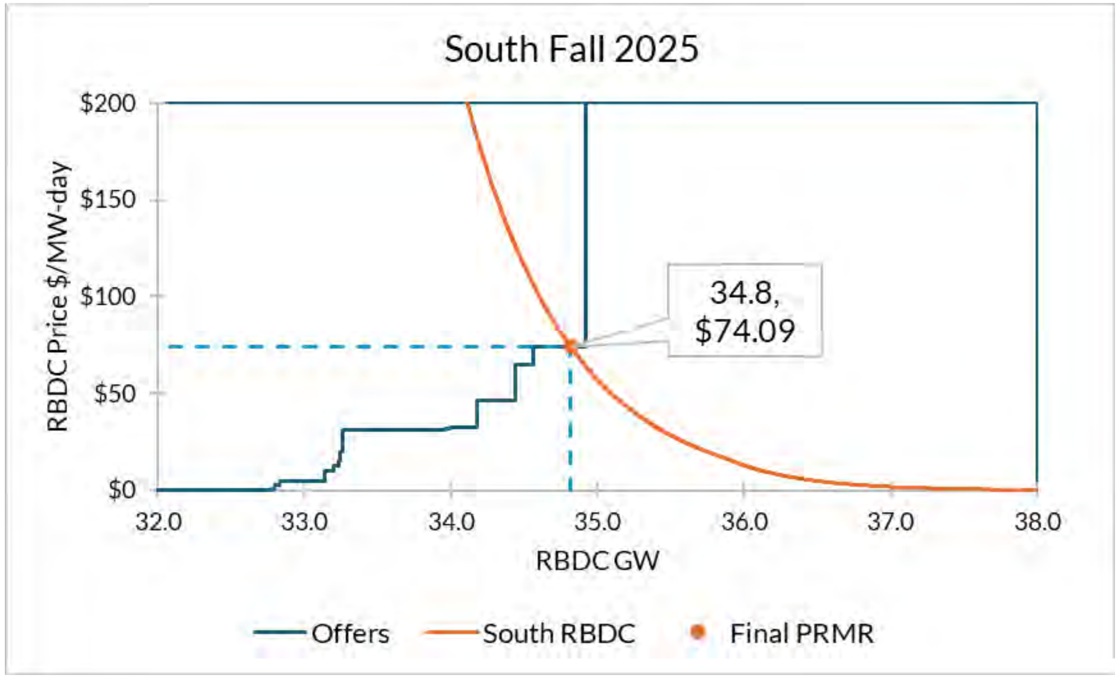
For the South, new capacity additions nearly offset the negative impacts of decreased accreditation, suspensions/retirements



BTMG: Behind the Meter Generation | Capacity indicated is offered accredited value

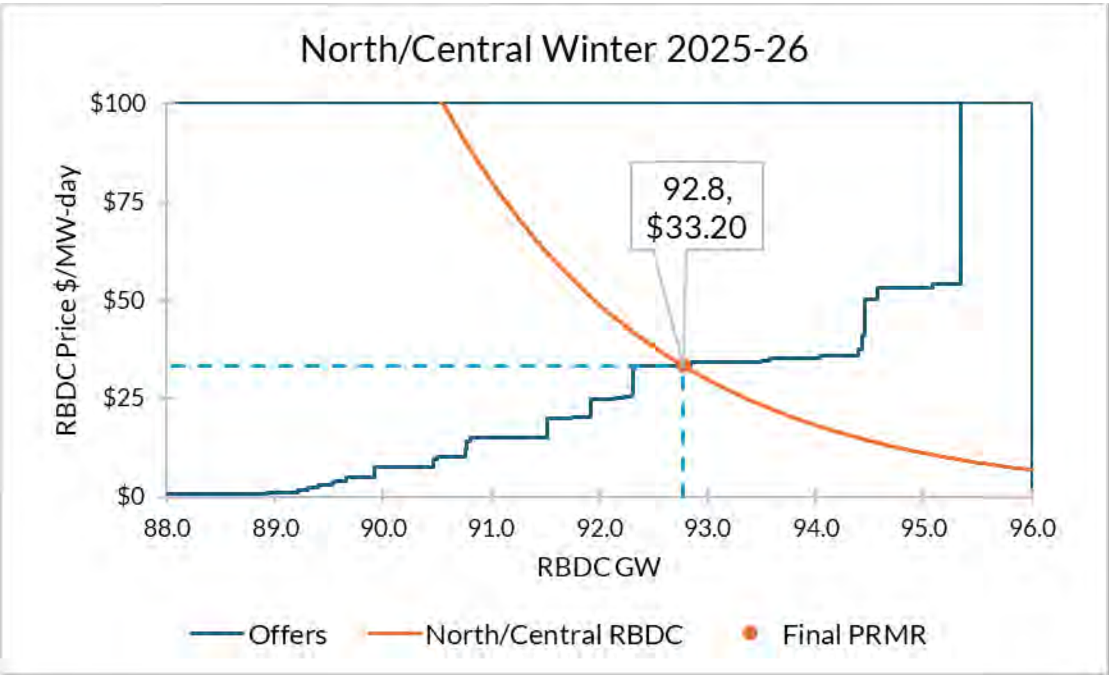
Fall 2025 Reliability-Based Demand Curve, Offer Curves and Auction Clearing Prices

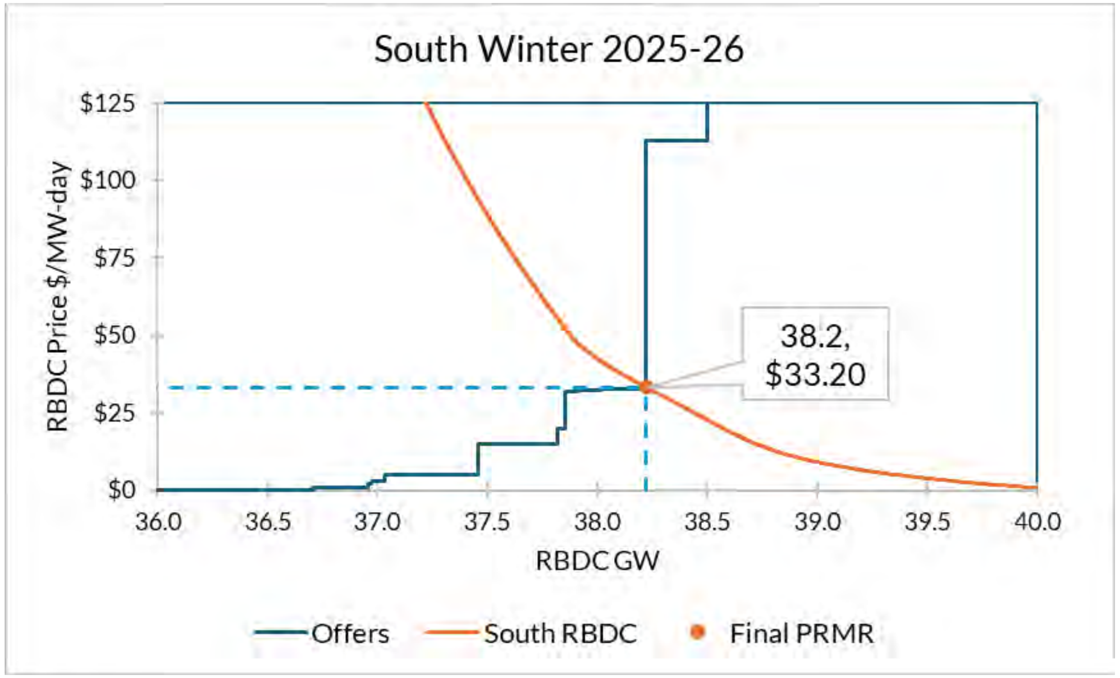




- Subregional RBDCs are determining clearing for both subregions
- Subregional Power Balance Constraint (SRPBC), South to North, is binding resulting in price separation between North/Central and South subregions in Fall season
    - ACP for North subregion is $91.60, and $74.09 South subregion
    - A marginal resource in the South sets the price in that subregion
- In fall season, “effective” margin for North/Central subregion is at 18.4% and 15.2 % for South subregion vs. target of 14.9%

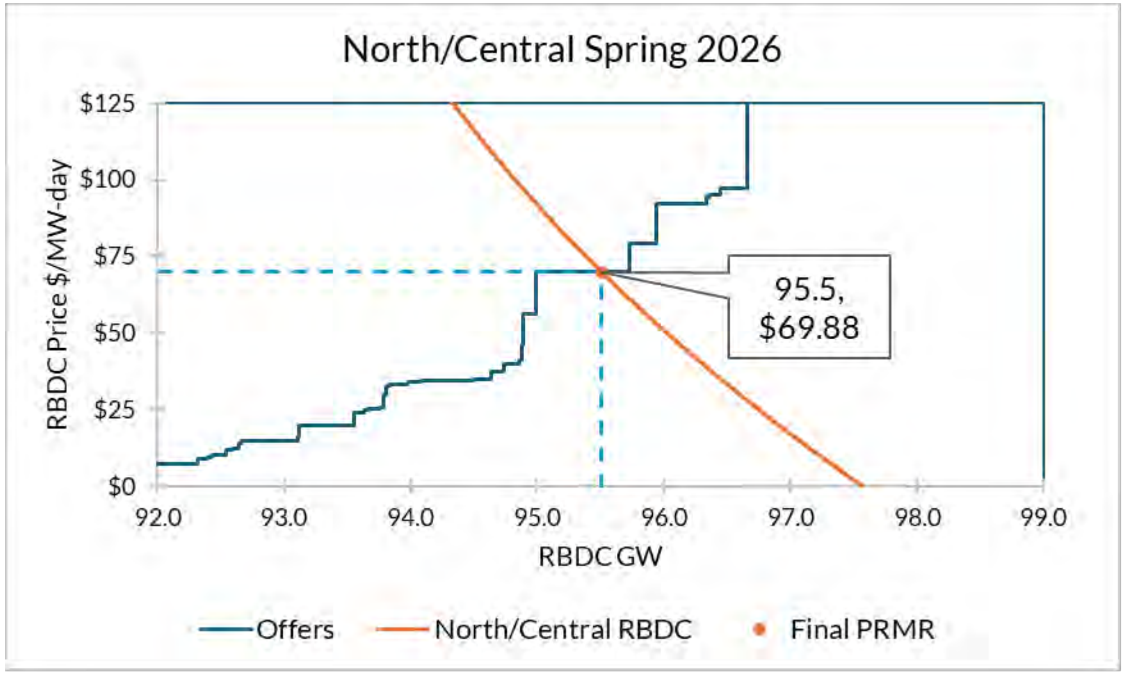
Winter 2025/26 Reliability-Based Demand Curve, Offer Curves and Auction Clearing Prices

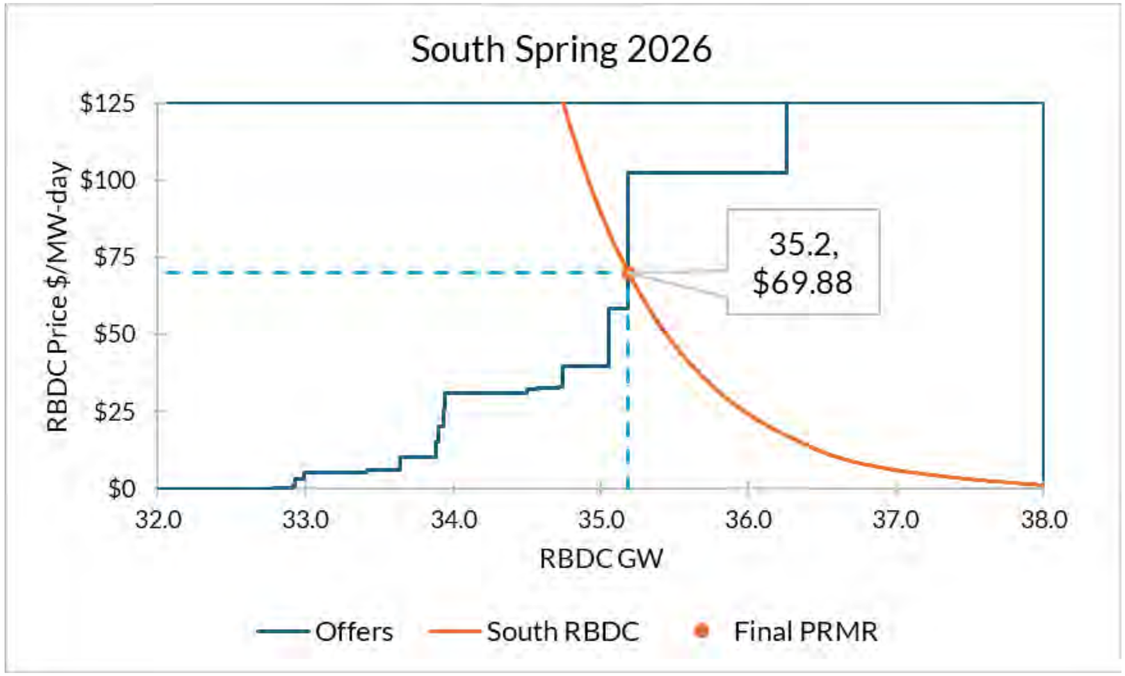




- Subregional RBDCs are determining clearing for both subregions
- No price separation between North/Central and South subregions in winter
  - ACP for both subregions is $33.20
  - Multiple marginal resources, cleared *pro rata*, sets the price
- In winter, "effective" margin for North/Central subregion is at 23.3% and $27.3% for South subregion vs. target of 18.4%

Spring 2026 Reliability-Based Demand Curve, Offer Curves and Auction Clearing





- Subregional RBDCs are determining clearing for both subregions
- No price separation between North/Central and South subregions in spring
    - ACP for both subregions is $69.88
    - A marginal resource sets the price
- In spring, "effective" margin for North/Central subregion is at 27.5% and 25% for South subregion vs. target of 25.3%

Summer 2025 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	North	South	System
Initial PRMR	18,459.4	13,190.2	10,889.2	9,237.6	8,281.3	18,484.8	21,228.0	8,487.8	21,812.2	5,142.9	N/A	99,770.5	35,442.9	135,213.4
Final PRMR	18,843.5	13,464.4	11,116.0	9,430.10	8,453.5	18,868.9	21,669.2	8,552.6	21,978.8	5,182.3	N/A	101,845.6	35,713.7	137,559.3
Offer Submitted (Including FRAP)	19,732.4	14,569.7	11,321.4	9,328.1	6,737.9	16,123.6	20,883.9	11,517.3	20,498.6	5,543.3	1580.1	99,952.6	37,883.7	137,836.3
FRAP	4,619.2	10,252.6	456.9	789.4	0.0	1,080.7	541.3	494.9	157.5	1,507.7	46.8	17,779.2	2,167.8	19,947.0
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Self Scheduled (SS)	4,985.3	3,344.1	10,450.2	7,677.2	6,647.8	11,080.3	20,305.5	10,260.6	17,870.6	3,831.3	1,358.8	65,567.6	32,244,1	97,811.7
Non-SS Offer Cleared	10,127.9	973.0	414.3	861.5	90.1	3,962.6	37.1	761.8	2,193.5	204.3	174.5	16,605.8	3,194.8	19,800.6
Committed (Offer Cleared + FRAP)	19,732.4	14,569.7	11,321.4	9,328.1	6,737.9	16,123.6	20,883.9	11,517.3	20,221.6	5,543.3	1,580.1	99,952.6	37,606.7	137,559.3
LCR	15,696.9	9,719.3	8,049.3	2,577.8	6,071.1	13,051.7	19,681.4	8,487.0	19,615.0	2,523.8	-	N/A	N/A	N/A
CIL	6,025	4,370	5,555	8,525	4,117	8,651	3,569	2,568	4,361	4,474	-	N/A	N/A	N/A
ZIA	6,023	4,370	5,460	7,757	4,117	8,366	3,569	2,358	4,361	4,474	-	N/A	N/A	N/A
Import	0.0	0.0	0.0	101.7	1,715.5	2,745.5	785.5	0.0	1,757.1	0.0	-	1,893.0	0.0	1,580.1
CEL	3,991	4,614	4,618	4,584	3,939	6,881	5,726	6,299	4,286	2,097	-	N/A	N/A	N/A
Export	888.8	1105.2	205.5	0.0	0.0	0.0	0.0	2964.7	0.0	360.9	1,580.1	0.0	1,893.0	-
ACP ($/MW-Day)	666.50	666.50	666.50	666.50	666.50	666.50	666.50	666.50	666.50	666.50	666.50			N/A

Values displayed in MW SAC; ERZ: External Resource Zones | Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.

Fall 2025 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	North	South	System
Initial PRMR	17,290.4	12,086.4	10,179.1	8,950.4	7,898.3	17,939.5	20,493.9	8,019.3	21,578.1	5,142.6	N/A	94,838.0	34,740.0	129,578.0
Final PRMR	17,811.9	12,450.7	10,486.0	9,220.4	8,136.0	18,480.2	21,111.9	8,037.4	21,627.1	5,154.2	N/A	97,697.1	34,818.7	132,515.8
Offer Submitted (Including FRAP)	18,893.1	14,291.7	13,615.9	8,887.5	6,839.6	15,518.1	19,517.6	11,000.8	21,112.5	5,516.6	1,582.1	98,835.3	37,940.2	136,775.5
FRAP	4,233.2	9,259.1	582.7	773.3	0.0	983.1	533.1	459.4	153.4	1,518.3	44.6	16,402.6	2,137.6	18,540.2
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Self Scheduled (SS)	4,646.8	3,423.5	10,580.4	7,036.0	6,706.5	10,590.4	16,911.4	9,029.4	17,788.1	3,286.3	1,208.0	60,831.1	30,375.7	91,206.8
Non-SS Offer Cleared	9,019.0	834.8	2,452.8	1,078.2	133.1	3,728.7	1,089.1	1,512.0	2,406.6	254.9	259.6	18,563.3	4,205.5	22,768.8
Committed (Offer Cleared + FRAP)	17,899.0	13,517.4	13,615.9	8,887.5	6,839.6	15,302.2	18,533.6	11,000.8	20,348.1	5,059.5	1,512.2	95,797.1	36,718.7	132,515.8
LCR	14,691.0	6,591.1	6,331.4	2,588.7	4,857.2	11,725.4	18,196.1	5,006.3	18,963.6	2,577.6	-	N/A	N/A	N/A
CIL	5,740	6,537	7,797	7,773	4,679	8,952	5,115	5,839	4,741	4,508	-	N/A	N/A	N/A
ZIA	5,688	6,537	7,704	7,013	4,679	8,672	5,115	5,675	4,741	4,508	-	N/A	N/A	N/A
Import	0.0	0.0	0.0	332.8	1,296.8	3,178.0	2,578.2	0.0	1,278.9	94.7	-	1,900.0	0.0	1,512.2
CEL	6,115	4,259	5,831	4,309	5,816	5,191	5,168	4,055	4,173	3,164	-	N/A	N/A	N/A
Export	87.2	1,066.8	3,129.9	0.0	0.0	0.0	0.0	2,963.3	0.0	0.0	1,512.2	0.0	1,900.0	-
ACP ($/MW-Day)	91.60	91.60	91.60	91.60	91.60	91.60	91.60	74.09	74.09	74.10	83.24-91.60			N/A

Values displayed in MW SAC; ERZ: External Resource Zones | Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.

Winter 2025/26 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	North	South	System
Initial PRMR	17,823.8	10,789.8	9,889.1	8,549.5	7,954.8	17,939.1	16,123.6	8,545.6	21,864.3	5,136.1	N/A	89,069.7	35,546.0	124,615.7
Final PRMR	18,565.8	11,238.7	10,300.9	8,905.1	8,285.9	18,685.7	16,794.7	9,189.0	23,511.0	5,522.7	N/A	92,776.8	38,222.7	130,999.5
Offer Submitted (Including FRAP)	19,750.7	13,217.2	12,059.1	7,547.1	6,339.9	14,679.5	19,957.3	10,751.9	22,273.0	5,939.7	1,746.5	94,964.8	39,297.1	134,261.9
FRAP	4,683.9	8,342.7	479.4	513.4	0.0	1,176.6	566.3	441.6	130.9	1,822.6	16.1	15,771.2	2,402.3	18,173.5
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Self Scheduled (SS)	5,835.8	3,156.0	10,468.3	6,685.7	6,188.7	9,146.2	18,640.6	10,018.6	18,579.3	4,046.0	1,550.8	61,380.9	32,935.1	94,316.0
Non-SS Offer Cleared	7,977.9	1,062.6	1,044.5	271.5	99.9	4,008.7	397.0	291.7	3,105.5	71.1	179.6	15,007.6	3,502.4	18,510.0
Committed (Offer Cleared + FRAP)	18,497.6	12,561.3	11,992.2	7,470.6	6,288.6	14,331.5	19,603.9	10,751.9	21,815.7	5,939.7	1,746.5	92,159.7	38,839.8	130,999.5
LCR	13,462.0	5,951.6	8,008.4	1,371.4	3,644.7	11,074.8	15,500.2	8,014.7	20,593.7	3,534.1	-	N/A	N/A	N/A
CIL	6,177	6,522	5,877	7,232	4,922	7,927	4,762	3,613	4,418	3,458	-	N/A	N/A	N/A
ZIA	5,575	6,435	5,785	6,457	4,922	7,690	4,762	3,432	4,418	3,458	-	N/A	N/A	N/A
Import	68.0	0.0	0.0	1,434.8	1,997.3	4,354.1	0.0	0.0	1,695.2	0.0	-	617.1	0.0	1,746.5
CEL	2,991	4,706	7,388	4,756	4,814	1,674	5,712	3,602	3,618	2,028	-	N/A	N/A	N/A
Export	0.0	1,322.6	1,691.5	0.0	0.0	0.0	2,809.2	1,562.8	0.0	416.9	1,746.5	0.0	617.1	0.0
ACP ($/MW-Day)	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20			N/A

Values displayed in MW SAC; ERZ: External Resource Zones | Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.

Spring 2026 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	North	South	System
Initial PRMR	17,866.7	12,149.2	10,152.2	8,304.0	7,707.9	17,858.6	19,853.2	7,977.8	22,139.8	5,167.9	N/A	93,891.8	35,285.5	129,177.3
Final PRMR	18,174.5	12,358.6	10,327.0	8,447.2	7,841.0	18,166.7	20,195.5	7,955.2	22,076.1	5,157.7	N/A	95,510.5	35,189.0	130,699.5
Offer Submitted (Including FRAP)	18,662.6	14,525.3	12,333.3	9,178.5	6,118.7	15,824.7	19,451.0	11,495.2	21,064.7	5,864.0	1,542.6	97,313.7	38,746.9	136,060.6
FRAP	4,560.6	9,393.4	529.5	629.6	0.0	1,212.4	512.5	475.3	142.1	1,464.3	45.9	16,877.1	2,088.5	18,965.6
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Self Scheduled (SS)	4,600.8	3,602.8	10,816.2	7,415.0	5,968.5	9,967.6	17,621.9	8,476.0	16,778.9	4,073.9	1,260.8	60,972.6	29,609.8	90,582.4
Non-SS Offer Cleared	8,578.5	1,069.5	589.6	1,133.9	150.2	4,001.0	719.2	1,470.2	2,947.5	325.8	166.1	16,372.9	4,778.6	21,151.5
Committed (Offer Cleared + FRAP)	17,739.9	14,065.7	11,935.3	9,178.5	6,118.7	15,181.0	18,853.6	10,421.5	19,868.5	5,864.0	1,472.8	94,222.5	36,477.0	130,699.5
LCR	12,239.1	6,737.5	5,014.7	1,823.8	4,700.3	10,377.1	16,453.6	4,243.1	19,790.5	3,178.8	-	N/A	N/A	N/A
CIL	6,598	6,439	7,829	8,142	4,453	9,457	5,166	6,289	4,855	4,365	-	N/A	N/A	N/A
ZIA	6,396	6,439	7,726	7,373	4,453	9,176	5,166	6,085	4,855	4,365	-	N/A	N/A	N/A
Import	434.5	0.0	0.0	0.0	1,722.2	2,985.6	1,341.9	0.0	2,210.8	0.0	-	1,288.0	0.0	1,472.8
CEL	5,083	6,119	5,936	5,111	5,797	6,425	5,499	3,520	4,146	3,072	-	N/A	N/A	N/A
Export	0.0	1,707.2	1,608.0	731.2	0.0	0.0	0.0	2,465.6	0.0	710.3	1,472.8	0.0	1,288.0	-
ACP ($/MW-Day)	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88			N/A

Values displayed in MW SAC; ERZ: External Resource Zones | Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.

Summer Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	Summer 2023	Summer 2024	Summer 2025	Summer 2023	Summer 2024	Summer 2025
Generation	122,375.6	123,395.6	121,015.6	116,989.7	119,479.2	120,738.6
External Resources	4,514.6	4,430.4	3,505.9	4,072.5	4,309.8	3,505.9
Behind the Meter Generation	4,175.2	4,180.2	4,282.8	4,129.4	4,143.5	4,282.8
Demand Resources	8,303.5	8,660.2	9,004.4	7,694.6	8,109.4	9,004.4
Energy Efficiency	5.0	22.5	27.6	5.0	22.5	27.6
Total	**139,373.9**	**140,688.9**	**137,836.3**	**132,891.2**	**136,064.4**	**137,559.3**

ZRC: Zonal Resource Credit

Fall Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	**Fall 2023**	**Fall 2024**	**Fall 2025**	**Fall 2023**	**Fall 2024**	**Fall 2025**
Generation	121,403.5	119,745.3	122,283.4	111,713.8	111,791.5	118,309.5
External Resources	4,095.4	4,366.8	2,833.5	3,979.6	3,990.2	2,763.6
Behind the Meter Generation	3,874.2	3,877.9	3,646.8	3,842.8	3,789.7	3,646.8
Demand Resources	6,999.2	6,866.1	7,983.7	6,254.4	5,957.5	7,767.8
Energy Efficiency	4.9	22.5	28.1	4.8	22.5	28.1
Total	**136,377.2**	**134,878.6**	**136,775.5**	**125,795.4**	**125,551.4**	**132,515.8**

ZRC: Zonal Resource Credit

Winter Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	**Winter 2023-2024**	**Winter 2024-2025**	**Winter 2025-2026**	**Winter 2023-2024**	**Winter 2024-2025**	**Winter 2025-2026**
Generation	124,632.7	133,457.4	120,225.1	114,886.6	118,253.8	117,392.0
External Resources	3,937.1	3,973.0	2,808.7	3,334.6	3,313.3	2,793.7
Behind the Meter Generation	3,257.8	3,111.5	3,082.9	3,173.9	2,957.3	3,082.6
Demand Resources	7,644.4	7,866.4	8,112.3	6,702.4	6,822.7	7,698.3
Energy Efficiency	6.7	29.7	32.9	6.7	29.7	32.9
Total	**139,478.7**	**148,438.0**	**134,261.9**	**128,104.2**	**131,376.8**	**130,999.5**

ZRC: Zonal Resource Credit

Spring Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	**Spring 2024**	**Spring 2025**	**Spring 2026**	**Spring 2024**	**Spring 2025**	**Spring 2026**
Generation	119,254.7	121,303.8	120,780.6	110,195.8	113,091.4	115,724.7
External Resources	3,794.1	3,481.8	2,640.1	3,409.1	3,406.5	2,570.3
Behind the Meter Generation	4,096.4	4,201.6	4,133.5	4,058.9	4,180.5	4,133.5
Demand Resources	7,282.9	7602.9	8,475.9	6,720.0	7,087.2	8,240.5
Energy Efficiency	5.3	25.0	30.5	5.3	25.0	30.5
Total	**134,433.4**	**136,615.1**	**136,060.6**	**124,389.1**	**127,790.6**	**130,699.5**

ZRC: Zonal Resource Credit

2025 PRA pricing compared with Independent Market Monitor (IMM) Conduct Threshold and Cost of New Entry (CONE)

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs	System CONE (Seasonal)	North/Central CONE (Seasonal)	South CONE (Seasonal)
Summer 2025	$666.50											$1,353.84	$1,384.36	$1,282.61
Fall 2025	$91.60							$74.09			$83.24-$91.60	$1,368.71	$1,399.58	$1,296.70
Winter 2025-26	$33.20											$1,383.92	$1,415.13	$1,311.11
Spring 2026	$69.88											$1,353.84	$1,384.36	$1,282.61
Cost of New Entry (Annual)	$127,720	$125,090	$121,220	$126,040	$136,170	$124,360	$130,930	$118,960	$117,710	$117,330	$136,170			
IMM Conduct Threshold*	$34.99	$34.27	$33.21	$34.53	$37.31	$34.07	$35.87	$32.59	$32.25	$32.15	-			

- *Zonal Auction Clearing Prices (ACP) shown in $/MW-day*

**Zonal Resource Credit (ZRC) offers that impact pricing should generally stay below the IMM Conduct Threshold and applies to all seasons.*

ERZ: External Resource Zones

Historical Summer Auction Clearing Price Comparison

<table>
<tr><th>PY</th><th>Zone 1</th><th>Zone 2</th><th>Zone 3</th><th>Zone 4</th><th>Zone 5</th><th>Zone 6</th><th>Zone 7</th><th>Zone 8</th><th>Zone 9</th><th>Zone 10</th><th>ERZs</th></tr>
<tr><td>2015-2016</td><td colspan="3">$3.48</td><td>$150.00</td><td colspan="3">$3.48</td><td colspan="2">$3.29</td><td>N/A</td><td>N/A</td></tr>
<tr><td>2016-2017</td><td>$19.72</td><td colspan="6">$72.00</td><td colspan="3">$2.99</td><td>N/A</td></tr>
<tr><td>2017-2018</td><td colspan="10">$1.50</td><td>N/A</td></tr>
<tr><td>2018-2019</td><td>$1.00</td><td colspan="9">$10.00</td><td>N/A</td></tr>
<tr><td>2019-2020</td><td colspan="6">$2.99</td><td>$24.30</td><td colspan="4">$2.99</td></tr>
<tr><td>2020-2021</td><td colspan="6">$5.00</td><td>$257.53</td><td>$4.75</td><td>$6.88</td><td>$4.75</td><td>$4.89-$5.00</td></tr>
<tr><td>2021-2022</td><td colspan="7">$5.00</td><td colspan="3">$0.01</td><td>$2.78-$5.00</td></tr>
<tr><td>2022-2023</td><td colspan="7">$236.66</td><td colspan="3">$2.88</td><td>$2.88-236.66</td></tr>
<tr><td>Summer 2023</td><td colspan="11">$10.00</td></tr>
<tr><td>Summer 2024</td><td colspan="11">$30.00</td></tr>
<tr><td>Summer 2025</td><td colspan="11">$666.50</td></tr>
</table>

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Fall Auction Clearing Price Comparison

<table>
<tr><th>PY</th><th>Zone 1</th><th>Zone 2</th><th>Zone 3</th><th>Zone 4</th><th>Zone 5</th><th>Zone 6</th><th>Zone 7</th><th>Zone 8</th><th>Zone 9</th><th>Zone 10</th><th>ERZs</th></tr>
<tr><td>Fall 2023</td><td colspan="8">$15.00</td><td>$59.21</td><td colspan="2">$15.00</td></tr>
<tr><td>Fall 2024</td><td colspan="4">$15.00</td><td>$719.81</td><td colspan="6">$15.00</td></tr>
<tr><td>Fall 2025</td><td colspan="7">$91.60</td><td colspan="3">$74.09</td><td>$83.24-$91.60</td></tr>
</table>

- Auction Clearing Prices shown in $/MW-Day
- Price separation present in Fall 2025 between the North and South subregions since the Sub-Regional Import Constraint (SRIC) / Sub-Regional Export Constraint (SREC) bound

ERZ: External Resource Zones

Winter Auction Clearing Price Comparison

<table>
<tr><th>PY</th><th>Zone 1</th><th>Zone 2</th><th>Zone 3</th><th>Zone 4</th><th>Zone 5</th><th>Zone 6</th><th>Zone 7</th><th>Zone 8</th><th>Zone 9</th><th>Zone 10</th><th>ERZs</th></tr>
<tr><td>Winter 2023-24</td><td colspan="8">$2.00</td><td>$18.88</td><td colspan="2">$2.00</td></tr>
<tr><td>Winter 2024-25</td><td colspan="11">$0.75</td></tr>
<tr><td>Winter 2025-26</td><td colspan="11">$33.20</td></tr>
</table>

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Spring Auction Clearing Price Comparison

<table>
<tr><th>PY</th><th>Zone 1</th><th>Zone 2</th><th>Zone 3</th><th>Zone 4</th><th>Zone 5</th><th>Zone 6</th><th>Zone 7</th><th>Zone 8</th><th>Zone 9</th><th>Zone 10</th><th>ERZs</th></tr>
<tr><td>Spring 2024</td><td colspan="11">$10.00</td></tr>
<tr><td>Spring 2025</td><td colspan="4">$34.10</td><td>$719.81</td><td colspan="6">$34.10</td></tr>
<tr><td>Spring 2026</td><td colspan="11">$69.88</td></tr>
</table>

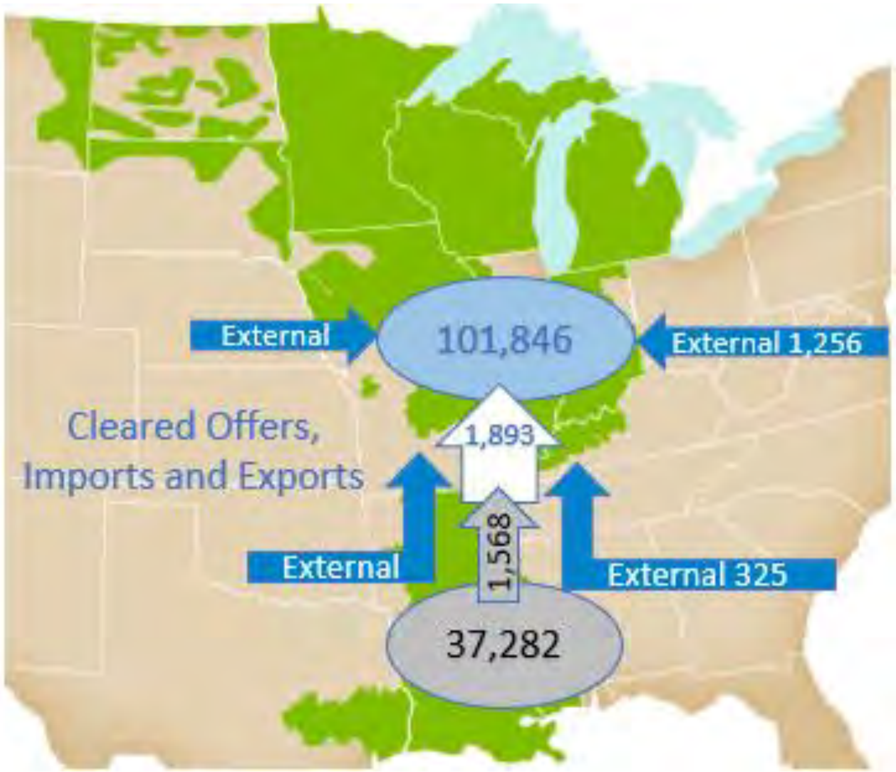
- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Summer 2025 Capacity

Offered Capacity & Final PRMR (MW)

Cleared Capacity, Imports & Exports (MW)



PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers

Fall 2025 Capacity

Offered Capacity & Final PRMR (MW)

Cleared Capacity, Imports & Exports (MW)

PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers

Winter 2025/26 Capacity

Offered Capacity & Final PRMR (MW)

Cleared Capacity, Imports & Exports (MW)

PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Spring 2026 Capacity

Offered Capacity & Final PRMR (MW)

Cleared Capacity, Imports & Exports (MW)

PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

The 2025 auction resulted in a surplus compared to the PRMR target, in contrast to the 2024 OMS-MISO Survey projection of a shortfall

Summer 2025 auction outcomes vs. 2024 OMS-MISO Survey projection for 2025

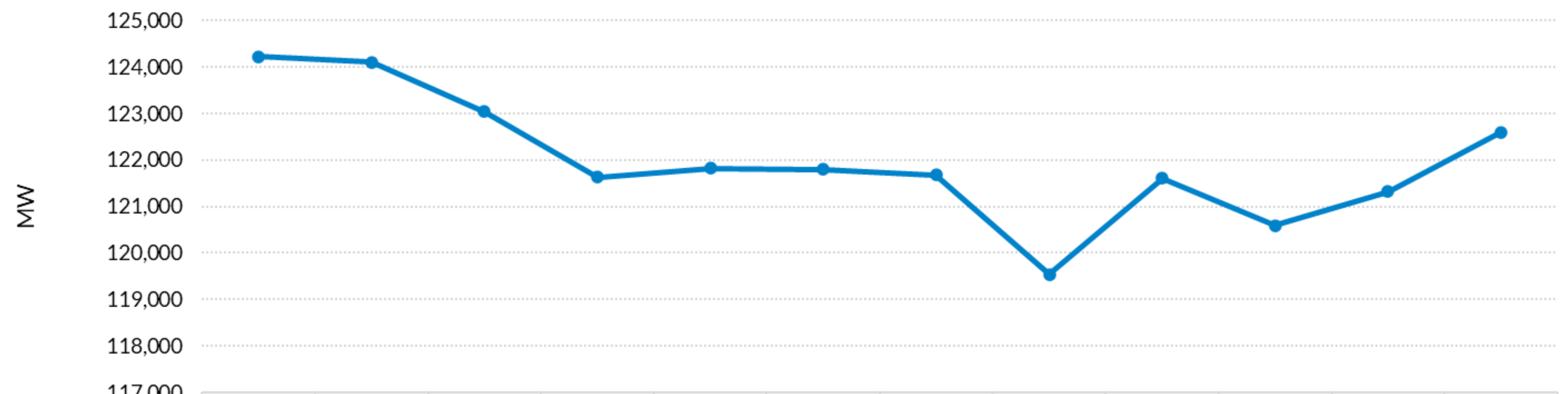
- Resource offers in the auction were comparable to "High Certainty" values projected in the OMS-MISO Survey
- Incremental accreditation reductions in the auction were offset by incremental increases in new resource additions
- Notably, initial PRMR was lower (5.5 GW) than projected in the OMS-MISO Survey

2024 OMS-MISO Survey Projection vs. 2025 PRA Actual PRMR Surplus (MW)

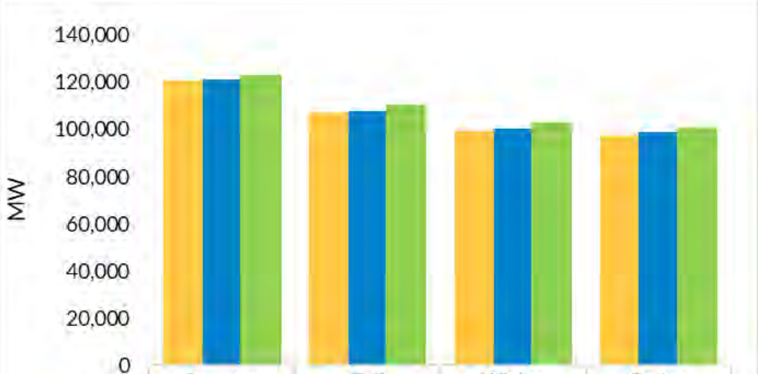
PRA Shortfall/Surplus relative to Initial PRMR | PRMR: Planning Reserve Margin Requirement

Coincident Peak Forecast

Year over year the Summer CPF (+1.3 GW), PRM (-1.1%) and Final PRMR (+1.5 GW) are higher.



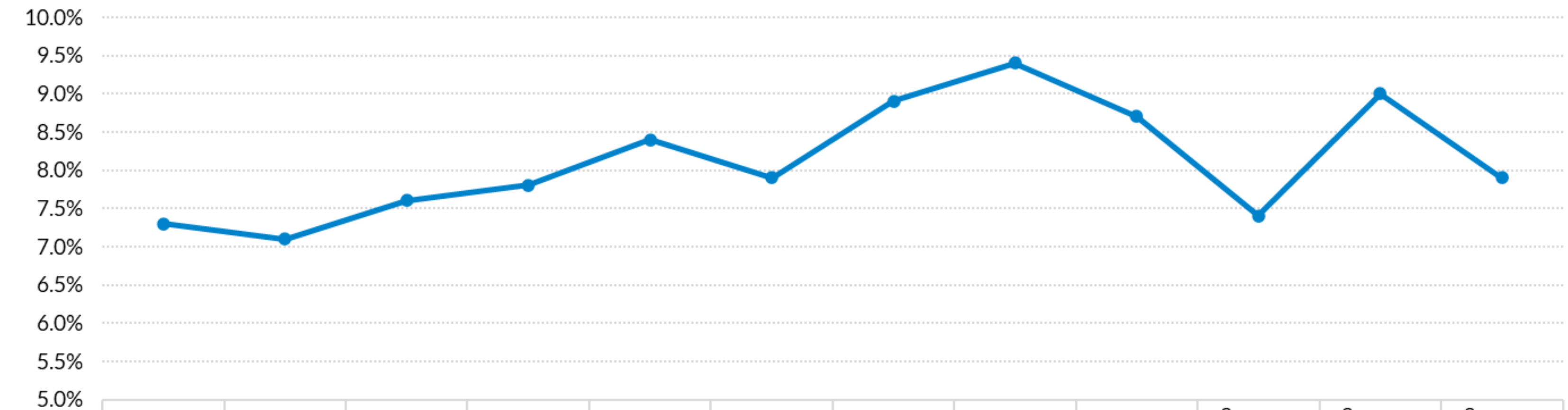
	2014	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023	Summer 2024	Summer 2025
Summer CPF	124,212.2	124,097.3	123,035.8	121,631.2	121,815.6	121,791.4	121,679.8	119,532.0	121,608.5	120,586.8	121,314.1	122,596.6



	Summer	Fall	Winter	Spring
2023-24	120,586.8	106,973.8	99,188.0	97,537.6
2024-25	121,314.1	107,701.4	100,114.6	98,697.8
2025-26	122,596.6	109,850.0	102,624.0	100,225.2

PRMR: Planning Reserve Margin Requirement

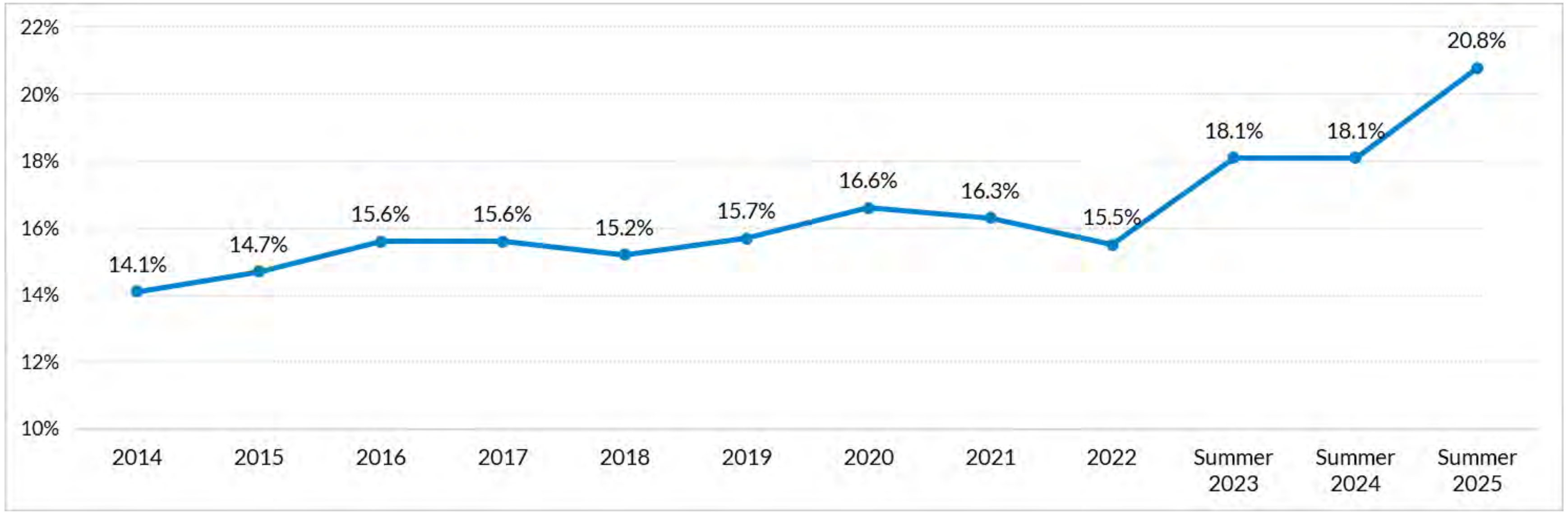
Planning Reserve Margin (%)



	2014	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023	Summer 2024	Summer 2025
PRM	7.3%	7.1%	7.6%	7.8%	8.4%	7.9%	8.9%	9.4%	8.7%	7.4%	9.0%	7.9%

	Summer	Fall	Winter	Spring
2023-24	7.4%	14.9%	25.5%	24.5%
2024-25	9.0%	14.2%	27.4%	26.7%
2025-26	7.9%	14.9%	18.4%	25.3%

Wind Effective Load Carrying Capacity (%)

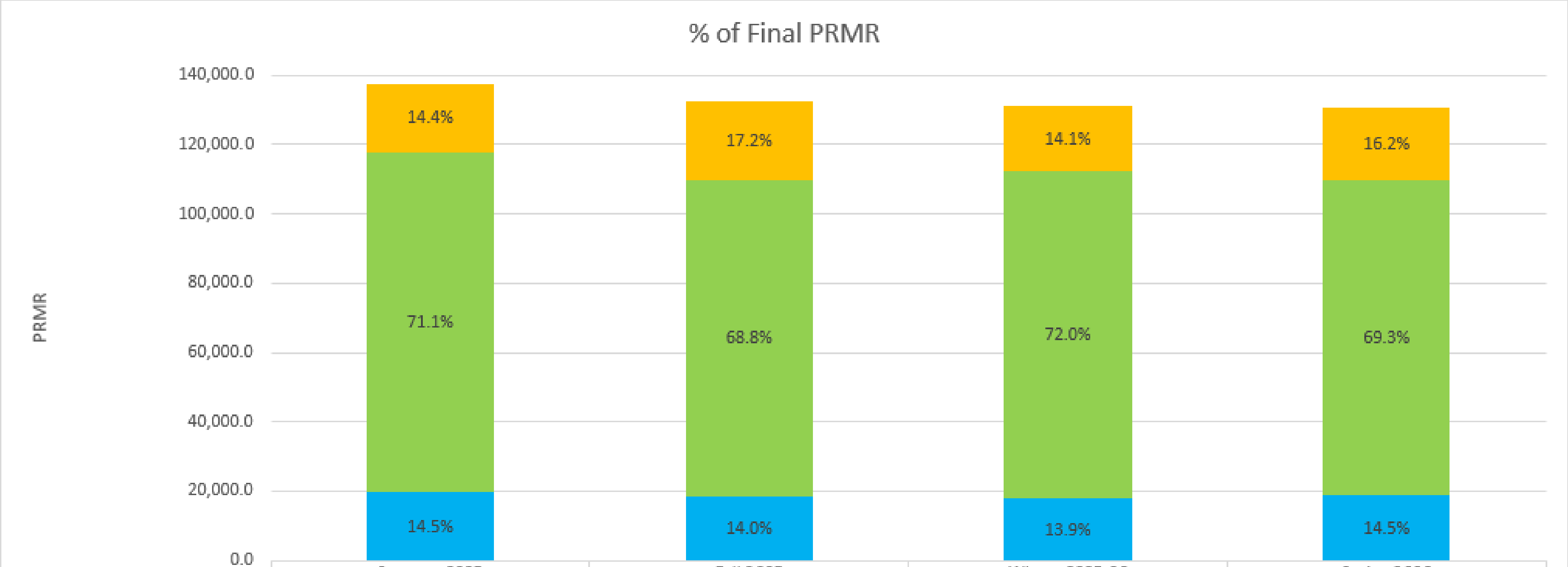


	Summer	Fall	Winter	Spring
2023-24	18.1%	23.1%	40.3%	23.0%
2024-25	18.1%	15.6%	53.1%	18.0%
2025-26	20.8%	30.7%	29.0%	25.3%

- No change to wind or solar accreditation methodology from previous years.
- Methodology applied on a seasonal basis.
- Wind ELCC and new solar capacity is established in the LOLE Study
- New solar class average
  - Summer, fall, spring 50%
  - Winter 5%

ELCC: Effective Load Carrying Capability LOLE: Loss of Load Expectation

2025/26 Seasonal Resource Adequacy Requirements are fulfilled similarly across all four seasons

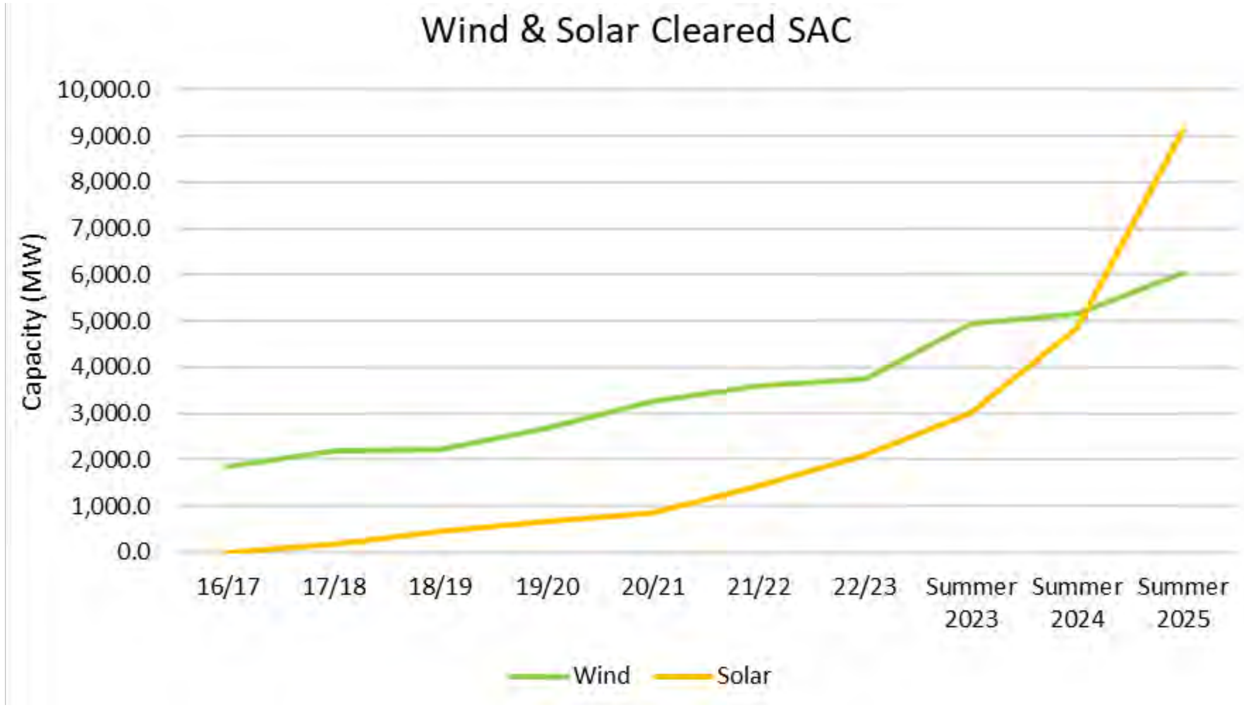


	Summer 2025	Fall 2025	Winter 2025-26	Spring 2026
Cleared Non-Self Scheduled	19,800.6	22,768.8	18,510.0	21,151.5
Self Scheduled	97,811.7	91,206.8	94,316.0	90,582.4
FRAP	19,947.0	18,540.2	18,173.5	18,965.6

PRMR: Planning Reserve Margin Requirement

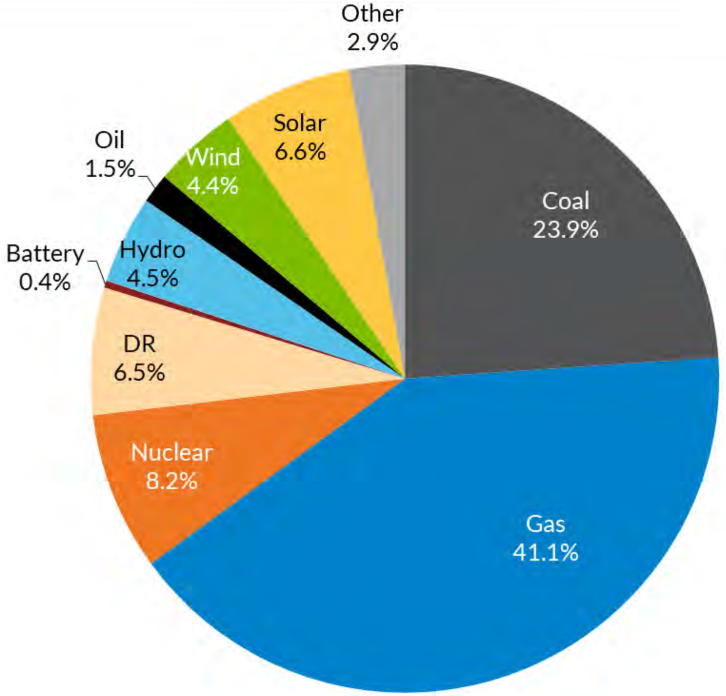
Although conventional generation still comprises most of the capacity, wind and solar continue to grow

- 9.1 GW of solar cleared this year's auction, an increase of 88% from Planning Year 2024/25 (4.9 GW)
- 6 GW of wind cleared this year, an increase of 17% compared to last year (5.2 GW)



Winter final PRMR is 6.6 GW (4.8%) lower than the summer with fewer solar resources to meet final PRMR in the winter versus the summer

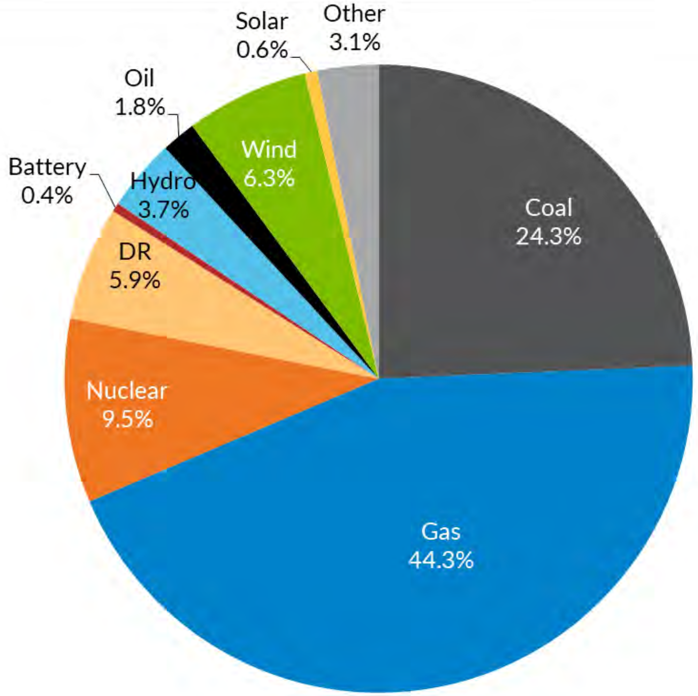
Summer 2025



MISO-wide

Cleared ZRC	Summer 2025	Winter 2025/26	Difference
Coal	32,909.6	31,887.2	1,022.4
Gas	56,470.0	57,990.5	-1,520.5
Nuclear	11,232.1	12,416.7	-1,184.6
DR	9,004.4	7,698.3	1,306.1
Battery	499.2	588.5	-89.3
EE	27.6	32.9	-5.3
Hydro	6,231.3	4,823.7	1,407.6
Oil	2,088.8	2,315.7	-226.9
Wind	6,039.1	8,282.9	-2,243.8
Solar	9,122.8	847.3	8,275.5
Misc	3,934.4	4,115.8	-181.4
PRMR	137,559.3	130,999.5	6,559.8

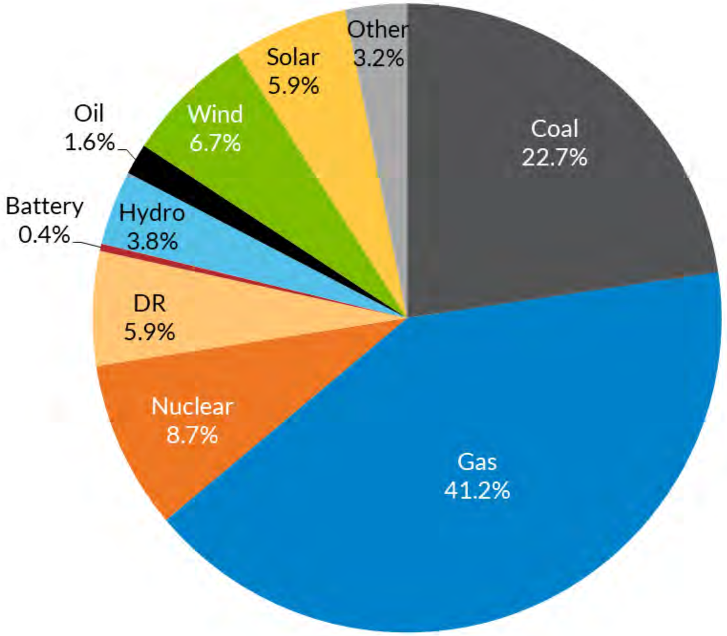
Winter 2025/26



PRMR: Planning Reserve Margin Requirement

Fall 2025 and Spring 2026 - Cleared ZRCs and Final PRMR

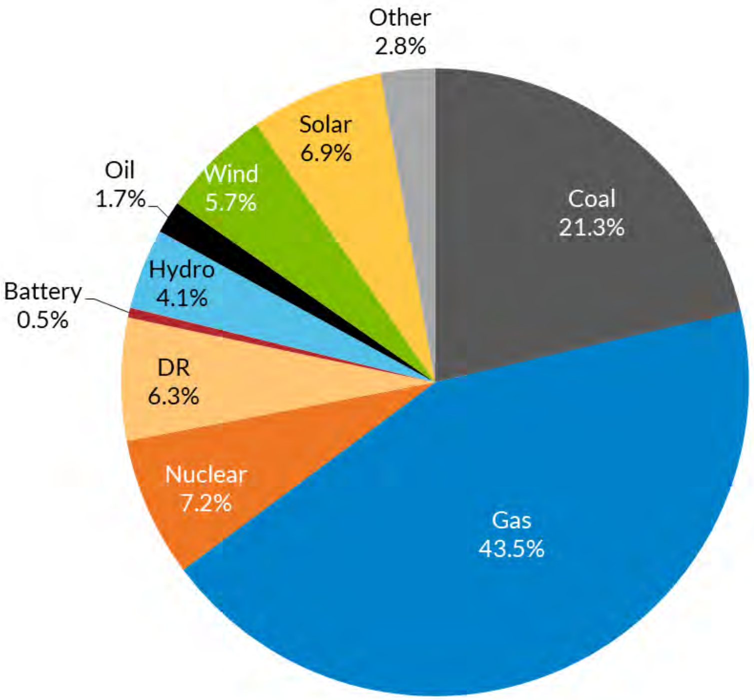
Fall 2025



MISO-Wide

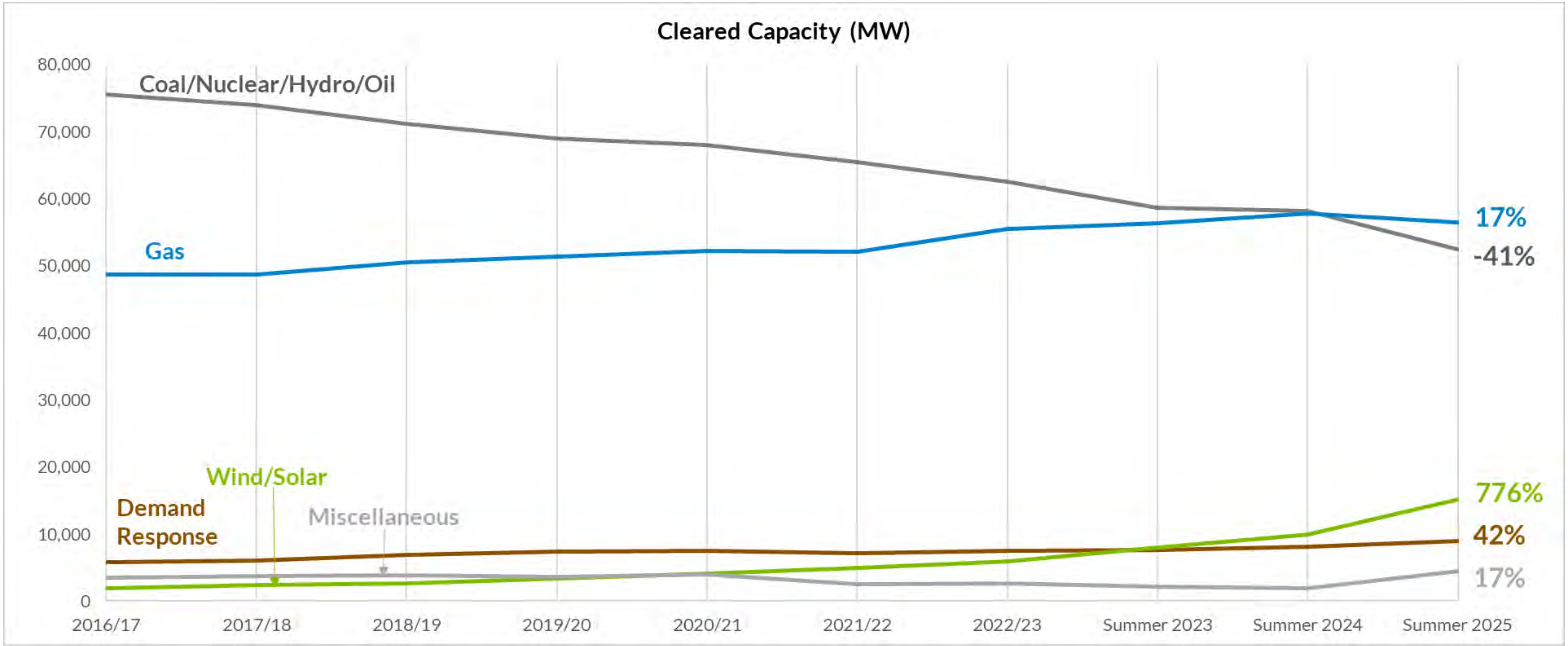
Cleared ZRC	Fall 2025	Spring 2026
Coal	30,038.9	27,886.8
Gas	54,636.4	56,820.7
Nuclear	11,482.1	9,405.4
DR	7,767.8	8,240.5
Battery	497.9	663.3
EE	28.1	30.5
Hydro	5,047.4	5,415.8
Oil	2,123.8	2,190.4
Wind	8,864.8	7,438.0
Solar	7,843.8	8,975.1
Misc	4,184.8	3,633.0
PRMR	132,515.8	130,699.5

Spring 2026

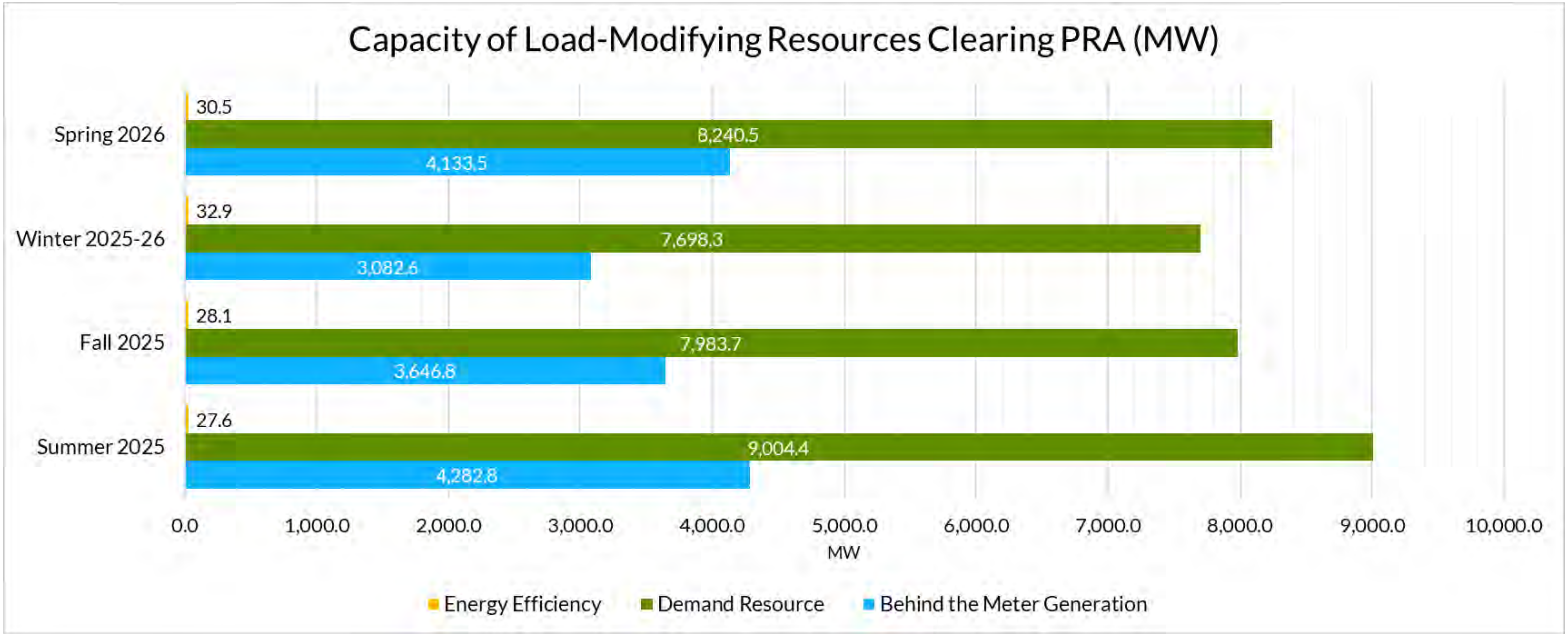


PRMR: Planning Reserve Margin Requirement

The planning resource mix shows the continuation of a multi-year trend towards less coal/nuclear/hydro/oil and increased gas and non-conventional resources



2025/26 Seasonally Cleared Load Modifying Resources Comparison



Visit MISO's Help Center
for more information
https://help.misoenergy.org/

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-26-22

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

Exhibit 32

MISO Emergency Declarations

Maximum Generation Emergency Declarations
through June 2024
(Updated 08/30/2024)

Contents

No Maximum Generation Emergency Declarations issued in 2015

Maximum Generation Emergency Declarations

through June 2024

(Updated 08/30/2024)

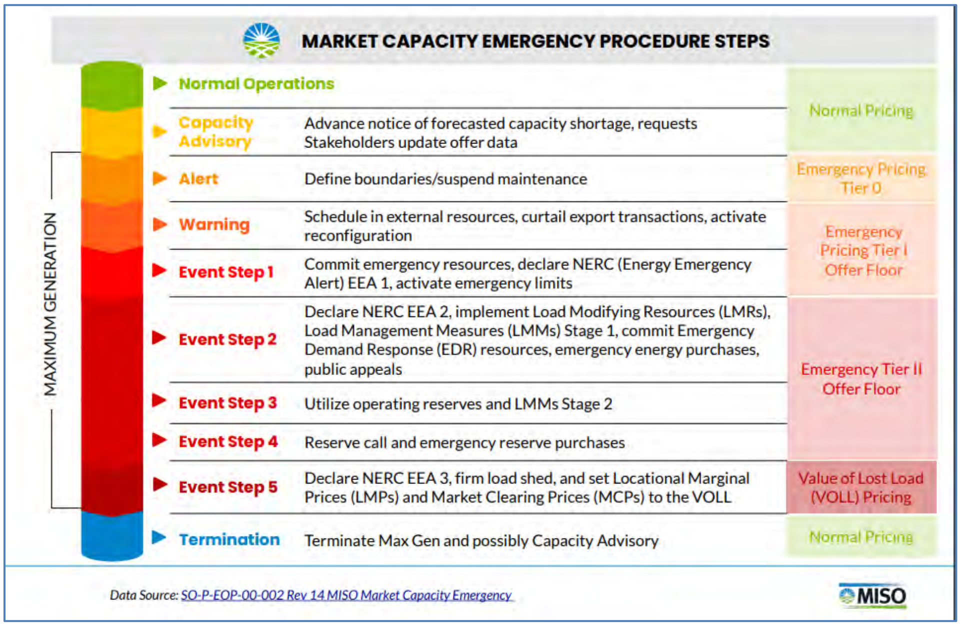


Table 4: Maximum Generation Emergency Overview

Level	MISO Major Actions	Stakeholder Major Actions
Declaration	Send MCS Declaration message	Prepare to implement this procedure and follow internal procedures for emergency conditions
	Declare Conservative System Operations	Follow instructions per Conservative System Operations procedure and declaration
Alert	Identity available Module E Resources	MPs communicate available Module E Resources
	Identify non-firm Export Schedules	MPs update energy interchange transaction E-tags of Capacity Resources
	Implement Emergency Pricing - Tier 0	LBA/TOP provide potential exclusion of constrained pockets within the declaration area
	Raise transfer capability or make constraint stranded generation available	TOPs coordinate with MISO RC to identify potential reconfiguration options
	Request MPs/LBAs ensure accuracy of LMM/LMR availability and Self Scheduled values	LBAs/MPs ensure accuracy of LMM/LMR availability and Self Scheduled values in MCS/DSRI Tools
	Send LBAs LMM survey	Affected GOPs communicate capacity limited facilities to MISO and update limits and offers
Warning	Implement Emergency pricing - Tier 1	
	Suspend CTS	
	Determine EDR availability and MW amounts	MPs update EDR availability and MW amounts
	Obtain updated MW amounts of relief available via Load Management Form in MCS	LBAs update LMM availability via Load Management Form in the MCS
	Review LMR availability using MCS-LMR tool	MPs ensure LMR availability data is correct in the DSRI Tool
	Schedule available Module E Resources into declaration area	As directed by MISO, MPs schedule available Module E Resources into the declaration area
	Curtail Export Schedules as required	
	Instruct TOPs to implement reconfiguration options	As directed by MISO RC, MPs implement reconfiguration options

Maximum Generation Emergency Declarations

through June 2024

(Updated 08/30/2024)

Page 37 of 37

Table 4: Maximum Generation Emergency Overview

Level	MISO Major Actions	Stakeholder Major Actions
Event Step 1a	Commit AME resources	As directed by MISO, LBAs/GOPs/MPs start AME Resources
Event Step 1b/EEA1	Declare EEA1	MPs review Offers and ensure all available Emergency ranges and Resources are offered
	Activate Emergency Maximum Limits	
Event Step 2a/EEA2	Declare EEA2	
	Implement Emergency pricing - Tier 2	
	Instruct Load to be reduced via LMMs - Stage 1 and LMRs	As directed by MISO, LBAs reduce load via LMM - Stage 1
	Implement LMRs	MPs implement LMRs via DSRI Tool
Event Step 2b	Commit EDR Resources	As directed by MISO, MPs commit EDRs
Event Step 2c	Implement Emergency energy purchases	LBAs issue public appeals to reduce demand per internal procedures and OE-417 filings
	Instruct LBAs to issue Public Appeals	
		LBAs in defined Event area shall prepare to shed Load
Event Step 3a	Notify affected GOPs with Generator de-rates to request waivers	Affected GOPs dispatch de-rated Generators with waivers from government regulations
	Implement spinning and supplemental reserves	
Event Step 3b	Elevate identified Priority 6-NN tags	
	Instruct Load to be reduced via LMMs - Stage 2	Affected LBAs reduce load via LMM - Stage 2
Event Step 4a	Implement Reserve Call from CRSG	MPs review Offers and ensure all available Emergency ranges and Resources are offered
Event Step 4b	Implement Emergency energy purchases from neighboring BAs (Operating Reserves)	
Event Step 5/EEA3	Declare EEA3	
	Issue Emergency Operating Instruction to shed load	LBAs shed load per MISO and confirm action via MCS Firm Load Shed Tool
	Set LMPs and MCPs to the VOLL	LBAs review OE-417 filing requirements

- **Maximum Generation (Max Gen) Capacity Advisory** - Provides advanced notice of forecasted capacity shortage and will request stakeholder update data.
- **Max Gen Alert** - Provides an early alert that system conditions may require the use of MISO's generation Emergency procedures.
- **Max Gen Warning** - MISO foresees or is experiencing conditions where all available economic Resources are committed to meet Load, firm transactions, and reserve requirements, and is concerned about sustaining required Operating Reserves.
- **Max Gen Event** - MISO's forecasted or real-time energy demand and Operating Reserve Requirements within the MBAA (or sub-area due to a transmission constraint) can NOT be satisfied with Economic Maximum Limits of all available Resources; MISO issues a Max Gen Event due to a shortage of economic Resources

2009

- 01/13/2009 18:00 – 20:30 EST – West Region Maximum Generation Emergency **ALERT** The reason for the Alert is cold temperatures and generation loss.

2010

- 08/11/2010 14:00 – 20:00 EST – Sub-Area Maximum Generation Emergency **ALERT** Declared for the subarea of FE-Northeast Ohio due to generation loss and forced outages.

2011

- 06/08/2011 12:00-19:00 EST –MISO RC declared a Maximum Generation Emergency **Alert** for the following entities: Central Region Market area(s) of: AMIL, AMMO, AMRN, BREC, CIN, CWLD, CWLP, HE, IPL, SIGE, SIPC and East Region Market area(s) of: ALTE, MECS, MGE, NIPS, UPPC, WEC, WPS and West Region Market area(s) of: ALTW, DPC, MEC, MPW due to Above Normal Temps.
  - This Alert does not include the following LBA's: GRE, NSP, SMP, MP, OTP, MDU, which are all in the Minnesota and the Dakotas area. Temperatures have dropped considerably from yesterday in this area.
- 07/18/2011 14:00-15:00 EST - Market Footprint Maximum Generation Emergency ALERT The reason for the **Alert** is because of Above Normal Temps and Higher than Forecasted Load.
- 07/21/2011 13:00 EST – 17:30 EST: The MISO Reliability Coordinator (RC) is declaring a Maximum Generation Emergency **Alert** for the following entities: Market Footprint. The reason for the alert is Above Normal Temps.
- 07/21/2011 15:00-17:30 EST - Market Footprint Maximum Generation Emergency **WARNING** The reason for the Warning is because of Forced Generation Outages, Above Normal Temps, Higher than Forecasted Load.
- 07/21/2011 12:00-15:00 EST - Market Footprint Maximum Generation Emergency **EVENT (Step 1)** The reason for the Event is because of Forced Generation

2012

- 06/28/2012 14:00-19:00 EST - Market Footprint Maximum Generation Emergency **ALERT** The reason for the Alert is because of Forced Generation Outages, Above Normal Temps.
- 06/29/2012 14:00-15:30 EST - Market Footprint Maximum Generation Emergency **ALERT** The reason for the Alert is because of Forced Generation Outages, Above Normal Temps.
- 07/02/2012 14:00-20:00 EST - Market Footprint Maximum Generation Emergency **ALERT** The reason for the Alert is because of Forced Generation Outages, Above Normal Temps.
- 07/05/2012 14:00 – 17:45 EST: The MISO Reliability Coordinator (RC) is declaring a Maximum Generation Emergency **Alert** for the following entities: Market Footprint. The reason for the alert is Forced Generation Outages, Above Normal Temps. 07/05/2012 14:00-17:45 EST - Market Footprint Maximum Generation Emergency **WARNING** The reason for the Alert is because of Forced Generation Outages, Above Normal Temps.
- 07/06/2012 12:00-12:30 EST - Market Footprint Maximum Generation Emergency **ALERT** The reason for the Alert is because of Forced Generation Outages, Above Normal Temps.
- 07/06/2012 12:30-18:30 EST - Market Footprint Maximum Generation Emergency **WARNING** The reason for the Alert is because of Forced Generation Outages, Above Normal Temps.
- 07/17/2012 12:00-13:00 EST - Market Footprint Maximum Generation Emergency **WARNING** The reason for the Alert is because of Above Normal Temps, Higher than Forecasted Load, Forced Generation Outages.
- 07/17/2012 13:00 – 17:45 EST: The MISO Reliability Coordinator (RC) is declaring a Maximum Generation Emergency **Alert** for the following entities: Market Footprint. The reason for the alert is Forced Generation Outages, Above Normal Temps.
- 07/17/2012 13:00-17:45 EST - Market Footprint Maximum Generation Emergency **Event Step - 1A.** The reason for the Alert is because of Above Normal Temps, Forced Generation Outages.

2013

07/17/2013 14:00-19:00 EST - The MISO Reliability Coordinator (RC) declared a Maximum Generation Emergency **Alert** for the following entities: Market Footprint due to Above Normal Temps, Higher than Forecasted Load

2014

- 01/07/2014 07:15-12:00 EST - Market Footprint Maximum Generation Emergency **ALERT** The reason for the Alert is because of Forced Generation Outages.
- 01/07/2014 07:30-11:15 EST - Market Footprint Maximum Generation Emergency WARNING The reason for the **Alert** is because of Forced Generation Outages.
- 01/07/2014 11:15 – 22:00 EST - Market Footprint Maximum Generation Emergency **ALERT** The reason for the Alert is because of Forced Generation Outages.
- 3/3/2014 05:30 EST – 11:00 EST: MISO Declared Maximum Generation Alert for the entire Market Footprint
- 3/4/2014 07:00 EST – 07:30 EST: MISO Maximum Generation **Alert** declared for MISO Balancing authority due to forced and unforced generation reductions combined with reduced NSI imports the reason.
- 3/4/2014 07:30 EST – 10:00 EST: MISO Maximum Generation **Event Step 1a** declared, AME units started, and external resources (Module E) scheduled into MISO.

2016

- 06/17/2016 12:00 – 20:00 EST: MISO declared Maximum Generation Emergency **Alert** for South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to Forced Generation Outages and Above Normal temperatures
- 07/21/2016 12:00 – 13:00 EST: MISO declared Maximum Generation Emergency **Alert**
- 07/21/2016 13:00 – 13:00 EST: MISO declared Maximum Generation Emergency **Warning**. Emergency Pricing Offer Floor 1 initiated
- 07/21/2016 13:00 – 16:00 EST: MISO declared Maximum Generation Emergency **Event 1B/C** and Energy Emergency Alert Level 1 (EEA 1)
- 07/21/2016 16:00 – 18:00 EST: MISO downgraded to Maximum Generation Emergency **Alert** and Energy Emergency Alert Level 0 (EEA 0)
- 08/29/2016 12:00 – 22:00 EST: The MISO Reliability Coordinator (RC) declared a Maximum Generation **Alert** effective for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, BWLT, CETO, CIN, CONS, CWLD, CWLP, HE, IPL, ITC, MCS-WPSC, MECS, METC, MGE, MIUP, NIPS, OVEC, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MCS-BEPC, MCS-CBPC, MCS-CFU, MDU, MEC, MHEB, MP, MPCN, MPW, NSP, OTP, RPU, SMP, WMUT due to Higher than Forecasted Load and Forced Generation Outages
- 10/04/2016 16:30 – 19:00 EST: MISO declared a Maximum Generation **Alert** for the South Region of the MISO footprint including the area(s) of: CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to forced generation outages and congestion
- 10/05/2016 13:00 – 15:00 EST: MISO declared Maximum Generation **Alert** for the South Region because of forced generation outages.
- 10/05/2016 15:00 – 15:00 EST: MISO declared Maximum Generation **Warning** and initiated Emergency Pricing Offer Floor 1 for the South Region area(s) of: CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to forced generation outages
- 10/05/2016 15:00 – 18:00 EST: MISO downgrade from the Maximum Generation Warning Level to a Maximum Generation **Alert** for the South Region area(s) of CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to an increase in schedule purchases from Southern Company (SOCO). The Maximum Generation Alert remained in effect due to forced generation outages

2017

- 04/04/2017 15:00-22:00 EST: MISO declared a Maximum Generation **Alert** declared for South Region area(s) of: CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to Forced Generation and Transmission outages. Upgraded to MISO declared a Maximum Generation Event at 14:00 EST
- 04/04/2017 14:00-15:00 EST: MISO declared a Maximum Generation **Event Step 1b/c** and NERC EEA-1 for South Region area(s) of: CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to Forced Generation and Transmission outages – emergency ranges enabled
- 04/04/2017 15:00-21:00 EST: MISO declared a Maximum Generation **Event Step 2a/b** and NERC EEA-2 for South Region area(s) of: CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME because of Forced Generation and Transmission Outages. – LMM/LMRs implemented
- 04/28/2017 14:00 EST: MISO declared a Maximum Generation **Alert** for the MISO South Region due to long term Forced Generation Outages
- 04/28/2017 14:00 – 20:00 EST: MISO escalated the Maximum Generation **Alert** to a Maximum Generation **Warning** for the MISO South Region due to long term Forced Generation Outages
- 04/29/2017 13:00-15:30 EST: MISO declared a Maximum Generation **Alert** for the South Region due to long term Forced Generation Outages
- 09/21/2017 12:00 – 20:00 EST: MISO declared a Maximum Generation **Alert** for the MISO Market Footprint due to generation outages, above normal temperatures, seasonally high load, and heavy congestion
- 09/22/2017 12:30 – 14:00 EST: MISO declared a Maximum Generation **Alert** for the MISO Market Footprint due to generation outages, above normal temperatures, high loads, and heavy congestion
- 09/22/2017 14:00 – 14:30 EST: MISO declared a Maximum Generation **Event Step 1a (AME Resources**) due to generation outages, above normal temperatures, seasonally high load, and heavy congestion to access AME Resources
- 09/22/2017 14:30 – 18:15 EST: MISO declared a Maximum Generation **Event Step 1b/c** due to generation outages, above normal temperatures, seasonally high load, and heavy congestion to access Emergency Maximum Limits In addition, declared NERC EEA 1. All available Resources in use.
- 09/23/2017 13:00 – 14:00 EST: MISO declared a Maximum Generation **Alert** due to generation outages, above normal temperatures, seasonally high load, and heavy congestion

Maximum Generation Emergency Declarations

through June 2024

(Updated 08/30/2024)

- 09/23/2017 14:00 – 17:15 EST: MISO declared a Maximum Generation **Warning** due to generation outages, above normal temperatures, seasonally high load, and heavy congestion
- 09/25/2017 13:00 – 19:00 EST MISO declared a Maximum Generation **Alert** due to generation outages, above normal temperatures, seasonally high load, and heavy congestion

2018

- 01/17/2018 05:00 – 23:15 EST: MISO declared a Maximum Generation **Alert** for South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to forced Generation Outages and higher than forecasted load
- 01/17/2018 06:00 – 09:00 EST : MISO declared Maximum Generation **Alert** for Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, BWLT, CETO, CIN, CONS, CWLD, CWLP, HE, IPL, ITC, MCS-WPSC, MECS, METC, MGE, MIUP, NIPS, OVEC, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MCS-BEPC, MCS-CBPC, MCS-CFU, MDU, MEC, MHEB, MP, MPCN, MPW, NSP, OTP, RPU, SMP, WMUT due to forced Generation Outages and higher than forecasted load
- 01/17/2018 07:00 – 12:00 EST: MISO declared a Maximum Generation **Event Step 2a/b** and NERC EEA 2 for South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to Forced Generation Outages, Higher than Forecasted Load
- 01/17/2018 06:10 EST – 14:00 EST: MISO declared a Maximum Generation **Event Step 2c/d** (NERC EEA Level 2 already in effect) for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to Forced Generation Outages, Higher than Forecasted Load.
- 01/17/2018 14:00 – 19:00 EST: MISO reduced to a Maximum Generation **Event Step 1a** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME
- 01/17/2018 19:00 – 20:55 EST: MISO advanced to a Maximum Generation **Event Step 2a/b** and NERC EEA 2 for the South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME
- 01/17/2018 20:55 – 23:15 EST: MISO declared a Maximum Generation **Event Step 1b/c** and NERC EEA Level 1 for the South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME
- 01/17/2018 23:15 EST – 01/18/2018 10:45: MISO declared a Maximum Generation **Alert** for South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME
- 01/18/2018 06:00 – 10:45 EST: MISO declared to a Maximum Generation **Event Step 2c/d** and NERC EEA 2 for the South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME
- 01/18/2018 06:00 – 10:45 EST: MISO declared a Maximum Generation **Event Step 2d (Public Appeals)** (NERC EEA Level 2 already in effect) for the South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME

- 5/14/2018 12:00 EST – *5/13/2018 15:46 EST*: MISO declared a Maximum Generation **Alert** for the entire footprint effective Monday 05/14/2018 12:00 EST until Wednesday 05/16/2018 23:59 EST because of Forced Generation Outages and Above Normal Temps.
    - Maximum Generation Alert terminated on 05/13/2018 15:46 EST due to an increase in capacity.
- 06/04/2018 09:00 – 13:55 EST: MISO declared a Maximum Generation **Alert** for the following entities: South Region area(s) of: CLEC, EES, LAGN due to Forced Generation Outages
- 07/05/2018 11:00 – 17:30 EST: MISO declared a Maximum Generation **Alert** for the following entities: for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, HE, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP due to Higher than Forecasted Load
- 09/13/2018: MISO issued a **Capacity Advisory** due to limited generation surplus on Monday September 17
- 09/14/2018: Capacity Advisory extended to include Tuesday September 18
- 09/15/2018 13:05 – 15:00 EST: MISO declared a Maximum Generation **Alert** for the South Region
- 09/15/2018 15:00 – 18:00 EST: MISO declared a NERC EEA-2 and Maximum Generation **Event Step 2 c/d** for the South Region
- 09/15/2018 18:00 – 18:30 EST: MISO lowered to a NERC EEA-1 and Maximum Generation **Event Step 1 b/c** for the South Region
- 09/17/2018 12:00 EST – 17:30 EST: MISO declared a Maximum Generation **Alert** for the entire MISO Balancing Authority footprint
- 10/05/2018: MISO issued a **Capacity Advisory** Communication for Monday 10/08/2018

2019

- 01/30/2019 05:00 – 12:00 EST: MISO declared a Maximum Generation **Event Step 1a** for the following entities: Central Region area(s) of: AEP, ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, BWLT, CETO, CIN, CONS, CWLD, CWLP, DECO, HE, IPL, ITC, MCS-WPSC, MECS, METC, MGE, MIUP, NIPS, PION, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MCS-BEPC, MCS-CBPC, MCS-CFU, MDU, MEC, MHEB, MP, MPCN, MPW, NSP, OTP, RPU, SMP, WMUT due to forced generation outages and high load.
- 01/30/2019 08:00 – 22:00 EST: MISO declared a Maximum Generation **Event Step 2a/b** and NERC EEA 2 for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, HE, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP due to forced generation outages and high load.
- 01/30/2019 13:30 EST – 01/31/2019 11:00 EST: MISO declared a Maximum Generation **Event Step 1a** for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, HE, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP. The reason for the Event is because of Higher than Forecasted Load, Forced Generation Outages.
- 01/31/2019 07:00 – 11:00 EST: MISO declared a Maximum Generation **Event Step 1b/c** and NERC EEA Level 1 for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, HE, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP. The reason for the Event is because of extreme low temperatures and high loads
- 01/31/2019 09:30 – 11:00 EST: MISO declared a Maximum Generation **Warning** for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, HE, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP due to extreme temperatures and high load
- 05/16/2019 12:00 EST – 05/18/2019 20:00 EST: MISO issued a Maximum Generation **Capacity Advisory** for the South Region. Forward looking capacity assessments indicated limited operating capacity margins.

- 05/16/2019 12:00 – 14:00 EST: MISO declared a Maximum Generation Emergency **Alert** for the South Region area(s) of: CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to forced generation outages
- 05/16/2019 14:00 – 18:00 EST: MISO declared Maximum Generation Emergency **Event Step 2a** for South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to forced generation outages
- 05/16/2019 18:00 – 20:00 EST: MISO downgraded to a Maximum Generation Emergency **Alert** for South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME
- 05/17/2019 12:00 – 20:00 EST: MISO declared a Maximum Generation Emergency **Alert** for South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to forced generation outages
- 05/20/2019 06:00 EST – 05/24/2019 22:00 EST: MISO declared a Maximum Generation **Capacity Advisory** for the South Region
- 05/23/2019 12:00 – 22:00 EST: MISO declared a Maximum Generation Emergency **Alert** for the South Region area(s) of: CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to Planned and Forced Generation Outages, as well as Above Normal Temps.
- 06/03/2019 12:00 – 17:00 EST: MISO declares Maximum Generation Emergency **Alert** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to higher than forecasted Load and forced Generation Outages
- 06/03/2019 13:00 – 17:00 EST: MISO declares Maximum Generation Emergency **Warning** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to higher than forecasted load and forced generation outages
- 06/03/2019 17:00 EST – 06/04/2019 20:00 EST: MISO declares a Maximum Generation **Capacity Advisory** for MISO South Region
- 06/20/2019 14:00 – 17:30 EST: MISO declared Maximum Generation Emergency **Alert** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to forced transmission and generation outages.
- 07/19/2019 10:00 EST – 07/20/2019 20:00 EST: MISO declared a Maximum Generation **Capacity Advisory** for the entire MISO Market footprint.

2020

- 02/21/2020 07:30 – 09:00 EST: MISO Reliability Coordinator declared a Maximum Generation Emergency **Alert** for the following entities: South Region area(s) of CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to cold weather and units not able to start. All reserve requirements and reliable operations were maintained during this time period.
  - Units unable to start prior to the morning peak resulted in maximum generation conditions
  - South Region weather was colder than normal but not unseasonably cold. Temperatures in Arkansas were in the low 20s.
- 07/06/2020 8:00 EST – 07/10/2020 14:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation **Capacity Advisory** for the MISO North and Central Regions of the Market Footprint.
- 07/07/2020 13:00 – 17:30 EST: MISO is declaring a Maximum Generation Emergency **Alert** for the MISO Central and North Regions.
- 07/07/2020 13:00 – 17:30 EST: MISO is escalating the Max Gen Alert to a Maximum Generation Emergency **Warning** for the MISO North and Central Regions only. While the included projected calculations show a slight shortage, this escalation to the Warning level allows some actions to be taken that will relieve the capacity shortage
- 07/07/2020 13:00 - 17:30 EST: MISO declared a Maximum Generation Event **Step 1a** for Central and North Regions (no EEA declared)
- 08/27/2020 11:00 EST – 22:54 EST: MISO is declaring a Maximum Generation Emergency **Warning** for the South Region Western half of the WOTAB load pocket (including all of the Western load pocket) due to forced generation and transmission outages and unpredictable load patterns resulting from Hurricane Laura
- 08/27/2020 11:00 EST – 22:54 EST: MISO is declaring a Maximum Generation Emergency **Event Step 5** for the South Region Western half of the WOTAB load pocket (including all of the Western load pocket) due to forced generation and transmission outages and unpredictable load patterns resulting from Hurricane Laura. EEA Level 3 and VOLL Pricing implemented.
  - 12:02 EST: 300 MW of Load Shed for the Max Gen area ordered
  - 13:22 EST: 200 MW of additional Load Shed was ordered for the Max Gen area.
  - Maximum Generation Emergency declarations terminated after transmission returned to service

2021

- 02/15/2021 07:00 – 22:00 EST: MISO is declaring a Maximum Generation Emergency **Alert** for the MISO South Region
- 02/15/2021 09:00 EST – 02/19/2021 11:00 EST: MISO is declaring a Maximum Generation **Capacity Advisory** for the South Region.
- 02/15/2021 18:00 – 23:59 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Warning** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME (EEA 0) due to Forced Generation Outages, and high loads due to Extreme Winter Temps
- 02/15/2021 18:00 – 23:59 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Event Step 2c** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME (EEA 2) due to Forced Generation Outages, Extreme cold Temps.
- 02/16/2021 00:00 – 12:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Warning** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME (EEA 0) due to Forced Generation Outages, Higher than Forecasted Load.'
- 02/16/2021 08:00 – 22:00 EST: MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Event Step 2a** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME (EEA 2) due to Forced Generation Outages, Extreme Cold Temps
- 02/16/2021 07:30 – 14:00 EST: MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Event Step 1b** for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, GLH, HE, HMPL, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP (EEA 1) due to Forced Generation Outages and Transmission Constraints.
- 02/16/2021 18:35 EST – 02/17/2021 01:00 EST: MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Event Step 2c** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME (EEA 2) due to Force Generation Outages, Higher than Forecasted Load
- 02/16/2021 19:40 EST – 02/17/2021 01:00 EST: MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Event Step 5** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME (EEA 3) due to Forced Generation Outages, Higher than Forecasted Load

  - 19:50 EST: 700 MW Firm Load Shed requested
- 02/16/2021 22:00 EST – 02/17/2021 01:00 EST: MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Event Step 2a** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME (EEA 2) due to Forced Generation Outages
- 02/17/2021 00:00 – 02:00 EST: MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Event Step 1a** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME (EEA 2) due to Forced Generation Outages
- 02/17/2021 02:00 – 23:00 EST: MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Alert** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME (EEA 0) due to forced generation outages.
- 02/17/2021 18:00 – 23:00 EST: MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Event Step 2c** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME (EEA 2) due to Forced Generation Outages, Below Normal Temps
- 02/17/2021 21:30 EST – 02/19/2021 11:00 EST: MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Alert** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME (EEA 0) due to Forced Generation Outages, Higher than Forecasted Load
- 06/08/2021 10:00 – 20:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation **Capacity Advisory** for the MISO North and Central Regions only The Reserve Margin for the North and Central Regions is forecasted to be 3.9% on 06/08/2021. This is below the 5% threshold.
- 06/10/2021 10:00 – 20:00 EST: MISO is declaring a Maximum Generation **Capacity Advisory** its North and Central Regions only – expanded to MISO footprint
- 06/10/2021 13:00 – 18:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Alert** for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, GLH, HE, HMPL, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP due to Above Normal Temps, Forced Generation Outages.
- 06/10/2021 13:00 – 18:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Warning** for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD,

CWLP, DECO, GLH, HE, HMPL, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP due to Forced Generation Outages, Above Normal Temps, Higher than Forecasted Load

- 06/10/2021 14:00 – 18:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Event Step 2a** for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, GLH, HE, HMPL, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP due to Forced Generation Outages, Above Normal Temps, Higher than Forecasted Load.
- 06/10/2021 17:00 – 18:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Alert** for the following entities: Central Region area(s) of: AEP, ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, BWLT, CETO, CIN, CONS, CWLD, CWLP, DECO, GLH, GLHB, HE, HMPL, IPL, ITC, MCS-WPSC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MCS-BEPC, MCS-CBPC, MCS-CFU, MDU, MEC, MHEB, MP, MPCN, MPW, NSP, OTP, RPU, SMP, WMUT due to Forced Generation Outages, Above Normal Temps, Higher than Forecasted Load.
- 06/28/2021 12:00 – 22:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Alert** for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, GLH, HE, HMPL, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP due to Higher than Forecasted Load, Forced Generation Outages.
- 06/29/2021 11:00 – 22:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Alert** for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, GLH, HE, HMPL, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP due to Forced Generation Outages.
- 07/05/2021 08:00 EST – 07/06/2021 18:30 EST: The MISO Reliability Coordinator is declaring a Maximum Generation **Capacity Advisory** for the North and Central Regions
- 07/06/2021 13:00 – 18:30 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Alert** for the following entities: Central Region

area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, GLH, HE, HMPL, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP due to Higher than Forecasted Load, Forced Generation Outages.

- 07/19/2021 06:00 – 20:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation **Capacity Advisory** for North and Central Regions
- 07/27/2021 06:00 – 07/28/2021 22:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation **Capacity Advisory** for the entire market footprint
- 08/19/2021 12:00 – 22:10 EST: The MISO Reliability Coordinator is declaring a Maximum Generation **Capacity Advisory** NORTH and CENTRAL Regions
- 08/23/2021 08:00 EST – 08/25/2021 20:00 EST: MISO declared a Maximum Generation **Capacity Advisory** for entire MISO footprint
- 08/24/2021 15:00 – 19:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Alert** for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, GLH, HE, HMPL, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP due to above normal temperatures, generation outages, heavy congestion.
- 08/25/2021 09:00 – 20:00 EST: MISO is declaring a Maximum Generation Emergency **Alert** for the North and Central Regions of MISO due to Above Normal Temps, Forced Generation Outages
- 10/04/2021 07:00 – 20:10 EST: MISO declared a **Capacity Advisory** for North and Central Regions due to forced generation outages and tight capacity conditions.
- 10/04/2021 12:00 – 12:00 EST: MISO declared a Maximum Generation Emergency **Alert** for Central Region area(s) of: AEP, ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, BWLT, CETO, CIN, CONS, CWLD, CWLP, DECO, GLH, GLHB, HE, HMPL, IPL, ITC, MCS-WPSC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MCS-BEPC, MCS-CBPC, MCS-CFU, MDU, MEC, MHEB, MP, MPCN, MPW, NSP, OTP, RPU, SMP, WMUT due to forced generation outages.
    - System conditions improved prior to start time of the alert and was cancelled prior to start.
    - Although the Maximum Generation Alert was cancelled prior to start time due to improved system conditions, Conservative Operations and Capacity

Advisory were maintained to ensure continued reliability in tight capacity conditions.

2022

- 01/07/2022 06:00 – 09:30 EST: MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Warning** the following entities: Central Region area(s) of: AEP, ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, BWLT, CETO, CIN, CONS, CWLD, CWLP, DECO, GLH, GLHB, HE, HMPL, IPL, ITC, MCS-WPSC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MCS-BEPC, MCS-CBPC, MCS-CFU, MDU, MEC, MHEB, MP, MPCN, MPW, NSP, OTP, RPU, SMP, WMUT due to forced generation outages
- 05/12/2022 14:45 – 20:00 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Warning** for the following entities: MISO Balancing Authority Area due to Forced Generation Outages, Above Normal Temps.
- 05/12/2022 19:00 – 20:00 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Alert** for the following entities: MISO Balancing Authority Area due to Forced Generation Outages, Above Normal Temps, Higher than Forecasted Load.
    - This Alert is the de-escalation of the earlier Maximum Generation Warning.
- 05/13/2022 15:35 – 19:00 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Alert** for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, GLH, HE, HMPL, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS due to Forced Generation Outages, Higher than Forecasted Load, Above Normal Temps
- 05/18/2022 08:30 EST – 05/19/2022 20:00 EST: The MISO Reliability Coordinator declared a Maximum Generation **Capacity Advisory** for the MISO South Region due to reduced reserve margins
- 05/18/2022 14:30 – 19:30 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Alert** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due Forced Generation Outages, Above Normal Temperatures and Higher than Forecasted Load
- 06/15/2022 08:00 – 06/16/2022 22:00 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Capacity Advisory** for the MISO Market Footprint
- 06/13/2022 14:00 – 19:00 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Alert** for the following entities: South Region

area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to Forced Generation Outages, Above Normal Temps, High Congestion

- 06/15/2022 13:00 – 20:00 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Alert** for the following entities: MISO Balancing Authority Area due to Forced Generation Outages, Above Normal Temps, High Congestion
- 06/20/2022 06:00 – 22:00 EST: The MISO Reliability Coordinator declared a Maximum Generation **Capacity Advisory** for the South Region only
- 06/21/2022 06:00 EST – 06/23/2022 22:00 EST: The MISO Reliability Coordinator declared a Maximum Generation **Capacity Advisory** for the Market Footprint
- 07/05/2022 10:00 – 20:00 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Capacity Advisory** for the MISO Balancing Authority
- 09/20/2022 01:00 – 21:00 EST: The MISO Reliability Coordinator declared a Maximum Generation **Capacity Advisory** for the MISO Market footprint
- 10/12/2022 14:00 – 19:00 EST: The MISO Reliability Coordinator declared a Maximum Generation **Capacity Advisory** for the MISO Market South Region.
- 12/23/2022 09:15 – 13:00 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Warning** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to Higher than Forecasted Load, Forced Generation Outages
- 12/23/2022 16:30 – 17:30 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Warning** for the following entities: the ENTIRE MISO Balancing Authority Area due to Forced Generation Outages, Higher than Forecasted Load
- 12/23/2022 17:30 – 18:00 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Event Step 1b – EEA1** for the following entities: MISO Balancing Authority Area due to Forced Generation Outages, Higher than Forecasted Load
- 12/23/2022 18:00 – 21:00 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Event Step 2a – EEA2** for the following entities: MISO Balancing Authority Area due to Forced Generation Outages, Higher than Forecasted Load

2023

- 06/02/2023 07:00 - 21:00 EST: The MISO Reliability Coordinator is declaring a **Maximum Generation Capacity Advisory** due to elevated temperatures, forced generation outages, and higher than normal forecasted loads.
- 06/26/2023 13:00 - 16:07 EST: The MISO Reliability Coordinator is declaring a **Maximum Generation Capacity Advisory** for MISO South Region
- 06/29/2023 12:00 – 22:01 EST: The MISO Reliability Coordinator is declaring a **Maximum Generation Capacity Advisory** for the Market Footprint due to extreme heat and high load
- 07/26/2023 12:00 EST – 07/28/2023 20:00 EST: MISO Reliability Coordinator declared a **Maximum Generation Capacity Advisory** for the MISO North and Central Regions
- 07/27/2023 12:00 – 18:00 EST: MISO Reliability Coordinator declared a **Maximum Generation Emergency Ale**rt for the following entities: Central Region area(s) of: AEP, ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, BWLT, CETO, CIN, CONS, CWLD, CWLP, DECO, GLH, GLHB, HE, HMPL, IPL, ITC, MCS-WPSC, MEC1, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MCS-BEPC, MCS-CBPC, MCS-CFU, MDU, MEC, MHEB, MP, MPCN, MPW, NSP, OTP, RPU, SMP, WMUT due to Above Normal Temps, Forced Generation Outage
  - MISO is forecasting high load which may cause MISO to be within 500 MW of obligations for operating day Thursday 07/27/2023.
  - With increased risk and uncertainty, it may be necessary for MISO to escalate further based on changing system conditions
- 07/28/2023 12:00 – 20:00 EST: MISO Reliability Coordinator is declaring a **Maximum Generation Emergency Alert** for the following entities: Central Region area(s) of: AEP, ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, BWLT, CETO, CIN, CONS, CWLD, CWLP, DECO, GLH, GLHB, HE, HMPL, IPL, ITC, MCS-WPSC, MEC1, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MCS-BEPC, MCS-CBPC, MCS-CFU, MDU, MEC, MHEB, MP, MPCN, MPW, NSP, OTP, RPU, SMP, WMUT due to Forced Generation Outages, Above Normal Temps
- 08/14/2023 10:00 – 20:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Capacity Advisory for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME

- 08/21/2023 10:00 EST – 08/24/2023 23:00 EST: The MISO Reliability Coordinator is declaring a **Maximum Generation Capacity Advisory** for the MISO Market Footprint
- 08/24/2023 12:00 – 12:00 EST: The MISO Reliability Coordinator is declaring a **Maximum Generation Emergency Alert** for the following entities: MISO Balancing Authority Area
    - o Escalated to Maximum Generation Emergency Step 2a before start of the Alert
- 08/24/2023 12:00 – 19:30 EST: MISO is escalating to a **Maximum Generation Emergency Event Step 2a** for the MISO Balancing Authority Area due to Forced Generation Outages, Above Normal Temps, Higher than Forecasted Load.
- 08/24/2023 19:30 – 21:00 EST: MISO is de-escalating Maximum Generation Event Step 2A to **Maximum Generation Warning**

2024

- 5/07/2024 11:00 – 19:00 EST: MISO declared **Capacity Advisory** for South Region areas of AXLT, CLEC, CWLT, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to an increase of load forecast, forced generation outages, and limited transfer capabilities from the MISO Classic Region to the MISO South Region.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-26-22

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

Exhibit 33

MISO Market Capacity Emergency

MISO Market Capacity Emergency

SO-P-EOP-11-002 Rev: 21

ROLE			ROLE	
BAO	☑		SM	☑
IRAC	☑		RC	☑
UDS	☑		G&I	☑
SOE	☑		LBA	☑
TOP	☑		MP	☑
GOP	☑		ORM	☑

Rev History	Reason for Issue	Revised By	Issue Date	Effective Date
21	Annual Review. Added actions under Step 4.2.8. Updated procedure number. Added Operations Risk Management (ORM) Role. Removed references to MCS when not related to LMM, LMR or EDR. Compliance Review Completed. Operating procedure owner approval on file.	Chris Hoffman/ Becca Skalko/ Bill Puller	03/03/2025	03/03/2025
20	Annual Review. No changes. Compliance Review Completed. Operating procedure owner approval on file.	Chris Benton/ Becca Skalko/ Bill Puller	06/01/2024	06/01/2024

1.0 Purpose

Provide a set of emergency Operating Plans to address Capacity Emergencies and Energy Emergencies within the MISO Balancing Authority Area (MBAA), which shall include the following:

1. Roles and responsibilities for the MISO Operators, Local Balancing Authorities (LBAs), Transmission Operators (TOPs), Generation Operators (GOPs), and Market Participants (MPs).
2. Process for preparation, management, and recovery from an Emergency.

2.0 Precautions and Limitations

1. As conditions require, MISO may provide instructions to move to any section or step in this procedure while providing instructions to complete actions described in earlier levels or steps as time permits.
2. Should sufficient relief be obtained during the implementation of one of the actions during a declaration step, subsequent actions within that declaration step need NOT be taken.
3. The Operating Reserve Requirement for the MBAA consists of Regulation and Contingency Reserve Requirements.
4. The Operating Reserve Requirement for a Region or Sub-Area consists of a Contingency Reserve Requirement based on the Most Severe Single Contingency (MSSC) within its boundaries.
5. Available Economic Resources are the Available Economic Max (including BTM but reduced by Resources that cannot be committed due to congestion or excessive Time-to-Start) and adjusted for Constraint Stranded MW and NSI Obligations.
6. South Region Available Economic Resources are the South Available Economic Max (including BTM but reduced by Resources that cannot be committed due to congestion or excessive Time-to-Start) and adjusted for South Constraint Stranded MW, the Regional Dispatch Transfer NSI (RDT NSI), and Resources from the Central and North Regions that are deliverable to the South via the RDT up to the Regional Dispatch Transfer Limit (RDTL, typically 3,000 MW).
7. The 5% Reserve Margin Entry Condition for an MBAA Capacity Advisory includes allowance for loss of the MSSC and subsequent recovery within 90 minutes for the second MSSC (if applicable), plus uncertainties.

8. Increasing the Reserve Margin Entry Condition may be required when relying on a significant amount of capacity returning from outage or if there are other forecasting uncertainties or risks to the interconnection.
9. MISO will use the Mid-term Load Forecast (MTLF) or Short-term Load forecast (STLF) where applicable to determine available Operating Reserves. MISO may adjust the load forecast values based on sustained error over time and will document the reasons for the adjustment.
10. Transmission System Emergencies that require immediate action will be declared and resolved through actions identified in MISO SO-P-EOP-00-004 Transmission System Emergency. Transmission constraints, which result in limitations in transferring energy into the MBAA or a sizable sub-area of the MBAA and result in a capacity or energy Emergency for such area will be managed through the current procedure.
11. Energy deficient BA obligations include immediate actions to mitigate any undue risk to the Interconnection, including Load shedding.
12. MISO posts Max Gen Declaration notification to the MISO Market and Operations - Real-Time Operations Website.
13. Depending on the urgency of the Max Gen Emergency, manual Load Shedding may be used to control the Emergency at any time. This includes the immediate shedding of load to return Area Control Error (ACE) to zero.
14. MISO's posting of the Max Gen Declaration notification to the RT Ops Website [via Operator Interface (OI)] serves as notice of the existence and duration of the conditions requiring the implementation of the procedures set forth in Section 40.2.20 of the Tariff. Historical Max Gen Declarations can be found on the MISO's Open Access Same Time Information System (OASIS) page.
15. MISO will render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory or statutory requirements.
16. If MISO is NOT able to send Load Modifying Resource (LMR) availability reminders to MPs, MISO will communicate, via the Demand Side Resource Interface (DSRI) Tool, implementation instructions using the then current availability information in the tool, assuming it to be correct.
17. MISO Shift Manager (SM) should evaluate additional staffing requirements per SO-I-NOP-00-441 Real-Time Event Resolution.

18. The Reserve Procurement Enhancement (RPE) objective for the RDT North-to-South is to elevate MCP and energy prices in the South Region to clear additional Contingency Reserves to allow recovery of the RDT Flow to 116% post-contingent of the South MSSC. Operators must determine how to reduce the RDT Flow further to 100% from 116%. When RPE on RDT is violating, additional generation should be started.
19. An infographic of MISO's Market Capacity Emergency Procedure steps is included in Attachment 8 — Summary of Market Capacity Emergency Procedure Steps.

3.0 Entry Conditions

3.1 Capacity Advisory

1. Entry conditions are based on the Reserve Margin, which is the Total Operating Reserves compared to the Operating Reserve Requirement, either in MW or % of the Load, plus Operating Reserve Requirements. Attachment 1 — Reserve Margin Example Calculations has example calculations.
   - Reserve Margin:
     Total Operating Reserves - Operating Reserve Requirement
   - Reserve Margin (%):
     100 * (Total Operating Reserves - Operating Reserve Requirement) /(Load + Operating Reserve Requirement)
   - Total Operating Reserves MBAA:
     (Avail Eco Max - Constraint Stranded - NSI) - Load
   - Total Operating Reserves South Region:
     (Avail Eco Max - Constraint Stranded - RDT NSI + RDTL) - Load

ORM/
SM

Note [□]

- IF a positive but somewhat low Reserve Margin is forecast THEN:
- A Capacity Advisory will typically be declared 2 to 3 days in advance, however, it may be declared in any time frame.
- A decision to declare a Capacity Advisory may take into account other information such as time frame, weather and other risk factors
- Increasing the Reserve Margin may be required when relying on a significant amount of capacity returning from outage or if there are other uncertainties or risks to the Interconnection.

1. IF any of the following conditions are identified THEN **PERFORM** Section 4.1 Capacity Advisory: [□]
   - MBAA, Region or Sub-Area forecasted Reserve Margin (%) is less than 5%
   - South Region forecasted Reserve Margin is less than 2,000 MW

3.2 Max Gen Alert

SM

Note [□]
• A positive but low Reserve Margin is forecasted in a Max Gen Alert. • For a negative Reserve Margin, a Warning or Event should be declared. • Increasing the Reserve Margin may be required when relying on a significant amount of capacity returning from outage or if there are other forecasting uncertainties or risks to the interconnection.

1. IF any of the following conditions are identified, THEN **PERFORM** Section 4.2.2 Max Gen Alert - MISO Actions: [□]
   - MBAA, Region or Sub-Area forecasted Reserve Margin is less than 1500 MW, or largest single contingency for Sub-Area
   - South Region forecasted Reserve Margin is less than 500 MW

3.3 Max Gen Warning

SM

Note [□]
A negative Reserve Margin means that Load and Operating Reserve Requirement cannot be met with normal Economic Resources. In that scenario a Max Gen Warning or Event should be declared.

1. IF the following condition is identified, THEN **PERFORM** Section 4.2.3 Max Gen Warning - MISO Actions: [□]
   - MBAA, Region, or Sub-Area actual or forecasted Reserve Margin is less than zero

3.4 Max Gen Event

SM

1. IF the following condition is identified, THEN **PERFORM** Section 4.2.4 Max Gen Event Step 1a - MISO Actions when: [□]
   - MBAA, Region, or Sub-Area actual or forecasted Reserve Margin is less than zero
   - Warning level actions are NOT sufficient

4.0 Instructions

4.1 Capacity Advisory

ORM/SM

4.1.1 Capacity Advisory - MISO Actions

1. **COMMUNICATE** Capacity Advisory as follows: [□]
   A. **DEFINE** boundaries of Capacity Advisory area. [□]
   B. **DEFINE** start time of Capacity Advisory and **COMMUNICATE** potential end time to UDS Operator to allow STR Default and RPE MSSC Overrides to be entered. [□]

C. **SEND** Capacity Advisory declaration to affected members via OI per SO-I-NOP-00-448 Event Communications Matrix. [□]

D. **SEND** Capacity Advisory declaration via Reliability Coordinator Information System (RCIS). [□]

SM 2. IF OI is down or SM determines a conference call is necessary, THEN **PERFORM** conference call with affected reliability entities per SO-P-NOP-00-483 Reliability Coordination Conference Call. [□]

SM 3. IF a significant shortage of Operating Reserves is anticipated in any Reliability Assessment Commitment (RAC) process, THEN **DETERMINE** whether to issue LMR Scheduling Instructions in anticipation of a Max Gen Emergency Event Step 2a or higher. [□]

A. **SEND** informational message via MCS/OI to impacted area(s) that LMRs have been called in anticipation of a Max Gen Emergency. [□]

B. **SEND** LMR scheduling instructions (from longest to shortest lead time) via MCS for forecasted Max Gen Emergency. [□]

UDS

Note [□]
For Steps 4. through 7., REFER to Attachment 7 — UDS Operator Actions During MISO Market Capacity Emergency Conditions.

4. IF a Capacity Advisory is declared for the North/Central Region only, THEN **OVERRIDE** STR RPE MSSC Default value(s) as specified in SO-I-EOP-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing for Non-Zone only in the EMD Global Reserve Requirements menu, for the duration of a Capacity Advisory or higher declaration. [□]

UDS 5. IF during the course of a Capacity Advisory or higher declaration for the North/Central Region, and a Capacity Advisory or higher declaration is declared for the South Region, THEN **OVERRIDE** System Wide STR Default value(s) and **OVERRIDE** South Region STR RPE MSSC in Zone 8 in the EMD Global Reserve Requirements menu, for the duration of the Capacity Advisory or Higher declaration, as specified in SO-I-EOP-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing. [□]

UDS

6. IF a Capacity Advisory is declared for the South Region <u>only</u>, THEN **OVERRIDE** STR RPE MSSC Default value(s) in Zone 8 only in the EMD Global Reserve Requirements menu, for the duration of the Capacity Advisory or higher declaration, as specified in SO-I-EOP-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing. [□]

UDS

7. IF during the course of a Capacity Advisory or higher declaration for the South Region, a Capacity Advisory or higher declaration is added for the North/Central Region, THEN **OVERRIDE** System Wide STR Default value(s) <u>and</u> **OVERRIDE** North/Central STR RPE MSSC for Non-Zone in the EMD Global Reserve Requirements menu for the duration of Capacity Advisory or higher declaration, as specified in SO-I- EOP-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing. [□]

8. IF a System Wide Capacity Advisory is declared, THEN **OVERRIDE** STR Default value(s) AND Override North/Central STR RPE MSSC for Non-Zone AND Override South Region STR RPE MSSC for Zone 8 as specified per SO-I-EOP-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing in the EMD Global Reserve Requirements menu for the duration of Capacity Advisory or above declaration. [□]

ORM/ SM

9. NOTIFY Day Ahead (DA) and Forward Reliability Assessment and Commitment (FRAC) operators when STR update is complete. [□]

4.1.2 Capacity Advisory - MISO Stakeholder Actions

1. WHEN notified by MISO, THEN **ENSURE** all market data is updated with best available information for operating day(s) including the following: [□]
   - Facility and generation availability, outages and de-rates
   - Generation Offers, including any changes to reflect fuel availability
   - Fuel supply and inventory concerns
   - Fuel switching capabilities
   - Environmental constraints
   - Load forecast Values
   - LMR Availability in the DSRI
   - Voluntary Load Management information

- Load Management Measures (LMM) and any Voluntary Load Management in the MCS
- Emergency Demand Response (EDR) offers

MP

Note	[□]
LMRs should be implemented NO less than the MW amount scheduled and within guidelines given by MISO.	

2. IF notified by MISO, THEN **IMPLEMENT** LMRs. [□]

MP 3. **UPDATE** DSRI Tool as follows: [□]

A. **NAVIGATE** to the Active Event by clicking <u>either</u> of the following: [□]
   - the Scheduling Instruction event banner
   - the Active Event from the dashboard, <u>or</u>
   - the Events tab

B. **REVIEW** Event Timeline and LMR Instructions broken down by each LBA. [□]

C. **ACKNOWLEDGE** LMR Scheduling Instructions. [□]

D. **NAVIGATE** to Resource Deployment tab of the Active Event. [□]

E. **ENTER** <u>and</u> **SUBMIT** MW Amounts of Resources that will be deployed in order to meet the LMR Scheduling Instruction obligation per LBA. [□]

F. After receiving the LMR Scheduling Instruction, **UPDATE** LMR Availability of those Resources that were designated to respond to LMR Scheduling Instruction to reflect what is newly available to MISO. [□]

4.2 MISO Actions during a Max Gen Emergency

4.2.1 Max Gen Declaration - MISO Actions

SM 1. **DECLARE** applicable Max Gen Alert/Warning/Event as follows: [□]

- A. **DEFINE** boundaries of declaration area. [□]
- B. **DEFINE** start and end time of declaration. [□]
- C. **SEND** Max Gen Declaration via OI per SO-I-NOP-00-448 Event Communications Matrix. [□]
- D. SEND Max Gen declaration summary information via RCIS within 30 minutes. [□]

SM 2. **ENSURE** Conservative System Operations has been declared per SO-P-NOP-00-449 Conservative System Operations. [□]

SM 3. IF OI is down or SM determines a conference call is necessary, THEN **PERFORM** conference call with affected reliability entities per SO-P-NOP-00-483 Reliability Coordination Conference Call. [□]

4.2.2 Max Gen Alert - MISO Actions

SM 1. IF starting declaration at a Max Gen Alert, THEN **DECLARE** Max Gen Alert per Section 4.2.1 Max Gen Declaration - MISO Actions. [□]

UDS 2. **IMPLEMENT** Emergency Pricing Tier 0 per SO-I-EOP-00-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing. [□]

SM

Note [□]
This survey is to gain an idea of amount of LMM load reduction to expect to be available if needed.

3. **SEND** survey via MCS LMM Tool in the Load Management Tab to LBAs to ensure LMM information is updated. [□]

- A. IF the Drill Mode is currently on. THEN **ENSURE** to “Switch to Live Mode”. [□]

BAO 4. IF Operating Reserve availability changes are identified, THEN **NOTIFY** SM. [□]

IRAC 5. **ENSURE** available economic resources are committed to meet load, firm transactions, and reserve requirements. [□]

G&I

A. COORDINATE with MPs with Module E Resources as follows: [□]

(1.) **DETERMINE** available Resources for implementation during potential Warning declaration. [□]

B. IF MPs have remaining available External and Internal Resources (Module E registered Capacity Resources), THEN **REQUEST** amount available for implementation during potential Warning declaration. [□]

(1.) **ENSURE** MPs identify specific information on physical location and path External Resources (Module E registered Capacity Resources) would use to deliver energy into potential Warning area. [□]

SM
G&I

C. **NOTIFY** SM of Total MW of non-firm energy sales and MISO exporting Capacity Resources. [□]

RC

Note [□]

The following analysis should be completed in time for implementation during the potential Warning declaration.

D. **COORDINATE** with neighboring Reliability Coordinators (RCs) and MISO TOPs to raise transfer capability into declaration area or make available constraint stranded generation (on or off line) in declaration area including: review Transmission Loading Relief (TLR) activity, binding constraints, available reconfiguration options, and use of short term emergency ratings. [□]

UDS

E. **LOG** actions taken and relevant information in response to the declaration. [□]

Note [□]

- Actions are taken to attempt to preserve Resources dedicated to firm Load and maintaining Operating Reserves.
- Actions available at this level should be fully utilized, time permitting, for all entities within the defined declaration area prior to declaring an emergency.

4.2.3 Max Gen Warning - MISO Actions

SM

1. IF starting declaration at a Max Gen Warning or escalating from a Max Gen Alert, THEN **DECLARE** Max Gen Warning per Section 4.2.1 Max Gen Declaration - MISO Actions. [□]

UDS	2.	**IMPLEMENT** Emergency Pricing Tier 1 per SO-I-EOP-00-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing.	[□]
IRAC	3.	**SUSPEND** Coordinated Transaction Scheduling (CTS) for the duration of the capacity emergency per SO-I-AOP-00-224 CTS Failure Modes.	[□]
G&I	4.	**COMMUNICATE** CTS suspension with PJM.	[□]
SM	5.	**REVIEW** EDR offers to determine EDR availability and MW amounts for Warning period.	[□]
SM	6.	**OBTAIN** updated MW amounts of relief available during effective Warning period by LBA from MCS. • LMMs – Stage 1 • LMMs – Stage 2	[□]
SM	7.	**REVIEW** LMRs availability in MCS-LMR Tool for declaration period.	[□]
SM	8.	**DIRECT** the following to raise forecasted capacity:	[□]
BAO		A. **TERMINATE** Inadvertent Payback process per SO-I-NOP-00-462 Inadvertent Interchange Management.	[□]
BAO		B. **DETERMINE** if request for time error correction termination should be made per SO-P-NOP-00-455 Balancing Authority Operations.	[□]
SM	9.	**SEND** OI message to MPs to schedule remaining available External and Internal Resources (Module E Registered Capacity Resources) that would be deliverable to Warning area, given transmission constraints.	[□]
SM/ G&I	10.	**COORDINATE** to notify MPs to schedule Module E Resources into MBAA declaration area as follows:	[□]
G&I		A. **PROVIDE** instructions on amount and time to schedule External and Internal Module E Resources into declaration area.	[□]
G&I	11.	**NOTIFY** SM of forecasted changes in MBAA NSI due to loss of imports.	[□]
G&I	12.	**COORDINATE** to determine amount of non-firm Export Schedules to curtail.	[□]

G&I	13. IF Export Schedule Limits are exceeded, THEN **CURTAIL** Export Schedules from declaration area in amounts required to relieve shortage condition in the following order per SO-I-EOP-00-006 Interchange Scheduling Operations during Emergency Conditions: A. Non-Firm Transmission Schedules. B. Firm Schedules from Capacity (Module E) Resources that are NOT meeting their Schedule requirements and Capacity requirements. C. Firm Schedules from non-Capacity (Module E) Resources that are NOT meeting their Schedule requirements. D. Firm Transmission schedules from Power Purchase Agreements (PPAs) that represent a Fleet of Resources, when those resources are NOT meeting their collective resource obligation.	[□]
G&I	14. **MODIFY** webTrans E-tag validation mode to reflect Max Gen in affected area (North, South, or All) per SO-I-EOP-00-006 Interchange Scheduling Operations during Emergency Conditions.	[□]
RC	15. **NOTIFY** TOP to implement reconfiguration options agreed upon to raise transfer capability into declaration area or alleviate constraint stranded generation in declaration area.	[□]
ALL	16. **LOG** actions taken and relevant information in response to the declaration.	[□]

4.2.4 Max Gen Event Step 1a - MISO Actions

SM

Note [□]

Actions in this section are taken to attempt to preserve Resources dedicated to firm Load and maintaining Regulating Reserves.

1. IF starting declaration at a Max Gen Event Step 1a or escalating from a lower Max Gen level, THEN **DECLARE** Max Gen Event 1a per Section 4.2.1 Max Gen Declaration - MISO Actions. [□]

SM 2. **NOTIFY** Director On-Call to implement SO-P-AOP-00-217 MISO and State Officials 24X7 Communication Protocols During Emergencies. [□]

IRAC

Note [□]

AME are resources with a commit status of Emergency.

3. **COMMIT** the following Available Max Emergency (AME) designated resources: [□]
   - Generation Resources
   - Demand Response Resources – Type 1
   - Demand Response Resources – Type 2

4.2.5 Max Gen Event Step 1b - MISO Actions

SM 1. IF starting declaration at a Max Gen Event Step 1b or escalating from a lower Max Gen level, THEN **DECLARE** Max Gen Event Step 1b and EEA1
per Section 4.2.1 Max Gen Declaration - MISO Actions. [□]

IRAC

Note [□]

IRAC Operator ensuring emergency ranges are available for use by UDS and UDS Operator verifying these ranges are preliminary actions to implementing these ranges in Event Step 1b.

2. **ENSURE** unit emergency ranges are pushed per SO-I-EOP-00-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing. [□]

UDS

Note [□]

Resources selected to provide Regulating Reserve for each Generation Resource, Demand Response Resource – Type II and External Asynchronous Resource for use in MISO's RAC, Automatic Generation Control (AGC), and UDS for the MBAA (or sub-area due to a transmission constraint) are to be excluded when implementing Emergency Maximum Limits.

3. **ACTIVATE** Emergency Maximum Limits per SO-I-EOP-00-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing. [□]

ALL 4. **LOG** actions taken and relevant information in response to the declaration. [□]

4.2.6 Max Gen Event Step 2a - MISO Actions

SM

Note [□]

- LMM – Stage 1 and LMRs are utilized on a pro-rata basis within the declaration area based on availability of those actions, with the exception of EDRs, which are committed in merit order.
- LMRs can be called in anticipation up to one hour prior to their required notification time. If MISO does NOT declare a Max Gen Emergency Event Step 2a or higher at least two hours prior to the start of the Scheduling Instructions issued in anticipation, the LMRs are NOT obligated to perform.

1. IF starting declaration at a Max Gen Event Step 2a or escalating from a lower Max Gen level, THEN **DECLARE** Event Step 2a and EEA2 per Section 4.2.1 Max Gen Declaration - MISO Actions. [□]

UDS 2. **ENSURE** emergency pricing has been implemented as follows:
   - If previously implemented, THEN **CHANGE** to Tier 2. [□]
   - If NOT previously implemented, THEN **IMPLEMENT** Emergency Pricing Tier 2 per SO-I-EOP-00-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing. [□]

SM 3. **DETERMINE** Manitoba Hydro's EEA status. [□]

SM 4. IF Manitoba Hydro is in an EEA concurrently with MISO's EEA2 or higher, THEN PERFORM SO-I-NOP-00-481MISO-Manitoba Hydro Concurrent EEA. [□]

SM

Note [□]

- One MW value will be provided per LBA for load reduction.
- Determination of individual LMMs to be utilized will be managed at the LBA level.
- Reduction MW amounts by LBA will be determined by proration of total amount available in declaration area.
- If OI is unavailable, notifications will be made via phone.
- LMR load reduction amounts to LBAs are for information only. LBAs do not implement LMRs

5. **NOTIFY** LBAs of required Load reduction via LMM – Stage 1 and LMRs in MW amounts via MCS. [□]

SM 6. **COORDINATE** with MPs on implementing LMRs as follows: [□]

Note [□]

LMR implementation amounts are determined by taking prorated amount of LMR availability in each LBA area as compared to total available in declaration area, and based upon registration profile of each LMR, within the tolerances as set in the MCS-LMR Tool.

A. **DETERMINE** LMR implementation amounts by MPs. [□]
B. **PROVIDE** a MW minimum implementation amount to each MP based upon this pro-ration and profile of registered LMRs via MISO Communication System (MCS)-LMR Tool. [□]

SM 7. **DETERMINE** OE-417 reporting responsibilities per SO-P-NOP-04 MISO Event Reporting Operations Plan. [□]

SM 8. **ENSURE** required notifications are performed per SO-I-NOP-00-448 Event Communications Matrix. [□]

ALL 9. **LOG** actions taken and relevant information in response to the declaration. [□]

4.2.7 Max Gen Event Step 2b - MISO Actions

SM 1. IF starting declaration at a Max Gen Event Step 2b or escalating from a lower Max Gen level, THEN **DECLARE** Event Step 2b per
Section 4.2.1 Max Gen Declaration - MISO Actions. [□]

SM 2. **COMMIT** EDR resources, in merit order, to alleviate capacity shortage within declaration area per SO-I-NOP-00-404 Emergency Demand Response Implementation. [□]

ALL 3. **LOG** actions taken and relevant information in response to the declaration. [□]

4.2.8 Max Gen Event Step 2c - MISO Actions

SM	1.	IF starting declaration at a Max Gen Event Step 2c or escalating from a lower Max Gen level, THEN **DECLARE** Event Step 2c per Section 4.2.1 Max Gen Declaration - MISO Actions.	[□]
SM/ RC	2.	**COORDINATE** with neighboring RCs and BAs to determine Emergency energy available from external sources.	[□]
SM/ G&I	3.	**IMPLEMENT** Emergency energy purchases from neighboring BAs through existing Emergency contractual agreements in order to conserve Operating Reserves per SO-I-NOP-00-479 Purchasing and Selling Emergency Energy.	[□]
SM	4.	**EVALUATE** opportunities to reduce internal energy usage, such as sending non-essential personnel home, reducing lighting that is non-essential for personnel safety and reducing large electric loads.	[□]
SM		**Note** DOE Form OE-417 filing requirements for issuing Public Appeals is the responsibility of the LBA.	[□]
	5.	**INSTRUCT** LBAs in declaration area to issue public appeals to reduce demand per their internal procedures.	[□]

ALL	6. **LOG** actions taken and relevant information in response to the declaration.	[□]

4.2.9 Max Gen Event Step 3a - MISO Actions

SM	1. IF starting declaration at a Max Gen Event Step 3a or escalating from a lower Max Gen level, THEN **DECLARE** Event Step 3a per Section 4.2.1 Max Gen Declaration - MISO Actions.	[□]
SM	2. **NOTIFY** GOPs, via OI, in the declaration area who have Generators with de-rates from environmental restrictions to request waivers from appropriate government agencies.	[□]
BAO	3. **IMPLEMENT** use of all spinning and supplemental reserves as needed and as time permits.	[□]
SM	4. IF Contingency Reserves fall below minimum required (MSSC) for greater than 30 minutes and NO reasonable actions exist to restore within 90 minutes, THEN **DECLARE** an EEA3 per Section 4.2.1 Max Gen Declaration - MISO Actions.	[□]

4.2.10 Max Gen Event Step 3b - MISO Actions

SM	1. IF starting declaration at a Max Gen Event Step 3b or escalating from a lower Max Gen level, THEN **DECLARE** Event Step 3b per Section 4.2.1 Max Gen Declaration - MISO Actions.	[□]
SM	**Note** Reduction MW amounts by LBA will be determined by pro-rata of total amount available in declaration area.	[□]
	2. **NOTIFY** LBAs, via MCS, of required Load reduction via LMM – Stage 2 in MW of interruptible demands.	[□]
RC	3. IF TLR is called and MISO imports are being curtailed, THEN **COORDINATE** with SM to evaluate Priority 6-NN tags to exclude.	[□]
SM/ G&I	4. **COORDINATE** to elevate identified Priority 6-NN tags per SO-I-EOP-00-006 Interchange Scheduling Operations during Emergency Conditions.	[□]
SM/ G&I	5. **NOTIFY** RCs of tags that are being elevated to Firm.	[□]

ALL	6.	**LOG** actions taken and relevant information in response to the declaration.	[□]

4.2.11 Max Gen Event Step 4a - MISO Actions

SM	1.	IF starting declaration at a Max Gen Event Step 4a or escalating from a lower Max Gen level, THEN **DECLARE** Event Step 4a per Section 4.2.1 Max Gen Declaration - MISO Actions.	[□]
BAO	2.	**IMPLEMENT** Reserve Call from Contingency Reserve Sharing Group (CRSG).	[□]

4.2.12 Max Gen Event Step 4b - MISO Actions

SM	1.	IF starting declaration at a Max Gen Event Step 4b or escalating from a lower Max Gen level, THEN **DECLARE** Event Step 4b per Section 4.2.1 Max Gen Declaration - MISO Actions.	[□]
RC	2.	**COORDINATE** with neighboring RCs and BAs to identify additional available Emergency energy, including their Operating Reserves.	[□]
G&I	3.	**IMPLEMENT** Emergency energy purchases from neighboring BAs through existing Emergency contractual agreements and SO-I-NOP-00-479 Purchasing and Selling Emergency Energy.	[□]
SM	4.	IF Contingency Reserves fall below minimum required (MSSC) for greater than 30 minutes and NO **reasonable** actions exist to restore within 90 minutes, THEN DELARE an EEA3 per Section 4.2.1 Max Gen Declaration - MISO Actions.	[□]
IRAC	5.	**EVALUATE** excluding Regulating Units that have room between RegMax and Emergency Max from clearing Reg per SO-I-EOP-00-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing.	[□]
ALL	6.	**LOG** actions taken and relevant information in response to the declaration.	[□]

4.2.13 Max Gen Event Step 5 - MISO Actions

SM 1. IF starting declaration at a Max Gen Event Step 5 or escalating from a lower Max Gen level, THEN **DECLARE** Max Gen Event Step 5 and EEA3per Section 4.2.1 Max Gen Declaration - MISO Actions. [□]

SM

> **Note** [□]
>
> Attachment 4 — Slice-of-System PPAs Load/Schedule Curtailment provides additional information regarding sharing of load shedding with Slice of System PPAs.

2. **DETERMINE** manual Load Shedding requirements. [□]

SM

> **Note** [□]
>
> Issuing Emergency Operating Instructions for firm Load shed is based on the ratio of LBA forecasted or actual Load to the total forecasted or actual Load of the declaration area, taking into account applicable transmission security requirements.

3. **ISSUE** Emergency Operating Instructions to LBAs, in declaration area, of MW amounts of load to shed via MCS Firm Load Shed Tool or verbally per SO-P-NOP-00-431 Communications Protocol For Operating Instructions. [□]

UDS

> **Note** [□]
>
> Refer to SO-I-EOP-00-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing.

4. WHEN notified by MISO SM, THEN **PERFORM** the following:
   A. **CHECK** appropriate box(es) in the Energy Market Display (EMD) for the applicable LBAs in the column titled “Is Voll Price Enforced” [□]
   B. **SAVE** updates. [□]

SM 5. IF firm Load Shed is greater than 100 MW, THEN **DETERMINE** OE-417 reporting responsibilities per SO-P-NOP-04 MISO Event Reporting Operations Plan. [□]

SM 6. **ENSURE** required notifications are performed per SO-I-NOP-00-448 Event Communications Matrix. [□]

ALL 7. **LOG** actions taken and relevant information in response to the declaration. [□]

4.2.14 Max Gen Event Downgrade/Termination - MISO Actions

SM

Note [□]

- Steps and levels during Termination may be skipped as appropriate based on system conditions and projections.
- Emergency steps shall be exited in a controlled and deliberate manner so to NOT adversely affect system reliability while minimizing the impact of these emergency actions on the Load Serving Entities (LSEs).

1. WHEN actual obligations return below total MISO capability, THEN **DOWNGRADE/TERMINATE** Max Gen Event as follows: [□]
   - SM — A. **SEND** Max Gen Downgrade/Termination to affected members via OI per Section 4.2.1 Max Gen Declaration - MISO Actions. [□]
   - UDS — B. IF Max Gen Event Step 5 is being terminated, THEN **UNCHECK** flag in EMD, which previously set all LMPs and MCPs to the Value of Lost Load (VOLL). [□]
   - IRAC/ G&I — C. ENSURE CTS is enabled per SO-I-AOP-00-224 CTS Failure Modes. [□]
   - UDS — D. **UPDATE** or **TERMINATE** emergency pricing and emergency ranges per SO-I-EOP-00-001 as applicable. [□]
   - G&I — E. **RETURN** webTrans E-tag validation to normal mode per SO-I-EOP-00-006 Interchange Scheduling Operations during Emergency Conditions. [□]
   - IRAC — F. **EVALUATE** and **DECOMMIT** any online emergency generation (AME) that has met its Min Run. [□]
   - SM — G. **PERFORM** necessary actions to back out of steps taken in reverse order. [□]
   - UDS — H. IF STR requirement override is NOT needed for remainder of the declared emergency, THEN **REMOVE** STR requirement override in EMD from STR Default and STR MSSC Non-Zone and South Zone 8. [□]

SM — 2. **ENSURE** all SO-I-NOP-00-448 Event Communications Matrix notifications are performed. [□]

ALL — 3. **LOG** actions taken and relevant information in response to the declaration. [□]

4.3 MISO Stakeholder Actions during a Max Gen Emergency

4.3.1 Max Gen Alert Level Actions - MISO Stakeholder Actions

LBA/ TOP/ GOP

> **Note** [□]
> Deferring generation/transmission maintenance until the Max Gen declaration has been terminated ensures trips are minimized.

1. **FOLLOW** MISO's SO-P-NOP-00-449 Conservative System Operations procedure. [□]

LBA/ TOP

2. **DETERMINE** potential exclusions of constrained pockets within declaration area where there is expected to be adequate generation that may NOT be transferred to other parts of declaration area due to local constraints. [□]

TOP

3. **INFORM** MISO RC of identified areas. [□]

GOP

4. IF generators are derated, THEN **PERFORM** the following:

GOP

   A. INFORM the following of capacity limited facilities: [□]
      - LBAs
      - TOPs
      - MISO G&I Operator

GOP

5. **UPDATE** Limits and Offers. [□]

MP

> **Note** [□]
> - Schedules that source from a resource that is identified as a Capacity Resource in Module E for a MISO LSE must be identified in the tagging process per MISO BPM-007 Physical Scheduling Business Practice Manual Section 16 - Capacity Resource Scheduling.
> - This also includes a Generation Resource internal to the MBAA that is identified as a Capacity Resource for an external BA.
> - This identification allows for proper curtailment of non-firm imports and exports during a capacity emergency event.

6. **UPDATE** energy interchange transaction e-tags, sourcing or sinking, in MBAA to reflect the firmness of their Capacity Resources. [□]

MP

> **Note** [□]
> MISO will provide instructions on when and how much the MP should schedule into MISO during Max Gen Warning.

7. **NOTIFY** MISO G&I Operator of Available External and Internal Resources (Module E registered Capacity Resources) deliverable to the declaration area, including amount available. [□]

MP	8. **ENSURE** accuracy of LMR availability and Self-Scheduled/ Voluntary Load Management LMRs in the DSRI Tool.	[□]
LBA	9. **ENSURE** accuracy of Non-LMR Voluntary Load Management/ Self-Scheduled LMM information in the MCS-LMR Tool.	[□]
TOP	10. **COORDINATE** with MISO RC to determine reconfiguration options to raise transfer capability to declaration area or alleviate constraint stranded generation in declaration area.	[□]

4.3.2 Max Gen Warning - MISO Stakeholder Actions

LBA	1. Based on Load Shed methodology, **MAKE** preparations for potential Load Shed during an Event stage.	[□]
MP	2. **UPDATE** EDR offers for availability and MW amounts for declaration period.	[□]
LBA	3. **SUBMIT** LMM availability via MCS per Attachment 3 — Load Management Update Form Example.	[□]
MP	4. **ENSURE** accuracy of registered LMR availability in the DSRI Tool.	[□]
MP	5. WHEN notified by MISO, THEN **SCHEDULE** remaining available External and Internal Resources (Module E Registered Capacity Resources) that would be deliverable to declaration area, given transmission constraints.	[□]
LBA	6. **NOTIFY** Interruptible Loads of potential interruption.	[□]
LBA/ MP/ TOP/ GOP	7. **LOWER** energy use to a minimum using conservative measures.	[□]
TOP	8. **IMPLEMENT** agreed upon reconfiguration options to raise transfer capability into declaration area or make available constraint stranded generation in declaration area.	[□]

4.3.3 Max Gen Event Step 1a - MISO Stakeholder Actions

GOP	1. WHEN notified by MISO, THEN **START** applicable off-line AME Generation Resources.	[□]

4.3.4 Max Gen Event Step 1b - MISO Stakeholder Actions

GOP

Note [□]

MPs should ensure Emergency Range limits reflect actual resource capabilities. Specific information, limitations, and concerns on Emergency Range usage should be communicated to MISO G&I Operators as applicable.

1. WHEN Resources are dispatched, THEN **ENSURE** Resources move into Emergency range. [□]

GOP 2. **ENSURE** all co-generation and independent power producers are at maximum output and availability. [□]

GOP 3. **NOTIFY** MISO G&I Operator of change in output. [□]

GOP 4. IF additional reliable capacity is available (such as adding additional mills, duct burners, etc.), THEN **COORDINATE** adjustments with MISO G&I Operator. [□]

4.3.5 Max Gen Event Step 2a - MISO Stakeholder Actions

LBA 1. IF in declaration area and notified by MISO to reduce load, THEN **PERFORM** the following: [□]

LBA A. **REDUCE** load via LMM – Stage 1. [□]

LBA **Note** [□]

- Reductions through Load Management are NOT precise to the MW.
- Determination of individual LMMs to be utilized will be managed at the LBA level.

B. WHEN load reduction actions have been implemented, THEN **NOTIFY** MISO. [□]

MP **Note** [□]

LMRs should be implemented NO less than the MW amount scheduled and within guidelines given by MISO.

2. WHEN notified by MISO, THEN **IMPLEMENT** LMRs. [□]

MP 3. UPDATE DSRI Tool as follows: [□]

A. **NAVIGATE** to the Active Event by clicking either of the following: [□]
   - the Scheduling Instruction event banner
   - the Active Event from the dashboard, or
   - the Events tab

B. **REVIEW** Event Timeline and LMR Instructions broken down by each LBA. [□]

C. **ACKNOWLEDGE** LMR Scheduling Instructions. [□]

D. **NAVIGATE** to Resource Deployment tab of the Active Event. [□]

E. **ENTER** and **SUBMIT** MW Amounts of Resources that will be deployed in order to meet the LMR Scheduling Instruction obligation per LBA. [□]

F. After receiving the LMR Scheduling Instruction, **UPDATE** LMR Availability of those Resources that were designated to respond to LMR Scheduling Instruction to reflect what is newly available to MISO. [□]

4.3.6 Max Gen Event Step 2b - MISO Stakeholder Actions

MP

1. WHEN notified by MISO, THEN **COMMIT** EDR Resources. [□]

4.3.7 Max Gen Event Step 2c - MISO Stakeholder Actions

LBA

Note [□]

- Public appeals to reduce demand is based on internal LBA procedures, system conditions, and Event projections provided by MISO.
- The public appeals should include an educational message on how the public may reduce demand and conserve power.
- DOE Form OE-417 filing requirements for issuing Public Appeals is the responsibility of the LBA.

1. WHEN instructed by MISO, THEN **ISSUE** public appeals to reduce demand per internal procedures. [□]

LBA

2. IF in declaration area, THEN **PREPARE** to shed load. [□]

4.3.8 Max Gen Event Step 3a - MISO Stakeholder Actions

GOP

1. IF requested by MISO to dispatch available capacity in Event Step 3a, THEN **DISPATCH** as follows: [□]
   A. **VERIFY** Generators in declaration area with de-rates from environmental restrictions. [□]
   B. IF approved waiver from government regulations, THEN **DISPATCH** available generation. [□]

4.3.9 Max Gen Event Step 3b - MISO Stakeholder Actions

LBA

1. IF in declaration area and notified by MISO to reduce Load during Event Step 3b, THEN **PERFORM** the following:
   A. REDUCE Load via LMM – Stage 2. [□]

Note [□]

- Reductions through LMMs are NOT precise to the MW.
- Determination of individual LMMs to be utilized will be managed at the LBA level.

   B. WHEN Load reduction actions have been implemented, THEN **NOTIFY** MISO via MCS. [□]

4.3.10 Max Gen Event Step 4a/b - MISO Stakeholder Actions

GOP/MP

1. **REVIEW** Offers. [□]

GOP/MP

2. **ENSURE** all available Emergency range and resources are offered. [□]

GOP/MP

Note [□]

All Resources should be committed, producing energy or committed for reserves, except emergency ranges on Resources providing Regulating Reserves.

3. IF there are available Resources or capacity NOT being utilized, THEN **NOTIFY** MISO. [□]

4.3.11 Max Gen Event Step 5 - MISO Stakeholder Actions

LBA

Note [□]

In addition to ensuring load shed schemes are capable of implementation in a time frame adequate for mitigating the Emergency for load shed directed by MISO, LBAs are responsible to coordinate with TOPs for any load shed requirements, critical load evaluation in load shed schemes, and coordination including rotation of selected loads, with any other automatic load shed schemes such as Underfrequency and Undervoltage. The minimum MISO directed load shed per LBA should be maintained at all times, until load restore directions are provided by MISO.

1. **SHED** firm Loads per MISO issued Emergency Operating Instruction. [□]

LBA

2. **CONFIRM** actions taken with MISO RC via MCS Firm Load Shed Tool or verbally per SO-P-NOP-00-431 Communications Protocol For Operating Instructions. [□]

LBA

3. IF requested by MISO during Event Step 5, THEN **COMPLETE** Department of Energy (DOE) Form OE-417 as follows: [□]
   - A. **COMPLETE** DOE Form OE-417 for actions taken to reduce Load via Load Management Procedures per NERC EOP-004-4 and SO-P-NOP-04 MISO Event Reporting Operations Plan. [□]
   - B. **SUBMIT** completed DOE Form OE-417 to the following: [□]
     - DOE
     - NERC
   - C. **FORWARD** a copy of the submitted DOE Form OE-417 to the following: [□]
     - Regional Entities
     - MISO @ RTOpsCompliance@misoenergy.org

4.3.12 Max Gen Event Downgrade/Termination - MISO Stakeholder Actions

LBA/ MP/ TOP/ GOP

1. **PERFORM** requests of MISO SM or designee to back out of each level. [□]

5.0 Definitions

1. **Reserve Margin** - The difference between Total Operating Reserves and the Operating Reserve Requirement.
2. **Constraint Stranded MW** - Resource MW that are NOT available to meet load due to congestion on the electric grid.
3. **Emergency Demand Response (EDR)** - Load reductions, behind the meter generation, and other demand resources that are available to reduce demand or increase generation in exchange for guaranteed recovery of costs associated with the response in accordance with Schedule 30 (EDR Provisions) of the Tariff.
4. **Load Management Measures (LMM) Stage 1** – Load management actions that can be taken to reduce demand to preserve or maintain Operating Reserves that are NOT included in EDRs or LMRs.
5. **Load Management Measures (LMM) Stage 2** – Load management actions that can be taken to reduce demand including voltage reductions and reducing Loads that, by contract, can NOT be interrupted until reserves are being or are expected to be depleted and energy from Emergency Offers by Market Participants are being or are expected to be depleted. These do NOT include EDRs or LMRs.
6. **Load Modifying Resource (LMR)** - These are either Demand resources or Behind the Meter Generation that have an obligation to reduce demand or increase generation during declared system emergencies
7. **Maximum Generation (Max Gen) Capacity Advisory** - Provides advanced notice of forecasted capacity shortage and will request stakeholder update data.
8. Max Gen Alert - Provides an early alert that system conditions may require the use of MISO's generation Emergency procedures.
9. **Max Gen Warning** - MISO foresees or is experiencing conditions where all available economic Resources are committed to meet Load, firm transactions, and reserve requirements, and is concerned about sustaining required Operating Reserves.

10. **Max Gen Event** - MISO's forecasted or real-time energy demand and Operating Reserve Requirements within the MBAA (or sub-area due to a transmission constraint) can NOT be satisfied with Economic Maximum Limits of all available Resources; MISO issues a Max Gen Event due to a shortage of economic Resources.
11. **MBAA Sub-Region** - Sub-region may consist of a single LBA area, a group of LBA areas, or portions of an LBA area (for portions of an LBA area, a 1000 MW minimum threshold will generally be used).

6.0 References

6.1 NERC References

1. EOP-011-4 Emergency Operations
   - R2.2.1[Section 4.1.1 Step 1.]
   - R2.2.2 [Section 4.2.5 Step 1.][Section 4.2.6 Step 1.] [Section 4.2.13 Step 1.]
   - R2.2.3 [Section 4.1.2]
   - R2.2.4 [Section 4.2.8 Step 5.]
   - R2.2.5 [Section 4.2.9 Step 2.]
   - R2.2.6 [Section 4.2.8]
   - R2.2.7 [Section 4.2.3 Step 6.][Section 4.2.4 Step 3.][Section 4.2.6 Step 6.][Section 4.2.7 Step 2.]
   - R2.2.9 [Section 4.2.13 Step 3.]
   - R2.2.10 [Section 3.1 Note after Step 1]
   - R5 [Section 4.2.1 Step 1.D.]
   - R6 [Section 4.2.5 Step 1.][Section 4.2.6 Step 1.] [Section 4.2.1][Section 4.2.13 Step 1.]
2. IRO-014-4 Coordination Among Reliability Coordinators
3. R1 [Section 4.1][Section 4.2]
4. TOP-001-6 Transmission Operations
   - R2 [Section 4.1][Section 4.2]

6.2 FERC References

1. MISO Open Access Transmission, Energy, and Operating Reserve Markets Tariff, Section 40.2.20

6.3 MISO References

1. SO-P-EOP-11 MISO Emergency Operating Plan
2. BPM-007 Physical Scheduling Business Practice Manual Section 16 – Capacity Resource Scheduling
3. SO-I-EOP-00-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing
4. SO-I-EOP-00-006 Interchange Scheduling Operations during Emergency Conditions
5. SO-I-AOP-00-224 CTS Failure Modes
6. SO-I-NOP-00-404 Emergency Demand Response Implementation
7. SO-I-NOP-00-441 Operations Real-Time Event Resolution
8. SO-I-NOP-00-448 Event Communications Matrix
9. SO-I-NOP-00-462 Inadvertent Interchange Management
10. SO-I-NOP-00-481
11. SO-I-NOP-00-483 Reliability Coordination Conference Call
12. SO-P-EOP-00-004 Transmission System Emergency
13. SO-P-AOP-00-217 MISO and State Officials 24X7 Communication Protocols During Emergencies
14. SO-P-NOP-00-431 Communications Protocol For Operating Instructions
15. SO-P-NOP-00-449 Conservative System Operations
16. SO-P-NOP-00-455 Balancing Authority Operations
17. SO-P-NOP-04 MISO Event Reporting Operating Plan
18. SO-I-NOP-00-479 Purchasing and Selling Emergency Energy

Attachment 1 — Reserve Margin Example Calculations

1.0 Example 1: Projection for MBAA

Table 1: Calculation

Description	Value
MBAA Peak Load Forecast:	100,000
Operating Reserve Requirement:	2,410
Load plus Operating Reserve Requirement:	102,410
Available Economic Maximum in Area:	97,000
Constraint Stranded MW:	2,000
Available Economic Resources in Area:	95,000
Net Scheduled Interchange (NSI) into Area:	8,000
Reserve Margin = 95,000+8,000-102,410	+ 590
Reserve Margin (%) = (590/102,410)*100:	+ 0.6%

Assessment: Reserve Margin is forecasted to be +590 MW. Load plus Operating Reserve Requirement is met, however the Reserve Margin is less than 1500 MW. A Max Gen Alert declaration may be necessary.

2.0 Example 2: Projection for South Region

Table 2: Calculation

Description	Value
MBAA Peak Load Forecast:	30,000
Operating Reserve Requirement:	1,500
Load plus Operating Reserve Requirement:	31,500
Available Economic Maximum in Area:	29,000
Constraint Stranded MW:	1,000
Available Economic Resources in Area:	28,000
Net Scheduled Interchange (NSI) into Area (RDT NSI):	400
RDT Import Capability up to RDTL of 3,000	3,000
Reserve Margin = 28,000+3,400-31,500	-100
Reserve Margin (%) = (-100/31,500)*100:	- 0.3%

Assessment: Reserve Margin is -100 MW, meaning the South Region Load plus Operating Reserve Requirement is 100 MW short of being met. This means Load will be covered but the 1,500 MW Operating Reserve Requirement will not be. A Max Gen Warning or Event declaration may be necessary.

Attachment 2 — Maximum Generation Declaration Template

Maximum Generation Declaration Type: [Alert/Warning/Event]

The MISO RC is Declaring/Updating a Maximum Generation Alert/Warning/Event effective from [MM/DD/YYYY] [HH:MM] EST and [MM/DD/YYYY] [HH:MM] EST for the following entities:

[List the affected entities within the boundaries of the declaration by LBA. Include any constrained pockets within the declaration area with adequate generation that should be excluded from the Maximum Generation Emergency.]

The reason for the declaration is:
State the reason(s): Forced Transmission Outage, Forced Generation Outage, Higher than Forecasted Load, Above/Below Normal Temperatures, Loss of Import Interchange Schedules, Reduction in RDT limit, etc.

Members are to prepare for a Maximum Generation Emergency by performing the applicable MISO Member Maximum Generation [Alert/Warning/Event] Level Actions of SO-P-EOP-002 MISO Market Capacity Emergency procedure.

CTS Suspension: Attention Market Participants: CTS (Coordinated Transaction Scheduling) is Suspended as of [MM/DD/YYYY] [HH:MM] EST. Alternative scheduling methods should be utilized.

Projections (to LBAs and TOPs only):

- Peak hour for Area is Hour Ending [MM/DD/YYYY] [HH:MM] EST.
- Load plus Operating Reserve Requirement for Area: ____________
- Amount of Available Economic Resources in Area: ____________
- Imports into Area: ____________
- Reserve Margin shortfall(-)/surplus(+) for Area: ____________

1. Summary information (only) in the top of the OI Message/template will be communicated to MPs via the following:
   A. OI
   B. MISO public web site – Real Time Notifications Tab via OI View Real-Time Operations Updates at https://www.misoenergy.org/markets-and-operations/notifications-overview/

2. Completed OI message/template (summary & projections) will be communicated to TOPs, LBAs, BAs and neighboring BAs, and RCs as follows:
   A. OI
   B. RCIS
3. MISO will provide summary information to the following email exploder lists via OI message:
   - *MISO Alerts BA and TO
   - *MISO Alerts FERC, State Comm., RRO, Neighboring RCs and BAs
   - *RT Ops Notification

Attachment 3 — Load Management Update Form Example

Local Balancing Authorities report via MCS or phone to the RC Load reductions that would be available, time permitting, via Load Management should a Maximum Generation Emergency Event be implemented during the same time frame the Warning is effective. MISO will provide the expected notification time* for LBAs to assume when completing form.

Load Management may include but are NOT limited to public appeals, voltage reduction, and interruption of end use loads in accordance with applicable contracts, demand-side management, utility load conservation measures, and starting behind the meter generation*.

Load Management is separated into LMM – Stage 1 and LMM – Stage 2.

*Excludes Registered DRR Type 1 and DRR Type 2 Resources

Table 3: LBAs report the following estimated values:

LBA:	
Notification time for Load Management Measures (i.e. less than 4 hours)	
LMM Stage 1 available:	10
LMM Stage 2 available:	5
Total:	15
LBAs should list, LMM Stage 1 and LMM Stage 2 that are already or projected to be implemented at the Event time:	
LMM Stage 1:	100
LMM Stage 2:	0
Total:	100

Attachment 4 — Slice-of-System PPAs Load/Schedule Curtailment

1.0 Slice-of-System Power Purchase Agreements (PPAs) Curtailed Pro-Rata with Load in the Source Balancing Authority when Source Balancing Authority is in Emergency Procedures

1. PPAs in this category will continue to qualify as Planning Resources so long as the PPA only will be curtailed pro-rata along with load in the source Balancing Authority and only when the source Balancing Authority is operating under Emergency Procedures.
2. Under this situation, a PPA with a 1,000 MW export schedule from an external Balancing Authority with a 3,000 MW load will be curtailed pro-rata along with the load when the external Balancing Authority is operating under Emergency Procedures. That is, curtailment would take place three-quarters to firm load and one quarter to the firm schedule. This pro-rata treatment is triggered when MISO experiences emergency conditions at the same time as the external Balancing Authority.

2.0 Slice-of-System PPA in a Balancing Authority that Coordinates Planning Reserve Qualifications and Shares Emergency Responsibilities with MISO's Balancing Authority

1. In addition to the slice-of-system PPA treatment noted in category (B) above, slice-of-system PPAs can continue to qualify as External Resources under this category, and MISO and the external BA will share Load Shedding on a pro-rata basis in proportion to the load in the area under the Capacity Emergency, so long as the requirements of this category are met.
2. This qualification category has several requirements for the host BA:
   - A. It must be in MISO's RC area.
   - B. It must share Operating Reserves with the MISO BA.
   - C. It must have a Seams Operating Agreement with MISO containing several features.
3. Seams Operating Agreement must specify the following:
   - A. The host BA has established planning reserve processes and criteria similar to MISO's.
   - B. Actions that will be taken by both entities – MISO and the host BA – during Emergency Procedures prior to implementing Load Shedding.
   - C. BA responsibilities include:
     - (1.) Submitting load estimates to MISO in a similar manner as submitted by other Load entities under Module E-1.

(2.) Providing generator testing data for all resources used to serve firm requirements of the host Balancing Authority.

(3.) Providing transparency to such resource plans in the form of a Fixed Resource Adequacy Plan, pursuant to Module E-1.

4. With these requirements in place, when both BAs have exhausted other emergency operating actions and are in a firm load shedding event, load shedding is shared on a pro-rata basis in proportion to the load in the area under the capacity emergency.

Example 1

If the load of an external BA in capacity emergency is 3000 MW and the load of the area in MISO in capacity emergency is 17,000 MW, then pro-rata load shed is 3/20 of the total for the external Balancing Authority and 17/20 for the area in MISO in the capacity emergency.

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5. This treatment is appropriate for BAs that meet the requirements indicated above because MISO can count on the fact that the external BA is planning and testing its resources in an equivalent manner to MISO, and is part of MISO's RC area and subject to emergency procedures it has developed with MISO. It has also agreed to operate its system in a similar manner, including the agreement to share its Operating Reserves with MISO during emergency conditions.

3.0 When MISO is in an EEA and the external BA with PPA is not, then MISO will determine if the PPA should flow or determine the curtailable MWs of the PPA.

1. LBA NET(Excess Capability) =
   Σ(LBA_online RTmw - LBA_online MaxObligation)
   - Where RTmw = Current RT MWs of Resource
   - Where MaxObligation = The lesser of a resource's Effective ICAP (capacity obligation) and their Real-Time Must Offer availability
2. Prior to any curtailments, MISO will contact the external BA by phone.
3. If the BA indicates that the curtailment will cause the BA to enter an EEA, then MISO will initiate SO-I-NOP-00-481.
4. If the BA indicates that the curtailment will NOT cause the BA to enter an EEA, then MISO will curtail any relevant schedule(s).

Attachment 5 — Additional Information

1.0 Max Gen Emergency

1. MISO may call for a Max Gen Alert, Warning or Event, or EEA level prior to the actual forecasted start time of such Alert, Warning, Event or EEA level.
    A. The purpose of this would be to communicate forecasted conditions that meet the criteria of these levels, as well as to provide notice of certain implementation steps which require longer notifications times.
    B. An example would be an LMR which has a 4-hour notification time, requiring implementation instructions to be sent prior to the actual start time of the Event, or EEA.
    C. Due to the dynamic nature of the Bulk Electric System (BES) these preliminary declarations and instructions may be canceled prior to the actual start time of the forecasted Alert, Warning, Event or EEA as conditions warrant.
    D. At the Max Gen Alert level, Emergency Pricing Tier 0 is in effect until termination of the Alert or increasing Max Gen level to Warning level or higher.
2. Max Gen Warning
    A. EDRs may also be registered as LMRs in Module E. If a MP has decided to offer in all or part of their resource as an EDR for an operating day, the MP should reduce the availability of that resource as an LMR in the DSRI Tool for all 24 hours of the same operating day by the maximum MW amount offered in for that resource as an EDR. In addition, if an MP has implemented any resources voluntarily, which are registered as an LMR, the MP should adjust the availability of that resource in the DSRI Tool.
    B. Tier 1 prices are in effect from Max Gen Warning until an Emergency Event Step 2a, when Tier 2 prices are implemented. This is an ex-post ELMP pricing change and does NOT affect system commitment or dispatch. Emergency Pricing will be utilized as necessary on an LBA basis.
3. Max Gen Event
    A. MISO will implement Emergency Pricing Offer Tier 2 during Step 2a of an Emergency Event. This is an ex-post ELMP pricing change and does NOT affect system commitment or dispatch. Emergency Pricing will be utilized as necessary on an LBA basis.

Attachment 6 — Maximum Generation Emergency Overview

The following is an overview of Max Gen Emergency actions and should be used for reference only during an actual event.

Table 4: Maximum Generation Emergency Overview

Level	MISO Major Actions	Stakeholder Major Actions
Declaration	Send OI Declaration message	Prepare to implement this procedure and follow internal procedures for emergency conditions
	Declare Conservative System Operations	Follow instructions per Conservative System Operations procedure and declaration
	Increase STR Default if System Wide or STR MSSC if North/Central or South Region	
Alert	Identity available Module E Resources	MPs communicate available Module E Resources
	Identify non-firm Export Schedules	MPs update energy interchange transaction E-tags of Capacity Resources
	Implement Emergency Pricing - Tier 0	LBA/TOP provide potential exclusion of constrained pockets within the declaration area
	Raise transfer capability or make constraint stranded generation available	TOPs coordinate with MISO RC to identify potential reconfiguration options
	Request MPs/LBAs ensure accuracy of LMM/ LMR availability and Self Scheduled values	LBAs/MPs ensure accuracy of LMM/LMR availability and Self Scheduled values in MCS/ DSRI Tools
	Send LBAs LMM survey	Affected GOPs communicate capacity limited facilities to MISO and update limits and offers

Table 4: Maximum Generation Emergency Overview

Level	MISO Major Actions	Stakeholder Major Actions
Warning	Implement Emergency pricing - Tier 1	
	Suspend CTS	
	Determine EDR availability and MW amounts	MPs update EDR availability and MW amounts
	Obtain updated MW amounts of relief available via Load Management Form in MCS	LBAs update LMM availability via Load Management Form in the MCS
	Review LMR availability using MCS-LMR tool	MPs ensure LMR availability data is correct in the DSRI Tool
	Schedule available Module E Resources into declaration area	As directed by MISO, MPs schedule available Module E Resources into the declaration area
	Curtail Export Schedules as required	
	Instruct TOPs to implement reconfiguration options	As directed by MISO RC, MPs implement reconfiguration options
Event Step 1a	Commit AME resources	As directed by MISO, LBAs/GOPs/MPs start AME Resources
Event Step 1b/EEA1	Declare EEA1	MPs review Offers and ensure all available Emergency ranges and Resources are offered
	Activate Emergency Maximum Limits	
Event Step 2a/EEA2	Declare EEA2	
	Implement Emergency pricing - Tier 2	
	Instruct Load to be reduced via LMMs - Stage 1 and LMRs	As directed by MISO, LBAs reduce load via LMM - Stage 1
	Implement LMRs	MPs implement LMRs via DSRI Tool
Event Step 2b	Commit EDR Resources	As directed by MISO, MPs commit EDRs

Table 4: Maximum Generation Emergency Overview

Level	MISO Major Actions	Stakeholder Major Actions
Event Step 2c	Implement Emergency energy purchases	LBAs issue public appeals to reduce demand per internal procedures and OE-417 filings
	Instruct LBAs to issue Public Appeals	
		LBAs in defined Event area shall prepare to shed Load
Event Step 3a	Notify affected GOPs with Generator de-rates to request waivers	Affected GOPs dispatch de-rated Generators with waivers from government regulations
	Implement spinning and supplemental reserves	
Event Step 3b	Elevate identified Priority 6-NN tags	
	Instruct Load to be reduced via LMMs - Stage 2	Affected LBAs reduce load via LMM - Stage 2
Event Step 4a	Implement Reserve Call from CRSG	MPs review Offers and ensure all available Emergency ranges and Resources are offered
Event Step 4b	Implement Emergency energy purchases from neighboring BAs (Operating Reserves)	
Event Step 5/EEA3	Declare EEA3	
	Issue Emergency Operating Instruction to shed load	LBAs shed load per MISO and confirm action via MCS Firm Load Shed Tool
	Set LMPs and MCPs to the VOLL	LBAs review OE-417 filing requirements

Attachment 7 — UDS Operator Actions During MISO Market Capacity Emergency Conditions

- If a North/Central declaration is in place and a South declaration is subsequently implemented, Increase STR Default Values as specified in SO-I-EOP-00-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing procedure.
- Implementation of these steps are outlined in SO-I-EOP-00-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing
- Does not include Max Gen Event Downgrade/Termination Actions as noted in section 4.2.1.14
- * STR RPE & STR Default Values are specified in SO-I-EOP-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing procedure

SO-P-EOP-00-002 MISO Market Capacity Emergency - UDS Operator Actions

		Increase STR RPE MSSC Default Values for Zone 8 (South) if not done in previous declaration*	Increase STR RPE MSSC Default Values for Non-Zone (N/C) if not done in previous declaration*	Increase STR Default Values for System Current (System Wide) if not done in previous declaration*	Implement Emergency Pricing Tier 0	Implement Emergency Pricing Tier 1	Activate Emergency Limits	Implement Emergency Pricing Tier 2	Check Is VOLL Price Enforced in EMD
System Wide Declaration Level	Capacity Advisory								
	Max Gen Alert								
	Max Gen Warning								
	Max Gen Event Step 1a								
	Max Gen Event Step 1b								
	Max Gen Event Step 2a and above								
	Max Gen Event Step 5								
North/Central Declaration Level	Capacity Advisory								
	Max Gen Alert								
	Max Gen Warning								
	Max Gen Event Step 1a								
	Max Gen Event Step 1b								
	Max Gen Event Step 2a and above								
	Max Gen Event Step 5								
South Declaration Level	Capacity Advisory								
	Max Gen Alert								
	Max Gen Warning								
	Max Gen Event Step 1a								
	Max Gen Event Step 1b								
	Max Gen Event Step 2a and above								
	Max Gen Event Step 5								
Single Region (North or Central) Declaration Level	Capacity Advisory								
	Max Gen Alert								
	Max Gen Warning								
	Max Gen Event Step 1a								
	Max Gen Event Step 1b								
	Max Gen Event Step 2a and above								
	Max Gen Event Step 5								

Figure 1: UDS Operator Actions During MISO Market Capacity Emergency Conditions

Attachment 8 — Summary of Market Capacity Emergency Procedure Steps

MARKET CAPACITY EMERGENCY PROCEDURE STEPS

Step	Action	Pricing
Normal Operations		Normal Pricing
Capacity Advisory	Advance notice of forecasted capacity shortage, requests Stakeholders update offer data	
Alert	Define boundaries/suspend maintenance	Emergency Pricing Tier 0
Warning	Schedule in external resources, curtail export transactions, activate reconfiguration	Emergency Pricing Tier I Offer Floor
Event Step 1	Commit emergency resources, declare NERC (Energy Emergency Alert) EEA 1, activate emergency limits	
Event Step 2	Declare NERC EEA 2, implement Load Modifying Resources (LMRs), Load Management Measures (LMMs) Stage 1, commit Emergency Demand Response (EDR) resources, emergency energy purchases, public appeals	Emergency Tier II Offer Floor
Event Step 3	Utilize operating reserves and LMMs Stage 2	
Event Step 4	Reserve call and emergency reserve purchases	
Event Step 5	Declare NERC EEA 3, firm load shed, and set Locational Marginal Prices (LMPs) and Market Clearing Prices (MCPs) to the VOLL	Value of Lost Load (VOLL) Pricing
Termination	Terminate Max Gen and possibly Capacity Advisory	Normal Pricing

MAXIMUM GENERATION (Alert through Event Step 5)

Figure 2: Market Capacity Emergency Procedure Steps

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO))))))	Order No. 202-26-22

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

Exhibit 34

Ramey MISO Comments

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Technical Conference Regarding The Challenge of Resource Adequacy In Regional Transmission Organization and Independent System Operator Regions	)	**Docket No. AD24-11-000**

COMMENTS OF TODD RAMEY
ON BEHALF OF
MIDCONTINENT ISO INC.

I. INTRODUCTION

<u>MISO's Resource Adequacy Challenge</u>

The electricity grid today is facing a significant transition at a pace never seen before. To ensure that our nation's bulk electric system remains reliable, it is important to recognize and stay ahead of the challenges and trends that are impacting electricity production and consumption. Today, the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, insufficient transmission system infrastructure, growing pressures from extreme weather, and rapid load growth. The ultimate responsibility for resource adequacy in the MISO region lies with its member states and other Relevant Electric Retail Regulatory Authorities ("RERRAs"). MISO works closely with stakeholders, including the states, to provide market tools and information necessary to support regional transparency that, in turn, support and inform resource investment decisions relating to resource adequacy. MISO has made significant advancements over the past several years enhancing its market price signals, improving resource accreditation, assessing expected resource needs and improving its generation interconnection queue processes and tools.

The MISO region predominantly consists of vertically integrated utilities with responsibility for providing adequate electric generation to meet load for their area and states having jurisdiction over resource adequacy decisions. This is distinct from some other RTOs, which rely more heavily on competitive markets to shape electric resource adequacy needs. A combination of state and federal policies and consumer demand for carbon free energy has resulted in rapid growth of wind and solar energy accompanied by the retirement of many coal and natural gas power plants. While weather-dependent resources like solar and wind are being added in large numbers and provide many benefits, including lower electricity production costs than natural gas or coal as well as the lack of carbon emissions, they typically do not provide the same 24/7 availability, flexibility, and duration attributes as the retiring power plants they are replacing. For example, MISO has experienced 11 wind droughts since 2020, including one lasting 40 consecutive hours. Similarly, solar output is dramatically reduced in overcast or cloudy weather conditions, as often occur in winter storms, and output is virtually zero in the overnight hours. While energy storage technology is beginning to integrate into MISO's markets, we are not expected to see the volume of such resources be deployable in order to help support meeting resource adequacy and reliability needs for several more years. MISO works collaboratively with the states, utilizing its regional perspectives and insights, to ensure they have an understanding of evolving system needs and conditions. This is accomplished, in part, through MISO's work on long-term load forecasting, resource accreditation, and Futures Planning Scenarios.

MISO has a healthy partnership with the Organization of MISO States ("OMS"), an independent organization with its own dedicated staff representing the collective interests of state and local utility regulators in the MISO region. Many of the changes MISO has implemented were made possible due to their collaboration and role in communicating and facilitating the insights of the RERRAs in the MISO region.

By coordinating with states and other RERRAs, MISO is able to develop a range of expected outcomes we call Future Planning Scenarios. MISO's Future Planning Scenarios estimate that while the total amount of installed electric generation will increase significantly over the next 20 years due to the rapid growth of wind and solar, the actual amount of electricity available to the system during could face a net decline of about 32 GW[1] due to the operational characteristics of these new resources. Emerging technologies with the needed characteristics, such as longer-duration battery storage and small modular nuclear reactors, hold great promise in the future but are likely years away from grid-scale viability.

MISO also creates significant value for the region, which is quantified in the MISO Value Proposition study.[2] While resource development is critical, we must also recognize that the existing electric transmission infrastructure is vital in supporting resource adequacy and is a significant value driver by reducing the overall resource obligation to each load serving entity in the MISO region. The largest value driver in the MISO Value Proposition is the savings associated with the reduction in reserve margin needed to meet resource adequacy targets. Our work to maintain reliability, administer wholesale markets and conduct transmission planning on a regional scale generates substantial benefits. In 2024 alone MISO created approximately $5.1 billion in savings for the region, and over $50 billion since 2007. Ultimately, this results in lower costs to consumers. To continue driving high levels of value and low costs, the transmission system needs to keep pace with the location of the resources that will be developed to provide the energy that will be

[1] This projection is found in MISO Future 2A found in the MISO Futures Report developed in November 2023. More information on MISO Futures Series 2A Report can be found here https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf

[2] MISO's Value Proposition is an annual study that breaks MISO's business model into recognized categories of benefits and calculates a range of dollar values for each defined category. In 2024, MISO's annual benefit was valued at $5.1 billion. More information available at https://www.misoenergy.org/meet-miso/MISO_Strategy/miso-value-proposition/

needed in future years, and to provide the connectivity to move energy across the generation fleets to population centers.

MISO's region, like most of the country, is also experiencing changing weather patterns, including more frequent occurrences of extreme weather, particularly winter storms affecting large areas of the country. These extreme weather events create challenging operating conditions, with high demand for electricity sometimes accompanied by reduced solar or wind output and, in some instances, challenges with adequate fuel supplies for natural gas and coal power plants. This highlights the need for a diverse electric generation fleet and a robust transmission system to move energy over long distances.

Finally, demand for electricity is growing at an accelerated pace. Over the last few decades, we have experienced growth in electrification through electronic devices, smart home products, and electric vehicles, but minimal growth in electric peak demand, largely due to increasing energy efficiency. Looking ahead, however, we expect much stronger growth from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy hungry data centers to support artificial intelligence. In fact, based on the current trajectory, peak electric load in the MISO region is projected to grow at a 1.6% compound annual growth rate ("CAGR").[3] This compares to an average 0.5% CAGR between 2009 and 2024 and threatens to outpace new electric resource additions if urgent action isn't taken.

This combination of factors significantly increases operational challenges, uncertainty, and reliability risks to the electric grid. This, in turn, creates significant economic and security risks for our nation. If electricity production and delivery from all sources cannot keep up with growing demand, then the planned growth of manufacturing, artificial intelligence, and data centers cannot occur. A timely and coordinated approach is necessary if we are to continue meeting the nation's need for reliable and low-cost electricity. MISO is committed to meeting this challenge in coordination with our states, members and stakeholders as articulated by our Reliability Imperative effort.

MISO Reliability Imperative

The electric industry in general, and the MISO Region in particular, are changing in significant ways. In the past, MISO maintained a reliability standard significantly above the "one day in ten years" that is the minimum acceptable rate of reliability. However, as MISO has been emphasizing since 2022, we have seen resource margins and reliability standards decline due to policy drivers, aging resources and financial incentives. Today, the MISO region is meeting the 1:10 minimum, and we are working to maintain at least this level going forward.

Looking ahead, we have four tools for maintaining reliability: 1) maintain existing generation, as needed for resource adequacy; 2) enhance the utilization of demand response; 3) build new generation and transmission when existing resources are

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[3] More information on the current trajectory of peak load growth can be found in MISO's Long-Term Load Forecast published in December 2024 and found here https://cdn.misoenergy.org/MISO%20Long-Term%20Load%20Forecast%20Whitepaper_December%202024667166.pdf

unavailable to support new load growth; and 4) be prepared for more frequent instances of targeted load shed to ensure system reliability during extreme operating conditions.

The sharing of responsibility between MISO, Load Serving Entities ("LSEs"), and RERRAs is needed to address the challenges of rapid fleet change, increased frequency and severity of extreme weather events, and other factors that pose a threat to reliability in the MISO Region. MISO calls this shared responsibility the 'Reliability Imperative.' The word 'imperative' is appropriate for several reasons. First, the work we are doing is not optional—to maintain system reliability, we must respond to the unprecedented change we and our members face. Second, this work cannot be put off for months or years—much of it has long lead times, so we need to act now. And third, our stakeholders are counting on us—regulatory agencies, utilities and other entities are looking to MISO to identify problems and find solutions."[4]

MISO published a report in December 2020 that documents these trends and explains why these trends create a Reliability Imperative for the region.[5] MISO's response to these issues focuses on four pillars: (1) Market Redefinition; (2) Operations of the Future; (3) Transmission Evolution; and (4) Systems Enhancements (formerly called Market System Enhancements). Pillars #1 and #3 profoundly affect resource adequacy.

As explained by MISO's Chief Executive Officer, John Bear: "The industry's longtime reliance on conventional baseload power plants is declining sharply, driven by economic factors and consumer preferences for clean energy, among other things. Meanwhile, the grid is becoming increasingly reliant on wind and solar resources that are available only when the wind is blowing or the sun is shining. To be sure, there are upsides and opportunities associated with these trends. But the changes we are seeing also pose a host of complex and urgent challenges to electric system reliability in the MISO Region. Utilities, states, and MISO all have roles to play in addressing these challenges."[6]

Pillar #1: Market Redefinition

MISO's market design guiding principles are an important guide to evaluating and developing market enhancements that have been used as a foundation for conducting the Planning Resource Auction (PRA). MISO's Market Design Guiding Principles are as follows:

- Support an economically efficient wholesale market system that minimizes cost to distribute and deliver electricity,
- Facilitate non-discriminatory market participation regardless of resource type, business model, sector, or location,
- Develop transparent market prices reflective of marginal system cost, and cost allocation reflective of cost-causation and service beneficiaries,

[4] See MISO's Response to the Reliability Imperative (December 2020), available at https://cdn.misoenergy.org/MISO%20Response%20to%20the%20Reliability%20Imperative%20FINAL504018.pdf.

[5] More information on MISO's Reliability Imperative at https://www.misoenergy.org/meet-miso/MISO_Strategy/reliability-imperative/

[6] MISO's Response to the Reliability Imperative, found here https://cdn.misoenergy.org/MISO%20Response%20to%20the%20Reliability%20Imperative%20FINAL504018.pdf

- Support Market Participants ("MPs") in making efficient operational and investment decisions, and
- Maximize alignment of market requirements with system reliability requirements

All aspects of MISO's resource adequacy construct have been and are being evaluated to better ensure energy readiness under this Reliability Imperative. Specific efforts in this area include providing a longer-term and deeper assessment of system needs across all hours of the year, including required capabilities such as flexibility, shifting to verifying sufficient generation adequacy across all hours of the year, improving how resources are accredited, ensuring that prices accurately reflect market conditions, especially during emergencies, and developing market products that provide the right incentives for resources to maintain system reliability The initiatives in this category aim to ensure that resources with the types of capabilities and attributes the system needs will be available in all 8,760 hours of the year. Hence, MISO has moved from an annual auction to a seasonal one. This is important because as noted above, the region is increasingly facing reliability risks outside of the summer peak-load months that historically posed the greatest challenges. On the supply side, MISO has improved accreditation efforts, to reflect the availability of resources during hours in each season exhibiting low capacity margins.

On the demand side, MISO determined that the implementation of a Reliability Based Demand Curve ("RBDC") (sometimes referred to as a "sloped demand curve") in the PRA will support MPs by establishing more efficient capacity prices based on market fundamentals, where the marginal reliability benefit of the last MW procured is equal to its marginal cost.

With better price formation and improved capacity accreditation, MPs can make better informed operational, retirement, and investment decisions, and the PRA will significantly improve alignment of market requirements with system reliability requirements.

Pillar #3: Transmission Evolution

Over the last several years, MISO has approved over $30 billion in new transmission lines through a Reliability Imperative initiative called Long-Range Transmission Planning, or LRTP, with more expected in the coming years. These projects are projected to have a benefit-to-cost ratio of approximately 2.6 to 1 and will substantially improve electric transfer capabilities and enable the electric reliability and associated economic growth being planned across the nation.

Intermittent resources such as wind and solar work with the transmission system very differently than conventional power plants. For this reason, the ongoing trend of conventional resources retiring from service as intermittent renewables continue to grow poses significant challenges to the reliability of the transmission system in the MISO region. These challenges are framed up in MISO's Renewable Integration Impact Assessment work. Fortunately, MISO can leverage its large footprint and resources to ease some of the challenges. One of the keys will be transmission projects that support these new resources in the region. LRTP is designed to assess the region's future transmission needs, starting from a base of the utility and state plans on where to site and build new resources. LRTP does not replace other transmission-planning efforts that have long existed at MISO, such as the annual studies contained in the MISO Transmission Expansion Plan (“MTEP”). LRTP will coordinate closely with those efforts, and it will also be a transparent and cooperative part of the MISO stakeholder process.

LRTP is a comprehensive “transmission roadmap” that will identify and drive investments in transmission projects addressing all needs of the region as the resource fleet continues to evolve. The roadmap will be updated as needed to align with evolving resource fleets and business plans, state energy/environmental policies, and other dynamic factors that affect the region’s transmission needs. As solutions are identified through LRTP, they are moved into the ongoing MTEP process for final approval by MISO management and Board of Directors.

Recent Accomplishments

MISO and its stakeholders have made great progress under the Reliability Imperative in recent years. Some of our key accomplishments to date include:

> *Seasonal Resource Adequacy Construct*: In August 2022, the Federal Energy Regulatory Commission (“the Commission”) approved MISO’s proposal to shift from its summer-focused resource adequacy construct to a new, four-season construct that better reflects the risks the region now faces in winter and shoulder seasons due to fleet change, more frequent and severe extreme weather, electrification, and other factors. This new construct seeks to ensure that resources will be available when they are needed most by aligning resource accreditation with availability during the highest risk periods in each season.
>
> *LRTP Tranche 1*: The first of four planned portfolios of LRTP projects was approved by the MISO Board of Directors in July 2022. This tranche of 18 projects represents a total investment of $10.3 billion — the largest portfolio of transmission projects ever approved by a U.S. Regional Transmission Organization. These projects will integrate new generation resources built in MISO’s North and Central subregions, supporting the reliable and affordable transition of the fleet and further hardening the grid against extreme weather events.
>
> *Reliability-Based Demand Curve*: MISO’s Planning Resource Auction (PRA) was not originally designed to establish appropriate capacity clearing prices based on the reliability risk of clearing MWs above or below the one-day-in-ten reliability standard. This lack of a “warning signal” when reserve margins decline can mask an imminent shortfall — as occurred with the 2022 PRA. Efficient capacity pricing is also crucial to make effective investment and retirement decisions. MISO worked with its stakeholders to design an RBDC that will improve price signals in the PRA. Full implementation began in the 2025 PRA, with first year results demonstrating that the refined PRA is working as designed.
>
> *Futures Refresh*: The MISO Futures utilize a range of economic, policy and technological inputs to develop three scenarios that “bookend” what the region’s resource mix might look like in 20 years. In 2023, MISO updated its Futures to

lay the groundwork for LRTP Tranche 2 and to better reflect evolving decarbonization plans of MISO members and states. The refreshed Futures also model how the financial incentives for clean energy in the 2022 Inflation Reduction Act could further accelerate fleet change. The refreshed Futures are indicated with an "A" (e.g., Future 2 was updated and renamed Future 2A).

Queue Reforms: MISO has instituted several reforms to speed up the queue cycles, including a cap on the number of projects that can enter the queue in a given cycle, and is working on several technological enhancements and process improvements to eventually get to a one-year queue cycle. In the interim, an Expedited Resource Addition Study, or ERAS, process was recently submitted to the Commission for consideration. If approved, this process would provide a temporary framework, sunsetting by the end of 2028, for the accelerated study of electric generation projects that are required to address urgent resource adequacy and reliability needs

MISO's extensive analysis and operational experience make it clear that no single electric generating resource, transmission line, process improvement, emerging technology, or other solutions will solve all our challenges. Addressing our nation's future electricity needs requires a multi-faceted and coordinated approach that leverages all of these tools.

Next Steps

The operational challenges and reliability risks of the MISO region are largely mirrored across the country. To address them, we need to take several important steps to turn around the decline in available energy and expedite the construction of new electric generation and the transmission lines necessary to move necessary energy from where it is produced to where it is needed. Specifically:

- Ensure that states and utilities have the information they need to make prudent electric resource decisions to support resource adequacy.
- Continue to improve the loss-of-load modeling effort which underpins the planning reserve margins determined to meet the reliability standards. This includes better representation of all resources' availability and outage patterns, continued effort to model load growth and variability, and incorporate correlated impacts across both supply and demand.
- Let reliability needs help inform the pace of retirement of existing electric generating resources. Having the right mix of resources on the system means that we don't have to choose between decarbonization and reliability.
- Continue developing new resources at a rapid pace. Streamline the approval of new electric generation and transmission projects, and work to mitigate the regulatory, supply chain, and workforce challenges that can hinder development of these projects.
- Leverage an "all of the above" approach that includes a mixture of solar, wind, natural gas, storage, emerging technologies, and transmission to achieve reliability.

- Continue reforms, like MISO's ERAS and Demand Response and Emergency Resource reforms, that enable the more effective and efficient utilization of existing resources and capabilities.
- Continue exploring Distributed Energy Resources ("DERs") as a potential additional tool to address resource adequacy and reliability challenges.
- Support and encourage continuous interregional collaboration on future transmission needs and operational protocols that maximize the use of the existing system.

II. PANEL 1: THE RESOURCE ADEQUACY CHALLENGE IN RTOs/ISOs

***Question 1**: What is the current state of resource adequacy across RTO/ISO regions?*

a. ***Is this static or variable? Are resource adequacy challenges more acute in RTO/ISO regions with capacity markets compared to those RTO/ISO regions with alternative resource adequacy constructs? Why or why not?***

MISO has seen surplus capacity margins declining over the last several years. When considering capacity margins, MISO particularly views the level of "accredited capacity" as the key factor to assess resource adequacy. It is essential to consider the accredited value of capacity, rather than the simple "nameplate" value, since accredited is the only value that can be relied upon to ensure that energy will be provided by a resource during the periods of greatest need. The decline in accredited capacity is primarily due to the retirement of existing dispatchable generation, while new capacity additions have generally been non-dispatchable resources with lower accreditation values.

The reduction in reserve margin is a significant concern. MISO has continued to work closely with the states and stakeholders to ensure that the region remains, in excess of the 1-day-in-10-year Loss of Load Expectation (LOLE) reliability standard. Over the past several years, MISO has (1) initiated reforms to improve capacity accreditation to better signal the value of needed resource additions, (2) converted to a seasonal capacity construct to better reflect differing seasonal operating needs and characteristics, (3) continued collaboration with states with a transparent survey of future capacity expectation to inform policy makers, (4) provided longer term assessment of the resource mix changes in our Regional Resource Assessment ("RRA") to further inform long term policy and investment decisions, and (5) enhanced risk modeling to better align between the manner in which seasonal risk is being evaluated and resources are being accredited to meet the designated need.

The 15 states in the MISO region take their rights and responsibilities towards resource adequacy seriously and the MISO capacity market recognizes that. The OMS has supported developments in pursuit of MISO's Reliability Imperative. The Reliability Imperative was developed in 2020 to address urgent and complex issues facing the grid and contains four pillars: Market Redefinition, Operations of the Future, Transmission Evolution, and System Enhancements. Collaboration between MISO and the OMS allows for a reliable grid amongst changes in the diverse MISO footprint. MISO provides transparency in expectations of future resource adequacy plans through Futures

Modeling, the RRA, and the OMS-MISO Survey. We are confident that the footprint will continue to be resource adequate in the near and longer term.

MISO uses a few tools to assess the state of resource adequacy in its footprint. The RRA[7] is one of the periodic studies MISO conducts to forecast how the mix of electricity-generating resources in the MISO region could evolve going forward. Another is the OMS-MISO Survey. While RRA and the OMS-MISO Survey are similar in some ways, there are some key differences that provide resource planners. The RRA is a 20-year outlook based on publicly announced resource plans and policy goals. It projects that members and states will add new generation capacity at an unprecedented rate of 17 GW/year (compared to the average of 4.7 GW/year added over the last decade) for the next 20 years to reliably achieve their publicly announced resource plans and policy goals.[i] Accordingly, the RRA projects capacity surpluses in 2030 and beyond. In contrast, the OMS-MISO Survey is more focused on the near term and projects new installed capacity coming online at the pace at which resources have received interconnection agreements and come online in recent history. The 2024 OMS-MISO Survey therefore forecasted a range of possible outcomes, varying from capacity deficits beginning in 2025 (which did not materialize) to capacity surpluses through 2029. Again, these divergent results reflect that the RRA and the OMS-MISO Survey were designed for different purposes and use different data inputs, methodologies, assumptions.

MISO is confident that its current capacity construct is the best tool to identify, analyze, and address resource adequacy issues in the MISO region. The MISO capacity construct works because:

- The Reliability Imperative describes the shared responsibility between LSEs, states and RERRAs, and MISO to maintain a reliable grid.
- MISO respects states' rights toward resource adequacy and acknowledges that LSEs have the obligation to serve their end-use customers. In fact, most LSEs engage in some form of integrated resource planning that is used to meet these obligations and filed with their appropriate RERRA.
- This type of resource planning makes sense because investments in generation have expected lifetimes of well over 30 years, so asset owners require some level of confidence that these builds can recover their capital costs.
- MISO works closely with the OMS and RERRAs to communicate regional needs to maintain resource adequacy. Both the OMS-MISO Survey and the RRA provide information to MISO and MISO members on where resource adequacy conditions are trending. From this state-specific information, MISO conducts analyses that are made public around the different types and amounts of resources necessary to meet the reliability standards being imposed by NERC.
- The "1-day-in-10-years" LOLE criterion established by NERC and codified in our Tariff has served the region well and sets the benchmark used to design an adequate system.[8] MISO translates this LOLE criterion into an amount of planning reserve margins that LSEs are obligated to have.

[7] More information on MISO's 2024 Regional Resource Assessment can be found here https://cdn.misoenergy.org/2024%20RRA%20Report_Final676241.pdf

[8] MISO's reply to question 6 below recognizes that other reliability metrics on resource adequacy may be of use in the future.

- MISO conducts its prompt PRA to inform LSEs and RERRAs of resource adequacy trends in MISO. A one year clearing price is akin to the role of energy prices in MISO's real time market; well over 95% of an LSE's obligation for energy is procured in the day-ahead market, the real time market is an imbalance market but real time prices can drive Power Purchase Agreements ("PPAs") and expected day-ahead prices. Well over 90% of the obligations of LSEs in any PRA are met with owned or contracted for resources, which is consistent with integrated resource planning processes of the LSEs.
- The PRA has, since inception, served as a residual capacity auction, giving those LSEs that are long or short an opportunity to sell or buy, but the PRA is a voluntary auction.
- The PRA is conducted a few months before the beginning of the Planning Year, and conducted on a seasonal basis to recognize the differences in risks across the seasons.
- The prompt nature of the PRA significantly reduces uncertainty around where demand is heading and which resources are available to meet that demand for the upcoming Planning Year.
- With the adoption of the RBDC design, capacity prices are more reflective of the reliability contributions of the amount of MWs cleared, but they can still vary based, in part, on the amount and offer prices of supply.
- MISO's Value Proposition, highlighted above, shows the savings MISO members achieve in reduced reserve margins while maintaining the 1-in-10 LOLE through the risk sharing pool they participate in.

MISO's recent shift to a seasonal capacity market with seasonal accredited capacity better reflects extreme weather conditions that have become more prevalent. These weather conditions affect both the seasonal peak demand and the available seasonal supply. In addition, the seasonal construct better reflects the seasonal planned & forced outage patterns of supply. The recent implementation of the RBDC reflects the contributions to reliability incremental MWs can add to the system. On the supply side, resources are being accredited based on availability during all times of need, across all seasons (Schedule 53, seasonal accredited capacity resources).

<u>Question 2</u>: Given load growth and generation forecasts, what are your resource adequacy challenges going forward?

MISO's challenge is ensuring that the new generation in the region is able to keep pace to reliably meet the expected load growth while older generation resources with strong reliability attributes continue to retire. Existing dispatchable generation with flexibility attributes, such as natural gas and coal, is retiring rapidly and is being replaced by weather-dependent generation such as wind and solar that does not have the same 24/7 availability. Carbon-free resources that can provide the needed attributes – such as longer-duration battery, hydrogen, and small modular nuclear – is likely several years away from grid-scale viability.

This gap between dispatchable generation and highly accredited carbon-free replacements caused capacity shortfalls in the 2022/2023 planning year, being short in the North subregion by 1,230 MWs. Additionally, the extreme price volatility in the vertical demand curve auctions may have eroded confidence in the capacity construct by sending inefficient price signals, but this has been addressed with RBDC. Changes to the resource adequacy construct highlighted in the previous question, and the information provided through the OMS-MISO survey and RRA effort have initiated renewed efforts on the part of LSEs and RERRAs to address resource adequacy requirements.

Reliably navigating the energy transition requires more than just having sufficient generating capacity; it also requires urgent action to avoid a looming shortage of broader system reliability attributes. In 2023, MISO completed a foundational analysis of attributes, with a focus on three priority attributes where risk for the MISO system is most acute. System adequacy is the ability to meet electric load requirements during periods of high risk. MISO focused on the near-term risk factors of availability, energy assurance, and fuel assurance. Flexibility is the extent to which a power system can adjust electric production or consumption in response to changing system conditions. MISO focused on the near-term risk factors of rapid start-up and ramp-up capability. System stability is the ability to remain in a state of operating equilibrium under normal operating conditions and to recover from disturbances. MISO focused on the nearest-term risk factor of voltage stability. No single type of resource provides every needed system attribute; the needs of the system have always been met by a fleet of diverse resources. However, in many instances, the new weather-dependent resources that are being built today do not have the same characteristics as the dispatchable resources they are replacing. While studies show it is possible to reliably operate the system with substantially lower levels of dispatchable resources, the transformational changes require MISO and its members to study, measure, incentivize, and implement changes to ensure that new resources provide adequate levels of the needed system attributes.

In December 2023, MISO published an Attributes Roadmap report that recommends urgent action to advance a portfolio of market reforms and system requirements and to provide ongoing attributes visibility through regular reporting.[9]

<u>Question 3</u>: How do you reconcile your RTO's/ISO's resource adequacy objectives with state public policy requirements, which may accelerate the retirement of certain resource types or limit the entry of other resource types? For example, in light of such state public policy requirements and particularly in multi-state RTOs/ISOs, how does your RTO/ISO ensure resource adequacy?

MISO's resource adequacy objectives are formally communicated through the resource planning obligations on LSEs. As a general matter, the responsibility to assure resource adequacy belongs to the states. MISO runs an annual PRA to provide a tool for LSEs to complement their long-term resource adequacy procurement decisions under the supervision of their state regulatory authority.

MISO further supports adequacy objectives with state public policy requirements by assessing, analyzing, and providing states and other RERRAs with information on where resource adequacy conditions are moving. MISO uses the OMS-MISO Survey and RRA

[9] More information on the MISO Attributes Roadmap can be found here https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.

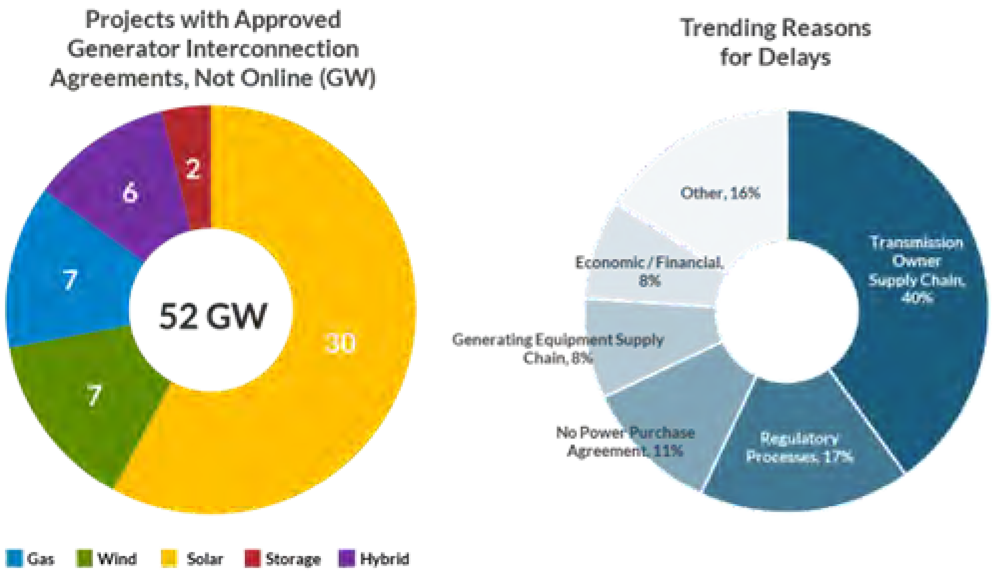
studies to highlight the needs of the entire footprint on a macro level. MISO is responsible for facilitating residual capacity transactions throughout the footprint through the PRA. Since MISO's inception, deference has been made to the jurisdictional authority of the states and other RERRAs with respect to resource adequacy rights and responsibilities that RERRAs take seriously. MISO respects states' rights towards resource adequacy and acknowledges that LSEs have an obligation to serve their end-use customers. As a result, MISO takes the resources offered into MISO's markets as given and procures resources to meet the margin requirements at least cost. This analysis is highlighted in the OMS-MISO survey and RRA studies. MISO has the obligation to translate the 1-in-10 LOLE requirements into planning reserve requirements and to facilitate residual capacity transactions through the PRA.

***Question 4**: What are the key drivers that cause delays in the construction and interconnection of generators in your RTO/ISO? What can be done to accelerate the interconnection of generators to help meet the resource adequacy challenge? How have factors external to your RTO/ISO, such as supply chains and siting/permitting, impacted generator interconnection timelines? What is the composition of resources in the queue? Will accelerating queue processes help address the challenge of resource adequacy? How many resources (by number and aggregate nameplate capacity) have received approval for interconnection but have not been constructed? How, if at all, are the expected resource adequacy contributions of a resource in the interconnection queue considered during the interconnection process?*

There is a combination of factors that contribute to delays in the construction and interconnection of new resources on the grid. This includes delays in the process to provide generation interconnection agreements to new generation resources and delays in those resource with generation interconnection agreements getting to commercial operation. MISO is taking significant steps to improve the queue processing delays and provide transparency to the delays in commercial operation dates to help facilitate identification of potential solutions to the problem.

The current reality is that study cycles are taking 3+ years in MISO's Generator Interconnection Queue process. This is, in part, due to the dramatic increase in the number of project submissions in recent years, which does not support the region's needs. Once a project receives a Generator Interconnection Agreement ("GIA") and is approved for construction, there may be construction delays due to supply chain challenges, regulatory hurdles, and other issues. More than half of all delays are attributable to transmission owner supply chain issues and regulatory processes. The next largest factor is lack of PPAs.

<u>Figure I.A.</u>[10]



An expedited study process that balances the responsibility for providing grid reliability and resource adequacy in the MISO region between MISO, LSEs, and the states can solve many of these problems. Projects that prove they have resolved the aforementioned barriers to success (such as funding, citing and permitting, etc.) should be able to enter a separate process to bring new generation online in the short-term to meet resource adequacy and reliability needs. This is especially needed in light of load growth and data center build out. Currently, data centers do not have a process in place to come online as quickly as the market would require. An expedited queue process can handle expected load growth, such as this, during a time when dispatchable resources are expected to leave the region at a rate much higher than accredited capacity can keep up with.

MISO found internal improvements to reduce study times as well. MISO's recently approved queue cap proposal will ensure a more manageable volume of projects, driving lower study times. Additionally, MISO's implementation of Suite of Unified Grid Analyses with Renewables ("SUGAR") software utilizes advanced data and analytics using machine learning and artificial intelligence to create reliable and informed planning and operations, as well as significantly lower study and modeling times. Full implementation of SUGAR will take study times from 3+ years to under 1 year. But it will likely take about 4 years for full implementation of SUGAR. Allowing for an accelerated study process for certain projects will address queue backlog until the entire queue process is improved to a 1-year timeframe.

To address supply chain issues MISO encourages long-term stability and certainty in federal energy policy. This will promote investments that are discouraged by volatility.

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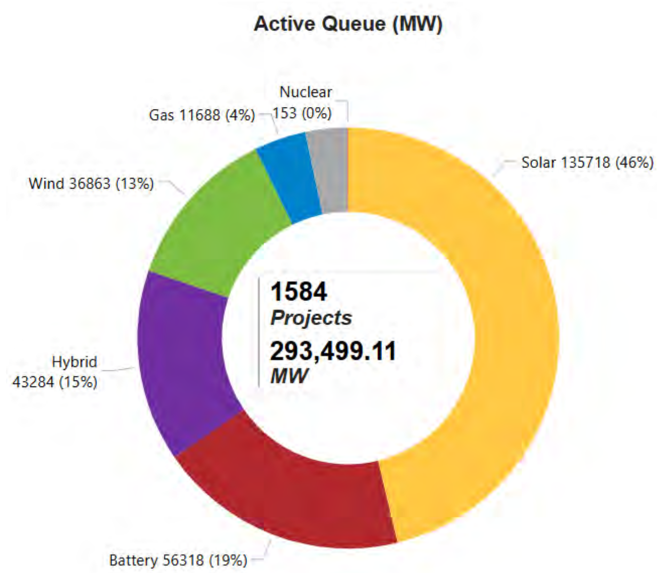
[10] Figure I.A. Compares 52 GW worth of generator interconnection projects with an Approved Generator Interconnection Agreement that have not come online with a breakdown of reported developmental delays. As of March 26, 2025.

Citing and permitting issues certainly causes delays, but these issues are not very different than they were 3-5 years ago. Generally, these factors should be addressed and resolved prior to entering the interconnection queue.

As a transmission planning organization, MISO is resource neutral and does not consider resource adequacy contributions during the interconnection process.

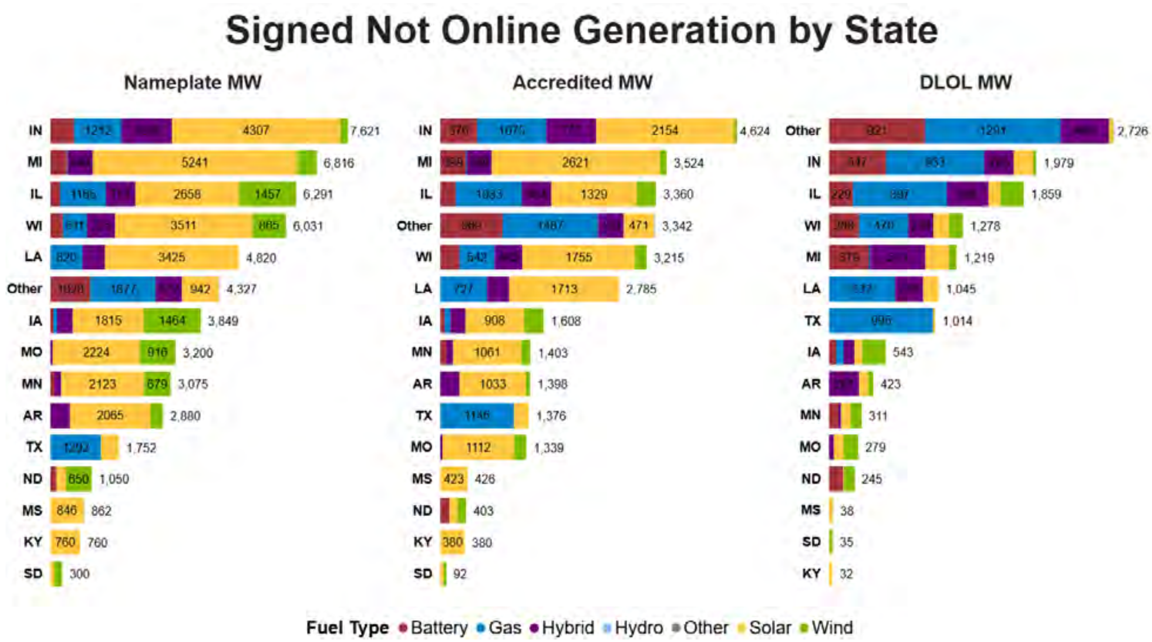
The current composition of resources in MISO's generation interconnection queue is illustrated in Figure I.B. This breakdown of capacity in the queue supports the points made in our answer to question 2 above about the potential looming shortage of broader system reliability attributes, being analyzed in the Attributes Roadmap report. Figure I.C. illustrates a breakdown of projects with signed GIAs that are not yet online.

Figure I.B.[11]



[11] MISO's Active Generator Interconnection Queue as of May 15, 2025.

Figure I.C.[12]



<u>Question 5</u>: Are there additional concerns that may affect resource adequacy in the near term (e.g., over the next five years) and in the longer term (e.g., ten years and beyond)?

In the long-term, an emerging gap between installed capacity[13] and accredited capacity[14] is a high priority. The MISO Futures utilize a range of economic, policy and technological inputs to develop three scenarios that "bookend" what the region's resource mix might look like in 20 years.[15]

Figure I.D. shows projected capacity change from 2022 to 2042 for all three Futures based on existing and member-planned resources, published in Series 1A MISO Futures Report. As the charts show, the region's level of *installed* capacity – the blue line – is forecasted to increase due to the many new resources – primarily wind and solar – that utilities and states plan to build in that 20-year time period. But because those new wind and solar resources have significantly lower accreditation values than the conventional resources that utilities and states plan to retire in the same 20-year period, the region's level of *accredited* capacity – the red line – is forecast to decline by 2042. With each Future increasing the total retirement of highly accredited thermal resources, this negative net change is more pronounced across Futures: Future 1A projects an 18 GW negative

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[12] Figure I.C. is a breakdown of signed generator interconnection agreements that have not yet reached their commercial operation date. This is displayed in nameplate capacity, accredited capacity, and projected implementation of approved capacity using Direct Loss of Load (DLOL)-based methodology, which will be implemented in 2028/2029.[12]

[13] Installed capacity, or ICAP, is the hypothetical amount of energy that can be produced under optimal conditions.

[14] Accredited capacity is the actual amount of energy that can be expected under real-life conditions.

[15] More information on MISO Futures Scenarios can be found here https://www.misoenergy.org/planning/futures-development/

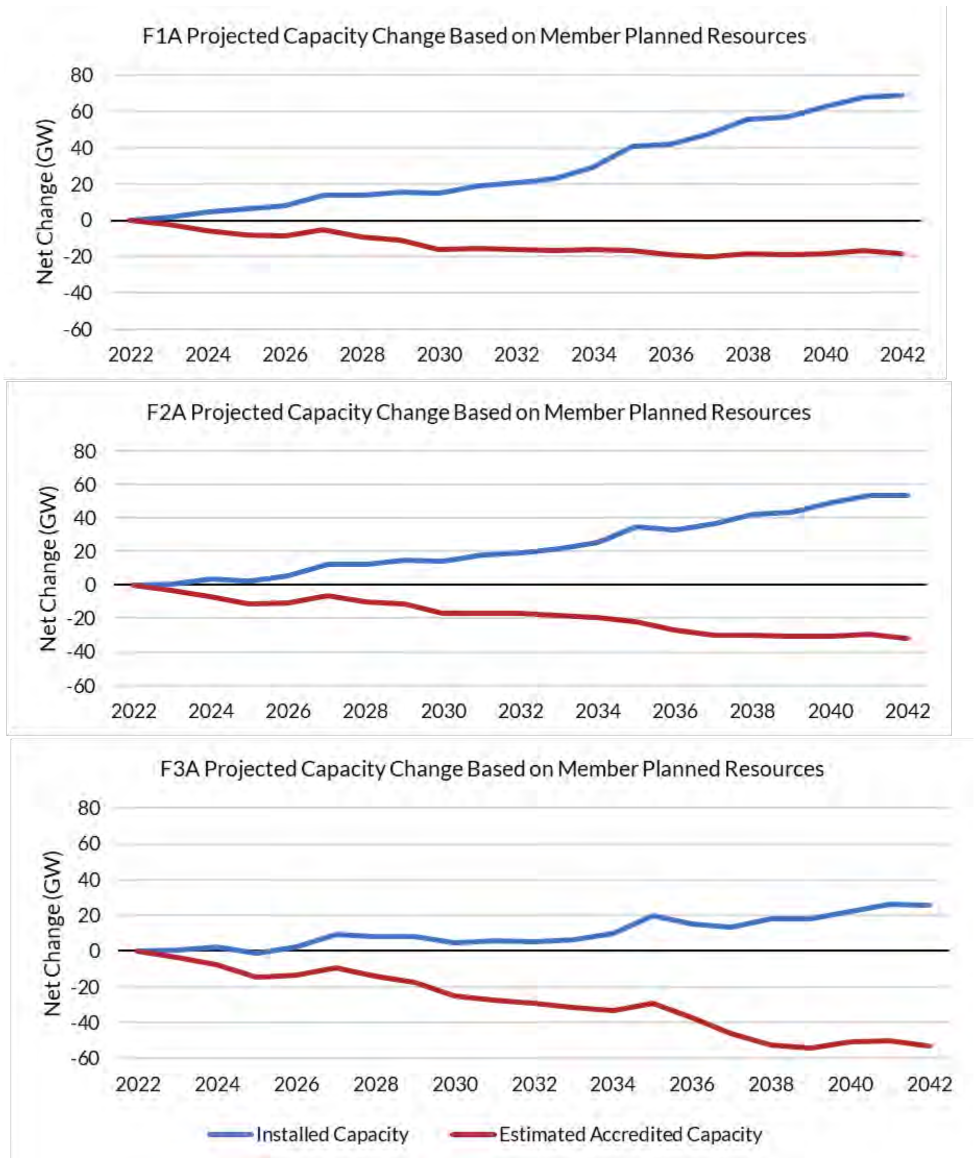
change in estimated accredited capacity across the study period, F2A projects a 32 GW negative net change, and F3A projects a 53 GW negative net change.

MISO modeling indicates that a reduction of that magnitude could result in load interruptions of three to four hours in length for 13-26 days per year when energy output from wind and solar resources is reduced or unavailable. Such interruptions would most likely occur after sunset on hot summer days with low wind output and on cold winter days before sunrise and after sunset.

Futures modeling is the key to addressing this shortfall. The MISO Futures team added 29 GW of Flexible Attribute Unit ("Flex") capacity to the Future 2A expansion and siting. Flex units are proxy resources that refer to a non-exhaustive range of existing and nascent technologies, representing potential generation that is highly available, highly accredited, low- or non-carbon emitting, and long in duration. As a proxy, potential Flex resources could be, but are not limited to: Reciprocating Internal Combustion Engines ("RICE") units, long-duration battery[16], traditional peaking resources, combined-cycle with carbon capture and sequestration, nuclear Small Modular Reactors ("SMRs"), green hydrogen, enhanced geothermal systems, and other emerging technologies. Flex units do not take away the need for previously identified resources but rather supplement them in periods of energy inadequacy.

[16] Greater than four hours.

Figure I.D.[17]



***Question 6*: In NERC's view, what aspects of resource adequacy planning could be improved? For example, what type of reliability metric (or metrics) should be used in resource adequacy planning models? What elements of resource adequacy planning can be improved or could serve as best practices?**

The 1-in-10 LOLE has served the region well and set the benchmark used to design an adequate system. However, many industry experts, including NERC, have raised questions about this framework's effectiveness in addressing future system risks. Of particular concern is the ability of the future resource fleet to serve load over extended

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[17] Figure I.D. comes from Series 1A MISO Futures Report published November 1, 2023. MISO is currently in the process of working with stakeholders to develop an updated Futures Report to reflect current circumstances. More information on Futures Redesign Workshop can be found here www.misoenergy.org/engage/committees/futures/

periods of time, with conditions that may lead to an energy-constrained system. For instance, a future system with no legacy thermal capacity and an abundance of variable and energy-limited generation may experience events much larger in magnitude and longer in duration than today's system. In response to Question 5, MISO's modeling indicates that a reduction of that magnitude could result in load interruptions of three to four hours in length for 13-26 days per year when energy output from wind and solar resources is reduced or unavailable. In 2024, MISO reviewed industry recommendations and new trends in the use of resource adequacy metrics. MISO also reviewed and analyzed adequacy metrics calculated in previous MISO studies. The result of this recommends a collaborative approach with states and the industry to revisit the 1-in-10 LOLE criterion, explore alternatives, and provide visibility to complementary metrics.[18] The Resource Adequacy Metrics and Critical Roadmap explores this issue and identifies the next steps by collaborating with the jurisdictions responsible for ensuring resource adequacy in the MISO region, including through the recently formed OMS Resource Adequacy Committee. MISO intends to continue engaging with stakeholders, provide a gap analysis to identify conditions under which energy adequacy materially erodes in a MISO system planned to 1-in-10 LOLE, and collaborate with OMS to develop a framework for identifying thresholds in risk metrics that may warrant potential changes to criteria in MISO's resource adequacy construct. Additionally, MISO plans to publish additional metrics more consistently across resource adequacy studies. MISO also seeks to increase industry collaboration, notably collaborating with other ISOs and research organizations and participating in the NERC drafting team of the new Planning Energy Assurance standard.[19]

<u>Question 7</u>: How does your RTO/ISO approach capacity accreditation? What are the benefits and drawbacks of harmonizing capacity accreditation methods across regions versus allowing for regional variation?

a. ***the current 1-in-10 LOLE criterion and the identification of additional analysis needed to evaluate whether there are gaps that need to be addressed. The Resource Adequacy Metrics Given that many regions use the same probabilistic models for both evaluating resource adequacy and/or reserve margins and for Effective Load Carrying Capability (ELCC) accreditation, are there best practices in approaches that NERC is observing that could help align various regions across the country in using the best modeling methodologies or data sources, etc.?***
b. ***What are the potential strengths, weaknesses, and implementation considerations of alternatives to ELCC when evaluating the contribution of various types of resources in meeting resource adequacy requirements?***

MISO has made significant reforms to improve the resource accreditation methodology to meet the regional reliability needs in the region. These reforms provide a strong foundation to ensure that LSEs bring the resources needed for MISO's operators to

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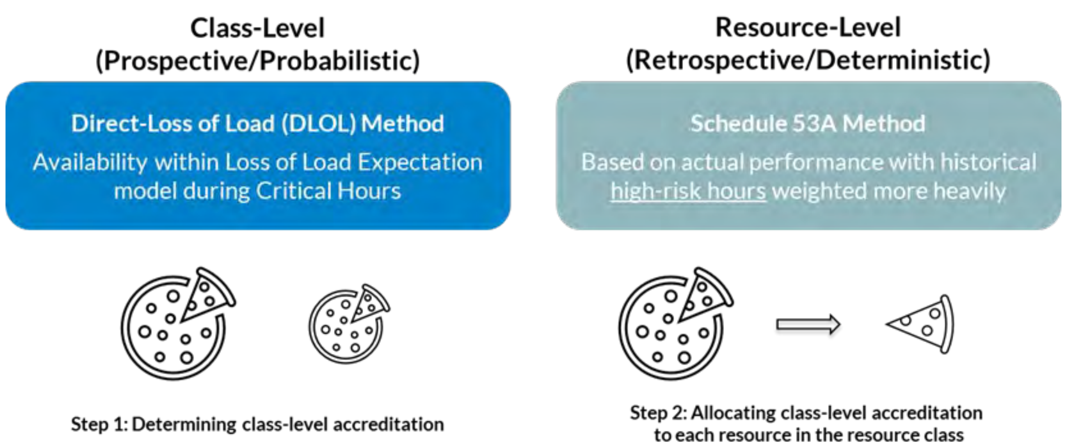
[18] Recommended through the Resource Adequacy Metrics and Criteria Roadmap document.
[19] More information on the NERC Planning Energy Assurance standard can be found here https://www.nerc.com/pa/Stand/Pages/Project-2024-02-Planning-Energy-Assurance.aspx

dispatch resources to meet customer demand for every hour in the day and the resource adequacy market provides a transparent signal for needed resource investment.

MISO is currently transitioning to a two-step accreditation approach (the "Direct Loss-of-Load" or "DLOL"-based methodology) that accredits capacity based on marginal contribution to reliability during periods of highest system risk ("marginal effective load carrying capability" or "marginal ELCC") and on Resource Class. MISO's DLOL-based methodology combines both probabilistic and deterministic elements into a single resource accreditation process. Simply described, the DLOL-based methodology takes two steps by first determining the size of the pie, and second, divvying up the pie.

Figure I.E.



Regional diversity evolved for various reasons and a prescriptive process is not optimal or productive. For example, the Tariff interregional study process with SPP, which has been in place 2020, has yielded no new projects. MISO supports allowing for regional variation to allow RTOs/ISOs to address the unique needs of their regions. MISO has a very diverse footprint: 6 out of 16 regulatory jurisdictions are elected, 4 jurisdictions have moderate to aggressive renewable portfolio standards, 7 jurisdictions lean towards a traditional, fossil fuel approach, and 5 jurisdictions take a balanced approach. The one uniform metric across all states and all RTOs/ISOs is 100% for grid reliability. But MISO does actively engage with all other RTOs in North America, in part through the ISO/RTO Council ("IRC") Markets Committee and also in part with direct discussions with RTO staff to follow best practices in the industry. If design attributes in another RTO look to potentially address MISO issues, we vet these before the stakeholder community and adopt them as appropriate. An example of this is the RBDC design being similar in nature to some of the eastern RTOs construct.

MISO does not speak on behalf of NERC, but MISO agrees with the Commission's previous statements that "using the same model for determining the amount of capacity required and the amount of capacity a resource is capable of providing is a reasonable modeling methodology. This method allows risk to be evaluated on a more granular level and provides for consistency between the system's resource adequacy requirements and resource accreditation to meet those requirements."[20]

MISO strongly believes that, while respecting regional variations, capacity should be accredited based on performance during times of high risk to properly recognize that not all capacity is created equal, nor will all capacity perform equal in any given situation. Weighing hours based on margin recognizes that not all the simulated events are equal, by assigning greater weights to those hours that have the highest unserved energy. It also provides a distinction between loss of load hours with negative margins and low margin hours with zero or small positive margins by providing higher weight to the former. This ensures that the expected reliability risk during critical hours is being appropriately accounted for in the resource class-level accreditation calculation.

MISO has considered a number of approaches and has found that approaches that accredit an entire class of resources based on the average contribution of the entire fleet do not align with the assumption that capacity exchange in the capacity market is fungible. Instead, marginal accreditation that measures the contribution of the next incremental addition to the resource fleet is a statistically robust method for measuring the incremental, or marginal, contribution to system reliability for any resource that reflects its availability during the hours of highest reliability risk.

The contribution of various resources in meeting resource adequacy requirements must be weighed in relation to their impacts on the system during high-risk hours. MISO has considered alternative weighting schemes, ranging from equal weights for all hours, weights based on the amount of unserved energy, combining the loss of load hours and low margin hours with a fixed ratio, and alternative weighting based on margin. None of these alternative schemes provide consistent emphasis on the hours with highest unserved energy to the level that weighing hours based on margin does. This properly accounts for the magnitude of expected reliability risks in each hour. This construct provides numerically stable results regardless of whether the group of hours include only loss-of-load hours, a few low margin hours, or a large number of low margin hours.

***Question 8*: How can the RTOs/ISOs ensure that their demand forecasts adequately take into account load growth from data centers and other large loads? How can the RTOs/ISOs ensure there is sufficient supply to meet these demands, and what will those sources of supply be?**

Appropriately forecasting load growth from data centers and other large loads is a significant challenge across the industry. The issue is present in both RTO and non-RTO regions. The visibility and transparency of the RTO framework allows the challenge to be more clearly identified and visible in the RTO regions. MISO ensures that there is ample supply to meet demand through a prompt capacity market, resource forecasts provided by the OMS-MISO survey, conducted annually, and the RRA effort. MISO works closely with the OMS coordinating and collaborating with all potential PRA reforms to better support grid reliability.

20 See PJM Interconnection, L.L.C., 186 FERC ¶ 61,080 (2024)("PJM Order").

Longer term load forecasts[21] originate with the LSEs. MISO validates and utilizes these forecasts to adequately take into account load growth from data centers and other large loads. MISO subject matter experts validate forecasts for the upcoming planning year through a random sampling approach. Included in this sampling is an assessment of the accuracy of the past year's forecasts which outlines a set of detailed questions related to the forecasts that each LSE must answer. Accounting for load growth from data centers and other large loads is asked directly to LSEs with a requirement on the LSE show support for their assumptions.

MISO recently updated our long-term[22] load forecasting process to better account for the impact of new sources of load growth on long-term planning. The process uses bottoms-up estimates of load for each of a set of drivers (e.g. data center announcements) along with assessed probabilities (e.g. likelihood of an announced data center being built on time) to develop a range of credible forecasts. These forecast are benchmarked against the LSE-provided forecast in the first few years. Longer-term load forecasts support MISO's transmission planning efforts and inform member resource planning decisions.

<u>Question 9</u>: How can demand flexibility and demand-side management solutions be utilized to address load growth and resource adequacy concerns?

Demand resources acting as supply are viable alternatives for LSEs to use in meeting their capacity obligations, and are used quite abundantly in MISO. MISO continues to explore future implementation of DERs to assist in resource adequacy challenges and is working closely with the OMS to be transparent around any future reliability issues. MISO has also recently filed reforms intended to better accredit demand-side resources to ensure those are resources appropriately valued as a resource adequacy tool.

<u>Question 10</u>: How do you reflect transmission availability—both regional and interregional—in your resource adequacy planning and requirements? To what extent do your transmission planning processes capture the resource adequacy benefits of regional and interregional transmission?

The changing resource mix requires more transmission to get generation to load. MISO's Tranche 2 portfolio of LRTP projects is progressing, with approval from MISO's Board of Directors in 2024. Planning is complex, but MISO has balanced the need to move quickly to meet resource adequacy objectives with the need to develop a robust, lowest-cost portfolio. Through the roll out of LRTP projects, transmission projects are in progress in areas with the greatest need based on ranges of economic, policy, and regulatory inputs. Availability of regional transmission capability affects the ability to import/export resources across the MISO footprint. MISO captures these capabilities in the capacity import and export limits modeled and respected in the PRA. These import/export limits are reevaluated annually and modeled in the PRA, allowing resources to meet local and regional capacity requirements.

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[21] Anything longer than a week or two out or any load forecasts that are not used in the Energy and Operating Reserve markets.
[22] 20-year.

To get customers to build out generation, they mainly need reasonable costs and cost certainty. MISO's JTIQ ("Joint Transmission Interconnection Queue") addresses this by spreading costs among interconnection customers so that customers do not hesitate to build out due to fear of being the project that triggers a higher cost than what is feasible. This allows all parties to pay reasonable costs that they can anticipate in advance.

Panel 5: MISO's Resource Adequacy Challenge

***Question 1**: What is the state of resource adequacy in MISO in the near term (e.g., over the next five years) and over the longer term (e.g., ten years and beyond)?*

a. Is MISO's resource adequacy construct delivering resource adequacy in MISO?

b. *What are the benefits and drawbacks to MISO's resource adequacy construct and residual capacity auction?*

There are urgent and complex challenges facing electric system reliability in the MISO region. These challenges include generation fleet change, regulatory hurdles, extreme weather events, and load additions, to name a few. In light of this, utilities, states and MISO have taken steps to coordinate with urgency to avoid any mismatch between the pace of adding new resources and the retirement of older resources. MISO is confident that by addressing the four pillars of the Reliability Imperative the region will remain in excess of the 1-in-10 LOLE Standard.

MISO uses a few tools to assess the state of resource adequacy in its footprint. The RRA is one of the periodic studies MISO conducts to forecast how the mix of electricity-generating resources in the MISO region could evolve going forward. In contrast, the OMS-MISO Survey is focused on the near term and is based on much lower expectations of new installed capacity, reflecting the pace at which resources have received interconnection agreements and come online in recent history. Each study was designed for a different purpose, uses different data inputs, covers different time periods, and uses different methodologies and modeling assumptions. Accordingly, the results differ. For example, the RRA assumes members and states will be able to add new generation capacity at an unprecedented rate of 17 GW/year for the next 20 years to reliably achieve their publicly announced resource plans and policy goals. Accordingly, the RRA projects capacity surpluses in 2030 and beyond. The 2024 OMS-MISO Survey therefore forecasted a range of possible outcomes, varying from capacity deficits beginning in 2025 to capacity surpluses through 2029. These divergent results reflect that the RRA and the OMS-MISO Survey were designed for different purposes and use different data inputs, methodologies, assumptions and time horizons.

In sum, given that the MISO states have rights towards resource adequacy, take their roles and responsibilities seriously, and MISO is providing transparency in expectations of future resource adequacy plans, we are confident that the footprint will continue to be resource adequate in the near and longer term. Capacity margins are declining but remain in excess of the 1-in-10 LOLE standard. MISO successfully implemented the RBDC in the capacity market for the 2025-2026 PRA. This construct provides more accurate price signals and encourages resource investments by reflecting the contributions to reliability incremental megawatts can add to the system. The capacity market has changed from an annual to a seasonal construct to better reflect the risks to resource adequacy shifting from mainly the summer peak demand conditions to periods across all seasons and time periods. On the supply side, resources are being accredited based on availability during all times of need, across all seasons. In the most recent PRA, the megawatts that cleared in the summer season exceeded 1-in-10 LOLE by an additional 2 percentage points because the reliability contribution of these additional megawatts exceeded the cost to procure them.

The RBDC construct values the reliability contribution of incremental MWs, the price signals that reflect that reliability value, and the prompt and residual nature of the capacity market. Prompt auctions have less uncertainty around demand values and supply availability. The residual nature recognizes that, in MISO, most LSEs come with resources that meet their requirements. There is the possibility that, without other actions, the prompt nature leaves little time to address any issues that arise, like shortfalls. This potential drawback is addressed through the OMS-MISO survey and RRA effort, providing more transparent information around future reliability requirements and resource margins.

<u>Question 2</u>: How have the recent outcomes of MISO's capacity auctions affected market participants and consumers in MISO? Do states and stakeholders have confidence that the MISO capacity market will be effective to achieve resource adequacy at just and reasonable rates?

The capacity shortfalls that occurred in the 2022/2023 planning year promoted a greater sense of urgency to MISO's ongoing efforts to continually enhance its market design. The vertical demand curve served the region well for many years but as the resource mix has changed and extreme weather events have increased, customer confidence in the capacity market eroded. The vertical demand curve created extreme price volatility that disincentivized investments. The RBDC, implemented for the first time in the 2025/26 PRA, has addressed this by providing more accurate price signals and encouraging resource investments by reflecting the contributions to reliability that incremental megawatts can add to the system. Most LSEs within MISO either have owned or contracted for resources that meet their obligations but, regardless, the more efficient capacity prices being established through the RBDC construct provide much better information to LSEs, RERRAs and generation owners to make more informed going forward investment decisions. This is akin to how Real Time energy market prices work – a very small percent of transactions are subject to real time prices, but Day Ahead prices are informed by what happens in real time. Changes to the resource adequacy construct highlighted above and the information provided through the OMS-MISO survey and RRA effort have initiated renewed efforts on the part of LSEs and RERRAs to address resource adequacy requirements.

States and stakeholders have shown confidence in the MISO capacity market to achieve resource adequacy at just and reasonable rates. This is in large part due to the collaborative relationship between MISO and its stakeholders. Since MISO's start, deference has been made to the states and other RERRAs with respect to resource adequacy rights. MISO has worked closely with OMS, the Independent Market Monitor ("IMM"), and other stakeholders to change the capacity market to a seasonal construct and implement the RBDC. OMS has reinforced the need for MISO's seasonal capacity construct and RBDC to properly accredit capacity in a world with more extreme weather and faster load growth than ever.

***Question 3*: How have the seasonal resource adequacy requirements and revised capacity accreditation methods worked in MISO to date? Have they helped MISO more accurately determine its resource adequacy needs? What issues or challenges has MISO experienced in implementing a seasonal construct and revising capacity accreditation, and how does MISO plan to address those issues or challenges?**

The seasonal construct has highlighted the seasonal differences in the planning reserve margins required to meet the reliability standards, the varying Loss of Load Probability distributed across the seasons, the variability in the values of accreditation for resources by season (the Seasonal Accredited Capacity, or, "SAC") and significant differences in load variability season by season. This has helped MISO more accurately determine its resource adequacy needs as extreme weather has reconfigured what it means to be resource adequate. Being resource adequate on the hottest day in the summer does not necessarily mean that an LSE is resource adequate on the coldest day in the winter. SAC allows MISO to stay reliable throughout the entire year by targeting the unique needs of each season.

Accreditation changes, SAC in particular, are much more reflective of availability of resources to meet needs in each season.[23] The changes MISO has made to accreditation has a prospective and retrospective tint to it on purpose, as it captures the class level performance during projected risk conditions, while still being grounded and calibrated against the reality of how actual units performed over the last 3 years. This allows good performers to continue having a great incentive to continue that performance. Spring & fall seasons can be quite variable with summer and winter weather patterns bleeding into the shoulder seasons. For example, as the weather changes, winter weather may continue into early spring. Each successive planning year provides MISO with additional data to support market design. Currently there is a limited sample size for assessing accreditation. MISO is addressing these and other issues with renewed effort on appropriate LOLE modeling, shared with stakeholders.

***Question 4*: How does MISO establish its load and resource forecasts?**

- ***a.* How does MISO integrate the load forecasts provided by load-serving entities and electric distribution companies into their planning reserve margin requirements?**
- ***b.* Does MISO verify the forecast methodologies and accuracy of forecasts?**
- **c. *Have the assumptions driving load and resource forecasts changed over time? If so, how?***

[23] The answer to question 7 in the above panel more fully describes the changes we have made.

d. ***How do the forecast models weight different inputs? Are some assumptions more uncertain, important, or impactful than others?***

e. ***How have the forecasts performed historically and are parties considering any changes to forecasting models or processes? For example, are you considering requiring demonstration of commercial readiness from prospective new large load additions?***

Anything longer than a few weeks or any load forecasts that are not used in the Energy and Operating Reserve markets are considered “longer-term forecasts” and originate with the LSEs. With such a wide and diverse footprint in MISO, LSEs are best positioned to have information on where energy & demand is moving in its localized area. Resource forecasts are provided by the OMS-MISO survey and the RRA efforts and are conducted annually.

MISO integrates previous LSE forecasts as direct inputs into the LOLE modeling which determines the planning reserve margin requirements. MISO verifies the forecast methodologies and accuracy of forecasts provided by LSEs. LSEs submit documentation, including a narrative with a complete description of the type of models being used, statistical model results, and spreadsheets with historic and forecast data, to MISO to support the LSEs’ forecast demands. MISO then draws a random sample of these LSEs broken up into identified segments. Current segments are large LSEs (demand greater than 1000 MWs), medium LSEs (demand between 100 MWs and 1000 MWs), and small LSEs (demand less than 100 MWs). MISO subject matter experts then assess and validate the credibility of the LSE’s submittals. Included in this is an assessment of the accuracy of the past year’s forecasts.

The values for the variables used in the forecast have changed over time and been updated to weigh different inputs appropriately. The variables themselves have not necessarily changed. For example, LSEs consistently see new commercial and industrial facilities being built and older facilities being closed, but more recently, new load growth predominantly from data centers has driven expectations of higher load growth in the near term. Statistical models calculate the weights endogenously.

Certainly, some assumptions are more uncertain than others. On the resource side, getting through the queue process has significant uncertainty. On the demand side, for instance, significant load additions, like data centers, have to be studied for reliability impacts and come with uncertain timing of these additions.

The forecasts have performed to acceptable industry standards in the past, though load growth has been minimal over recent time periods. MISO, however, is strengthening its load forecast validation process, providing more guidance on acceptable practices, and looking for discrete changes to the load forecasts.

Given the prompt nature of the PRA, demonstration of commercial readiness of prospective new load additions has always been a consideration.

<u>Question 5</u>: To what extent are barriers to entry (e.g., the interconnection queue backlog, supply chain limitations, siting and permitting delays, etc.) affecting resource adequacy in the MISO footprint?

The barriers affecting resource adequacy in the MISO footprint are less to entry, but rather barriers to success once projects exit the interconnection queue. Factors such as funding, off-taker agreements, supply chain, and permitting and citing delay projects from being built once they exit the generator interconnection process. There is over 50 GW of projects that have a signed generator interconnection agreement and are not yet online. Over half of them are already signaling they are delayed and cannot meet their originally expected in service date. New long-term stability and certainty in federal energy policy has further worsened these expected delays. A clearer signal on federal energy policies and import tariffs impacting necessary electrical components would promote investments and ease these delays. To improve visibility into these generators with interconnection agreements signed but not yet online, MISO created a Commercial Operation Date Dashboard on our website to help stakeholders understand when these resources are expected to come online.[24]

Another concern is the queue backlogs themselves. Although there is a significant amount of generation with a GIA waiting to come online, these resources may not have all the attributes necessary to ensure long term resource adequacy. The MISO queue has historically represented wind, solar, and battery storage projects. This includes 86% of the resources with a GIA waiting to come online, and over 96% of the 300 GW of projects in ongoing queue cycles. A significant shift is occurring for MISO's next queue cycle that will close in September of 2025. Currently there are 44 GW of projects submitted in the 2025 queue, and 26% of that is new natural gas resources. The queue backlog and delays mean these new resources may have to wait years to get an interconnection agreement.

To aid in the development of resources needed to address resource adequacy, MISO introduced a new process to study select projects outside the interconnection queue. The ERAS process was filed at Commission in March. This process would allow MISO to study individual projects, acknowledged by their RERRA and an off-taker agreement, with load to be studied by MISO through ERAS. This process would allow these projects to receive a GIA within months instead of years. This temporary process will only be in place until the queue backlog and delays have been mitigated.

<u>Question 6</u>: To what extent does the availability of regional and interregional transmission capability affect resource adequacy planning in MISO? How can MISO better address the effect of transmission capability on resource adequacy?

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[24] See the C.O.D. dashboard here https://app.powerbigov.us/view?r=eyJrIjoiOTU1ODlhNTktMjZjZC00N2I2LWJhYjMtMDEwOGNmZDM5ODk0IiwidCI6IjYwNDA5MTViLTlkZmYtNGQ0Ny1iYjM1LThhYzljOWE1ZGMxOCJ9&pageName=983a2cc8ca3ccf63608a.

Availability of regional transmission capability affects the ability to import/export resources across the MISO footprint. MISO captures these capabilities in the capacity import and export limits modeled and respected in the PRA.

MISO can increase study effectiveness to better address transmission capabilities. MISO is implementing the generator interconnection request cap (“queue cap”) and interconnection process improvements to achieve this. The queue cap limits requests at 50% of each region’s non-coincident peak load. This follows a first-in, first-selected approach to allow for more manageable request numbers which will improve effectiveness and efficiency. MISO is also implementing SUGAR software which has shown significant time reduction for preliminary studies so far. Additionally, a new application portal will be available for customers in June with improved interface and data quality.

<u>Question 7</u>: Would an alternative resource adequacy construct used by another RTO/ISO be more effective at delivering resource adequacy in MISO? If so, why?

No, the enhanced reforms with the DLOL construct provide an effective tool to deliver resource adequacy. The DLOL-based methodology respects states’ rights and responsibilities over resource adequacy. RERRAs have well established processes in place to meet the resource adequacy requirements determined by MISO and are expected to continue to do so. The residual nature of the resource adequacy construct is working as intended. The RRA studies and the OMS-MISO survey further support resource adequacy decision and planning across the footprint.

Additionally, MISO is not aware of any alternatives to the current residual market that would perform better in MISO at this time. Recent capacity market enhancements such as SAC, RBDC, and DLOL-based methodology will continue to be implemented, improve market signals, and support needed resource availability. MISO continues, however, to consider design changes to the resource adequacy construct that can enhance reliability and support needed resource investment decisions.

<u>Question 8</u>: What should be the allocation of roles and responsibilities between MISO and the states to ensure resource adequacy in the MISO region? How does MISO work with the states to identify and meet the region’s resource adequacy needs at just and reasonable rates? Has MISO studied the effects of state public policy on either resource adequacy or capacity market outcomes?

Every effort in pursuit of the Reliability Imperative is centered around the shared responsibility between MISO-member electricity providers, states, and MISO to maintain a reliable grid. MISO appreciates states’ responsibility for resource adequacy and acknowledges that LSEs have the obligation to serve their end-use customers. Both LSEs and RERRAs take their responsibilities seriously. Continued coordination is critical. With the pace of change confronting the electricity system, the impending influx of large data centers and the evolving generation portfolio there is heightened urgency to ensure the system remains reliable. Given this, MISO can assess, analyze and provide transparency on where resource adequacy conditions are moving, providing additional macro level views on the issues to help inform states and LSEs. MISO translates the 1-in-10 LOLE into planning reserve requirements and the responsibility of MISO to facilitate residual capacity transactions through the PRA.

MISO works closely with the OMS and RERRAs to communicate regional needs to maintain resource adequacy. Both the OMS-MISO Survey and the RRA provide information to MISO on state-specific forecasts. From this state-specific information, MISO conducts analyses that are made public around the need for different types of resources to meet the reliability standards being imposed by NERC.

MISO has not directly studied the effects of state public policy. MISO has, however, in its RRA studies, provided detailed analyses around the implications of state public policy. One example of this is increasing renewable energy trends. MISO puts priority on maintaining independence from individual MPs. We are fuel source and policy neutral, meaning we do not favor, prefer, or advocate any particular fuel or policy outcome. That doesn't mean, however, that we are disinterested observers. Our mission is to ensure the continued reliability of the bulk electric system.

III. CONCLUSION

MISO appreciates the opportunity to provide these responses to the Commission's questions regarding Challenge of Resource Adequacy in Regional Transmission Organization and Independent System Operator Regions.

Respectfully submitted,

/s/ Todd Ramey

Todd Ramey

Senior Vice President of Markets and Digital Strategy
Midcontinent Independent System Operator, Inc.

Appendix I

Appendix I summarizes data provided in this written statement through graphs, charts, and other images.

Figure I.A.

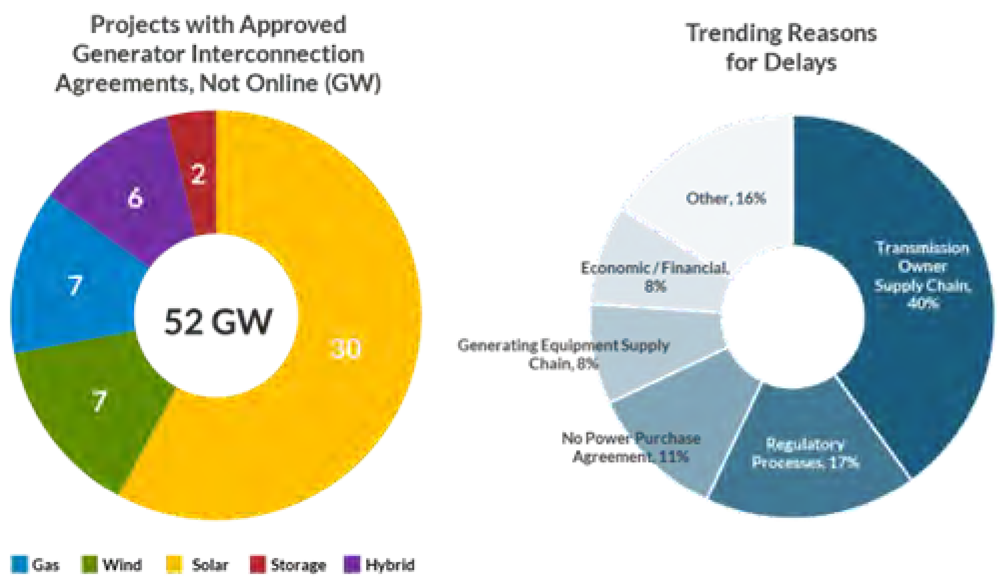


Figure I.A., found on page 13, compares 52 GW of Approved Generator Interconnection Requests in MISO with a breakdown of reasons for reported developmental delays and the percentage of delays affected by such set back.

Figure I.B.

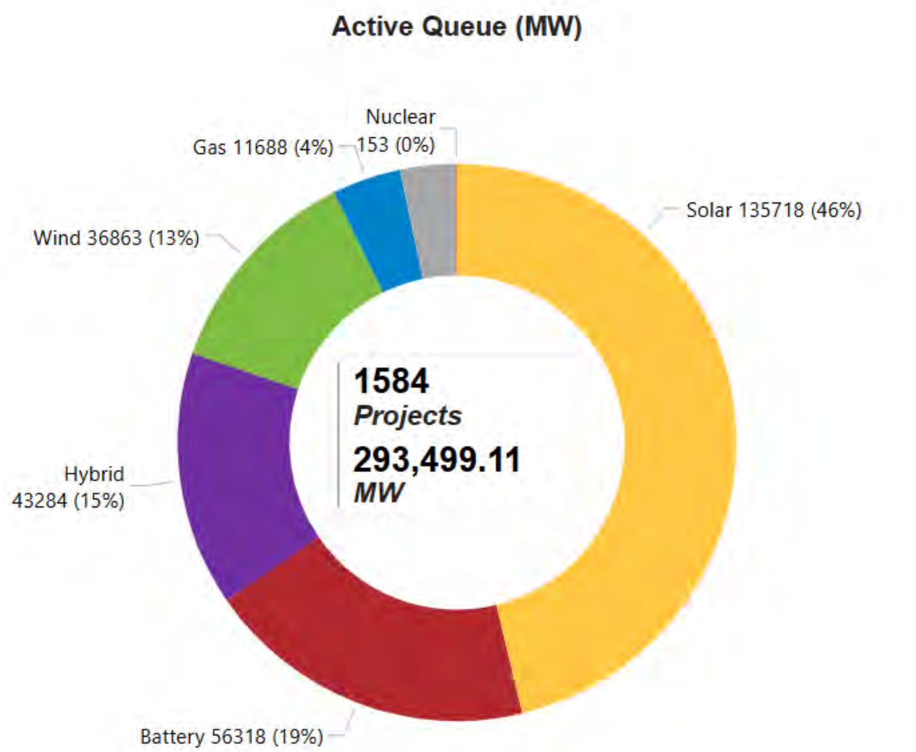


Figure I.B., found on page 14, illustrates the active MISO Generator Interconnection Queue by resource type. Does not reflect additional nameplate capacity from repowering existing generating facilities. As of February 6, 2025.

Figure I.C.

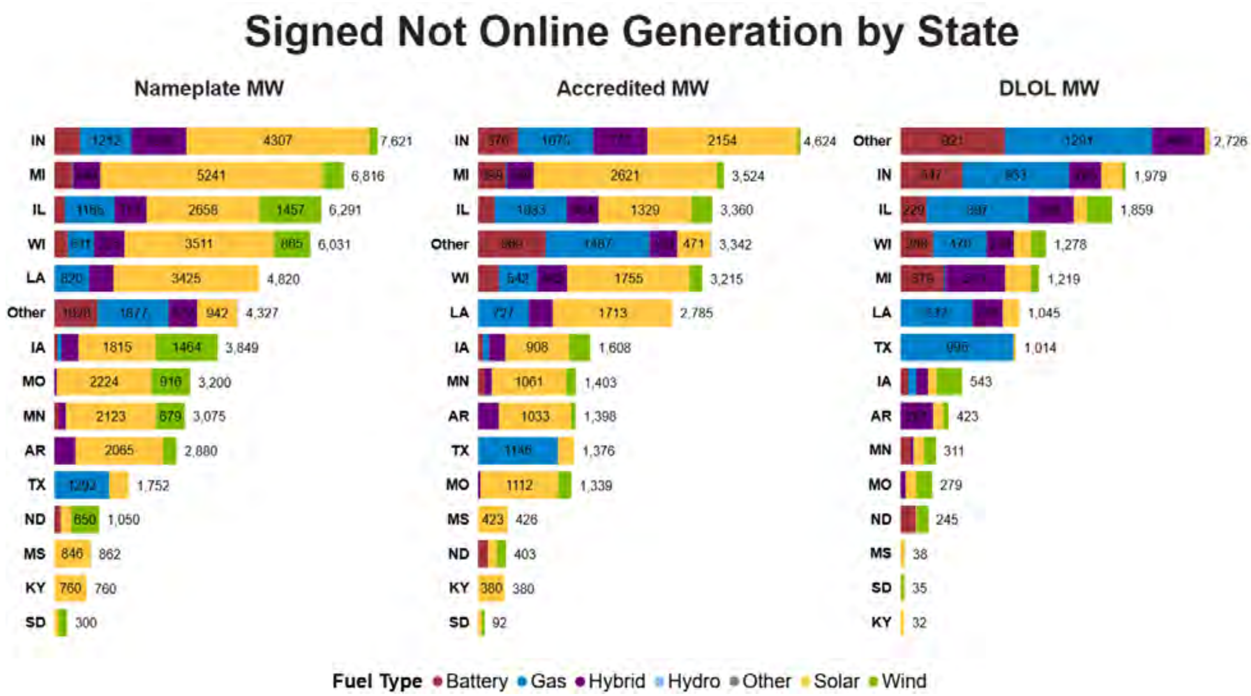


Figure I.C., found on page 15, illustrates a state-by-state comparison of MWs of Approved Generator Interconnection requests in nameplate capacity, accredited capacity, and DLOL-based methodology. The DLOL-based capacity accreditation assumptions are based on the fuel-based class average assumptions that are expected to be in place for the 2028/2029 planning year. The 2028/2029 Planning Resource Auction will be the first to utilize the DLOL-based methodology.

Figure I.D.

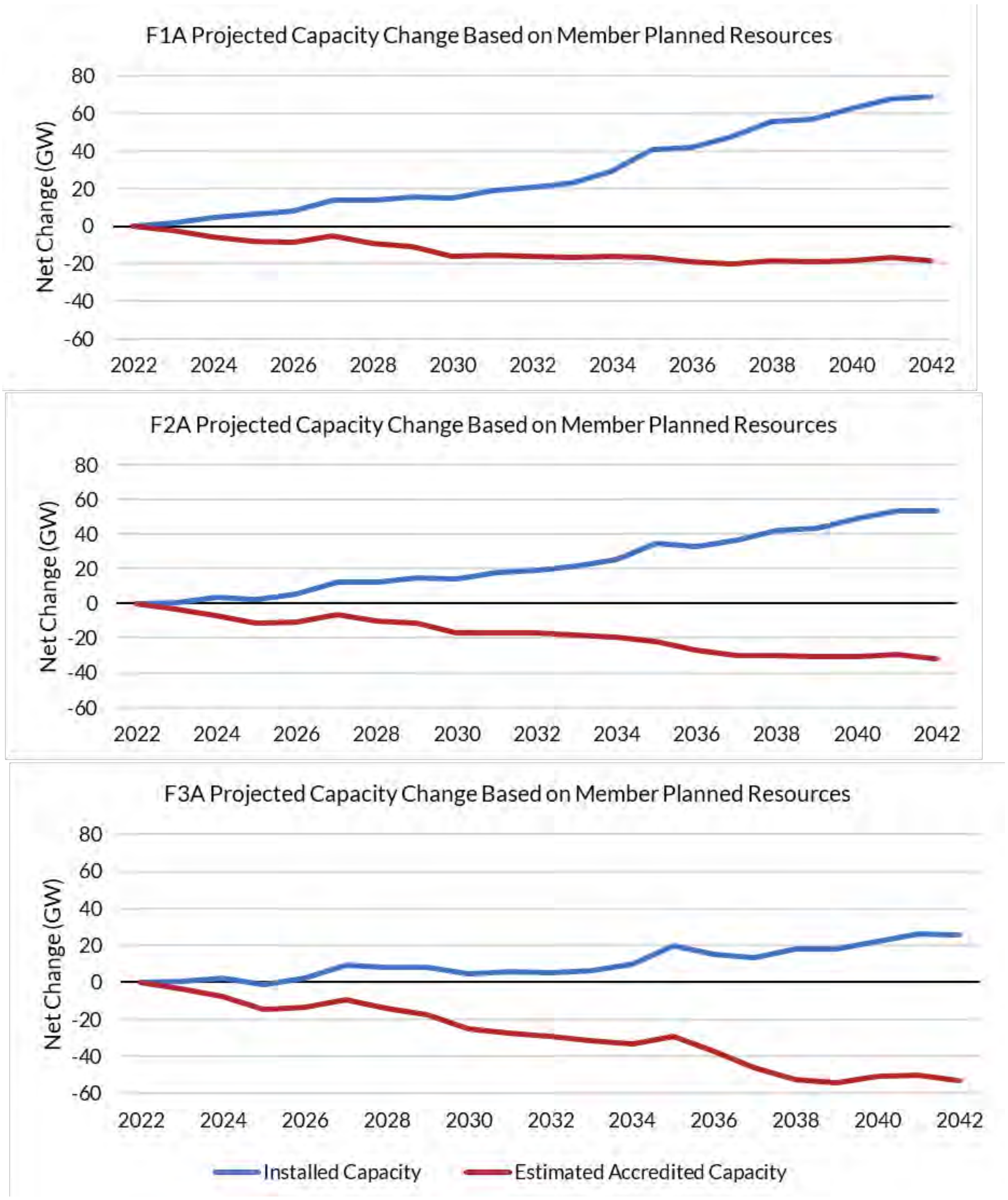


Figure I.D., found on page 17, shows projected capacity change from 2022 to 2042 for all three Futures based on existing and member-planned resources. Differences in the net change of installed and estimated accredited capacity are driven by the varying age-based retirement assumptions applied to existing resources across Futures. Figure I.D. is sourced from Series 1A MISO Futures Report. More information on this report can be found here https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf.

Figure I.E.

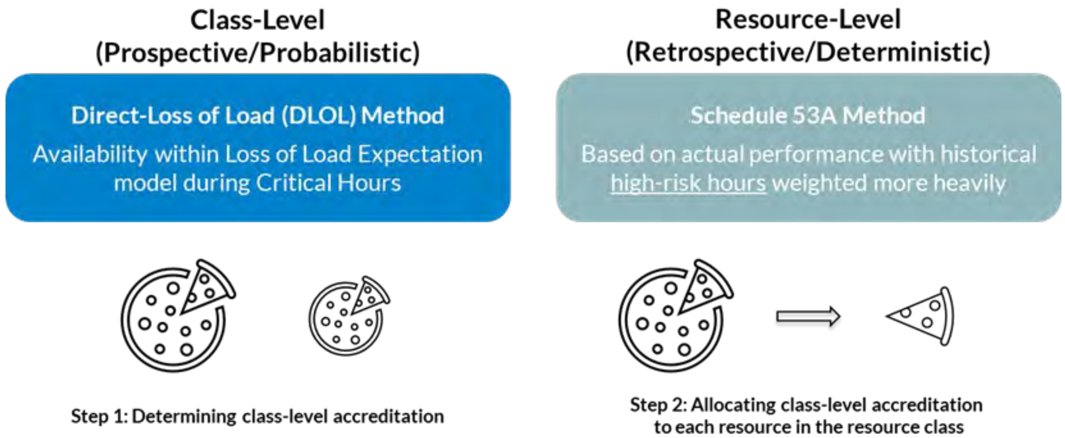


Figure I.E. explains the two-step DLOL-based resource accreditation methodology, further explained on pages 19. The DLOL-based capacity accreditation assumptions are based on the fuel-based class average assumptions that are expected to be in place for the 2028/2029 planning year. The 2028/2029 Planning Resource Auction will be the first to utilize the DLOL-based methodology.

Appendix II

Appendix II supplements information provided in this written statement with additional data on state generation retirements and additions.

Figure II.A.

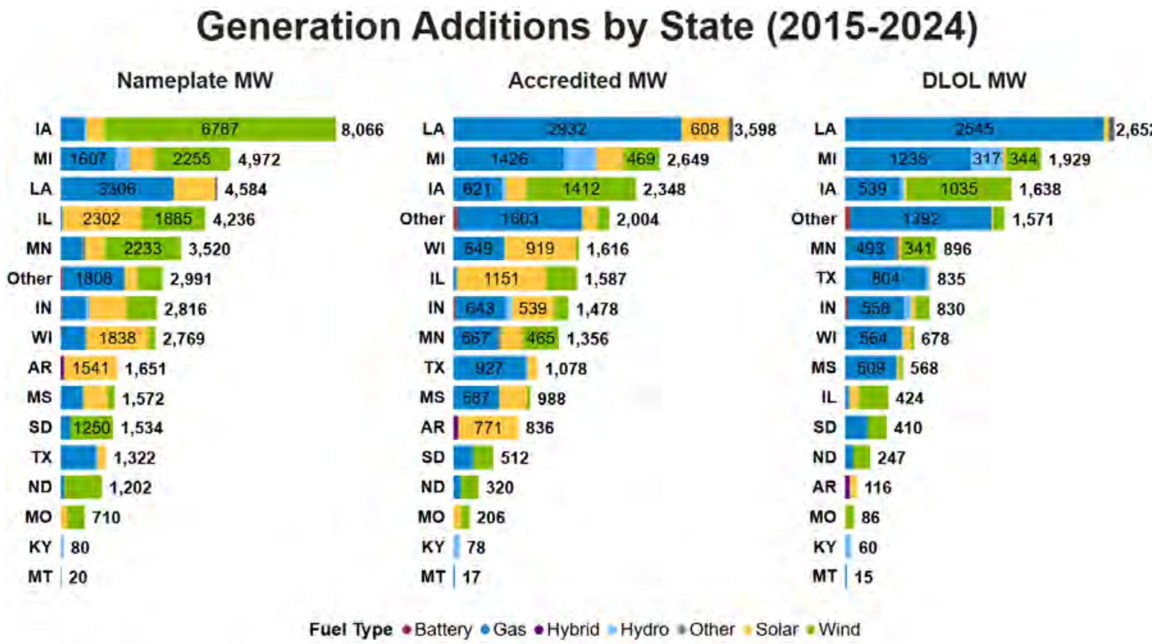


Figure II.A. illustrates a state-by-state comparison of generation that has come online over the last 10 years in the MISO region through new generation, surplus, and replacements. This is measured by nameplate capacity, current accredited capacity, and DLOL-based methodology. The DLOL-based capacity accreditation assumptions are based on the fuel-based class average assumptions that are expected to be in place for the 2028/2029 planning year. The 2028/2029 Planning Resource Auction will be the first to utilize the DLOL-based methodology.

Figure II.B.

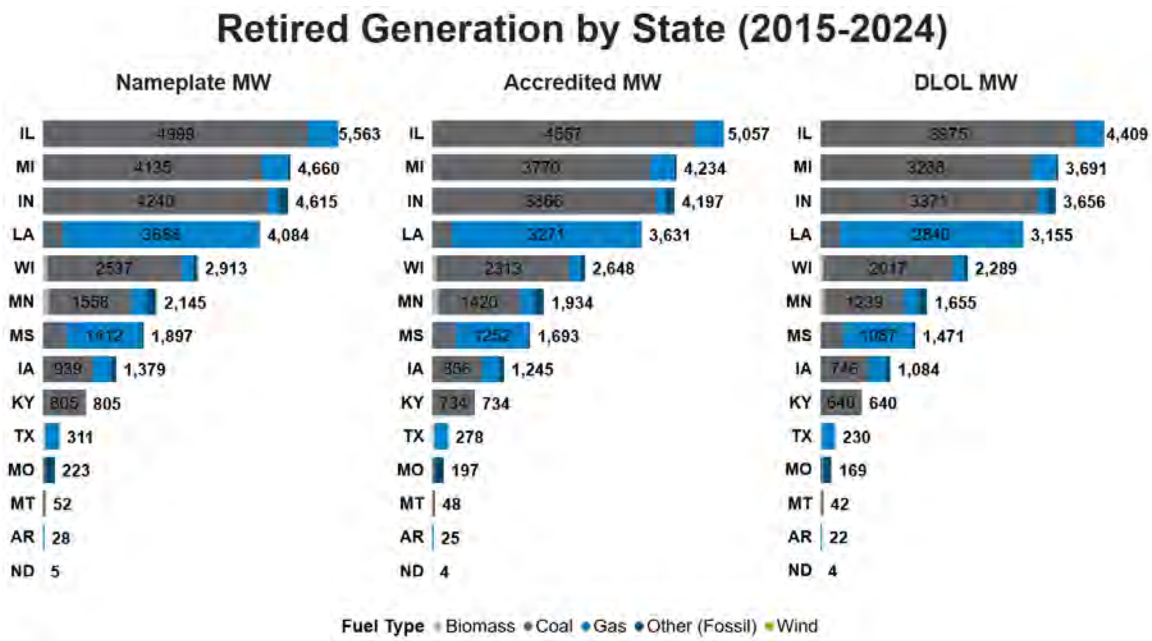


Figure II.B. illustrates a state-by-state comparison of retired generation over the last 10 years in the MISO region, measured by nameplate capacity, current accredited capacity, and DLOL-based methodology. The DLOL-based capacity accreditation assumptions are based on the fuel-based class average assumptions that are expected to be in place for the 2028/2029 planning year. The 2028/2029 Planning Resource Auction will be the first to utilize the DLOL-based methodology.

Figure II.C.

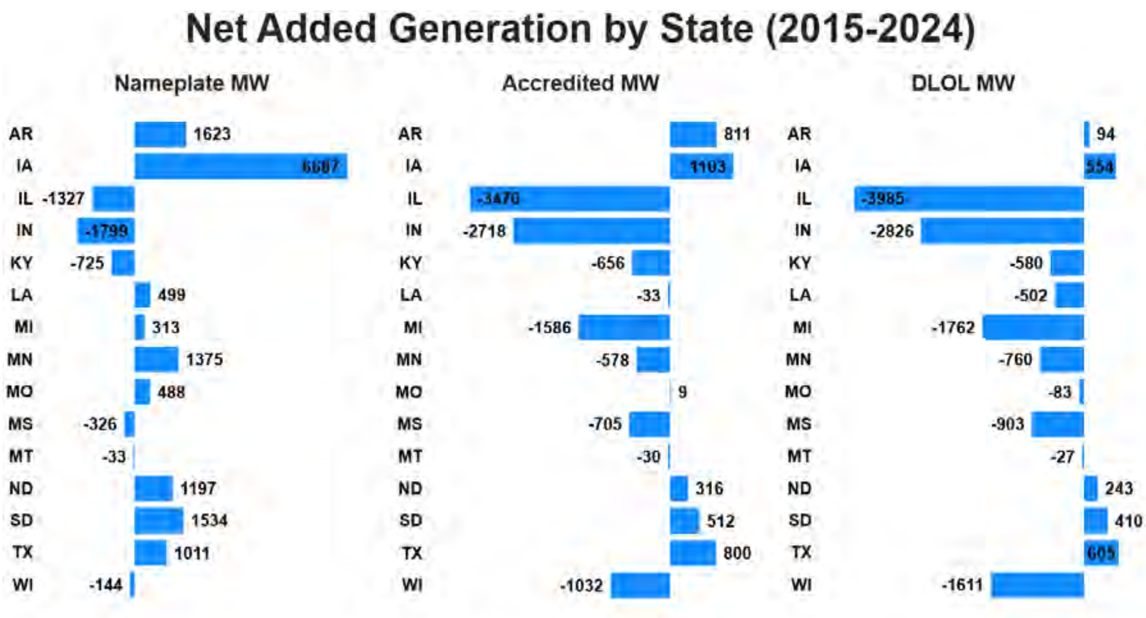


Figure II.C. illustrates a state-by-state comparison of net generation changes in megawatts over the last 10 years in the MISO region, measured by nameplate capacity, current accreditation, and DLOL-based methodology. The DLOL-based capacity accreditation assumptions are based on the fuel-based class average assumptions that are expected to be in place for the 2028/2029 planning year. The 2028/2029 Planning Resource Auction will be the first to utilize the DLOL-based methodology.

Document Content(s)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-26-22

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

Exhibit 35

Patton MISO Comments

TECHNICAL CONFERENCE COMMENTS OF
DAVID B. PATTON, PH.D.
MISO INDEPENDENT MARKET MONITOR

Meeting the Challenge of Resource Adequacy in RTO and ISO Regions
Docket No. AD25-7-000
June 4-5, 2025

Summary Bullets

- The resource adequacy challenges and risks in MISO are not nearly daunting as portrayed by MISO planning reports or the NERC 2024 Long-Term Reliability Assessment.
- For the first time, MISO has assembled all of the design elements needed to allow its capacity market to facilitate long-term decisions that achieve resources adequacy:
  - Prompt, seasonal market framework;
  - Demand aligned with reliability: reliability-based demand curves; and
  - Supply aligned with reliability: marginal reliability-based resource accreditation (to be implemented in 2028).
- The threats or issues achieving resource adequacy are now not related to the market design or rules, they include:
  - *State regulatory alignment with markets*: states must facilitate planning by their regulated entities that achieve both state policy goals and reliability objectives.
  - *Misalignment of MISO planning and markets*: planning and markets must be well-aligned to prevent uneconomic planned investment from undermining the incentives to invest in resources signaled by the markets. We have substantial concerns in this area.
  - *Market instability:* The most well-designed markets will fail to motivate efficient investment over the long term if the regulatory risk associated with changing market rules is large.
- There are many reasons to be optimistic about long-term resource adequacy in MISO:
  - MISO has made tremendous progress toward an efficient market design that will provide clear, efficient locational capacity price signals.
  - MISO's states and utilities are committed to maintaining the reliability of the system, in addition to meeting state policy goals.
  - I hope to continue to recommend changes to MISO's planning processes to improve their alignment with resource development trends, state goals, and market signals.
  - Hence, I recommend that the Commission not pursue or mandate substantial changes to MISO's capacity market.

WRITTEN STATEMENT OF DAVID B. PATTON, PH.D.
MISO INDEPENDENT MARKET MONITOR

The increase in projected load growth, the transition of the generating portfolio to much higher reliance on intermittent resources, and accelerating retirements of conventional dispatchable resources has increased resource adequacy concerns. I appreciate the opportunity to address questions regarding resource adequacy in the MISO region today.

Current Status of Resource Adequacy and Planning Projections

MISO is more than adequate moving into the Summer of 2025, and we do not have substantial concerns about the MISO region in the near term. The Commission cites the findings in the NERC 2024 Long-Term Reliability Assessment that MISO is at risk of running short of supply as soon as the Summer of 2025. We have reviewed this report and do not believe its results are accurate because it understates MISO's capacity in the areas of demand response, behind-the-meter generation, and firm capacity imports by more than 8 GW. Additionally, they consider potential retirements of coal, oil, and gas-fired resources that have not materialized.

Additionally, it is important to recognize that, unlike some other RTOs, MISO has tremendous import capability that is routinely utilized during tight conditions to supplement its internal resources. During emergency conditions, it has typically imported well over 4 GW of additional supply. Hence, we have no substantial concerns regarding the adequacy of resources in the MISO region in the near term.

The Commission also cites MISO's 2024 Regional Resource Assessment which asserts that 17 GW of new resources will need to be built every year for the next 20 years. For reasons I have documented for MISO and its stakeholders, this is not a credible forecast. MISO planning models assume that virtually all of the new capacity to be built over the next 20 years will be intermittent renewable resources, despite the fact that their reliability value under MISO's future marginal accreditation approach will fall to close to zero.

This is partly why such a massive amount of new capacity are reported to be needed. If one were to assume that participants will rationally build hybrid renewables, storage and dispatchable resources, the 17 GW per year of new resources falls to roughly 2 to 3 GW per year. Some of this demand for resources in the near term is likely to be satisfied by delayed retirements now that MISO's capacity market is beginning to send more efficient price signals to the market participants.

Further, investment in these classes of controllable resources will still allow MISO states to achieve its carbon goals and greatly reduces the transmission needs in the MISO region, which I have also indicated to MISO and its stakeholders.

Achieving Resource Adequacy in the Long-Term in MISO (or any RTO)

Few topics in wholesale electricity markets have engendered the debate and controversy as have resource adequacy. At the outset, it is helpful to review why capacity markets exist. Most RTOs and ISOs minimum planning requirements that correspond to a prescribed level of reliability, the most common of which is the one loss of load event in ten-year standard. The RTOs determine the resources that are needed to meet this standard.

The primary economic issue is that the 1-in-10 reliability standard implies a value of lost load (VOLL) in excess of $200,000 per MWh. Since the RTOs and ISO's do not price shortages in the energy and reserve markets based on a VOLL this high, energy and operating reserve markets will typically not provide enough revenue to keep this maintain capacity margins that will satisfy this reliability standard.

The capacity markets were developed to supplement the RTOs' energy and ancillary services markets to provide the necessary economic signals to inform long-term capacity decisions, including investment, retirement, and maintenance of resources. However, capacity markets are not the only approach for pursuing resource adequacy. In general, there are three primary approaches to achieve adequate resources through competitive wholesale electricity markets:

1. Capacity market – Designed to directly procure a sufficient quantity of capacity to satisfy a specified reliability standard.

- Pros: Predictably generates the net revenues needed to incent suppliers to invest in new resources and maintain existing resources to satisfy the reliability standard.
- Cons: Requires more complicated rules related to accreditation of generation and load resources. Poor rules can undermine the performance of the market, e.g., the vertical demand curve that had previously used in the MISO capacity market.

2. Decentralized capacity requirements – Some markets require LSEs to self-supply or procure capacity to satisfy a specified capacity requirement. This is effectively a decentralized capacity market that operates bilaterally.

- Pros: Increases the likelihood of satisfying the specified reliability standard compared to an energy-only market.

  Cons: Prices and procurements are likely to be much less efficient compared to a centralized capacity market. It is also difficult to model transmission constraints and system requirements as accurately as in a centralized capacity market.

3. Energy-only market – this market relies primarily on expected shortage revenues in the energy and ancillary services markets to motivate investment.

- Pros: Provides strong performance and availability incentives and it is closely aligned with reliability.
- Cons: Capacity levels are likely to be less than needed to satisfy the reliability standard. Even if a very aggressive VOLL is selected to price shortages, higher capacity margins produce less frequent shortages making it difficult to generate sufficient revenue. This market alternative can also produce highly volatile year-to-year costs and revenues that can be hedged by contracts.

If an RTO adopts a reliability standard that must be satisfied, a well-designed capacity market will generally be the most efficient means of doing so. However, MISO has struggled historically to develop an efficient capacity market design on both the supply and demand side. In recent years, most of the design issues have been addressed. MISO has now developed and has or will implement:

- A seasonal capacity market framework that operates in a prompt timeframe, roughly two months before the planning year commences.
- Reliability-based demand curves in 2025 that, for the first time, aligns the market demand with the reliability that the capacity provides.
- Marginal reliability-based capacity resource accreditation, which will be implemented in 2028. This ensures that the relative reliability value of different types of capacity resources is accurately reflected in the market.

Together, these fundamental elements will provide for efficient capacity procurement and prices that will efficiently facilitate investment and retirement decisions to maintain resource adequacy. Many of these decisions are made through utility and state planning processes, and others will be made by unregulated market participants. An efficient capacity market will facilitate both types of decisions.

To illustrate the importance of these design improvements, we can look at the results of MISO's recent 2025/2026 Planning Resource Auction (PRA). This was the first year under MISO's new reliability-based demand curves in its seasonal capacity market. The market cleared at $667 per MW-day in the summer and averaged more than $210 per MW-day for the entire planning year. This reflects almost 90 percent of the Cost of New Entry (CONE) of a gas peaking resources net of the energy and ancillary service net revenues the markets provide. This price level is efficient and reflects the marginal reliability value of resources in MISO because it procured only 2 percent more capacity than the minimum requirement. Importantly, these prices send clear signals to both developers and owners of existing generators regarding the value of resources in the MISO region.

In contrast, under the vertical demand curve that MISO had previously utilized, prices would have cleared at roughly $20 per MW-day. These prices would provide little incentive to build new units or maintain older existing units. We have shown in prior reports that the vertical demand curve contributed to large quantities of retirements of merchant resources and contributed to the tight capacity conditions that currently exist in the Midwest region.

Given MISO's tremendous progress in the design and implementation of its capacity market, we see no benefit in considering fundamental reforms to MISO's capacity market or alternative resource adequacy approaches.

Threats or Challenges to Resource Adequacy in MISO

Although it is essential for MISO's capacity market to be well-designed and competitive so it will produce efficient economic signals to support resource adequacy, there are other issues outside of the market that must be addressed or coordinated.

First, because most of the load is served by regulated utilities in MISO, state policy and regulation will play a key role in achieving resource adequacy. Although many of the states in MISO have aggressive carbon reduction goals, I believe they are also committed to reliability. Mandating and overseeing planning processes by regulated utilities that are designed to achieve both environmental and reliability objectives will be critical. In my discussions with states and with the regulated utilities, I believe they are committed to both objectives. The reforms MISO has implemented, particularly the transition to marginal accreditation, will inform these processes and facilitate success in achieving both objectives.

Second, MISO's planning processes must be well-aligned with its markets. While MISO does not determine the future development of resources in the region, it projects such development and load growth that together determine the MISO's transmission needs. Ultimately, therefore, these planning process help determine the future transmission investment in the region. Transmission investment that occurs outside of the market must be well-coordinated with investment in resources that are in-part or fully facilitated by the market. Excessive uneconomic investment in transmission that is guaranteed by regulated customers will undermine the incentives to invest in resources that can address the same transmission bottlenecks.

For example, strategically located storage resources in generation pockets can charge at low or negative prices when intermittent resources produce at very high levels would otherwise need to be curtailed to avoid overloading a transmission constraint. MISO's transmission congestion can create profitable opportunities for resources to site in these types of areas at no cost to regulated customers in order to relieve the congestion. Hence, it is critical to avoid excessive investment in uneconomic transmission, which I believe requires independent oversight given the concerns the IMM has identified in recent planning cycles.

Ideally, such oversight would be provided by the Commission but, unfortunately, FERC does not review or approve the portfolios of new transmission emerging from MISO's transmission planning process before these costs are embedded in transmission rates. This raises the potential for uneconomic transmission investment to raise RTOs' transmission rates to unreasonable levels. We believe the Commission should consider solutions to address this regulatory gap.

Finally, the most well-designed markets will fail to motivate efficient investment over the long term if the regulatory risk associated with changing market rules is large. This is because developers will discount future expected market revenues if they believe there is a reasonable probability that the RTO or the Commission will make substantial changes to the market rules or eliminate the market. Given the progress MISO has made to improve the design and performance of the capacity market, I recommend that the Commission not pursue or mandate substantial changes to it.

This concludes my written statement.

Document Content(s)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-26-22

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

Exhibit 36

MISO Elliott Max. Gen. Event Overview

Overview of Winter Storm Elliott December 23, Maximum Generation Event

Reliability Subcommittee

January 17, 2023

All data included in this presentation is preliminary as of January 12, 2023, and is subject to change

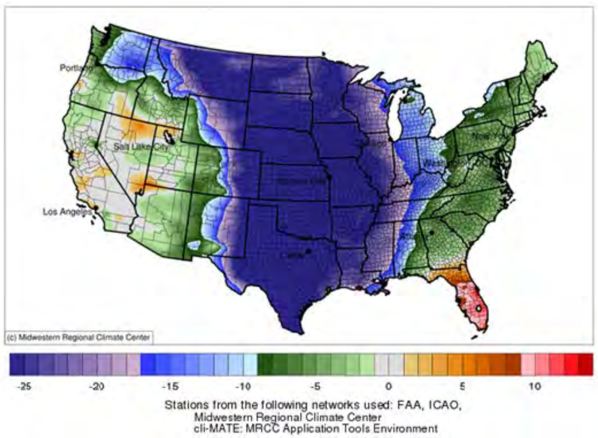
Executive Summary

- Winter Storm Elliott delivered rapid, extreme cold to the Eastern Interconnect in December as well as gas supply challenges and historic load forecast volatility
- MISO had enough capacity to manage uncertainty while serving exports to our neighbors
- There were no customer interruptions
- Lessons learned from Winter Storm Uri contributed to successful operations during Elliott; subsequent analysis will lead to additional lessons learned
- Load forecast uncertainty and fuel supply availability are examples of the increasing uncertainty being addressed under MISO's Reliability Imperative

On December 23, Winter Storm Elliott brought significantly below normal temperatures to MISO, driving high demand for heating; drawing similarities to Winter Storm Uri in 2021

WINTER STORM URI
FEBRUARY 12-18, 2021

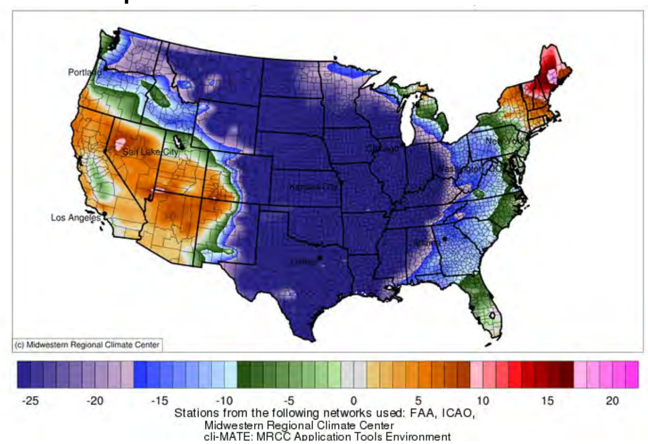
Average Temperature:
Departure from 30-Year Normal



System Peak Load	103 GW
Unplanned Outages *(South)*	18 GW
Scheduled Load Modifying Resources*	531 MW
RDT Max Flow & Direction	3.2 GW N-S
Precipitation: *Abundant snowfall across MISO's South and Central regions*	

WINTER STORM ELLIOTT
DECEMBER 23, 2022

Average Temperature:
Departure from 30-Year Normal



System Peak Load	107 GW
Unplanned Outages *(additional from previous day system-wide)*	19 GW
Scheduled Load Modifying Resources*	1.2 GW
RDT Max Flow & Direction	2.7 GW N-S
Precipitation: *Modest snowfall across MISO's North and Central regions*	

Load Modifying Resources requested for the peak load hour for the noted storm time period

MISO

Emergency operations were required to access additional capacity to mitigate uncertainty and support our neighbors

ALERTS

Cold Weather Alert (South)
DEC 22, noon EST – DEC 26, noon EST

Unseasonably cold weather expected across MISO

WARNINGS

Maximum Generation Warning (South)
DEC 23, 9:15 a.m. – 12:45 p.m. EST

Conservative Operations (South)
DEC 23, 9:15 a.m. EST –DEC 26, midnight EST

Tightened conditions due to unit trips and failures to start (~2 GW), higher-than-forecast South load (~2.5 GW), and reduced RDT flow limit N-S (to 1.5 GW)

Maximum Generation Warning (Footprint)
DEC 23, 4:30 p.m.

Conservative Operations (Footprint)
DEC 23, 9 p.m. EST –DEC 24, noon EST

Tighter conditions due to higher-than-forecast system-wide loads, forced outages driven primarily by fuel supply issues and units that failed to start

EVENTS

Maximum Generation Event, Step 1b (Footprint)
DEC 23, 5:30 p.m.

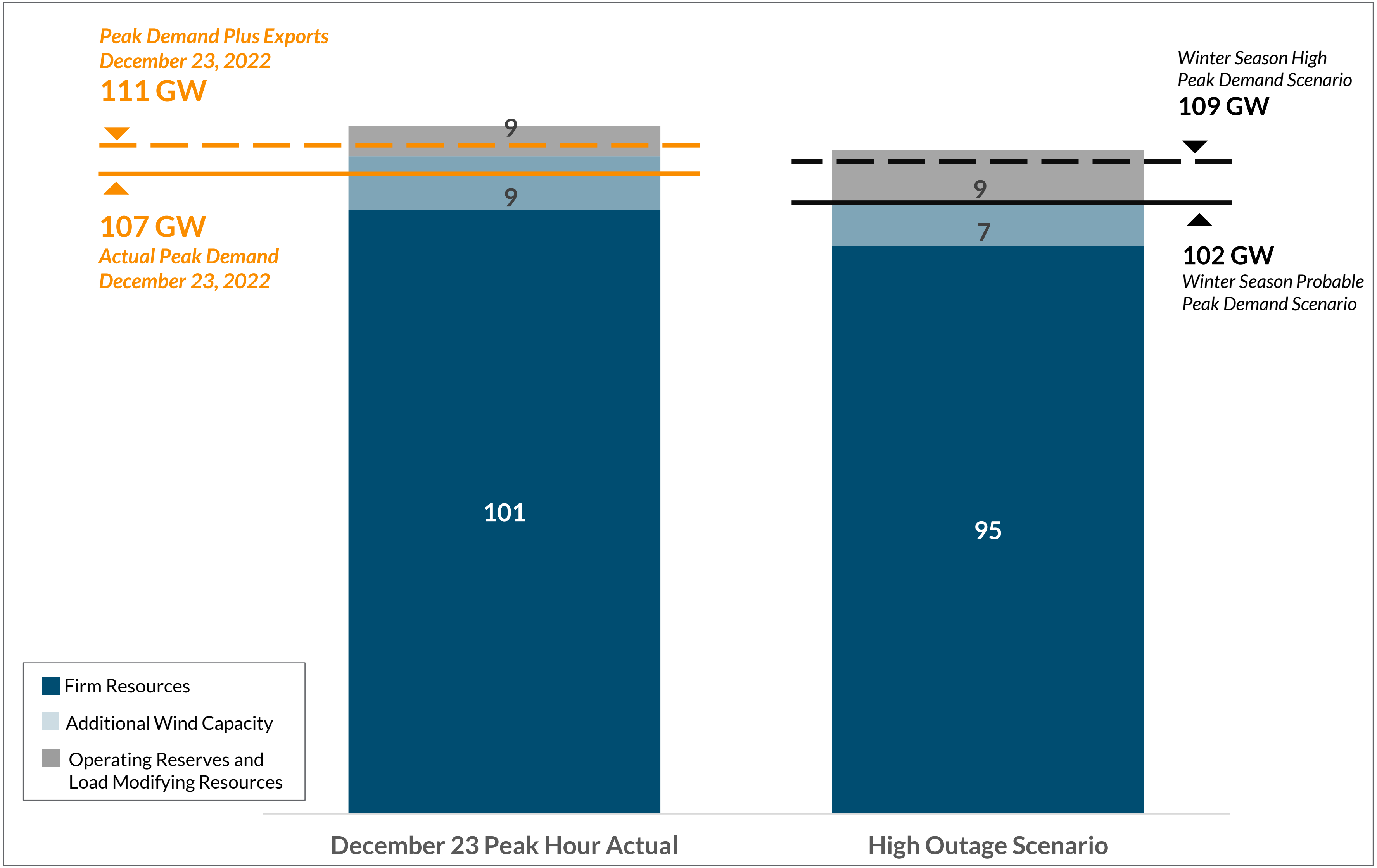
Tight conditions worsened with real-time transmission congestion and diminishing generation deliverability

Maximum Generation Event, Step 2a (Footprint)
DEC 23, 6 p.m. – 9 p.m. EST

Emergency procedures allowed access to demand response, which reduced the peak demand

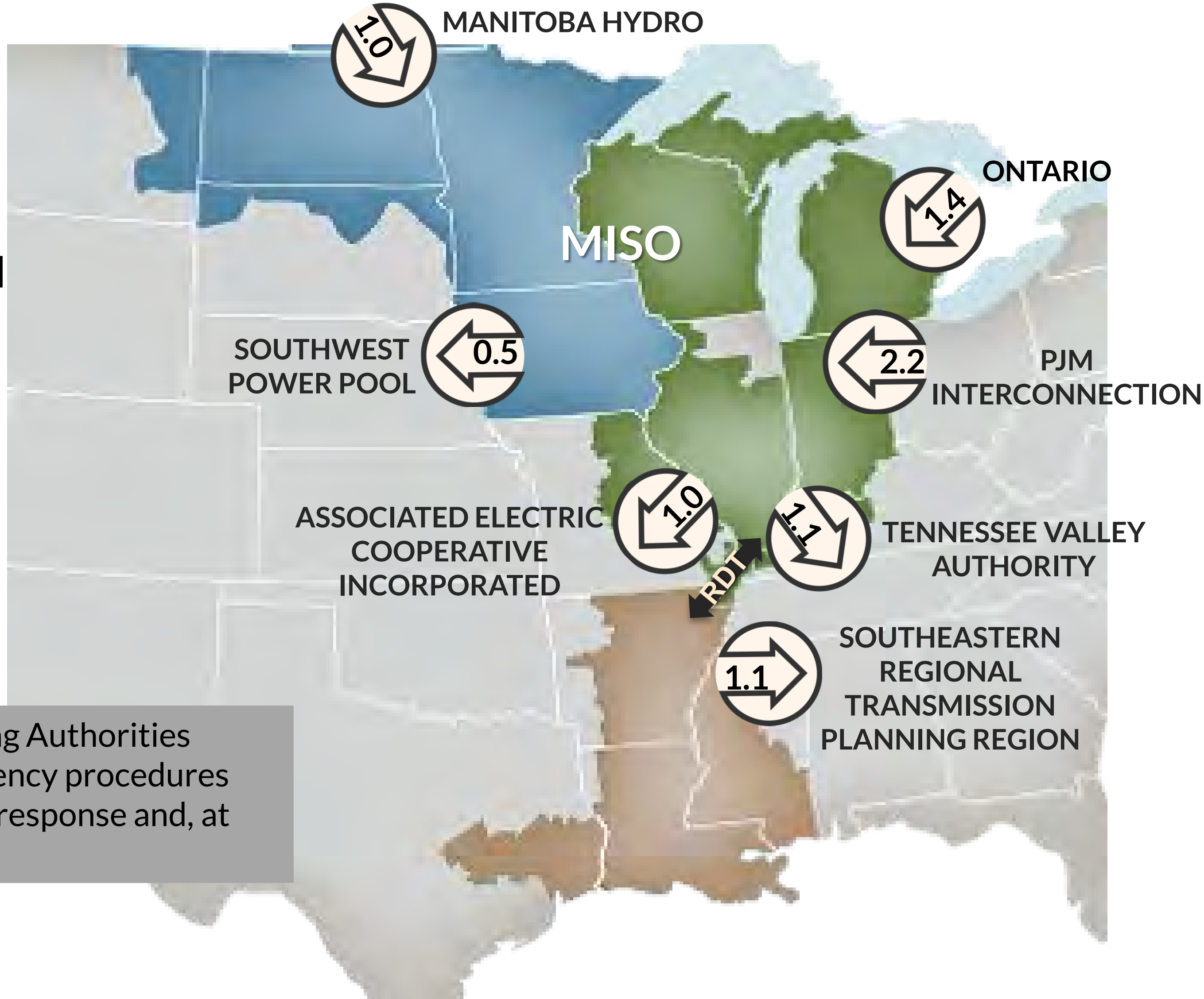
Note: All times indicate the effective time of each declaration

Reserve capacity was closely monitored, and exports would have been curtailed if conditions had worsened



MISO consistently exported power to southern neighbors with a maximum value of nearly 5 GW

Net Scheduled Interchange (GW)

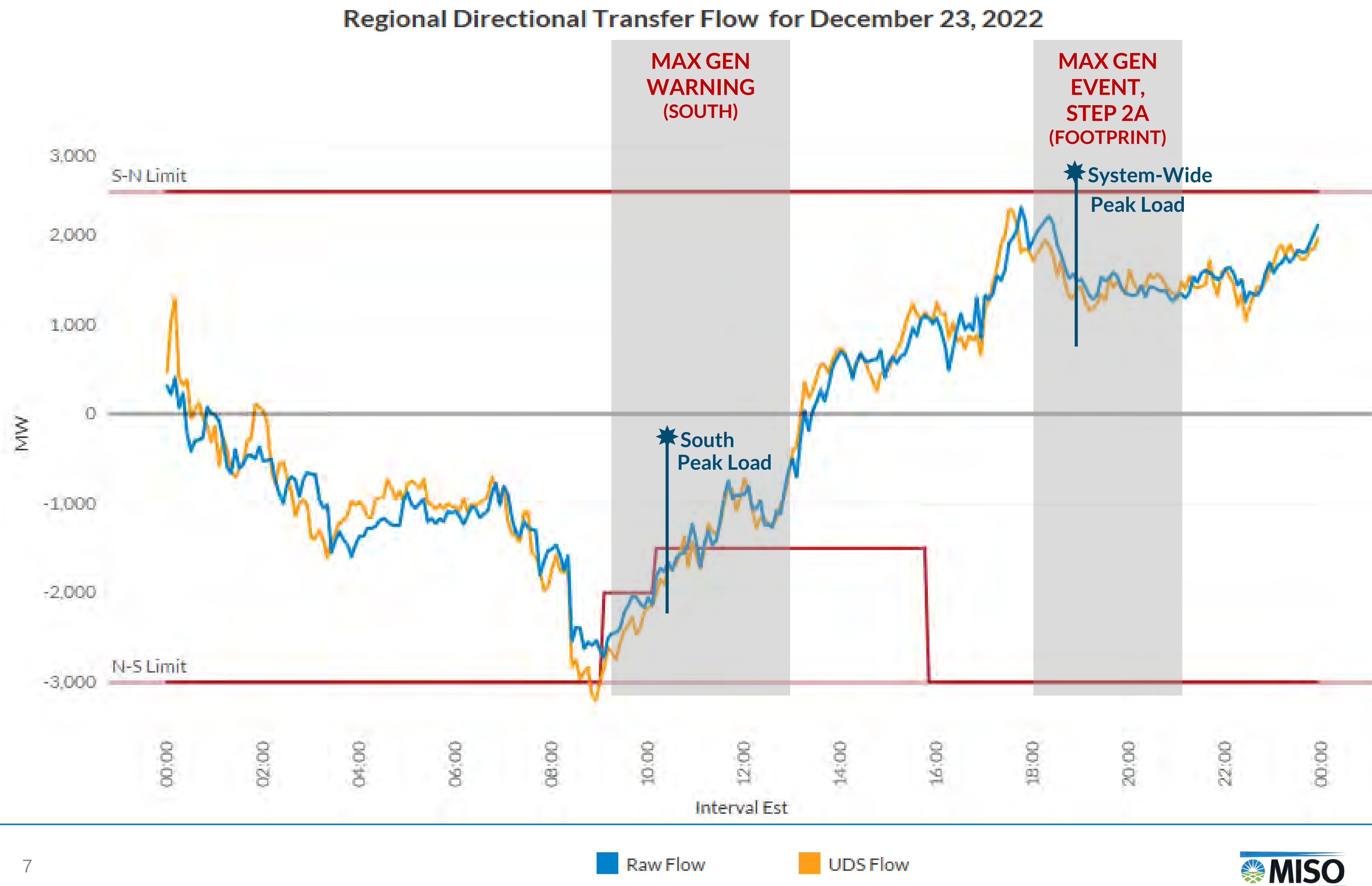


Multiple Balancing Authorities employed emergency procedures utilizing demand response and, at times, load shed

Image represents average flows into and out of MISO December 23, 2022

RDT = Regional Directional Transfer, which has a North-South limit of 3.0 GW and South-North limit of 2.5 GW

MISO complied with Joint Parties requests to reduce flows by 1,500 MW during the morning peak, which contributed to an emergency declaration in the South and a recall of non-firm exports

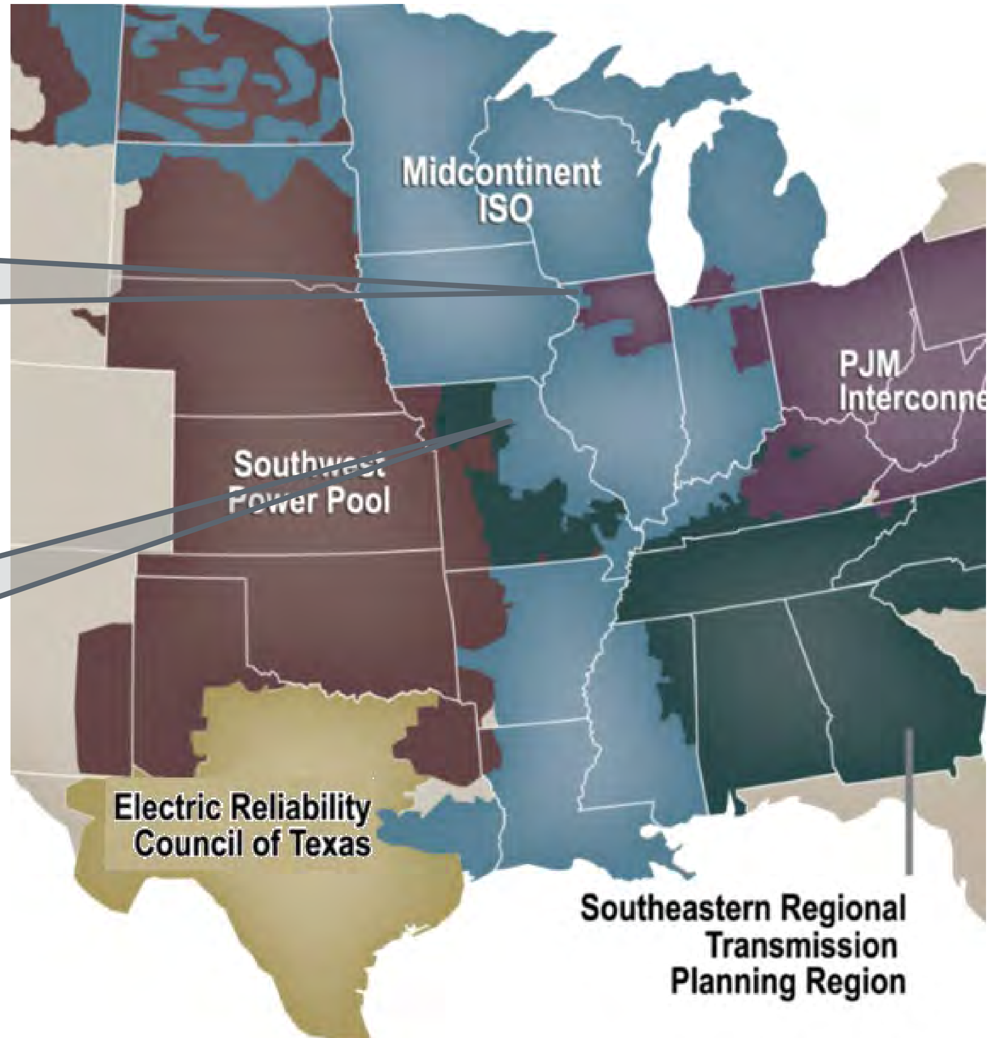


MISO

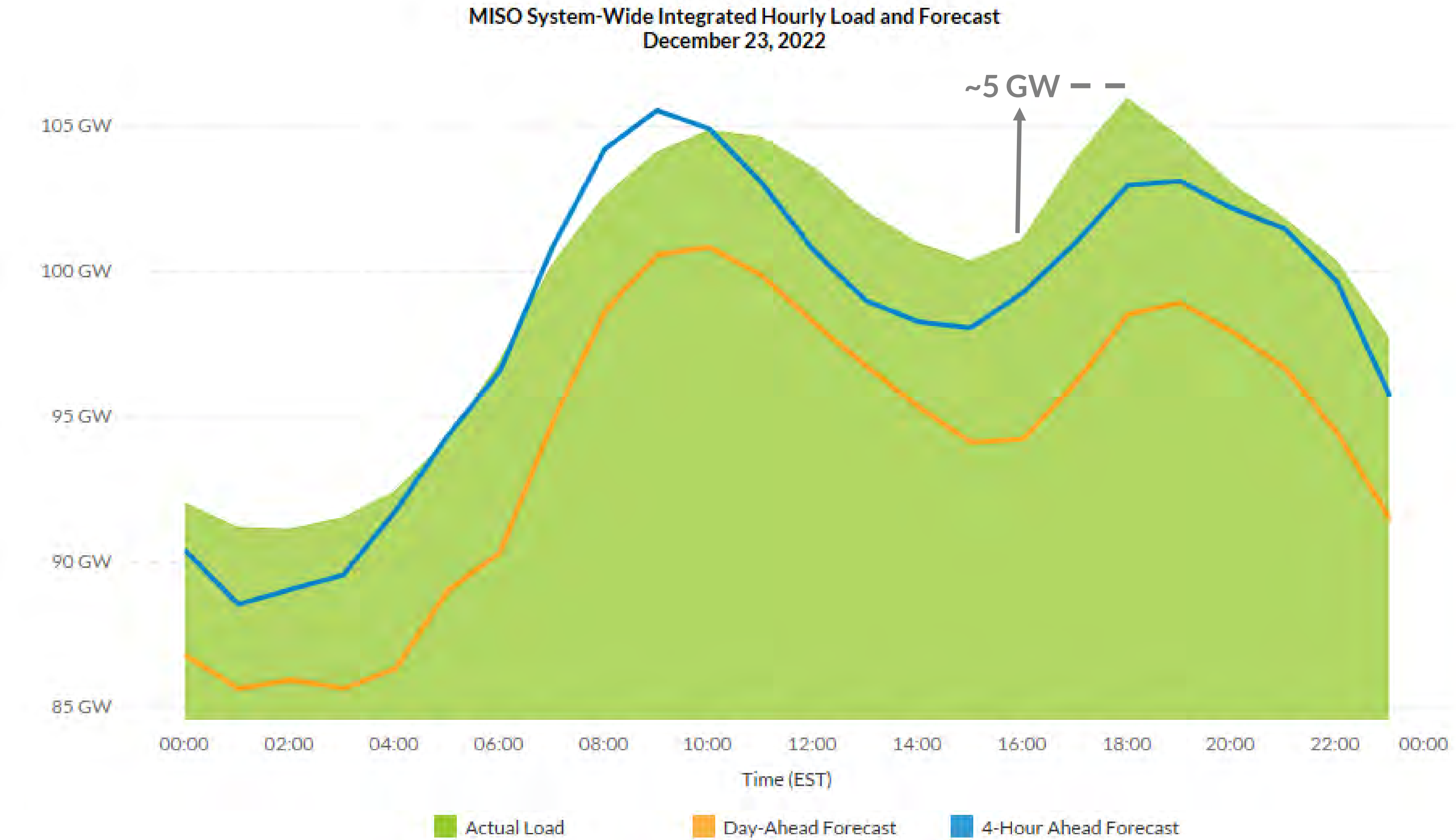
Two local transmission emergencies were declared to manage severe congestion on transmission lines

Local Transmission Emergency
SE Wisconsin
6:45 p.m. – 8 p.m. EST
December 23
(No customer interruptions)

Local Transmission Emergency
Central Missouri
6:27 p.m. – 8 p.m. EST
December 23
(No customer interruptions)

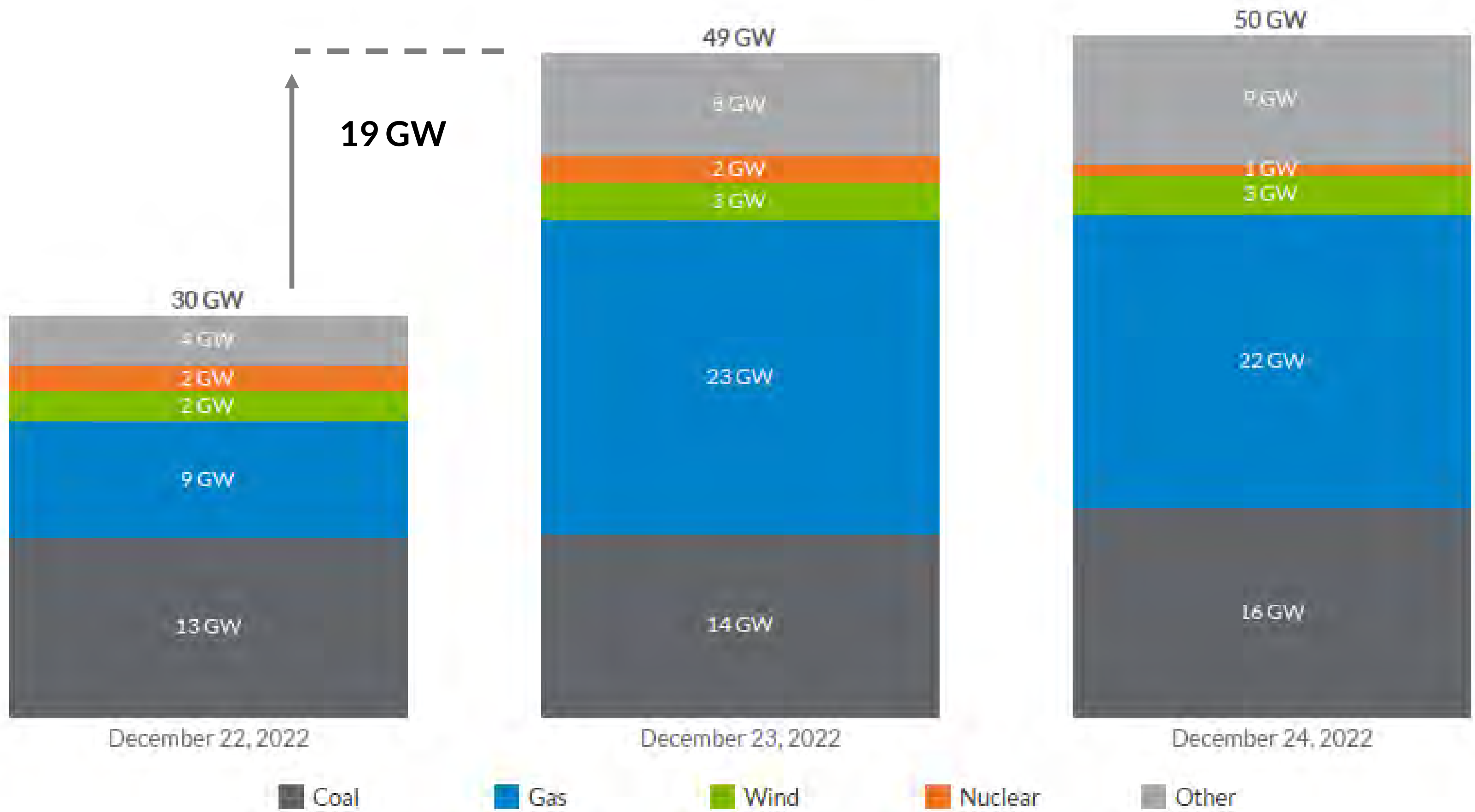


Abnormally high load forecasting errors occurred due to a lack of historical data for similar extreme conditions in December



Gas supply availability contributed to increased unplanned outages, particularly in the afternoon, that pushed MISO into emergency procedures

MISO System-Wide Daily Average Unplanned* Generation Outages by Fuel

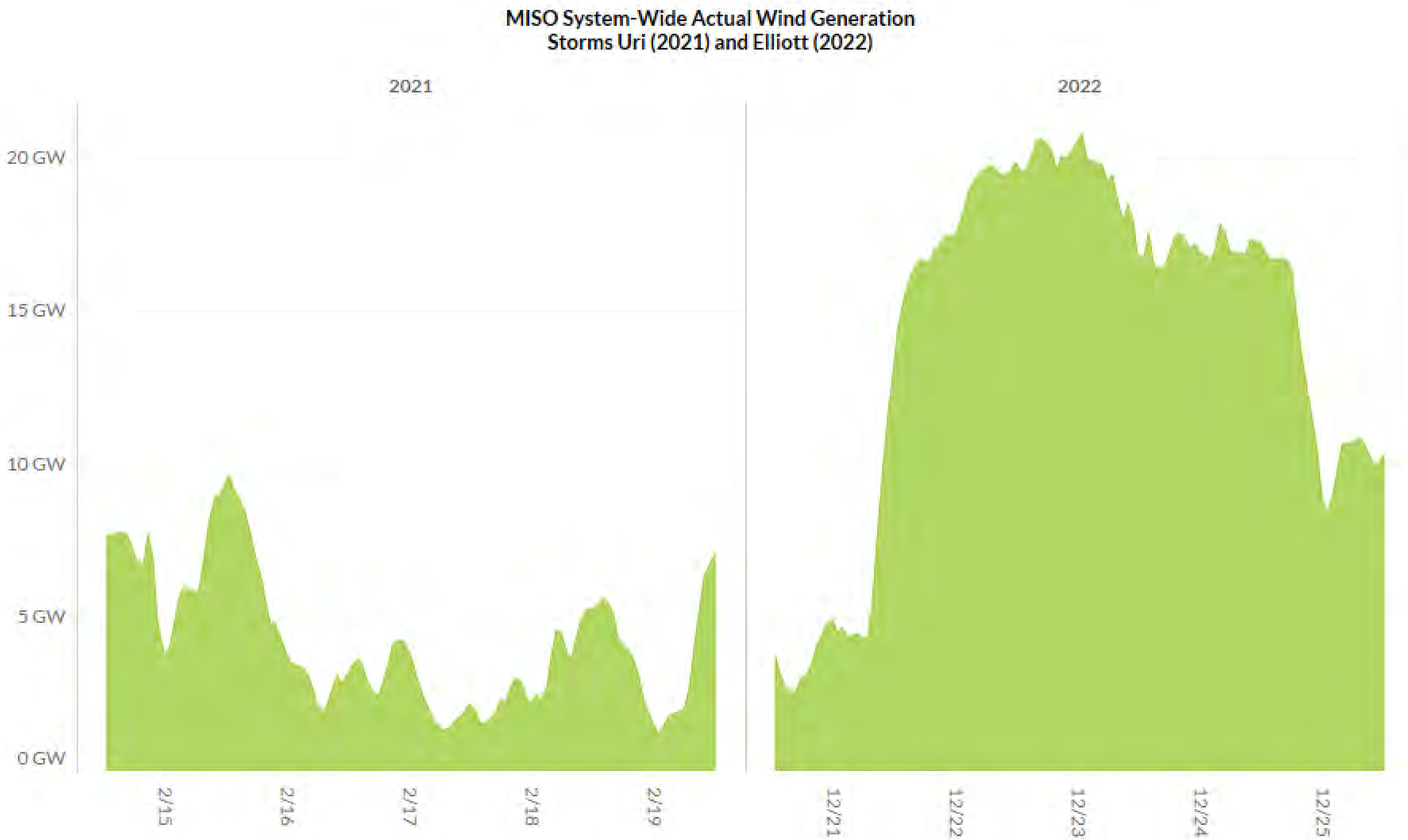


**Unplanned = forced outages and derates*

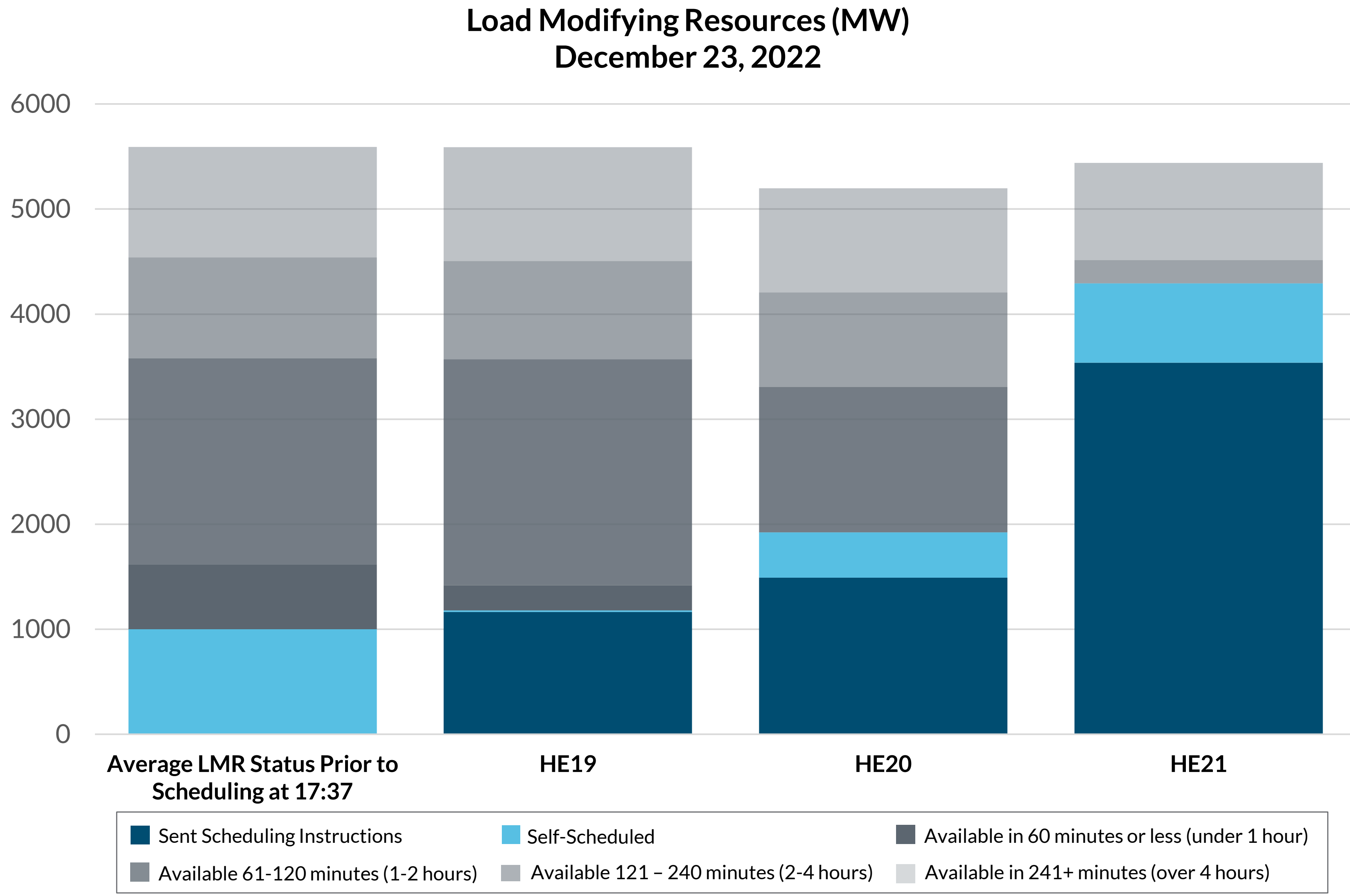
Charts reflect data in the CROW outage system on January 5, 2023

Wind often reported as derated over the time period

Wind production remained high during Winter Storm Elliott, providing support to the transmission system



Requested 3 GW of Load Modifying Resources at 17:37 to meet increasing load and continue exports to neighbors



While each storm is unique, lessons learned from Winter Storm Uri in 2021 contributed to successful operations during Elliott

REFINED WINTER READINESS ACTIVITIES

- Increased focus on extreme scenarios
- Improved understanding of generator winter preparedness through coordinated seasonal assessment and fuel and consumables data requests
- Implemented cold weather-specific operator drills in addition to emergency procedure drills and winter readiness workshops

PROCESS IMPROVEMENTS

- Process Improvements to Unit Commitment Processes and Operator Situational Awareness improved our ability to respond to changing risk profile during the operating day

IMPROVED COORDINATION

- Improved coordination activities with our neighbors that resulted in quicker decision making during the storm

View the complete [February Arctic Event report](#) on the MISO website

Appendix

MISO's operating procedures ensure reliability and gain access to additional resources during extreme situations

MARKET CAPACITY EMERGENCY PROCEDURE STEPS

MAXIMUM GENERATION

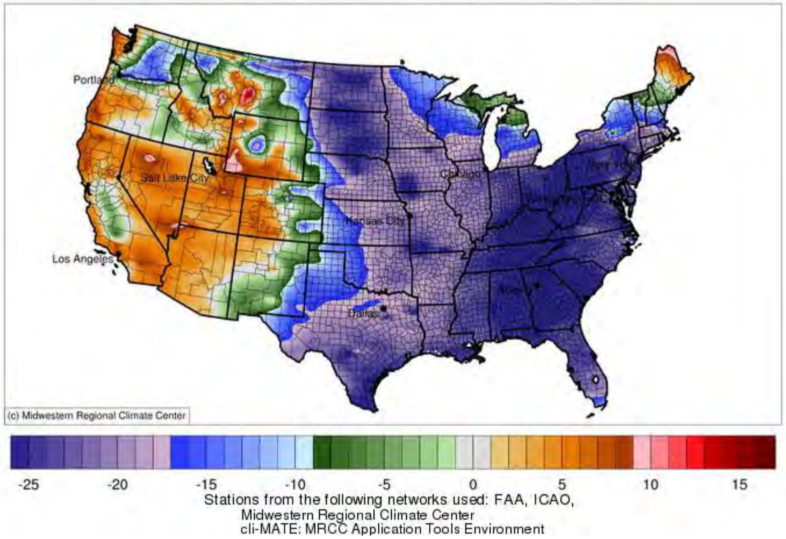
Normal Operations		Normal Pricing
Capacity Advisory	Advance notice of forecasted capacity shortage, requests Stakeholders update offer data	
Alert	Define boundaries/suspend maintenance	Emergency Pricing Tier 0
Warning	Schedule in external resources, curtail export transactions, activate reconfiguration	Emergency Pricing Tier I Offer Floor
Event Step 1	Commit emergency resources, declare NERC (Energy Emergency Alert) EEA 1, activate emergency limits	
Event Step 2	Declare NERC EEA 2, implement Load Modifying Resources (LMRs), Load Management Measures (LMMs) Stage 1, commit Emergency Demand Response (EDR) resources, emergency energy purchases, public appeals	Emergency Tier II Offer Floor
Event Step 3	Utilize operating reserves and LMMs Stage 2	
Event Step 4	Reserve call and emergency reserve purchases	
Event Step 5	Declare NERC EEA 3, firm load shed, and set Locational Marginal Prices (LMPs) and Market Clearing Prices (MCPs) to the VOLL	Value of Lost Load (VOLL) Pricing
Termination	Terminate Max Gen and possibly Capacity Advisory	Normal Pricing

Data Source: SO-P-EOP-00-002 Rev 14 MISO Market Capacity Emergency

Winter Storm Elliott continued to impact the Eastern Interconnect through December 25

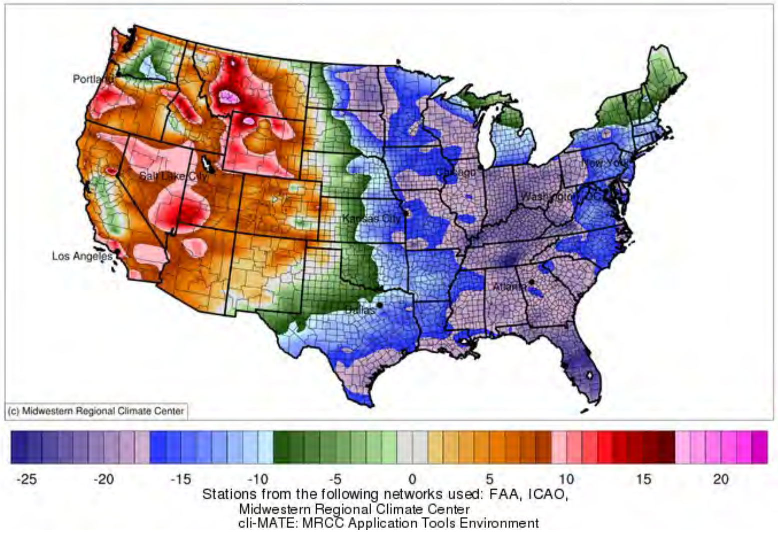
WINTER STORM ELLIOTT
DECEMBER 24, 2022

Average Temperature:
Departure from 30-Year Normal

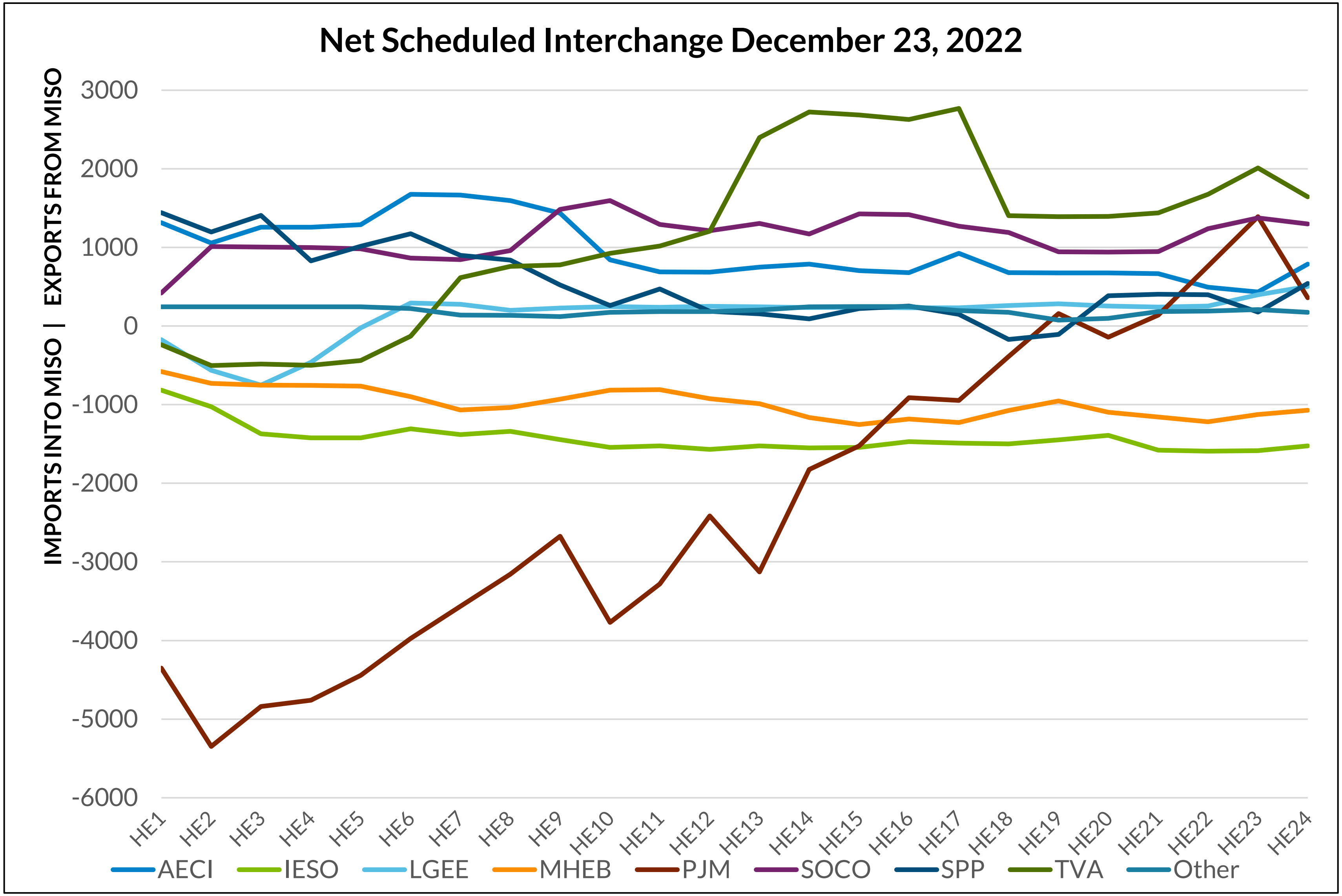


WINTER STORM ELLIOTT
DECEMBER 25, 2022

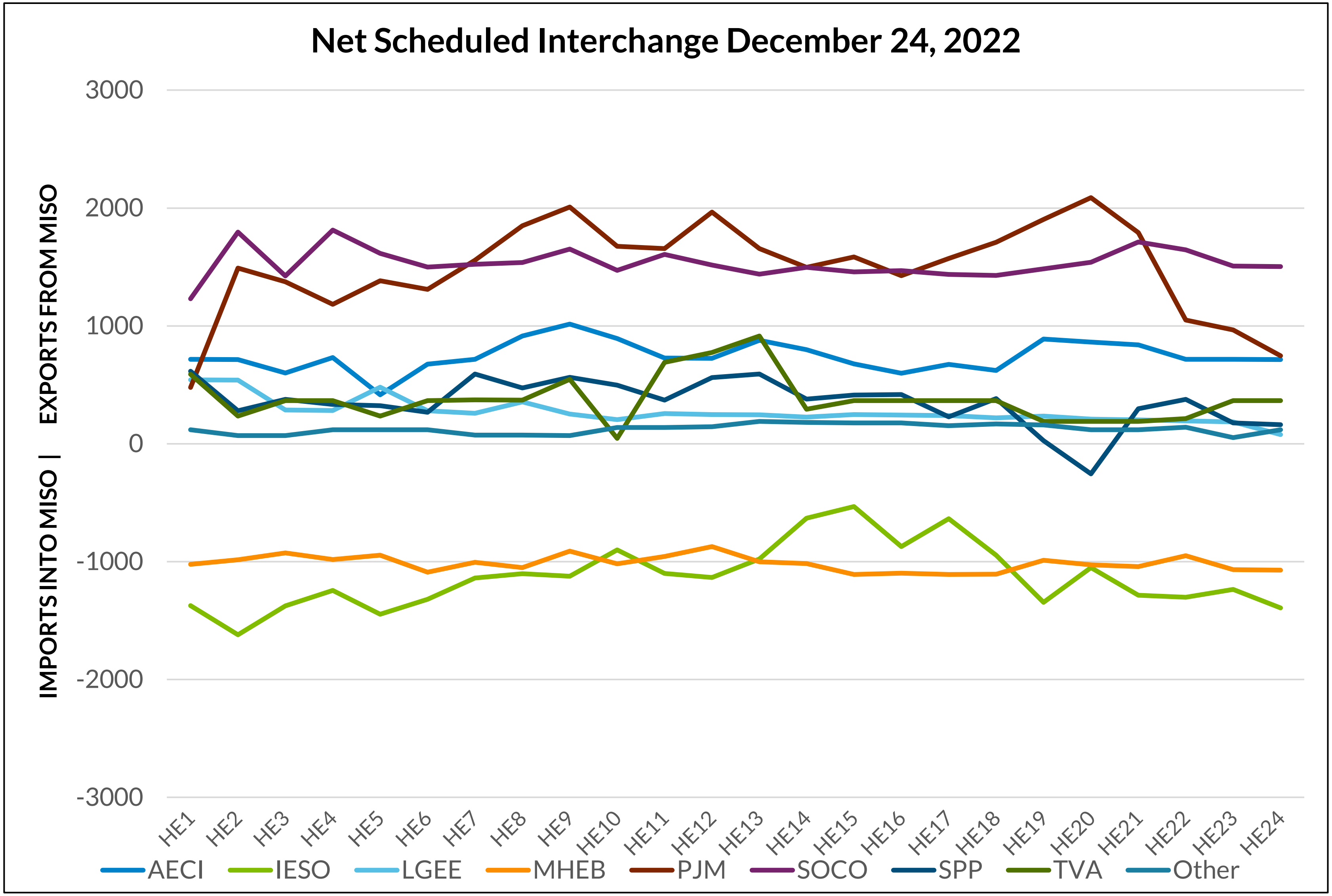
Average Temperature:
Departure from 30-Year Normal



MISO maintained its support for neighbors December 23-24



MISO maintained its support for neighbors December 23-24



BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-26-22

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

Exhibit 37

MISO 2025–26 CIL/CEL Final Results

2025-2026 PY Seasonal CIL/CEL Final Results

LOLE Working Group

October 24, 2024

Corrected Slides 6 & 17
10/24/2024

Purpose & Key Takeaways

Purpose:

Present the final Seasonal CIL/CEL Results for Planning Year 2025-2026

Key Takeaways:

- Highlight and discuss changes between the preliminary and final results due to stakeholder feedback
  - Generation and load was adjusted in the Summer 2025 model in LRZ 3, which resulted in a rerun of the Summer 2025 CIL/CEL model for LRZs 1-7
  - Line ratings were adjusted in LRZ 6 (Gibson – Douglas – Francisco) in the Summer 2025 model and resulted in a rerun of the Summer 2025 model for LRZ 7
- Finalize Planning Year 2025-2026 CIL/CEL results. It is important to note that a change in Controllable Export amounts could adjust results before the March 2025 Planning Resource Auction

Changes between Preliminary Results and Final Results

Season	Preliminary	Final	Reason
Summer 2025 Zone 1 CIL	2,897	6,025	Iowa LRZ 3 Load and Generation Update
Summer 2025 Zone 2 CIL	4,200	4,370	Iowa LRZ 3 Load and Generation Update
Summer 2025 Zone 3 CIL	5,274	5,518	Iowa LRZ 3 Load and Generation Update
Summer 2025 Zone 4 CIL	8,542	8,649	Iowa LRZ 3 Load and Generation Update
Summer 2025 Zone 5 CIL	3,403	4,117	Iowa LRZ 3 Load and Generation Update
Summer 2025 Zone 6 CIL	8,469	8,650	Iowa LRZ 3 Load and Generation Update
Summer 2025 Zone 7 CIL	2,973	3,579	Iowa LRZ 3 Load and Generation Update Gibson – Douglas – Francisco Line Rating Update
Summer 2025 Zone 1 CEL	3,418	3,991	Iowa LRZ 3 Load and Generation Update
Summer 2025 Zone 2 CEL	4,954	4,614	Iowa LRZ 3 Load and Generation Update
Summer 2025 Zone 3 CEL	1,272	4,655	Iowa LRZ 3 Load and Generation Update
Summer 2025 Zone 4 CEL	3,751	4,460	Iowa LRZ 3 Load and Generation Update
Summer 2025 Zone 6 CEL	6,866	6,881	Iowa LRZ 3 Load and Generation Update
Summer 2025 Zone 7 CEL	6,250	5,716	Iowa LRZ 3 Load and Generation Update

2025-2026 PY Zonal Import Ability Results

LRZ	Summer ZIA (MW)	Fall ZIA (MW)	Winter ZIA (MW)	Spring ZIA (MW)
1	6,023	5,688	5,575	6,396
2	4,370	6,537	6,435	6,439
3	5,460	7,704	5,785	7,726
4	7,757	7,013	6,457	7,373
5	4,117	4,679	4,922	4,453
6	8,366	8,672	7,690	9,176
7	3,569	5,115	4,762	5,166
8	2,358	5,675	3,432	6,085
9	4,361	4,741	4,418	4,855
10	4,474	4,508	3,458	4,365

2025-2026 PY Zonal Export Ability Results

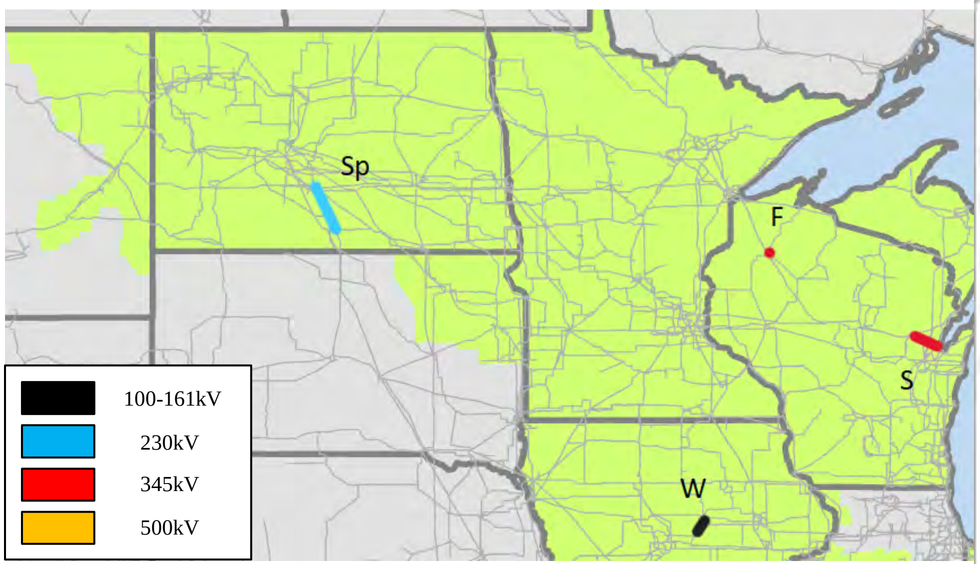
LRZ	Summer ZEA (MW)	Fall ZEA (MW)	Winter ZEA (MW)	Spring ZEA (MW)
1	3,993	6,167	3,593	5,285
2	4,614	4,259	4,793	6,119
3	4,713	5,924	7,480	6,039
4	5,352	5,069	5,531	5,880
5	3,939	5,816	4,814	5,797
6	7,165	5,471	1,911	6,706
7	5,726	5,168	5,712	5,499
8	6,509	4,219	3,783	3,724
9	4,286	4,173	3,618	4,146
10	2,097	3,164	2,028	3,072

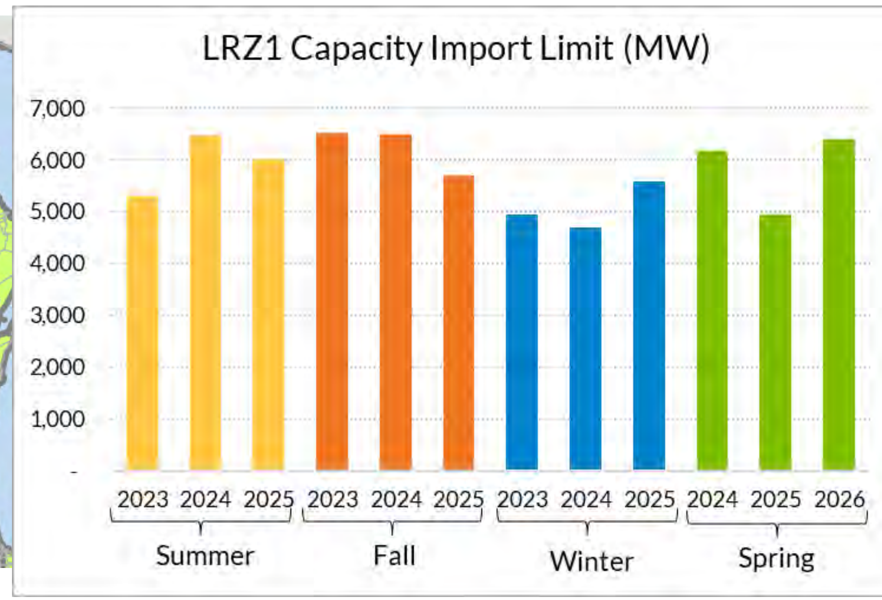
MISO

Planning Year 2025-2026 CIL Final Results

Capacity Import Limits
Zone 1: MN, MT, ND, SD and WI

LRZ1	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2025	North Appleton - Werner West 345 kV	North Appleton - Morgan 345 kV	10%	460MWx2	6023	6025
Fall 2025	Stone Lake 345/161 kV Transformer	Arrowhead 345/230 kV Transformer	None	515MWx2	5688	5690
Winter 2025-26	Laurel - Jasper 161 kV	Story County - Fernald 161 kV	None	601MWx2	5575	5577
Spring 2026	Mound City - Bismark 230 kV	Ft Thompson 1 - Chapelle 345 kV	None	352MWx2	6396	6398

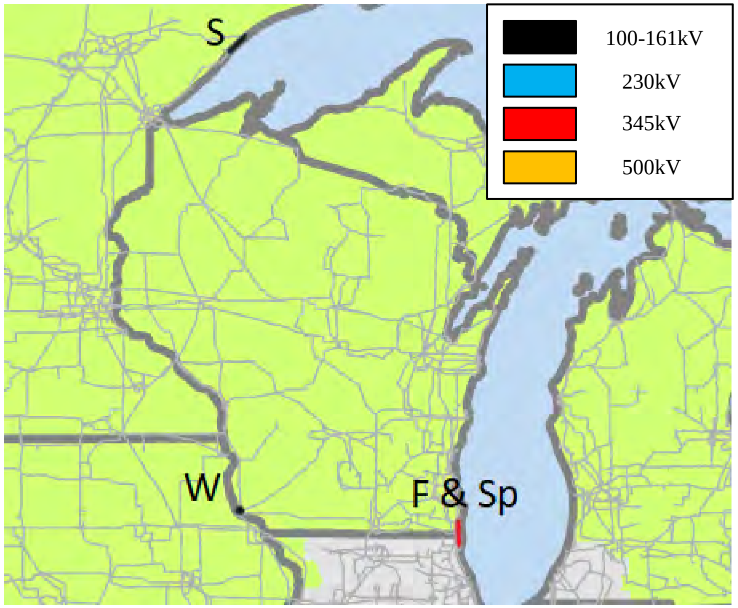


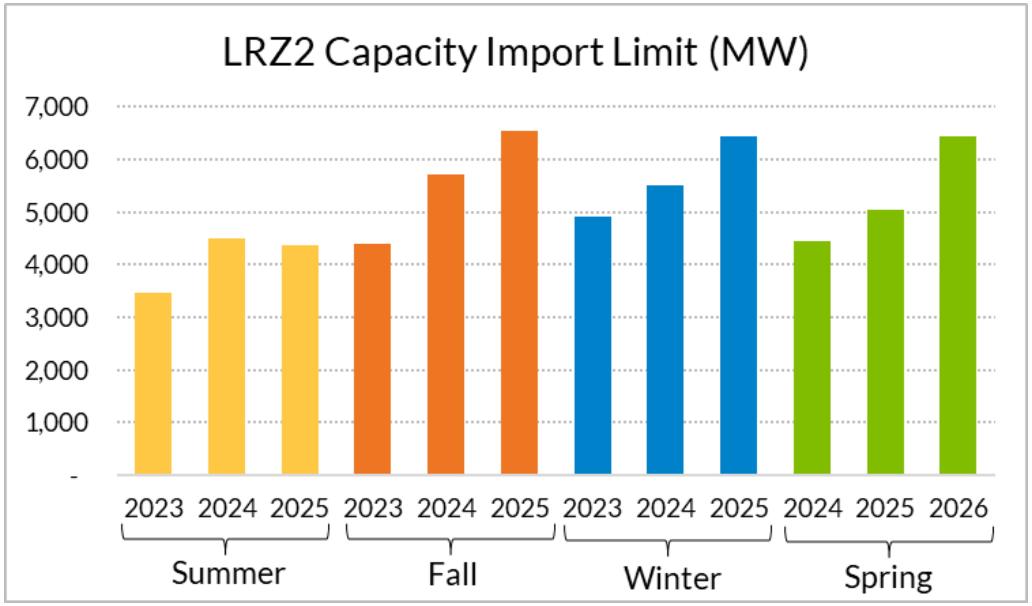


Capacity Import Limits

Zone 2: WI and MI

LRZ2	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2025	Two Harbors - Silver Bay 115 kV	Taconite Harbor - LTV Hoyt Lakes 115 kV	None	439MWx2	4370	4370
Fall 2025	Zion - Pleasant Prairie 345 kV	Zion EC - Pleasant Prairie 345 kV	None	666MWx2	6537	6537
Winter 2025-26	Nelson Dewey 161/138 kV Transformer	Hickory Creek - Hill Valley 345 kV	None	1000MWx2	6435	6435
Spring 2026	Zion EC - Pleasant Prairie 345 kV	Zion - Pleasant Prairie 345 kV	None	624MWx2	6439	6439

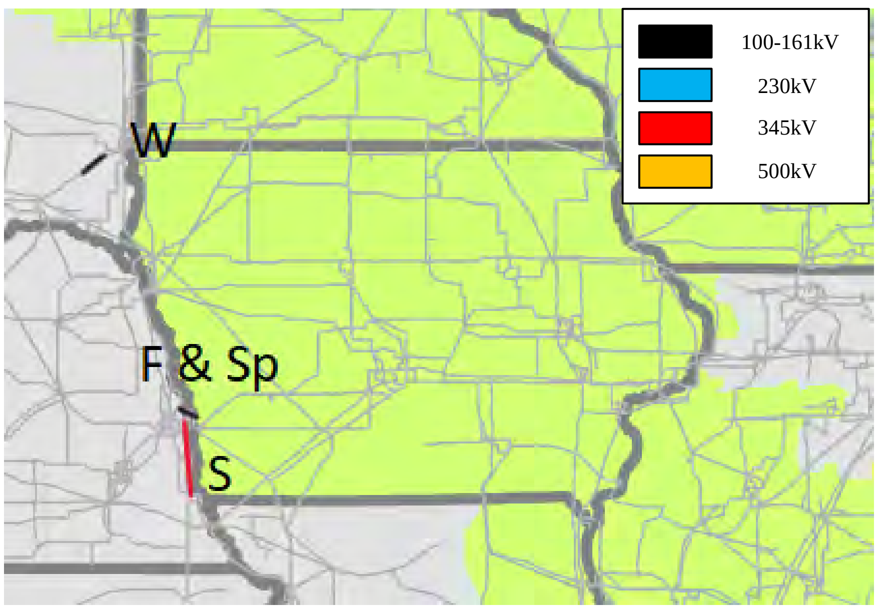


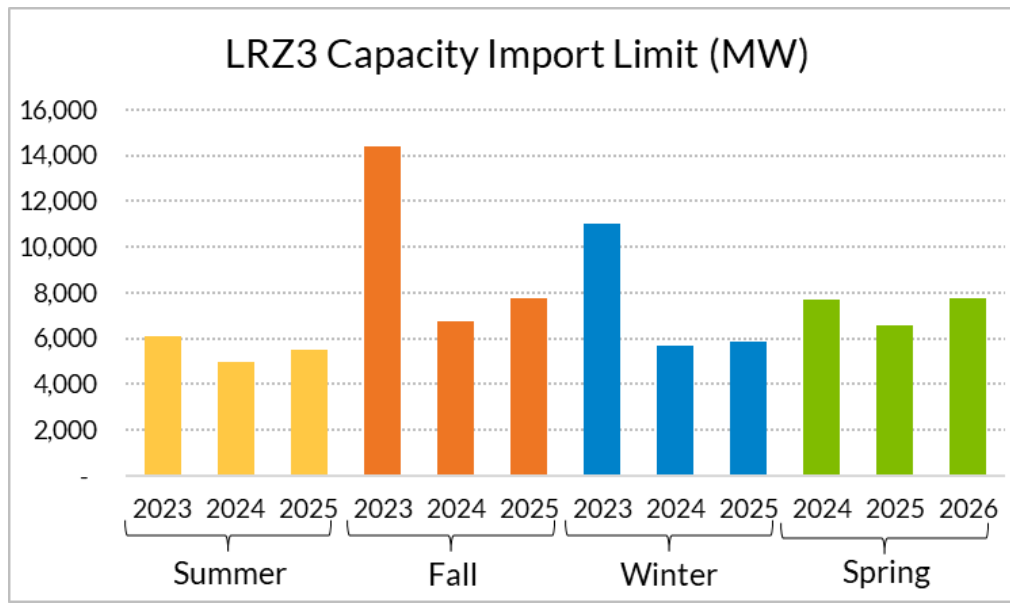


Capacity Import Limits

Zone 3: IA

LRZ3	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2025	Sub 3458 (Nebraska City) - Sub 3456 345 kV	Sub 3455 - Sub 3740 345 kV	None	302MWx2	5460	5518
Fall 2025	Sub 1211 - Sub 701 161 kV	Sub 3456 - Council Bluffs 345 kV	None	177MWx2	7704	7766
Winter 2025-26	Split Rock 7 - Split Rock 4 115 kV	Split Rock 3 - Sioux City 345 kV	None	1000MWx2	5785	5853
Spring 2026	Sub 1211 - Sub 701 161 kV	Sub 3456 - Council Bluffs 345 kV	None	138MWx2	7726	7784

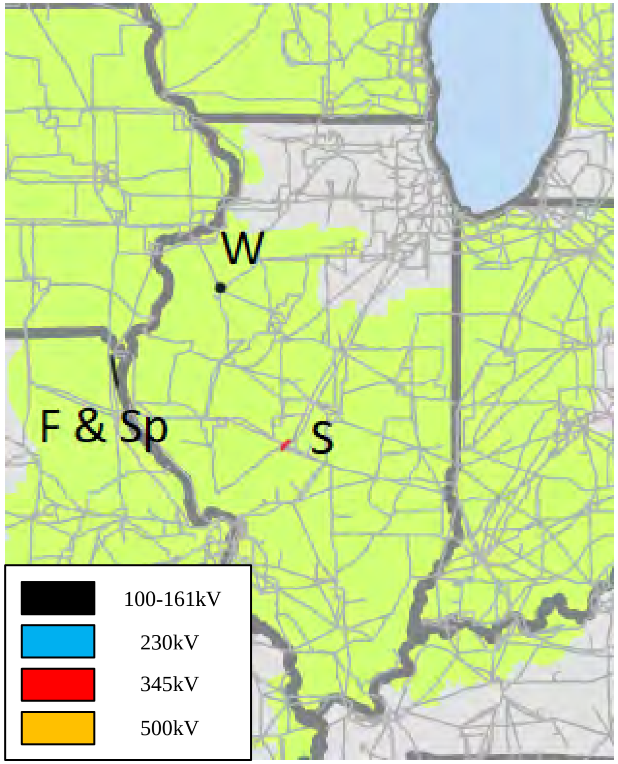


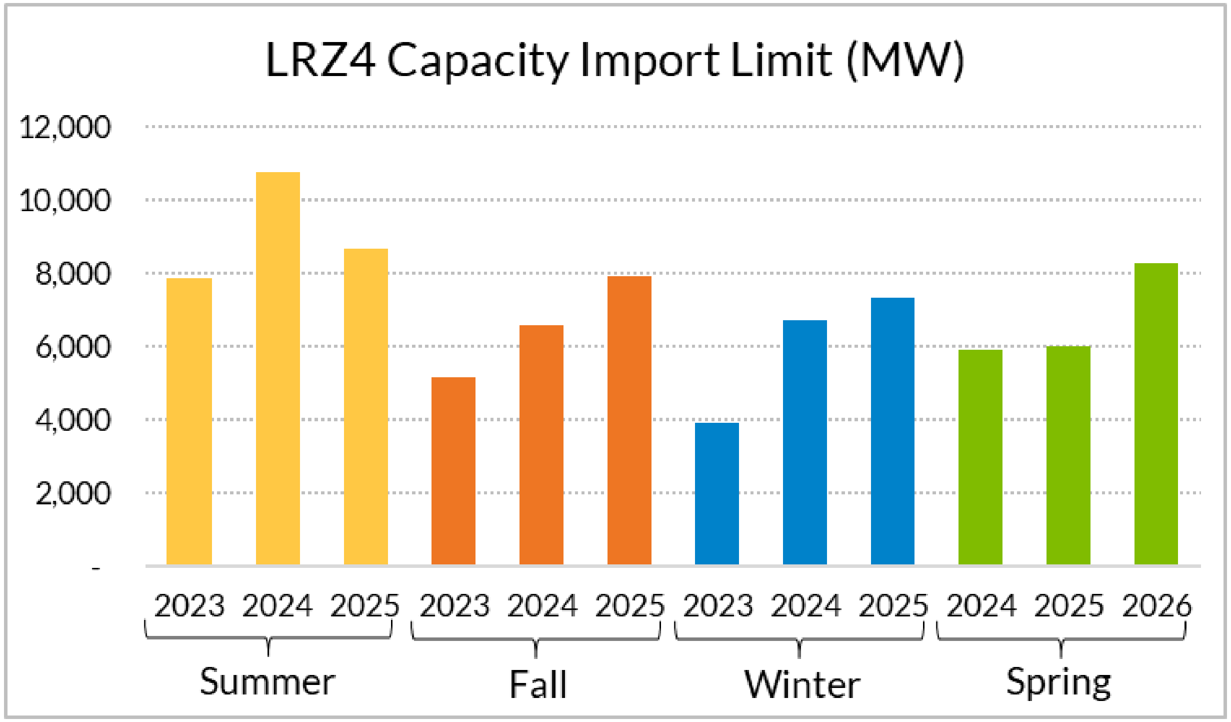


Capacity Import Limits

Zone 4: IL

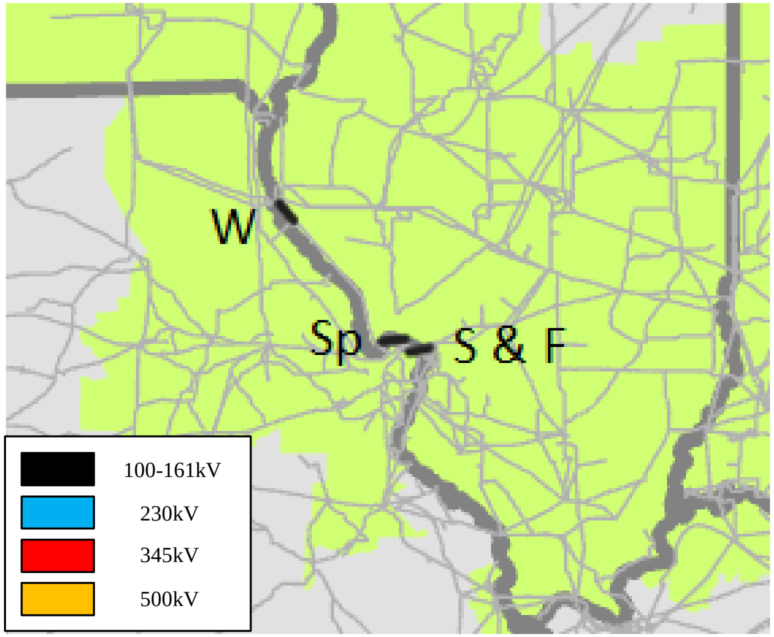
LRZ4	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2025	Kincaid - Austin 345 kV	Lincoln Land Generator	5%	247MWx2	7757	8649
Fall 2025	Palmyra - Marblehead North 161 kV	Herleman - Palmyra Tap 345 kV	25%	880MWx2	7013	7908
Winter 2025-26	Sandburg 161/138 kV Transformer	Galesburg - Oak Grove 345 kV	None	1000MWx2	6457	7353
Spring 2026	Palmyra - Marblehead North 161 kV	Herleman - Palmyra Tap 345 kV	25%	866MWx2	7373	8272

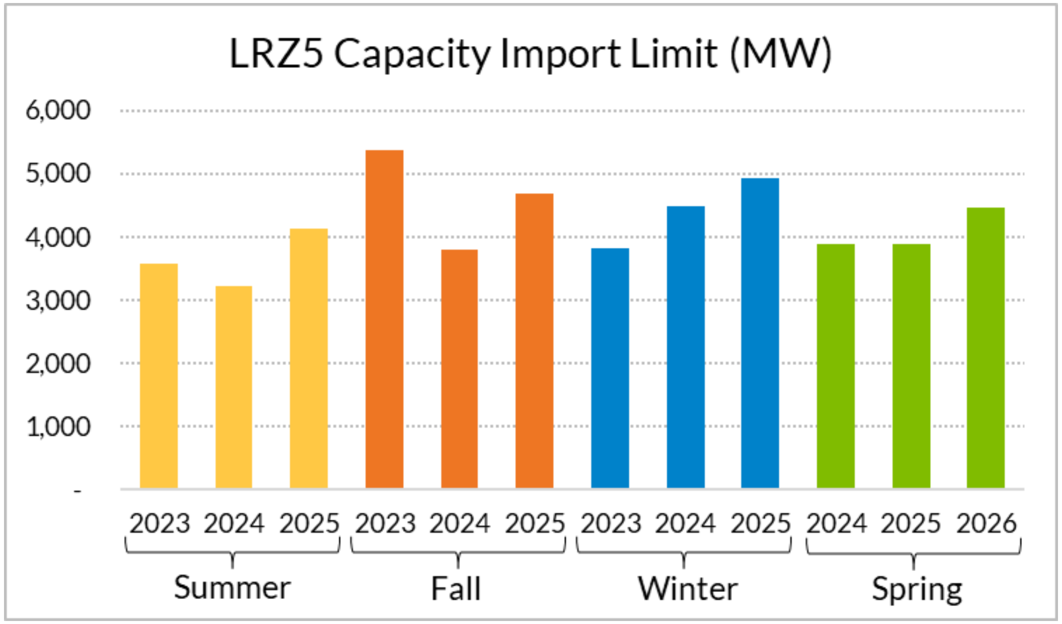




Capacity Import Limits
Zone 5: MO

LRZ5	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2025	Rezzy - Moro 138 kV	Redhawk - Moro 345 kV	None	697MWx2	4117	4117
Fall 2025	Rezzy - Moro 138 kV	Redhawk - Moro 345 kV	25%	608MWx2	4679	4679
Winter 2025-26	Hannibal West - Spalding 161 kV	Palmyra - Spencer Creek 345 kV	None	1000MWx2	4922	4922
Spring 2026	Mississippi Tap - Sioux 138 kV	Sioux Generator	10%	217MWx2	4453	4453

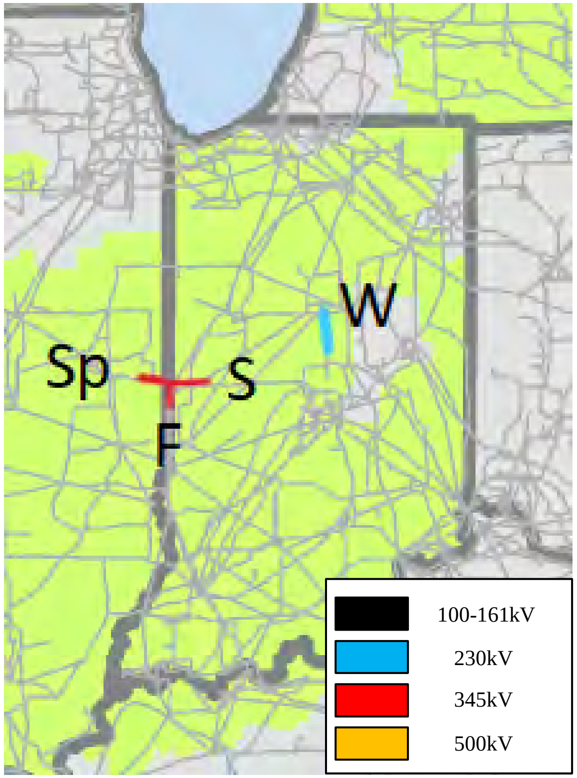


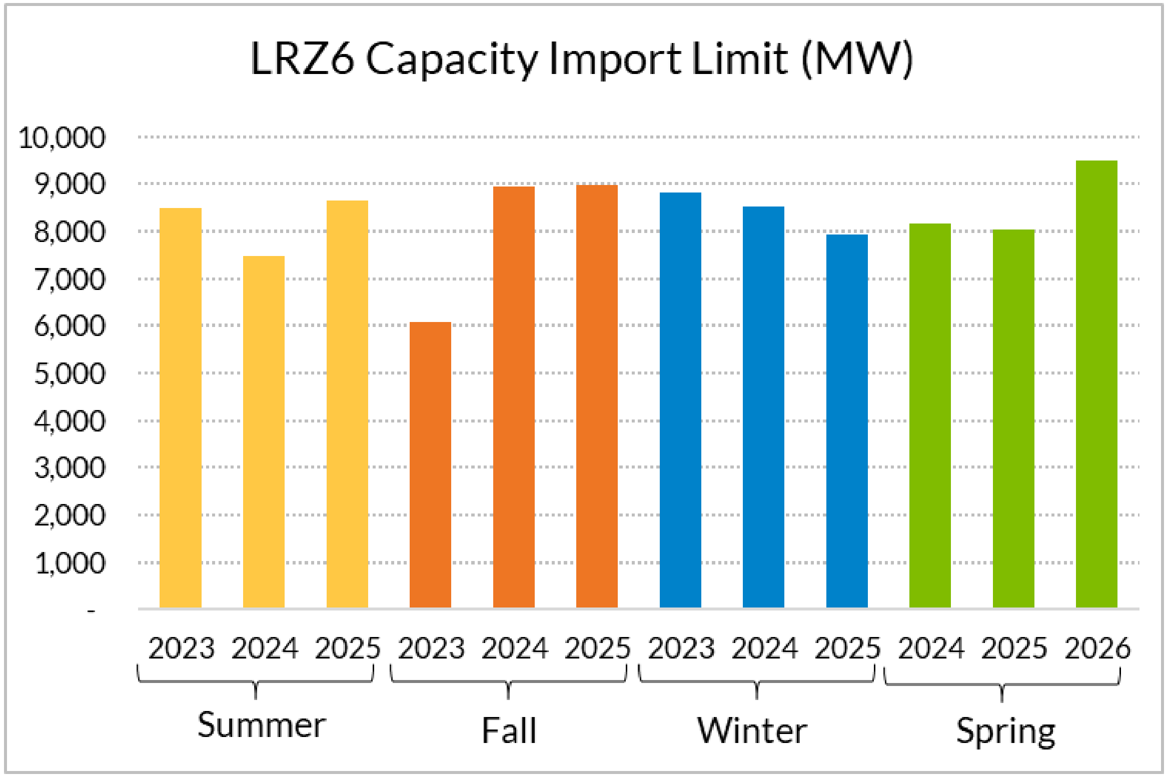


Capacity Import Limits

Zone 6: IN and KY

LRZ6	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2025	Cayuga - Nucor 345 kV	Dresser - Sugar Creek 345 kV	10%	571MWx2	8366	8650
Fall 2025	Cayuga - Cayuga Sub 345 kV	Kansas West - Sugar Creek 345 kV	None	162MWx2	8672	8970
Winter 2025-26	Kokomo Highland Park - Tipton 230 kV	Cayuga - Nucor 345 kV	None	1000MWx2	7690	7936
Spring 2026	Eugene - Cayuga Sub 345 kV	Kansas West - Sugar Creek 345 kV	None	431MWx2	9176	9491

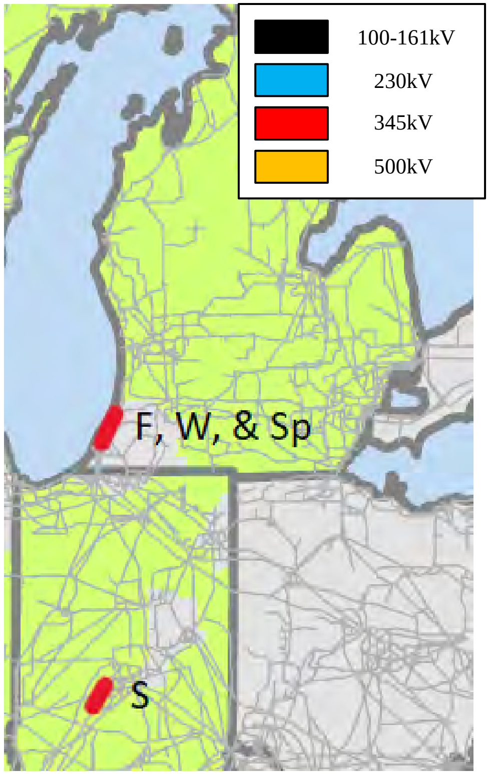


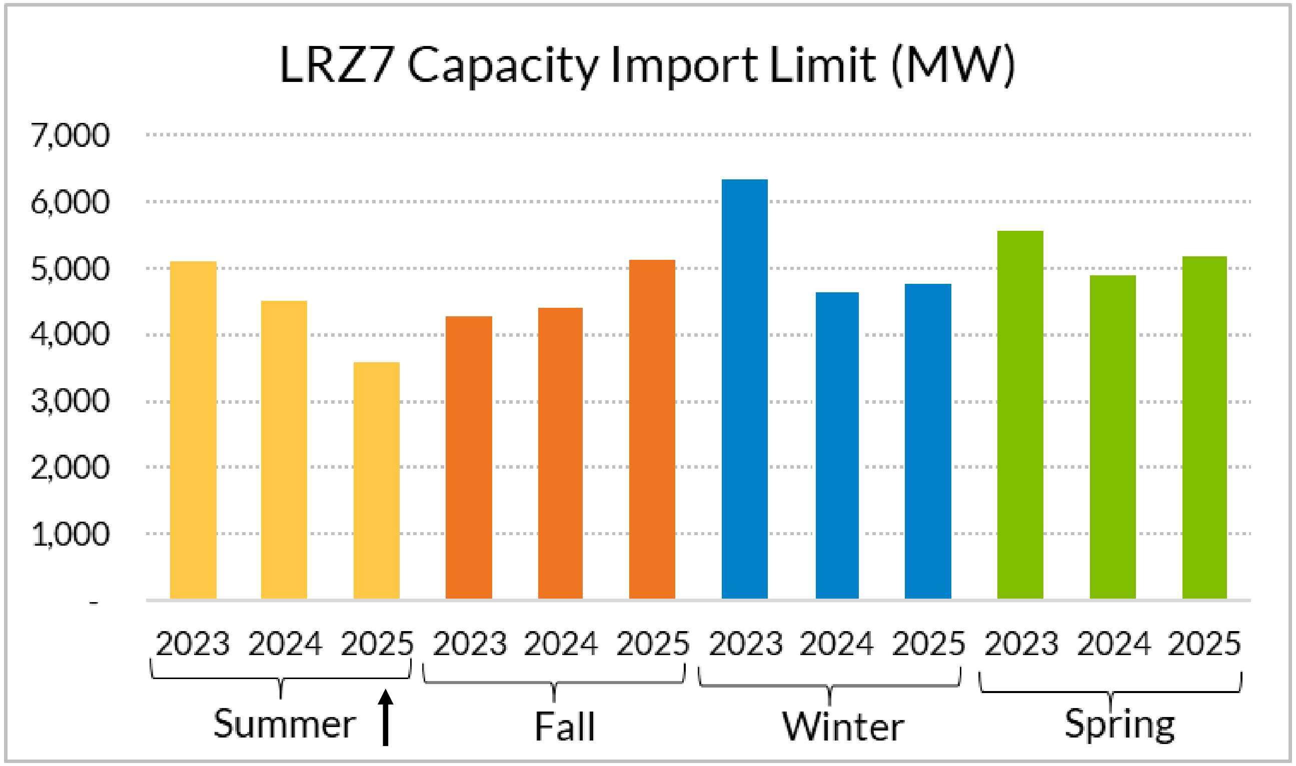


Capacity Import Limits

Zone 7: MI

LRZ7	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2025	Amo - Qualitech Steel 345 kV	Gibson - Wheatland 345 kV	None	1000MWx2	3569	3579
Fall 2025	Benton Harbor - Segreto 345 kV	Cook - Segreto 345 kV	None	1000MWx2	5115	5125
Winter 2025-26	Benton Harbor - Segreto 345 kV	Cook - Segreto 345 kV	None	1000MWx2	4762	4762
Spring 2026	Benton Harbor - Segreto 345 kV	Cook - Segreto 345 kV	None	643MWx2	5166	5166



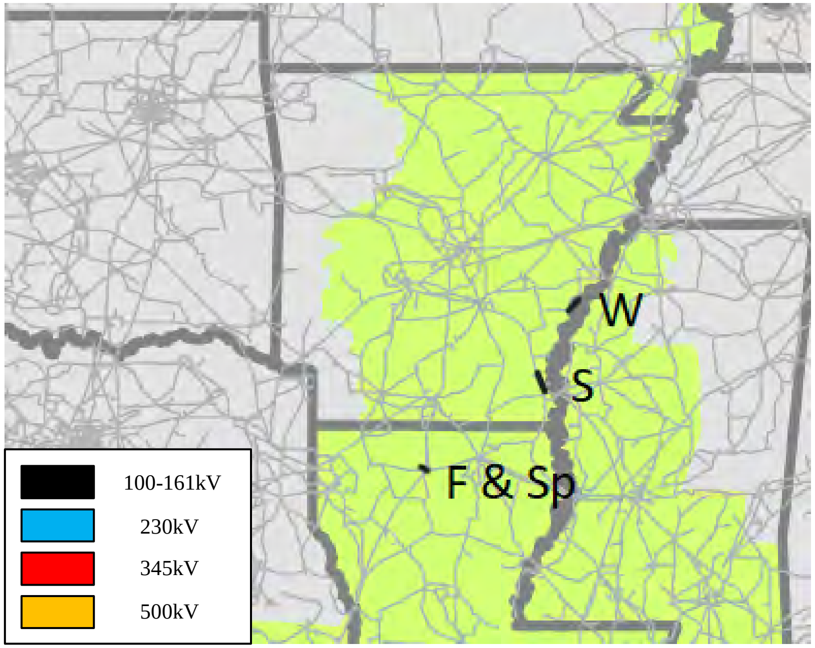


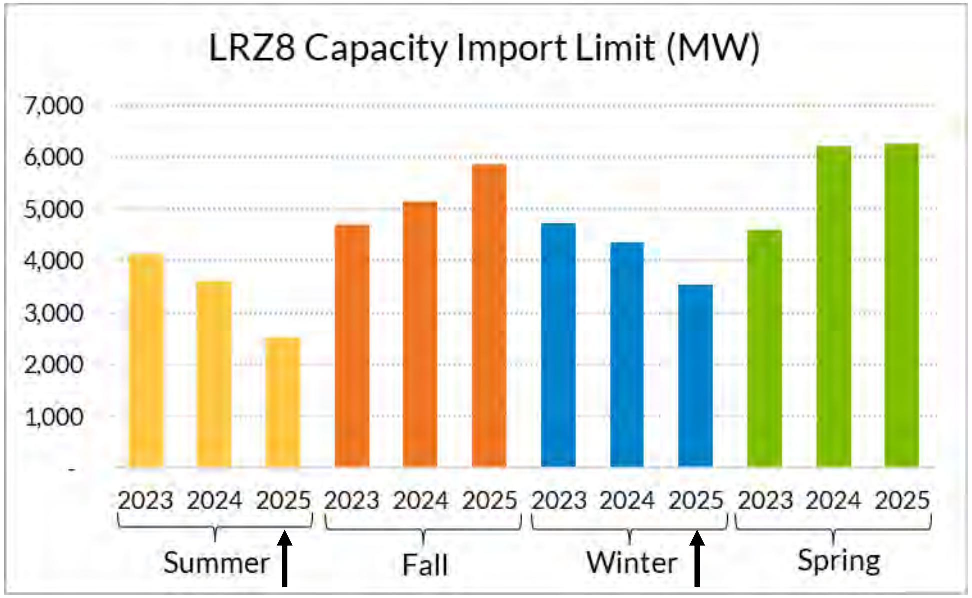
Primary Driver: Remaining resources binding earlier than previously due to lack of flexibility

Capacity Import Limits

Zone 8: AR

LRZ8	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2025	J620 - Dermott 115 kV	Lake Village Bagby - Reed SS 115 kV	None	697MWx2	2358	2522
Fall 2025	Mount Olive - Vienna 115 kV	Mount Olive - Eldorado 500 kV	None	1000MWx2	5675	5870
Winter 2025-26	Clarksdale - Lyon 115 kV	Moon Lake - Clarkesdale 230 kV	None	1000MWx2	3432	3534
Spring 2026	Mount Olive - Vienna 115 kV	Mount Olive - Eldorado 500 kV	None	1000MWx2	6085	6250

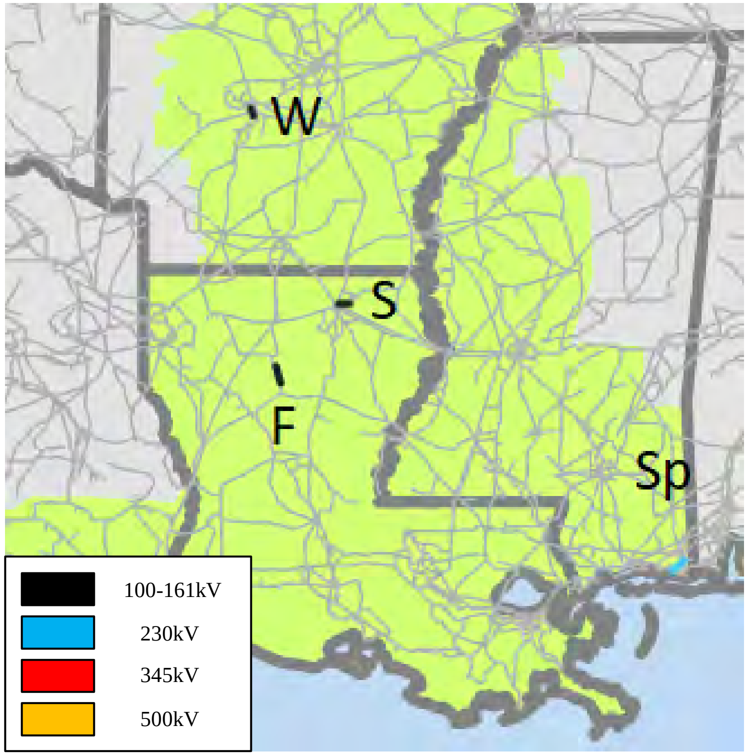


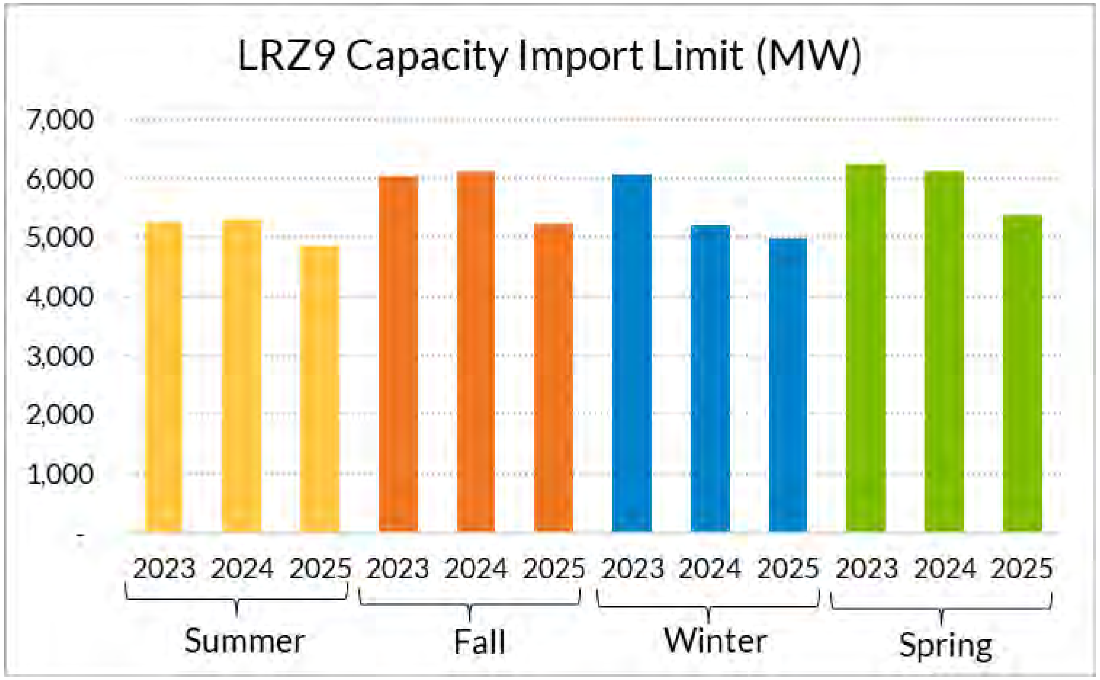


Primary Driver: New Resources are causing different flow patterns in base model, leading to earlier congestion

Capacity Import Limits
Zone 9: LA and TX

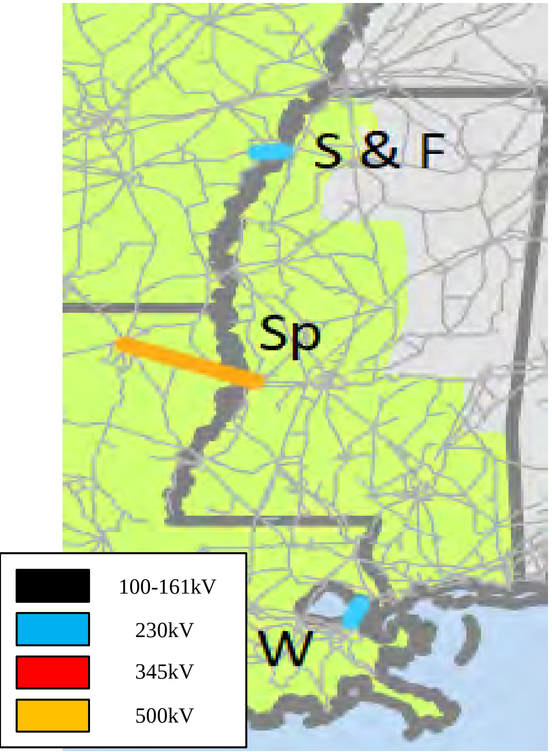
LRZ9	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2025	Sterlington - Downsville 115 kV	Mount Olive - Eldorado 500 kV	None	1000MWx2	4361	4872
Fall 2025	Danville - Dodson 115 kV	Mount Olive - Layfield 500 kV	None	1000MWx2	4741	5242
Winter 2025-26	Arklahoma - Hot Springs East 115 kV	Arklahoma - Hot Springs West 115 kV	None	1000MWx2	4418	4995
Spring 2026	Daniel - Daniel Intermediate 1 230 kV	Daniel - Daniel Intermediate 2 230 kV	None	1000MWx2	4855	5370

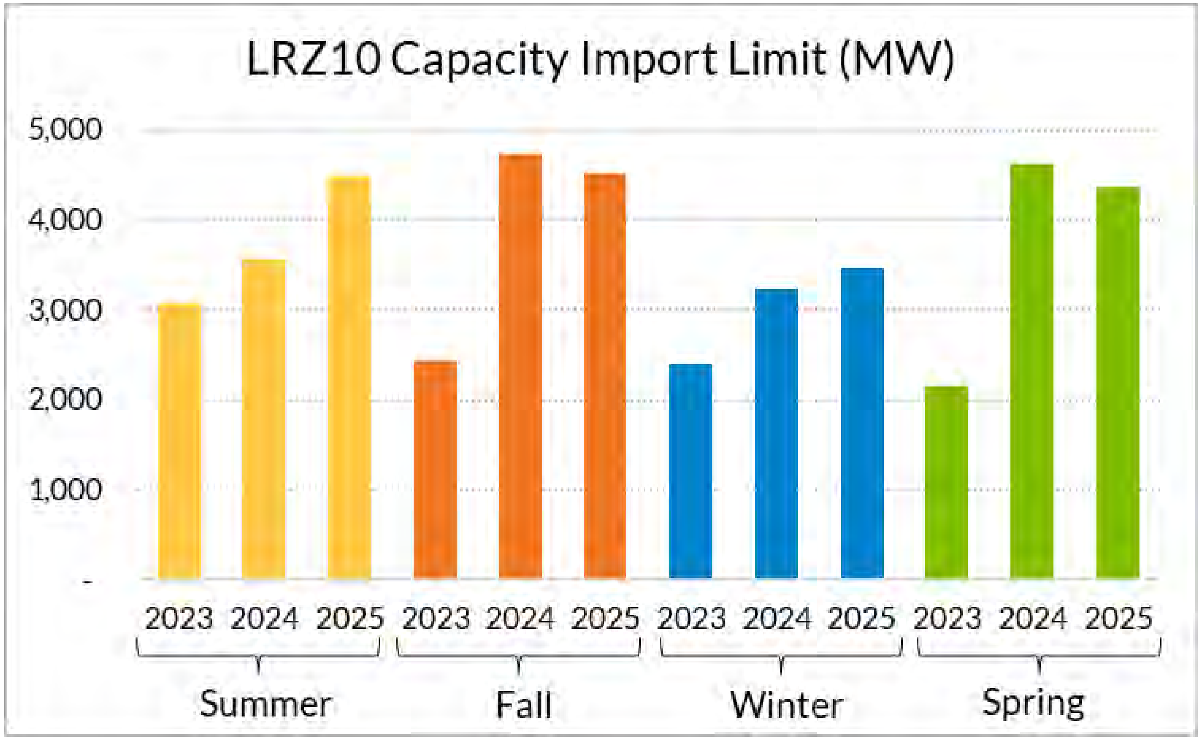




Capacity Import Limits
Zone 10: MS

LRZ 10	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2025	Ritchie - Moon Lake 230 kV	Perryville - Baxter Wilson 500 kV	None	1000MWx2	4474	4474
Fall 2025	Ritchie - Moon Lake 230 kV	Perryville - Baxter Wilson 500 kV	None	602MWx2	4508	4508
Winter 2025-26	Little Gypsy - Fairview 230 kV	Michoud - Front Street 230 kV	None	1000MWx2	3458	3458
Spring 2026	Perryville - Baxter Wilson 500 kV	Grand Gulf Generator	None	1000MWx2	4365	4365

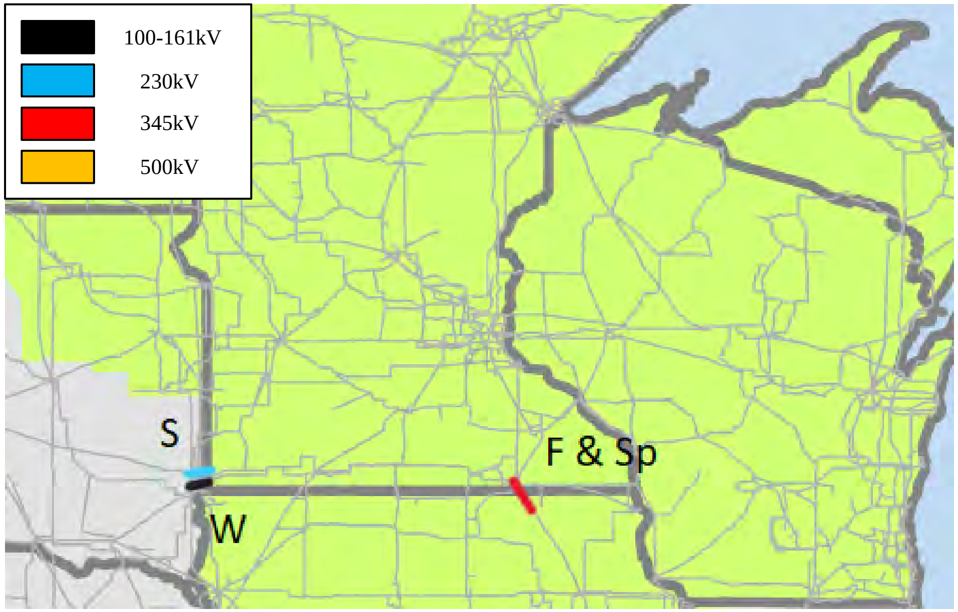


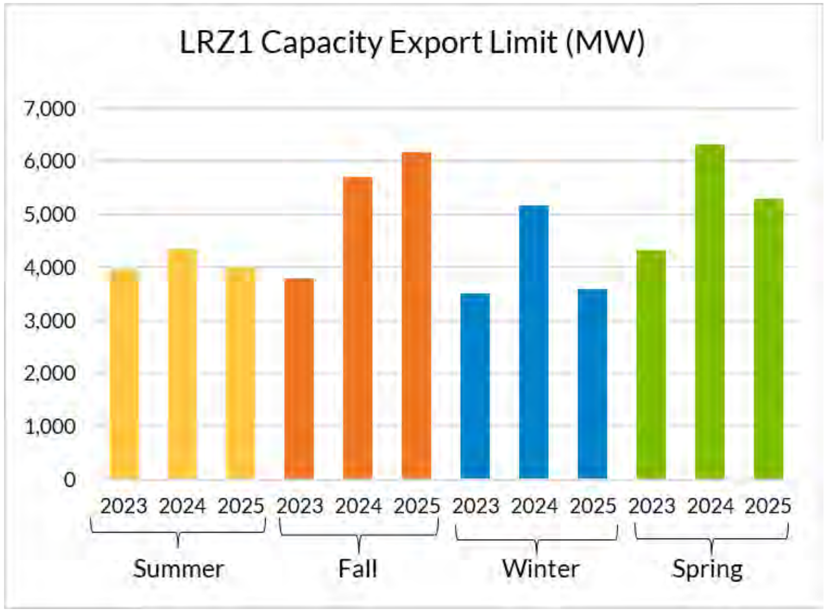


Planning Year 2025-2026 Final CEL Results

Capacity Export Limits
Zone 1: MN, MT, ND, SD and WI

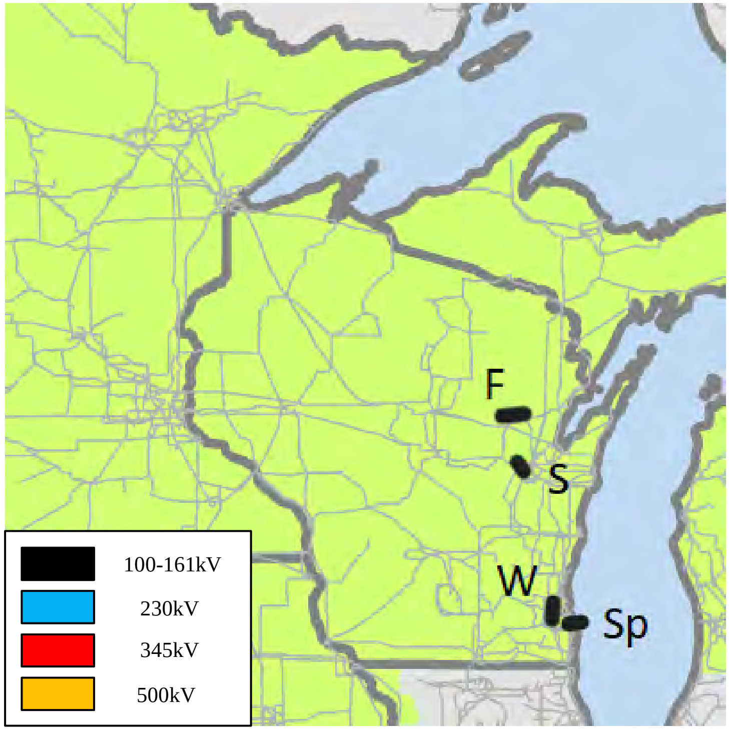
LRZ1	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2025	Split Rock 4 - Sioux Falls 230 kV	Split Rock 3 - Sioux City 345 kV	None	293MWx2	3993	3991
Fall 2025	Adams - Mitchell County 345 kV	Disconnect Blackhawk Reactor	None	270MWx2	6167	6165
Winter 2025-26	Split Rock 7 - Split Rock 4 115 kV	Split Rock - Sioux City 345 kV	None	721MWx2	3593	3591
Spring 2026	Adams - Mitchell County 345 kV	Disconnect Blackhawk Reactor	None	279MWx2	5285	5283

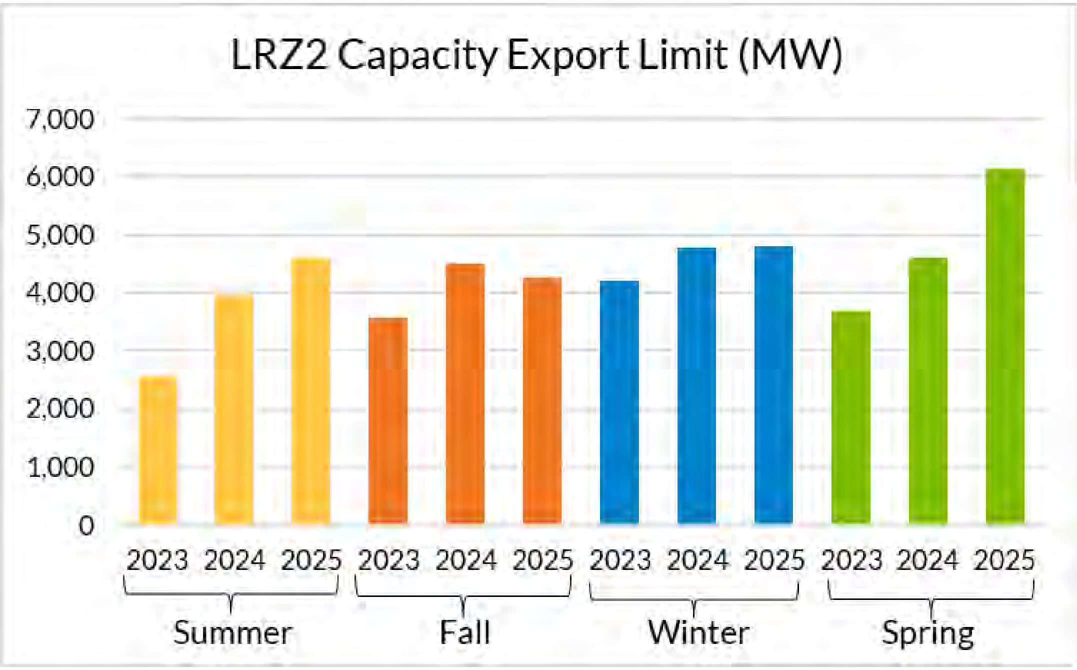




Capacity Export Limits
Zone 2: WI and MI

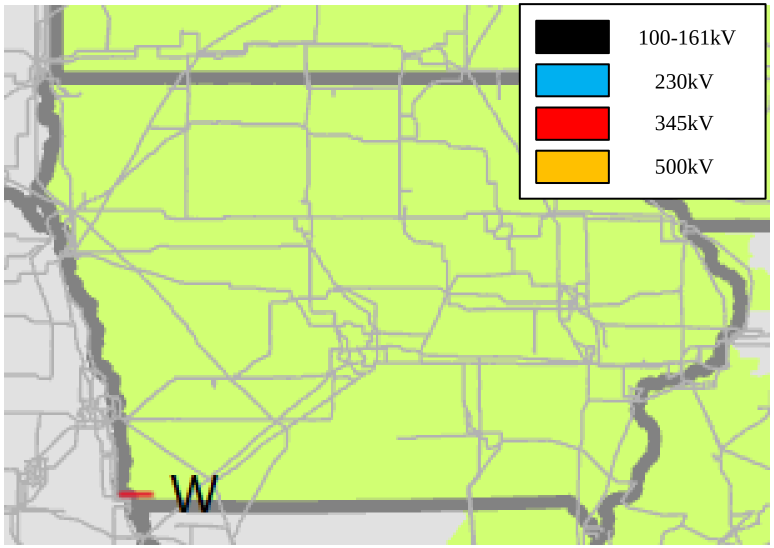
LRZ2	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2025	Neevin - Butte Des Morts 138 kV	Neevin-Woodenshoe 138 kV	25%	633MWx2	4614	4614
Fall 2025	Sherman Street - Sunnyvale 115 kV	Arpin - Rocky Run 345 kV	10%	909MWx2	4259	4259
Winter 2025-26	Granville - Butler 138 kV	Arcadian-Granville 345 kV	20%	561MWx2	4793	4793
Spring 2026	Berryville - Paris 138 kV	Paris 345/138 kV Transformer	30%	674MWx2	6119	6119

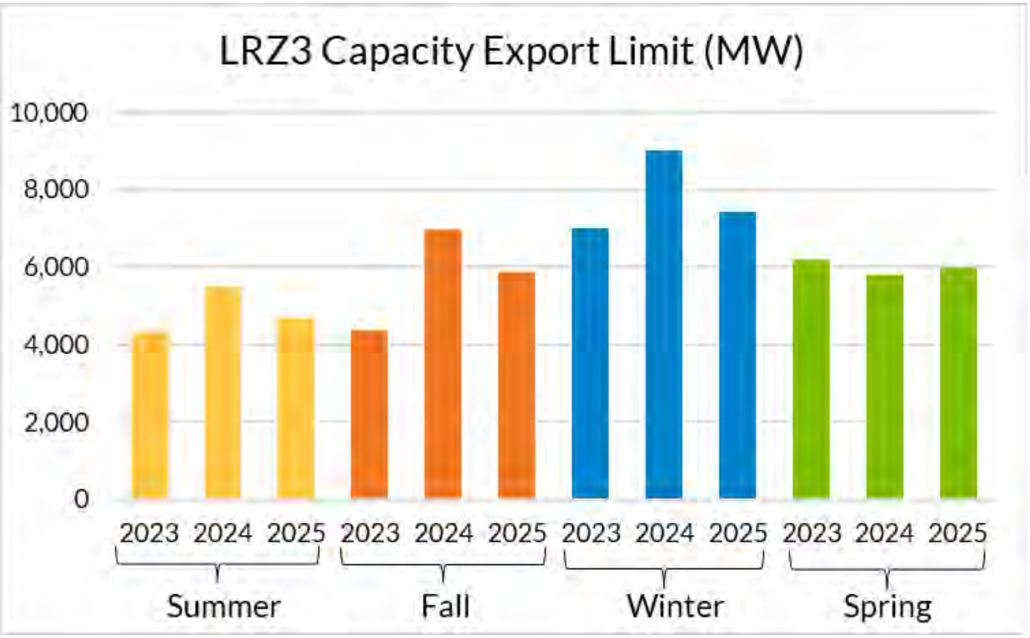




Capacity Export Limits
Zone 3: IA

LRZ3	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2025	No Limiting Element	None	50%	None	4713	4655
Fall 2025	No Limiting Element	None	50%	None	5924	5862
Winter 2025-26	Council Bluffs - Sub 3456 345 kV	Arbor Hill - Raccoon Trail 345 kV	None	561MWx2	7480	7412
Spring 2026	No Limiting Element	None	50%	None	6039	5981

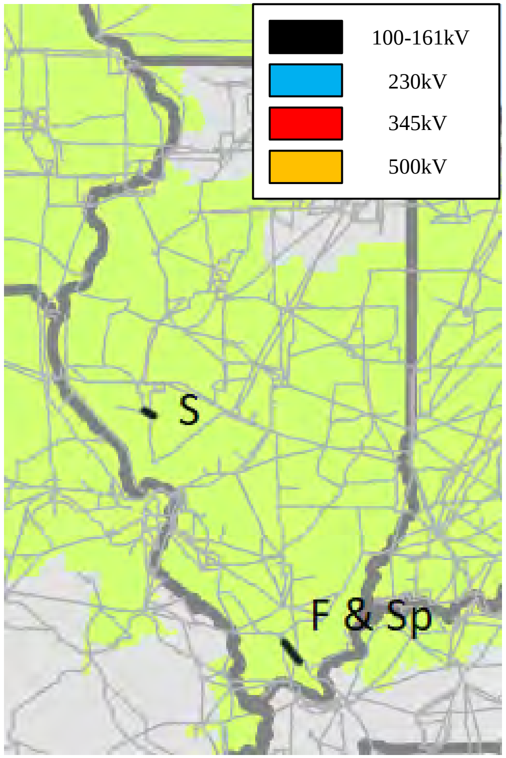


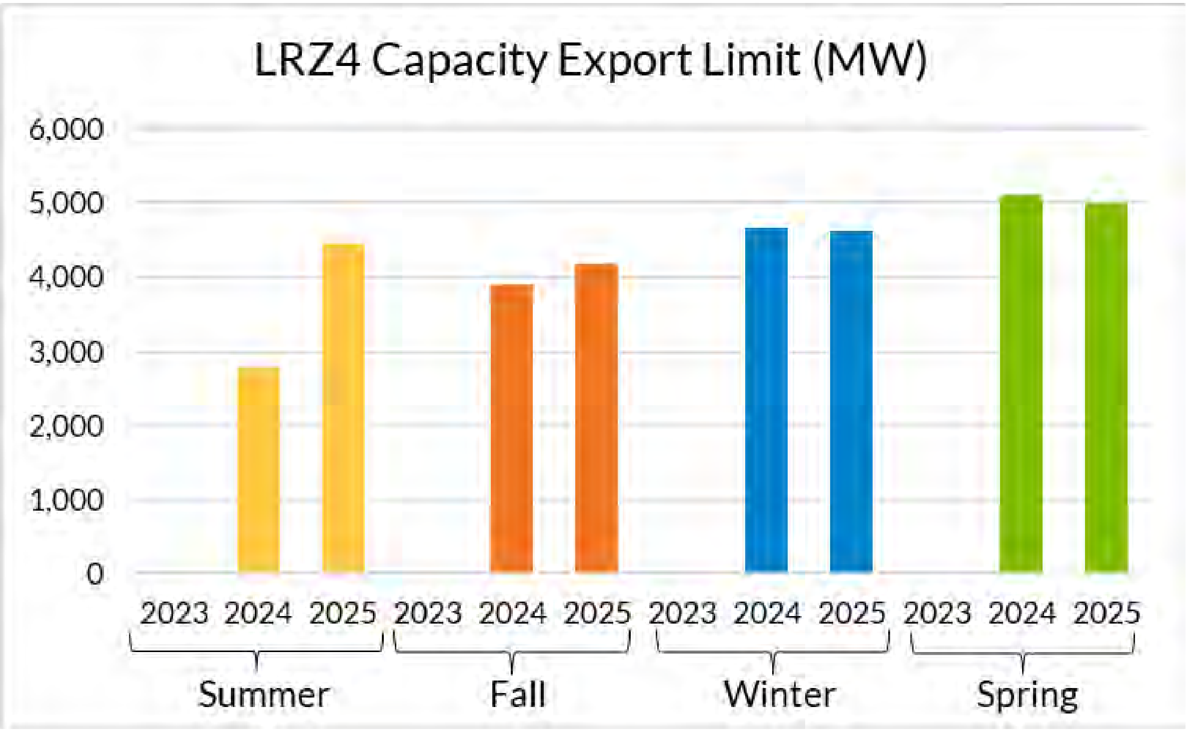


Capacity Export Limits

Zone 4: IL

LRZ4	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2025	Alsey - Winchester 138 kV	Alsey - Ballard 138 kV	40%	577MWx2	5352	4460
Fall 2025	Marion - Marion South 161 kV	Silver Mine Substation	None	1000MWx2	5069	4174
Winter 2025-26	No Limiting Element	None	50%	None	5531	4635
Spring 2026	Marion - Marion South 161 kV	Silver Mine Substation	None	212MWx2	5880	4981





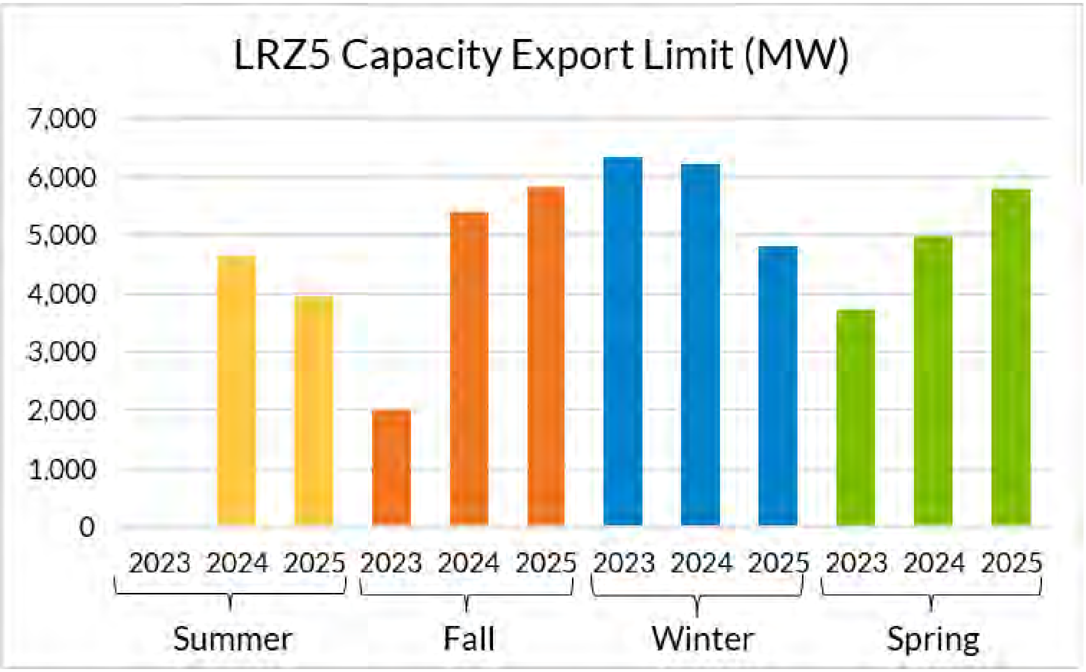
Capacity Export Limits
Zone 5: MO

LRZ5	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2025	No Limiting Element	None	45%	None	3939	3939
Fall 2025	No Limiting Element	None	50%	None	5816	5816
Winter 2025-26	No Limiting Element	None	50%	None	4814	4814
Spring 2026	No Limiting Element	None	50%	None	5797	5797

Limit: No Limit Found

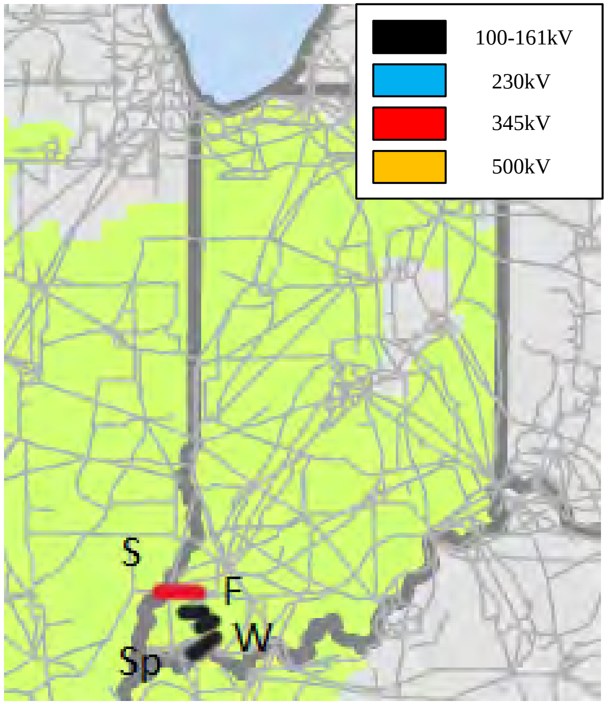
Per language in Section 5.2.2.1 of BPM-011 on Generation Limited Transfer for CIL/CEL:

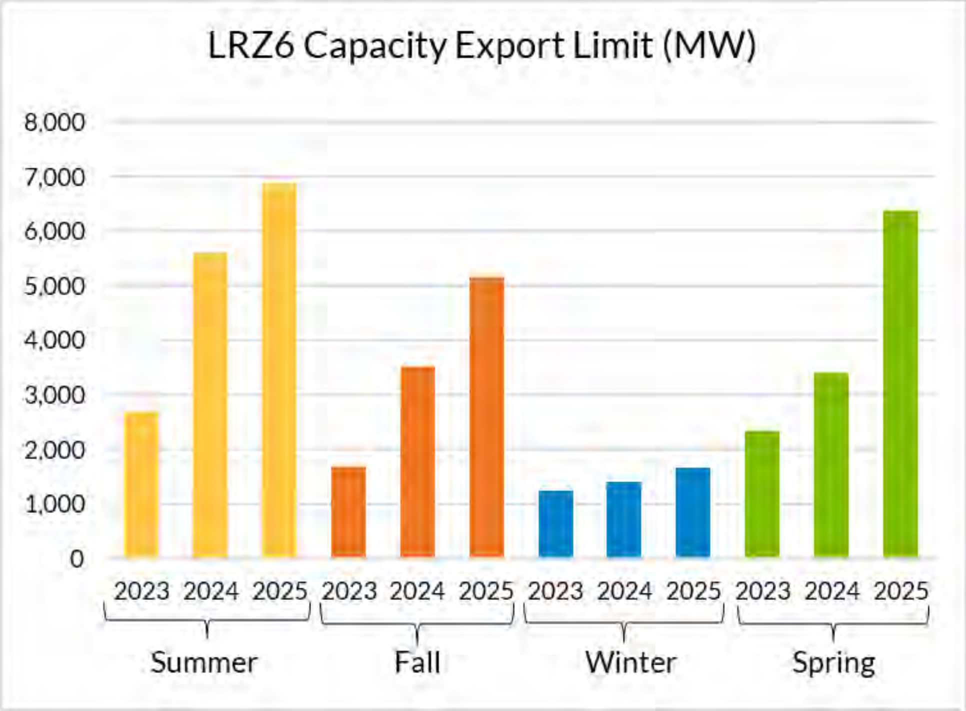
If the GLT does not produce a limit for a zone(s), due to a valid constraint not being identified, or due to other considerations as listed in the prior paragraph, MISO shall report the LRZ as having no limit and ensure that the limit will not bind in the first iteration of the Simultaneous Feasibility Test (SFT).



Capacity Export Limits
Zone 6: IN and KY

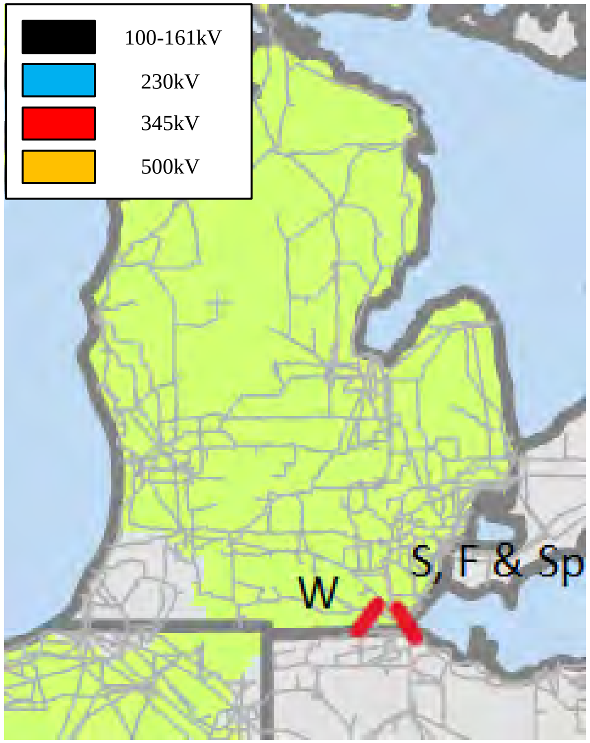
LRZ6	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2025	Gibson - Douglas 345 kV	AB Brown - Posey East 345 kV	40%	70MWx2	7165	6881
Fall 2025	AEP Rockport - Grandview 138 kV	AB Brown - Reid 345 kV	None	539MWx2	5471	5173
Winter 2025-26	AB Brown - AB Brown Reactor 138 kV	AB Brown - Reid 345 kV	None	518MWx2	1911	1665
Spring 2026	Holland - Dubois 138 kV	Duff - Francisco 345 kV	None	487MWx2	6706	6391

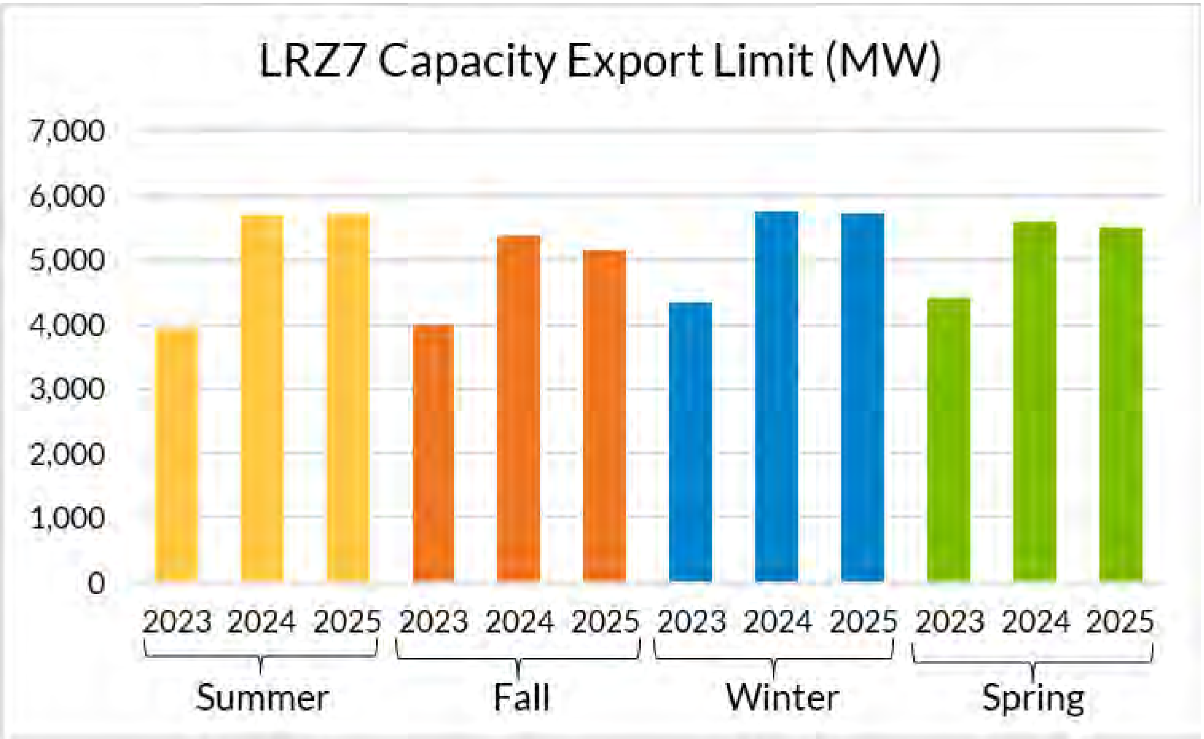




Capacity Export Limits
Zone 7: MI

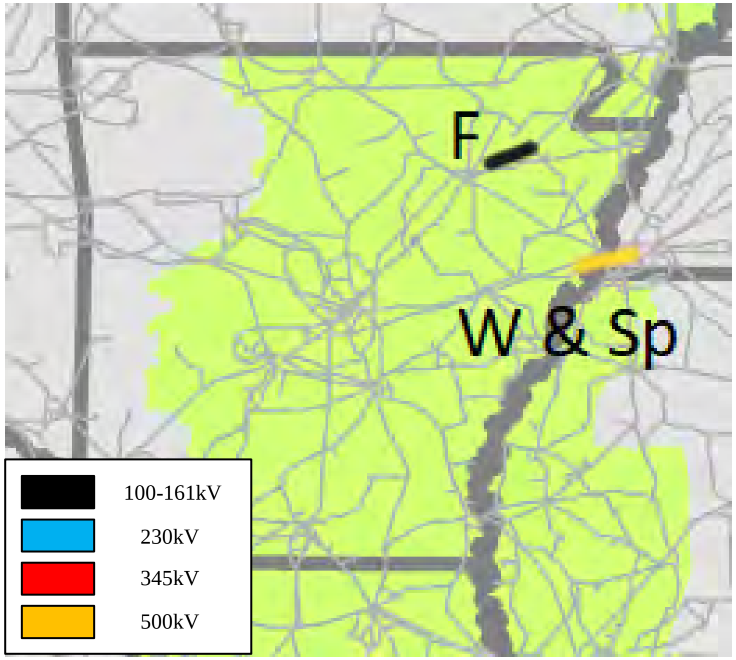
LRZ7	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2025	Monroe - Lallendorf 345 kV	Morocco - Allen Junction 345 kV	15%	1000MWx2	5726	5716
Fall 2025	Monroe - Lallendorf 345 kV	Morocco - Allen Junction 345 kV	None	1000MWx2	5168	5158
Winter 2025-26	Morocco - Allen Junction 345 kV	Monroe - Lallendorf 345 kV	None	1000MWx2	5712	5712
Spring 2026	Monroe - Lallendorf 345 kV	Morocco - Allen Junction 345 kV	None	1000MWx2	5499	5499

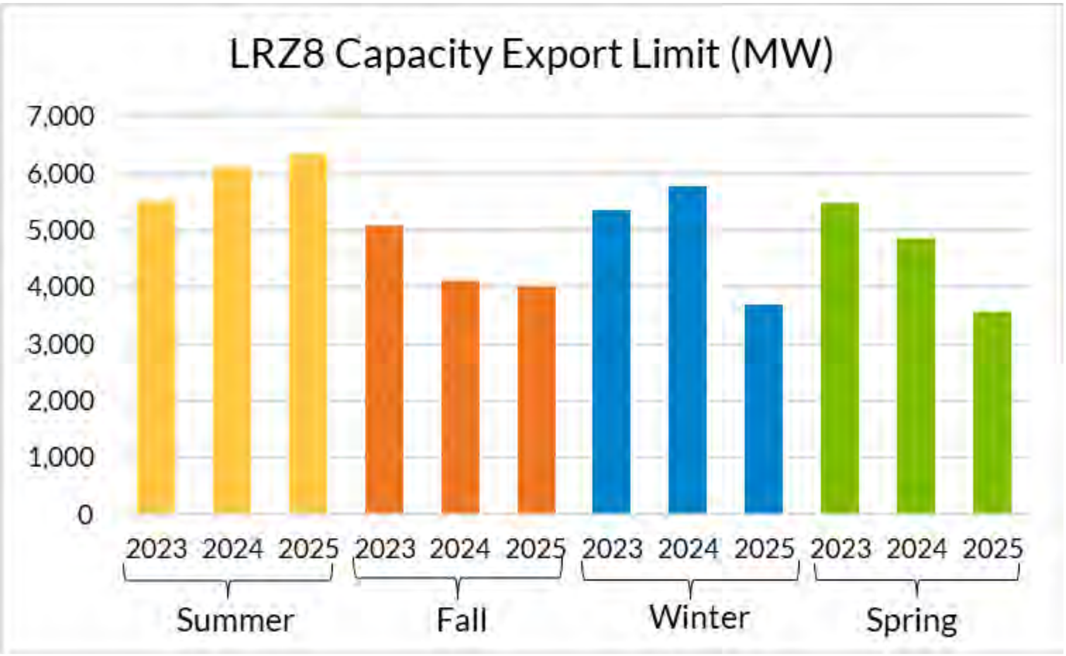




Capacity Export Limits
Zone 8: AR

LRZ8	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2025	No Limiting Element	None	50%	641MWx2	6509	6345
Fall 2025	Cash - Jonesboro 161 kV	Independence - Power Line Road 500 kV	None	1000MWx2	4219	4024
Winter 2025-26	Freeport - Cordova 500 kV	Sans Souci - Driver 500 kV	20%	422MWx2	3783	3681
Spring 2026	Freeport - Cordova 500 kV	Sans Souci - Driver 500 kV	None	382MWx2	3724	3559



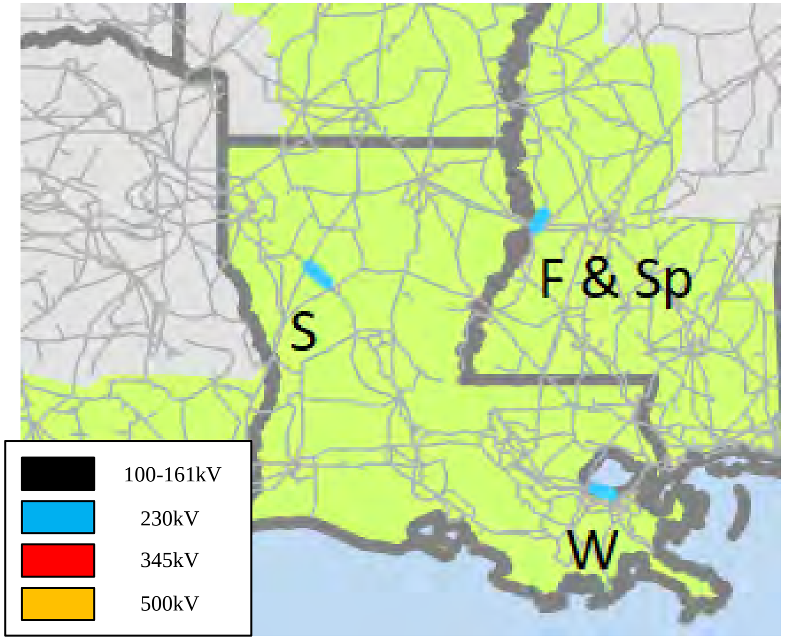


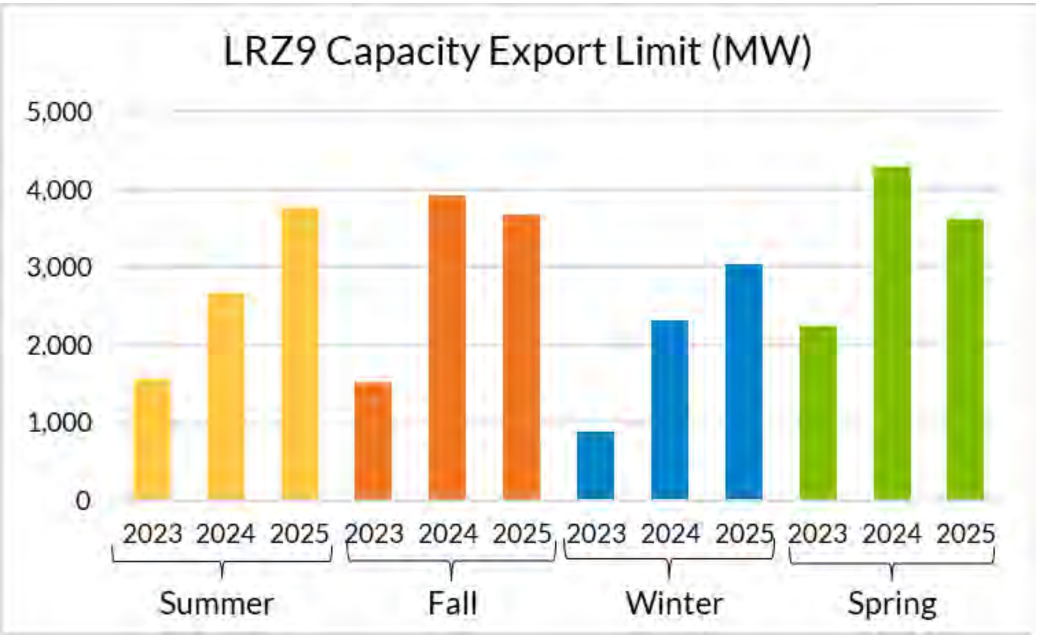
Primary Driver for Winter 2025-2026 & Spring 2026: New Resources are causing different flow patterns in the base model, leading to earlier congestion

MISO

Capacity Export Limits
Zone 9: LA and TX

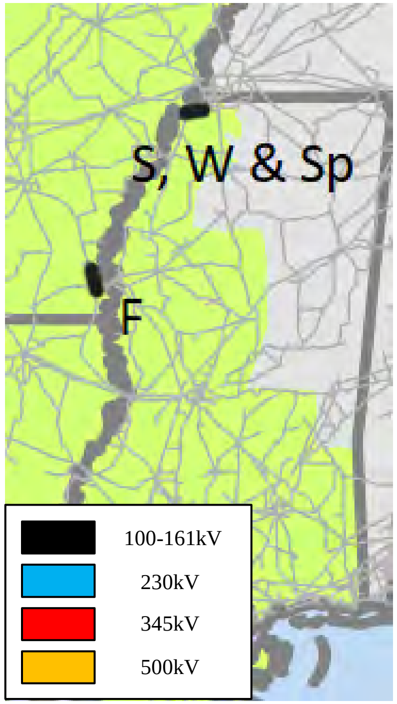
LRZ9	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2025	Montgomery - Clarence 230 kV	Montgomery - Winfield 230 kV	None	1000MWx2	4286	3775
Fall 2025	Ray Braswell - Northside Drive 230 kV	Ray Braswell - Lakeover 500 kV	None	1000MWx2	4173	3672
Winter 2025-26	Little Gypsey - Fairview 230 kV	Michoud - Front Street 230 kV	None	1000MWx2	3618	3041
Spring 2026	Ray Braswell - Northside Drive 230 kV	Ray Braswell - Lakeover 500 kV	None	1000MWx2	4146	3631

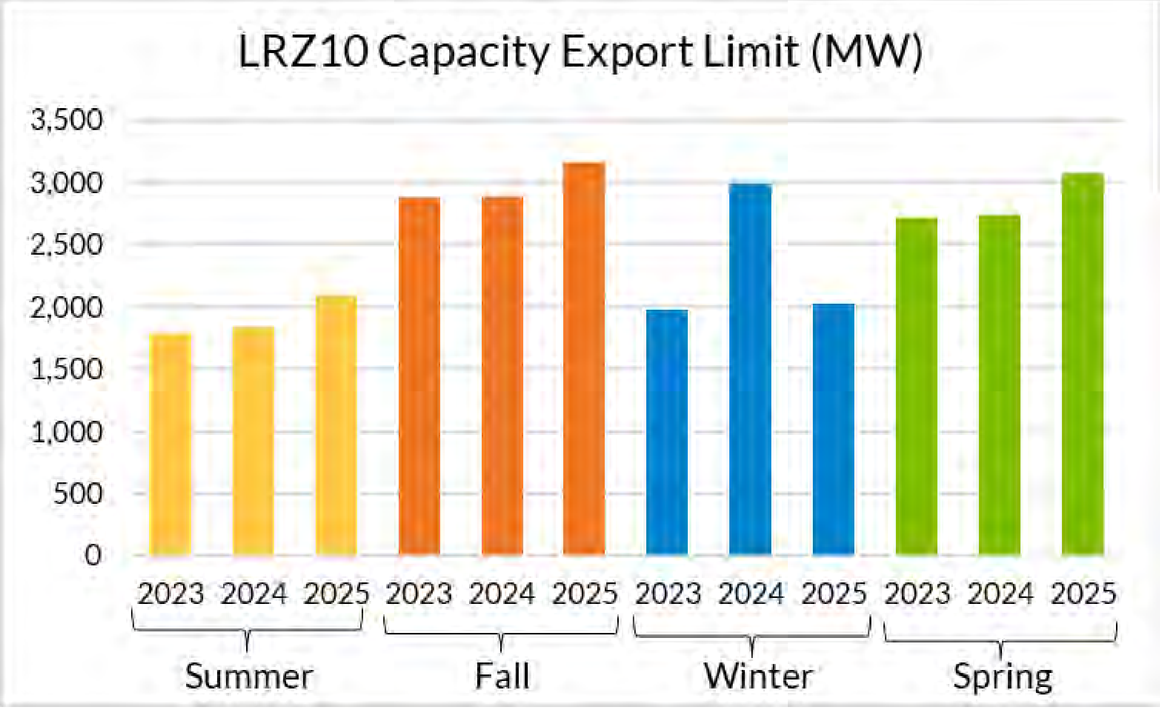




Capacity Export Limits
Zone 10: MS

LRZ10	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2025	Batesville - Tallahatchie 161 kV	Batesville - East Batesville 161 kV	None	710MWx2	2097	2097
Fall 2025	Lake Village Bagby - Macon Lake 115 kV	Lake Village Bagby - Reed 115 kV	None	650MWx2	3164	3164
Winter 2025-26	Batesville - Tallahatchie 161 kV	Choctaw - Clay 500 kV	None	710MWx2	2028	2028
Spring 2026	Batesville - Tallahatchie 161 kV	Batesville - East Batesville 161 kV	None	526MWx2	3072	3072





Primary Driver for Winter 2025-2026: New Resources are causing different flow patterns in the base model, leading to earlier congestion

Next Steps

- Planning Year 2025-2026 CIL/CEL values are finalized and will be entered in MECT.
- March 2025 – MISO will receive a final list of Controllable Exports and will adjust CIL/CEL values if necessary.

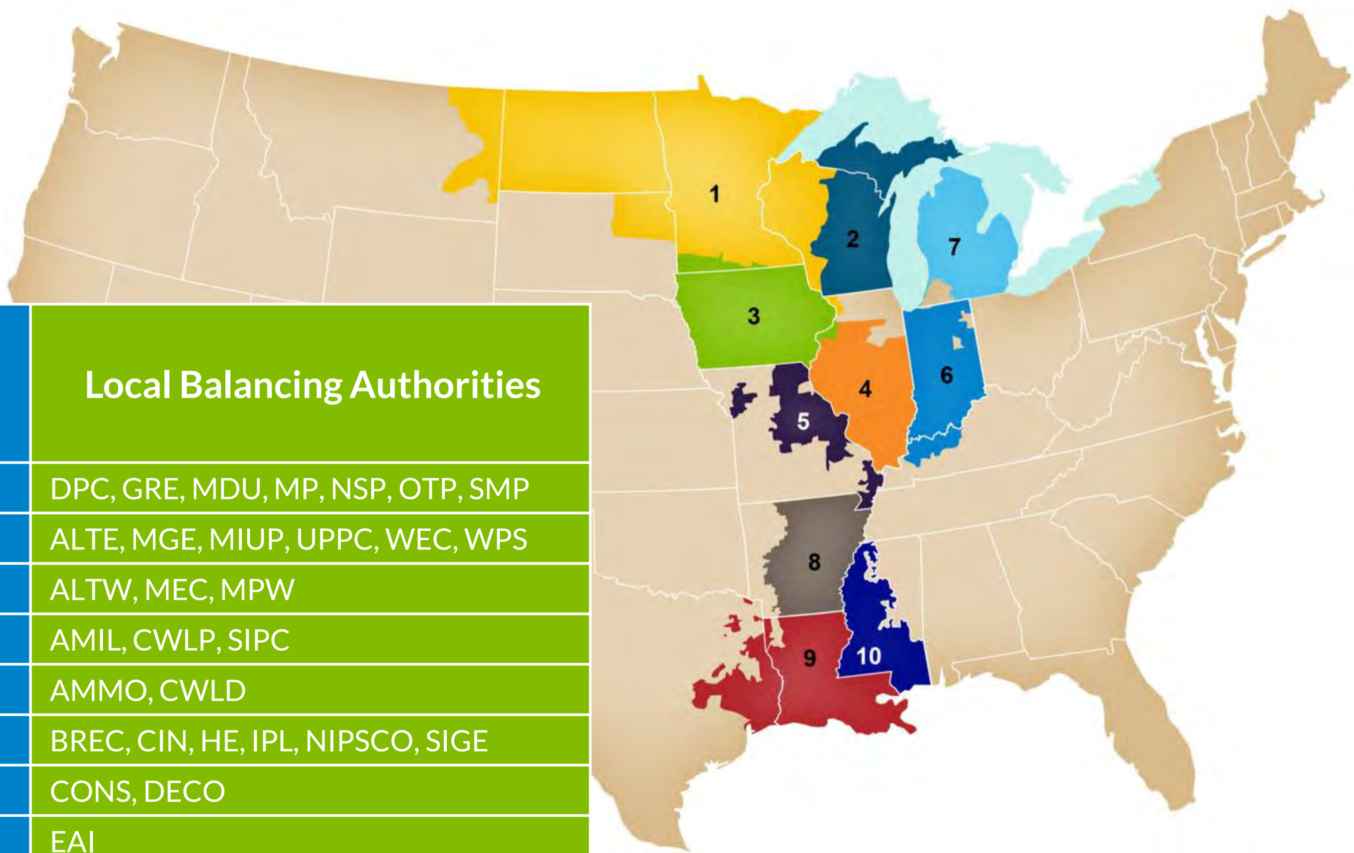
Contact

jdibasilio@misoenergy.org

MISO Help Center:

https://help.misoenergy.org/

MISO Local Resource Zones



Local Resource Zone	Local Balancing Authorities
1	DPC, GRE, MDU, MP, NSP, OTP, SMP
2	ALTE, MGE, MIUP, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, CIN, HE, IPL, NIPSCO, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EMBA, SME

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-26-22

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

Exhibit 38

MISO LOLE Presentation

LOLE 101: Probabilistic Analyses

LOLE 101 Training

5/8/2018

Loss of Load Expectation (LOLE) 101 Sections

- LOLE Background & History
- LOLE Study Connections to other MISO Processes
- Generating Availability Data System (GADS) Overview
- LOLE Modeling
- Strategic Energy Risk Valuation Model (SERVM)
- LOLE Results Walkthrough
- Takeaways
- Reference Materials

Loss of Load Expectation (LOLE) Definition

LOLE is the measure of how long, on average, the available generation capacity is likely to fall short of the load demand

Loss of Load Probability (LOLP) is the probability in a given hour	Sum of the Daily Peak LOLP values is an expectation (LOLE)	Sum of all LOLP values is called Loss of Load Hours (LOLH)

LOLE is used to study Generation (Resource) Adequacy

Generally considered to be the existence of sufficient resources, within a system, to satisfy consumer demand. A product of unit availability, "perfect storm". The study of low probability, high impact events.

1-day in 10-years LOLE Criteria

MISO Resource Adequacy criteria for Planning Reserve target is the industry standard LOLE objective:

<1-day in 10-years

=

NERC Standard BAL-502-RF-03

- Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year analyzed being equal to 0.1. (This is comparable to a “one day in 10 year” criterion).

Common Terminology Misconceptions

- 1 day in 10 years LOLE ≠ 24 hours in 10 years LOLH
  - Example: 2 hours of firm load shed = 2 loss of load hours and 1 day of loss of load
  - By definition 1 day/ 10 years LOLE ≤ 24 hours / 10 years LOLH

- Cannot calculate Loss of Energy Expectation (LOEE) from LOLH without running complete analysis

LOLE Connections to Various MISO Processes

- **LOLE**
  - **Planning Reserve Margin (PRM) Study**
    - **Resource Adequacy**
      - Tariff Module E-1
      - Planning Resource Action
    - **Planning Studies**
      - MTEP Futures Development
      - MTEP Study
  - **Assessments**
    - NERC Assessments
    - MISO Informational Forums

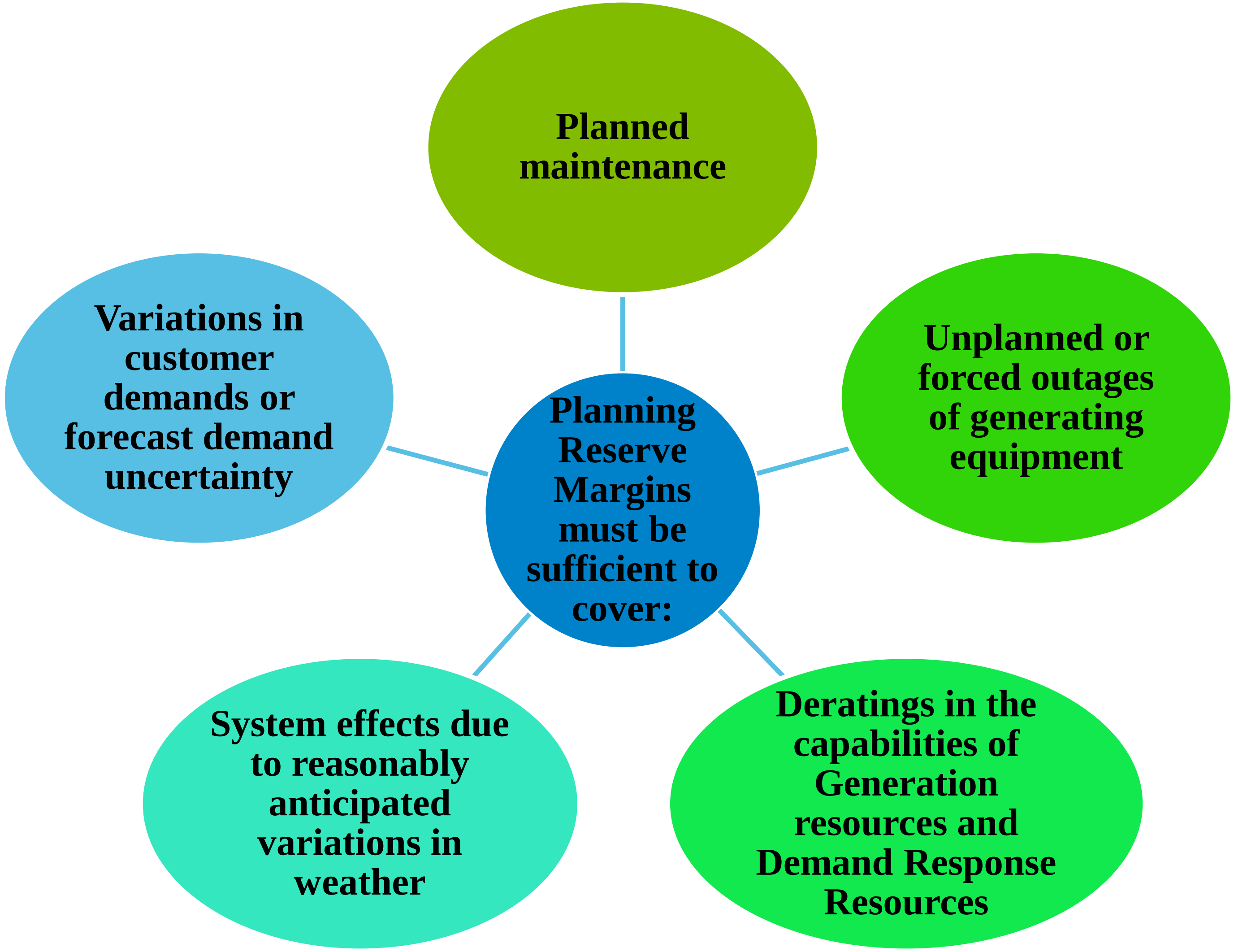
Resource Adequacy Overview

- Achieving reliability in the bulk electric systems requires that the amount of resources exceeds customer demand by an adequate margin

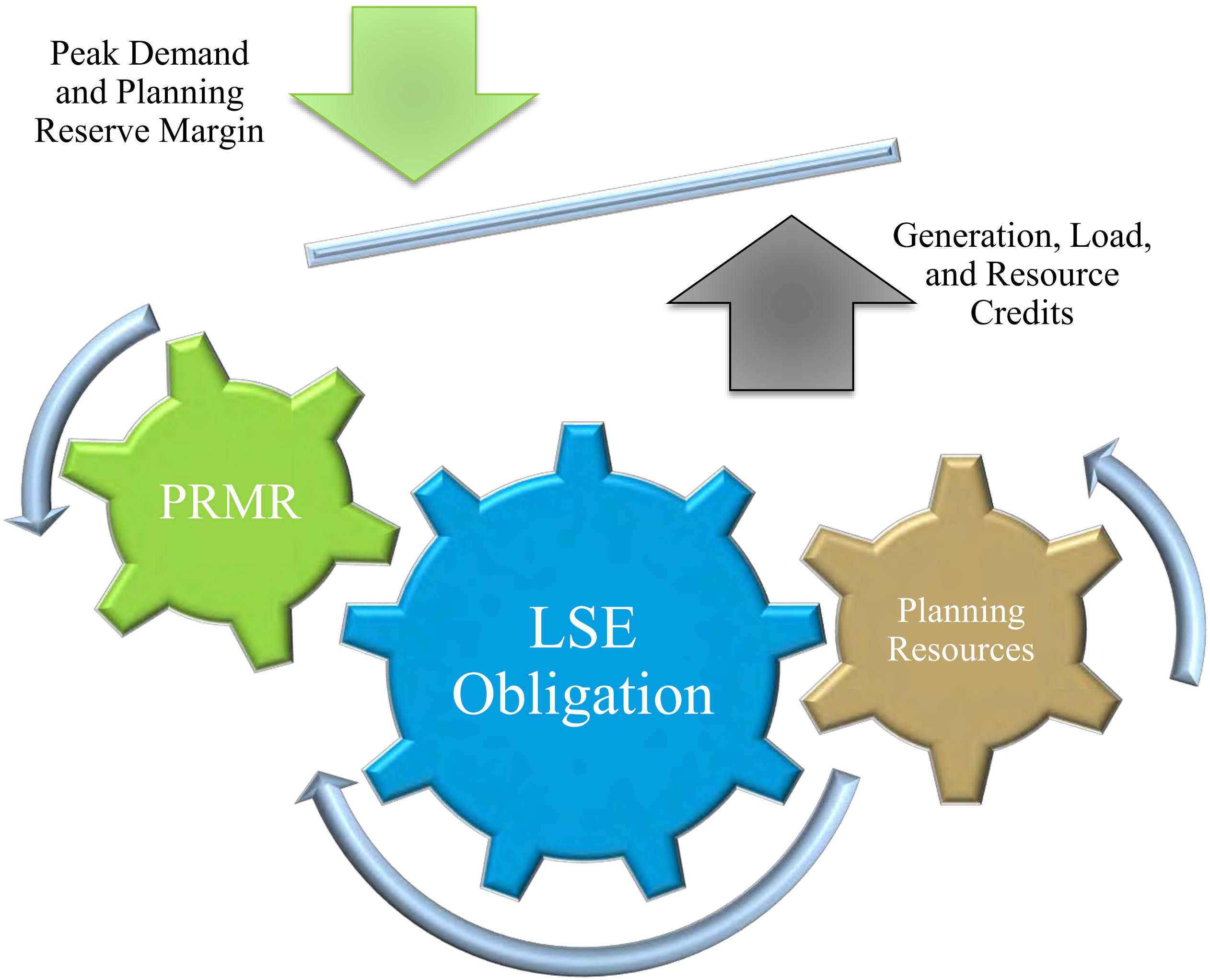
Margins necessary to promote Resource Adequacy need to be assessed on:

Longer-term planning basis	Near-term operational basis
Focus of MISO's RA Construct is on the longer-term planning margins used to provide sufficient resources to reliably serve load on a forward-looking basis	Resources dedicated to meet Demand have an obligation to be available to meet real-time customer demand and contingencies

Planning Reserve Margins (PRMs)



Overview of MISO Resource Adequacy Requirements



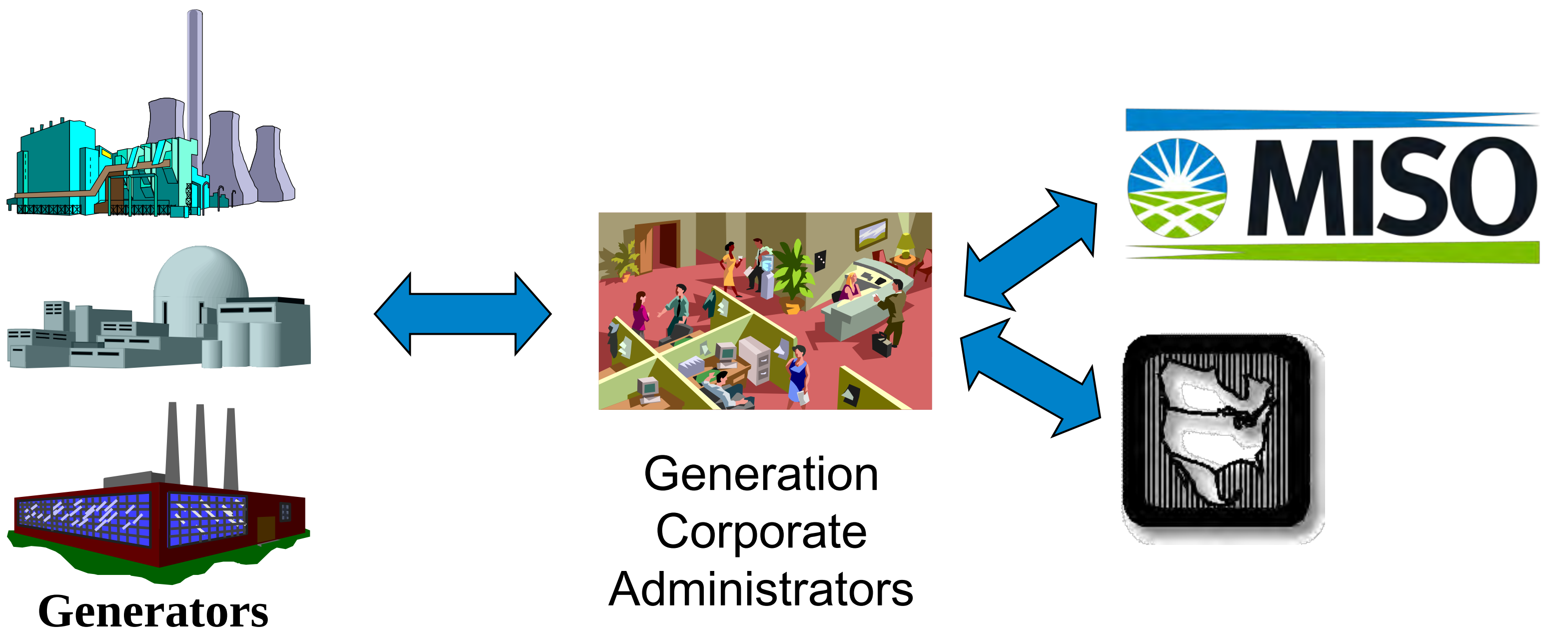
PowerGADS – Performance & Reliability System

For capacity planning and reliability study purposes,

all generating facilities declared as <u>capacity resources</u> in the MISO market

are required to submit GADS <u>event and performance</u> data

to determine the value of the facility as an unforced capacity resource



GADS Data Requirements…

- Generation Resources
- External Resources
- Demand Response Resources backed by behind the meter generation
- or Behind the Meter Generation (BTMG)

Greater than or equal to 10 MW, based on Generation Verification Test Capacity (GVTC)

- Must submit generator availability data (including, but not limited to, NERC GADS) into PowerGADS through the Market Portal

Less than 10 MW, based on (GVTC), that begin reporting generator availability data

- Must continue to report such information

GADS Data Requirements…

- Quarterly Submittal of Data
  - Stakeholders are expected to submit data on a quarterly basis
  - Quarterly GADS data must be received by the last day of the month following the operating quarter
  - Quarterly GADS data must be Level 2 Validated by the last day of the month following the operating quarter

GADS Data Requirements…

- A unit will receive 100% EFORd if it fails to submit GADS data and successfully Level 2 Validate

- Assigning 100% EFORd will impact a unit's unforced capacity calculation
  - $UCAP = GVTC * (1 - EFORd)$

Three Types of Data are to be Collected…

Event Data

- Each time a unit has a change in operating status or capability, an *event* is recorded
- From these event reports a unit's operational history can be reconstructed

Generation Performance Data

- A unit's actual generation, hours of operations, and operational characteristics

Fuel Performance Data (optional)

- A unit's actual fuel consumption and fuel quality data

PowerGADS – Event Data

Event data – to be collected:

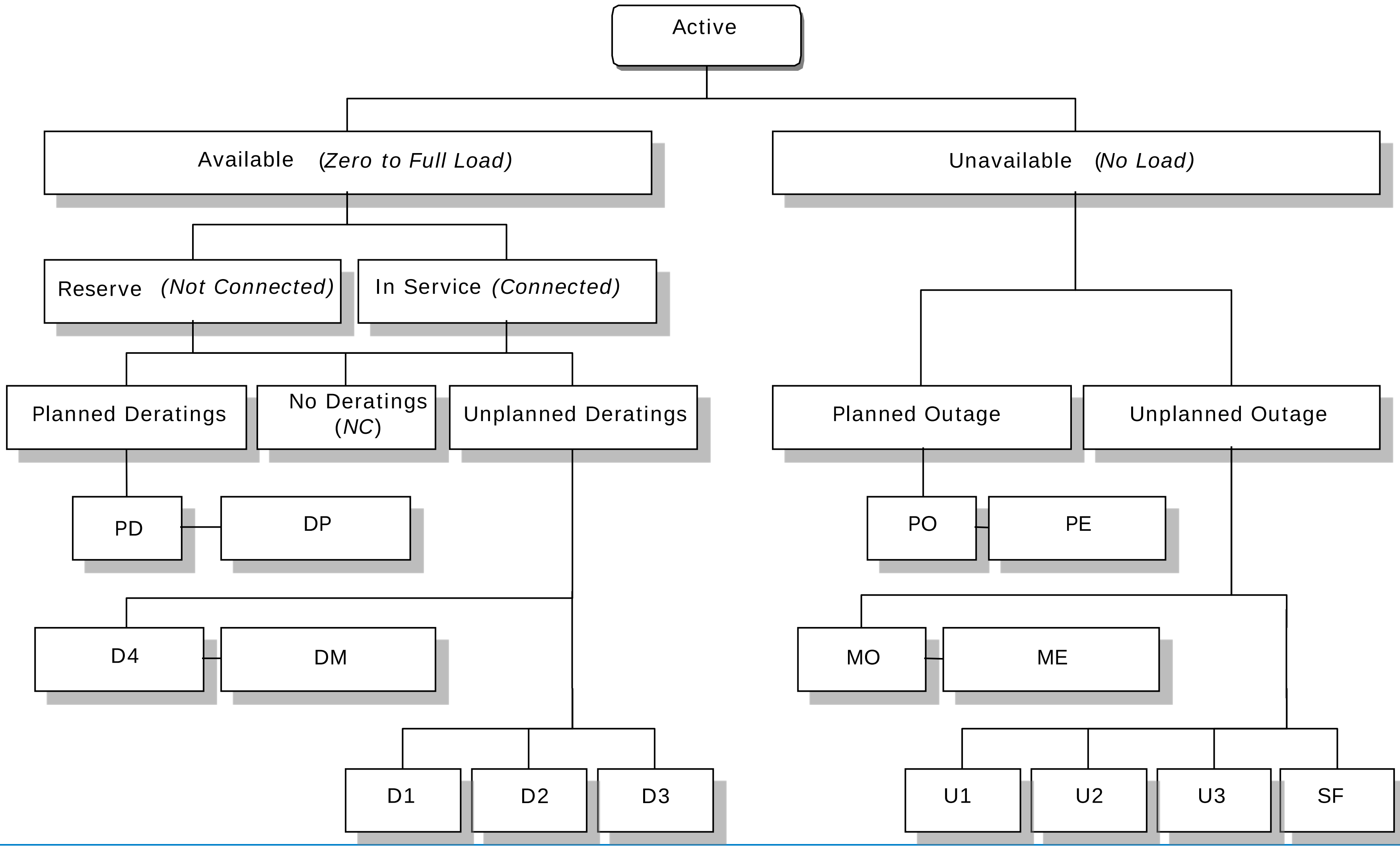
- Event Number
- Event Type
- Start of Event
- End of Event (Can be blank if event is ongoing)
- Net Available Capacity
- Primary Cause Code
- Additional Cause Code (Optional)
- Event Contribution Code
    - describes impact or contribution that this cause or component had on the event
- Verbal Description (Optional)
- Failure Code (Optional)

PowerGADS – Performance Data

Performance data – to be collected:

- Net Maximum Capacity
- Net Dependable Capacity
- Net Actual Generation
- Typical Unit Loading Code
- Loading Verbal Description
  (If Typical Unit Loading Code is 6)
- Attempted Unit Starts
- Actual Unit Starts
- Unit Service Hours
- Reserve Shutdown Hours
- Pumping Hours
- Synchronous Condensing Hours

PowerGADS – Event Types



LOLE Model Inputs Include:

Generation Resources

- Operating Parameters
- Unit Forced Outage Rates
- Planned Maintenance Schedules & Rates
- Dispatch Limits for Demand Response

Study System

- Zone & Pool definition
- External Tie Limits
- External System Model

Load

- Demand and Energy Forecast
- Load Shape/Profile
- Load Uncertainty

LOLE Model Inputs

Source of LOLE Model Input Data

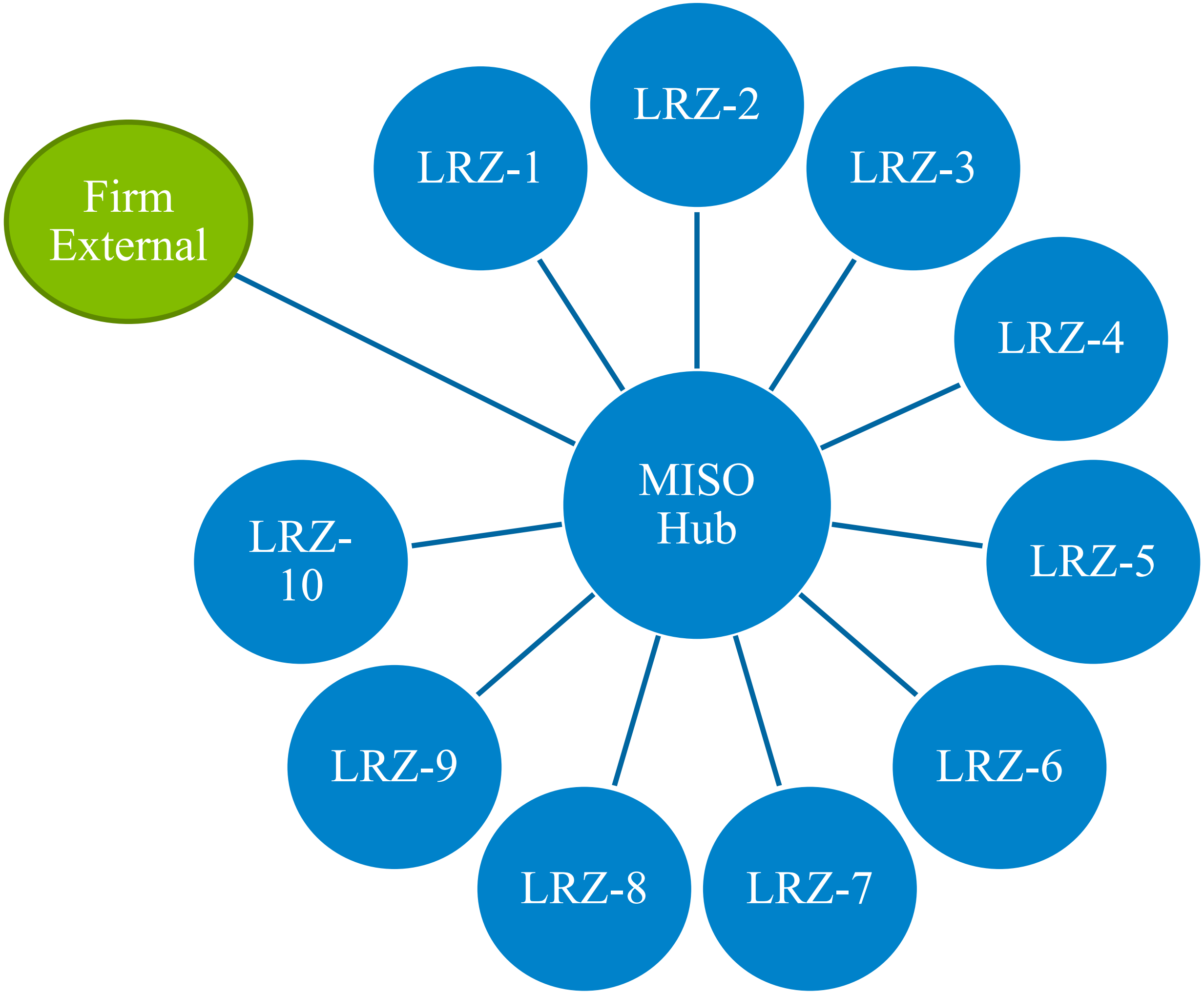
Generation Resources

- Generating Availability Data System (GADS)
  - Unit performance statistics used to calculate forced outage rates
  - Data is uploaded into the MISO system one month after end of each quarter
- Generation Verification Test Capacity (GVTC)
  - Units need to demonstrate maximum output level

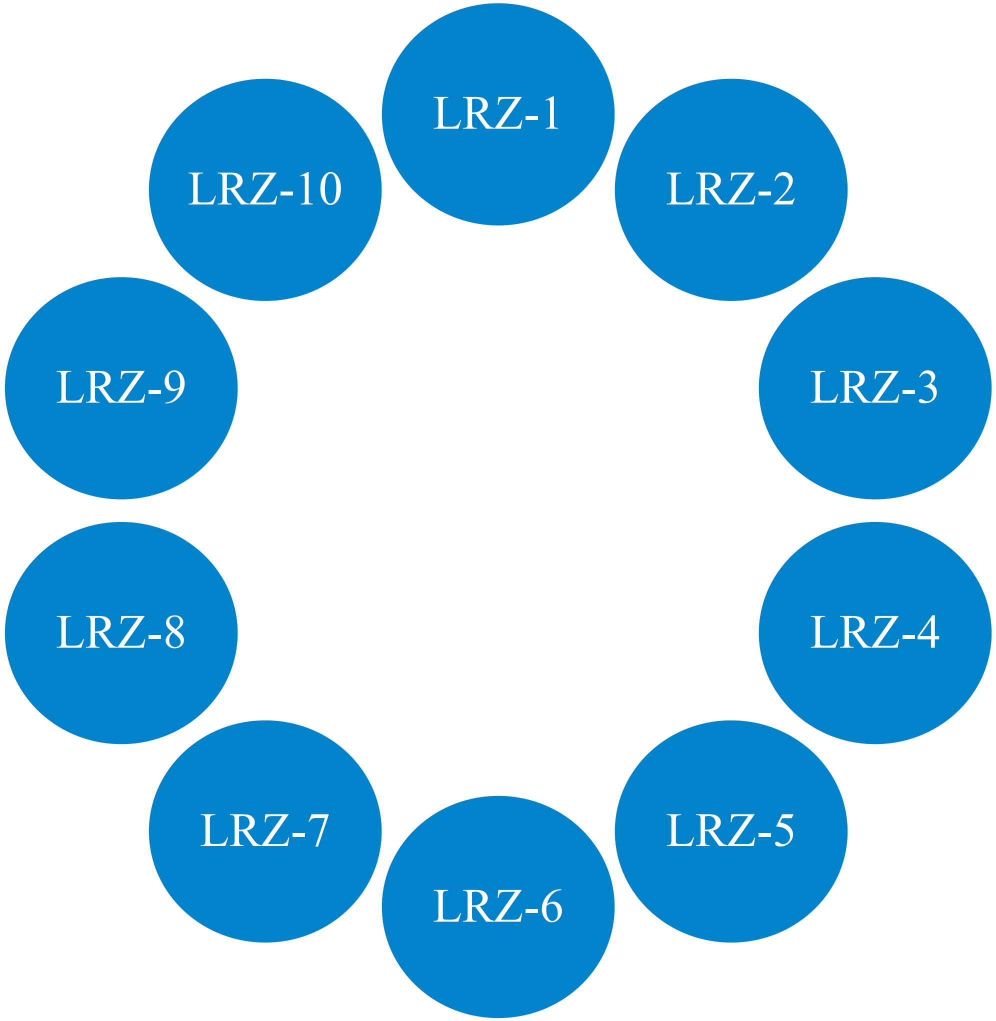
Load

- Load training using historical load and weather data
- Monthly Peak Demand, MISO Coincident Demand and Energy Forecast are uploaded by Load Serving Entities (LSEs) into the Module-E Capacity Tracking (MECT) Tool (deadline Nov. 1st)
- MISO reviews Forecast and Finalize review by March

MISO System LOLE Model



Local Resource Zone LOLE Model



MISO uses the Strategic Energy Risk Valuation Model (SERVM) Software

Managed by Astrapé Consulting

Originated within Southern Company back in the early 1980’s

Uses a sequential Monte Carlo simulation

- Steps through time chronologically and randomly drawing unit availability
- Replicating simulation with different sets of random events until statistical convergence is obtained

SERVM resource adequacy metrics consider

- Wide Variation of Load Shapes
- Growth Uncertainty
- Unit Performance

Utilizes a SQL Server database

Analytical vs. Monte Carlo approach to analysis

- Analytical methods work well for small systems and represent a system using mathematical model (A direct mathematical solution)

- Monte Carlo methods simulate the actual process and repeat simulation until convergence criteria is met

- For complex systems, a Monte Carlo “brute force” approach is more appropriate

Types of Monte Carlo Analysis

- Non-Sequential Monte Carlo Simulation
  - Each hour is independent of every other hour
  - Inability to model time-correlated issues
  - Inability to calculate frequency and duration indices
- Sequential Monte Carlo Simulation
  - Steps through time chronologically
  - Ability to model time correlated issues and calculate frequency and duration indices
  - Requires more detailed system data

Utilized SERVM Characteristics

- Multi Area Model
- Multiple Weather Years (supports up to 50 years)
- Detailed DR Representation
- Granular LOLE Calculations

Additional SERVM Characteristics

- Renewable Generation Modeling
- Transportation model to represent multiple neighbors and interconnections
- Full Economic Dispatch of Resources Allowing for Dispatch Constraints on Resources
- Alternative Dispatch During Reliability Events
- Operating Reserves Modeled Based on NERC Guidelines
- Economic Calculations
- Scarcity Pricing Algorithms
- Production Costing Ability

Utilized SERVM Modeling Components

- Weather Years
  - Multiple load shapes
- Economic Load Forecast Error (LFE)
- Unit Outage Modeling
- Energy Limited Resource Modeling
  - Demand Side Options

Additional SERVM Modeling Components

- Weather Years
  - Thermal Capacity/Hydro
- Energy Limited Resource Modeling
  - Hydro and Pump Storage
  - Renewable resources (.i.e. Wind & Solar)
- Scarcity Pricing, Neighbor Modeling, and Transmission Modeling
- Emergency Operating Procedures

Importance of Load Modeling in LOLE Analysis

- Loss of Load Expectation analysis is largely driven by two factors
  - Generation Uncertainty
  - Load Uncertainty
- Accurately capturing uncertainty is crucial to LOLE analysis
- Load Uncertainty
  - Load Shape
  - Weather Uncertainty
  - Economic Uncertainty

Load Modeling Framework

- Use historic weather years to capture load uncertainty
  - Variance in peak demand
  - Variance in load shape

- Results in more diverse and comprehensive load modeling
  - More accurate shoulder and non-peak load variance and uncertainty

- Utilize Neural-Net software to “train” data

Load Training Process

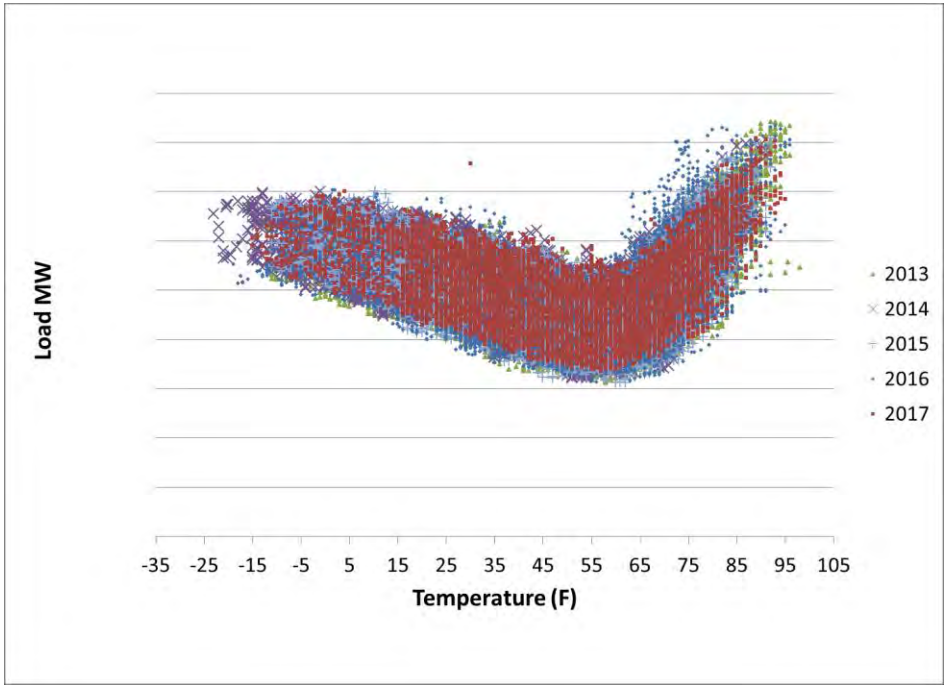
- Historical load and weather data formatting
- 5-year load growth adjustment
- Neural-net training
- Neural-net predicting
- Extreme temperature adjustment
- Load forecast adjustment

Data Sources for Load Training

- Historical real-time settlement load data
  - Source: MISO
  - 2013 to 2017
- Historical real-time LMR performance
  - Source: MISO
  - Voluntary and MISO deployments
  - 2015-2017
- Historical weather data
  - Source: NOAA
  - 1989 to 2017
- LSE load forecasts
  - Source: LSE submittals to MECT

Historical Load and Weather Formatting

- 5 years of hourly load and temperature (2013-2017)
- Weather data (2013-2017)
  - Month
  - Temperature
  - Time of Day
  - Day of Week
  - 24 hour ago Temperature
  - 48 hour ago Temperature
- Holidays are set to Sunday
  - New Year's Day
  - Memorial Day
  - Independence Day
  - Labor Day, Thanksgiving Day & Christmas Day



5-Year Load Growth Adjustment

- 5 years of load data should not include load growth due to economics

- Load normalized to consistent economics

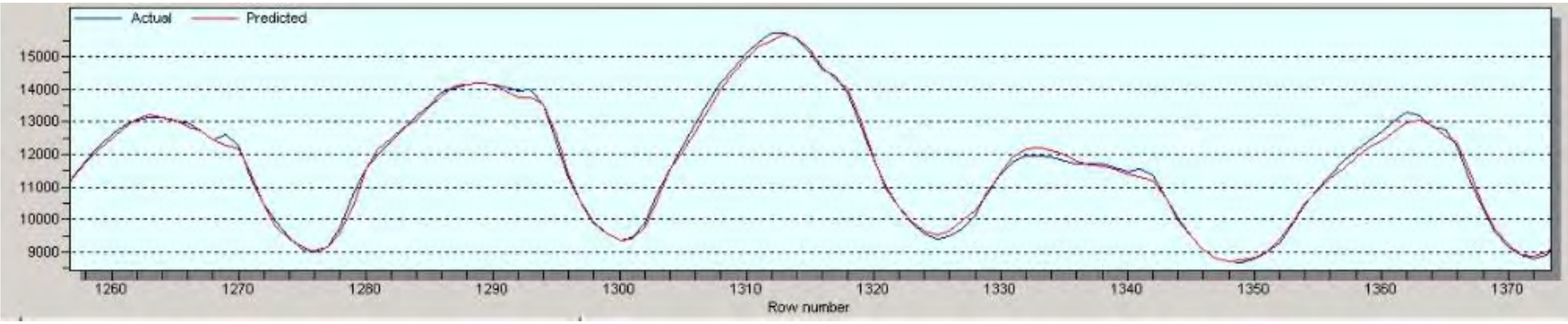
- Adjustment calculated based off high temperature load analysis i.e. 90 degrees and above

NeuroShell Predictor Software

- [Ward Systems Group Software]
- Used for pattern recognition of multi-variable problems
- Makes predictions based off of established neural-net functional relationships
- Software tutorial can be found at the link below:
  - http://www.wardsystems.com/predictortutorial.asp
- Load Training Input Variables:
  - Month
  - Day of week
  - Time of day
  - Previous hour load
  - Temperature
  - 24 hour ago temperature
  - 48 hour ago temperature
- Load Training Output Variables:
  - Actual Load

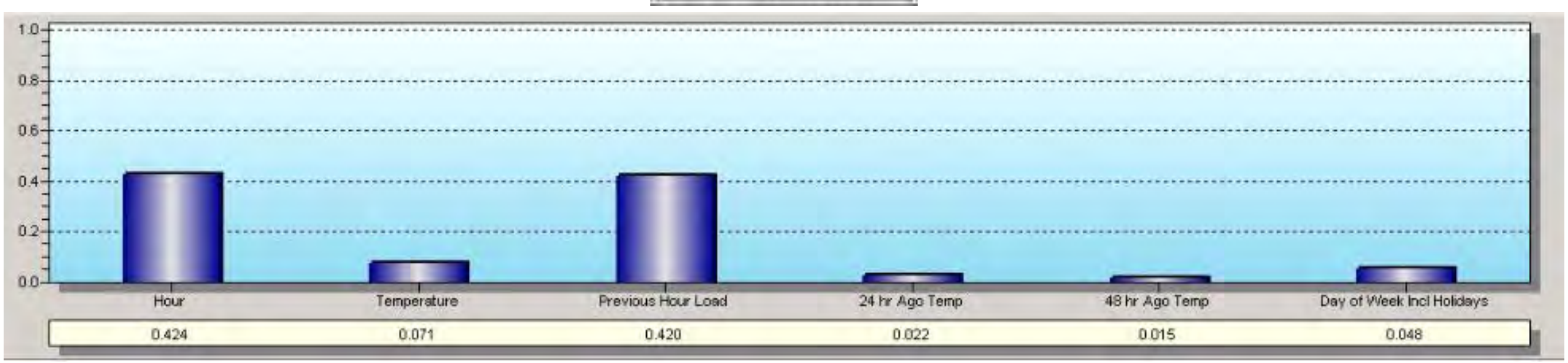
	Hour	Temperature	Previous Hour Load	24 hr Ago Temp	48 hr Ago Temp	Day of Week Incl Holidays	Actual Load
1	0	84	12984.172	78.5	82	1	12052.491
2	1	83	12052.491	70	80	1	11406.383
3	2	83	11406.383	69	76	1	10984.624
4	3	82	10984.624	69	75	1	10747.635
5	4	82	10747.635	72	75	1	10849.012
6	5	81	10849.012	73	74	1	11433.276
7	6	79	11433.276	74	74	1	12365.329
8	7	79	12365.329	74	74	1	13136.045
9	8	78	13136.045	76	75	1	13864.401
10	9	79	13864.401	78	77	1	14259.09
11	10	79	14259.09	82	80	1	14576.561
12	11	78	14576.561	83.5	82	1	14729.459
13	12	79	14729.459	85	84	1	14715.28
14	13	79	14715.28	84	86	1	14659.616
15	14	79	14659.616	87.33333333	87	1	14398.177
16	15	72.75	14398.177	88.5	88	1	14239.96
17	16	73	14239.96	90.5	89	1	14212.895
18	17	73.33333333	14212.895	92	89	1	14188.923
19	18	77.66666667	14188.923	92	90	1	14075.644
20	19	78	14075.644	92	90	1	13852.38
21	20	78	13852.38	90	89	1	13712.71
22	21	80	13712.71	90	87	1	13681.636
23	22	78	13681.636	88	86	1	12928.871
24	23	78	12928.871	87	85	1	12130.917
25	0	77	12130.917	84	78.5	2	11450.251
26	1	78	11450.251	83	70	2	10956.724
27	2	79	10956.724	83	69	2	10612.272

Neural-Net Training



Best net statistics

R-squared	0.996521
Avg.error	91.26518
Correlation	0.99829
MSE	13960.78
RMSE	118.1557
% in range	0.0%
% same sign	100.0%

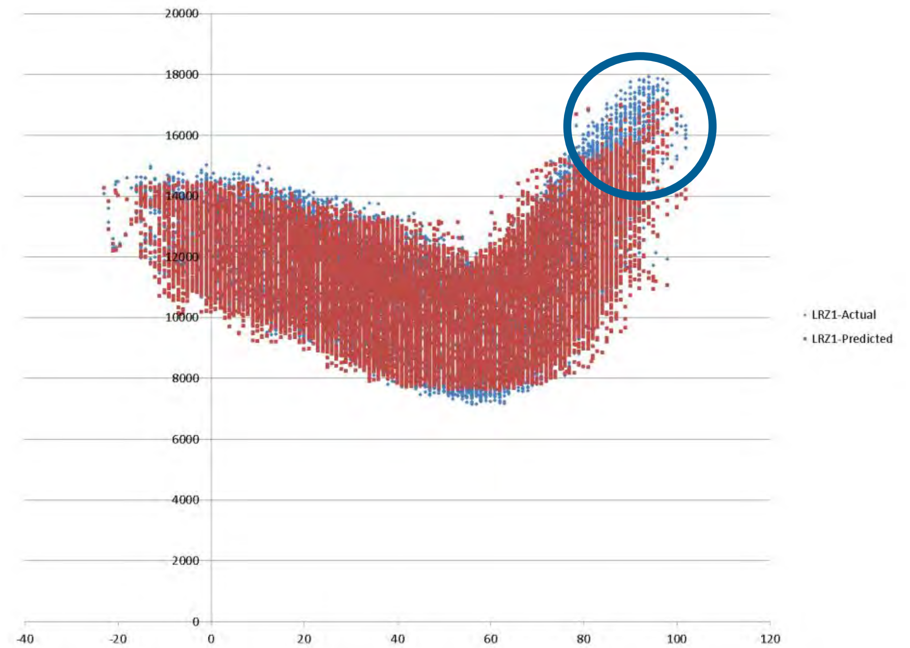


Neural-Net Predicting

- 30 years of historical weather
  - 1989 to 2017
- Neural-Net applied to 30 years of historical weather to predict load
- Output is 30 weather year load shapes at 5 year normalized economy
  - i.e. Predicted 2018 load with1999 weather

Extreme Temperature Verification

- Verify load training at extreme temperatures is accurate
- Less data points at temperature extremes for neural-net training



Load Forecast Adjustment

- Average of 30 predicted load shapes adjusted to match LRZ's 50/50 zonal peak load forecast for study year

- Ratio of 1st years Non-Coincident Peak Forecast to Zonal Coincident Peak Forecast applied to future years Non-Coincident Peak Forecast

- Results in 30 Planning Year weather load shapes
  - i.e. 2019-20 PY load if we have 1995 weather

Economic Load Forecast Error

- Use Projected and Actual GDP Growth Rates for Economic Uncertainty
  - Use Congressional Budget Office (CBO) projections for GDP growth (historic)
  - Compare with the actual GDP growth taken from the Bureau of Economic Analysis
  - Translate the GDP forecast error into electric utility forecast error by multiplying by a scalar
    - Rate at which electric load grows in comparison to GDP
  - Calculate the standard deviation of forecast error
  - Using the standard deviation, create a normal distribution of forecast error

Economic Load Uncertainty

- The 2018/19 PY LOLE study showed that the economic load uncertainty modeling resulted in a 0.2 percentage point increase to the MISO Planning Reserve Margin

	Load Forecast Error (LFE) Levels				
	-2.0%	-1.0%	0.0%	1.0%	2.0%
Standard Deviation in LFE	Probability to assigned to each LFE				
1.19%	10.4%	23.3%	32.6%	23.3%	10.4%

Advantages in Load Modeling with historical weather

- Multiple load shapes based on weather more accurately capture
  - Variance in load shapes
  - Variance in peak load
  - Seasonal load uncertainty
  - Frequency and duration of severe weather patterns

- Decouple weather and economic uncertainty

Unit Data

- Unit Name
- Unit Physical Local Resource Zone (LRZ)
- Installation Date
- Retirement Date
- Type (Thermal, Curtailable Load, Renewable)
- Unit Summary Type
  - Thermal (Nuclear, Fossil Steam, Combustion Turbine, Hydro, Pumped Storage Hydro)
  - Curtailable Load (Demand Response)
  - Renewable (Intermittent Resources such as Wind, Run-of-River Hydro, Biomass and Energy Efficiency)
- Thermal Units
  - Utilize the GVTC for a peak capacity and each unit's monthly Net Dependable Capacity (NDC) submitted in PowerGADS determines each unit's monthly capacity profile

Forced Outage Rates & Unit Maintenance – Thermal Units Only

- Forced Outage Rates
  - Time to Repair
  - Time to Failure
- Fixed Maintenance – Typically Nuclear Units
  - Begin Date
  - Stop Date
- Planned Outage Rates
  - Percentage of the year in which a unit will be on scheduled maintenance
  - Planned Outage Factor + Maintenance Outage Factor from PowerGADS
- Maintenance scheduled on days with maximum reserves

Curtailable Load Units (Energy Limited)

- SERVM dispatches Demand Response (DR) based on several constraints
  - Days per week
  - Hours per day
  - Hours per year
  - Dispatch price
- Use limitations to model fatigue
  - Minimum Megawatt (MW) – Zero
  - Maximum Megawatt (MW) – Monthly Profile

Demand Side Management (DSM)

- Renewable Units
- Net Hourly Load Modification
  - Maximum Megawatt (MW) – Monthly Profile
  - Positive values decrease load

Non-Firm Support

- Represents benefit of being part of Eastern Interconnect
- 1 MW of non-firm support reduces requirement by 1 MW
- Reliability targets highly sensitive to fluctuations in non-firm support
- LOLE study uses set MW amount of non-firm

Firm Imports

- External resources FRAP'ed or Offered in MECT are included in LOLE modeling
- External purchases are modeled similar to MISO units
- Modeled from external region to MISO
- Firm imports are only modeled in MISO PRM model and not zonal LRR model
- External firm imports impact LOLE based on unit characteristics

Firm Exports/Sales

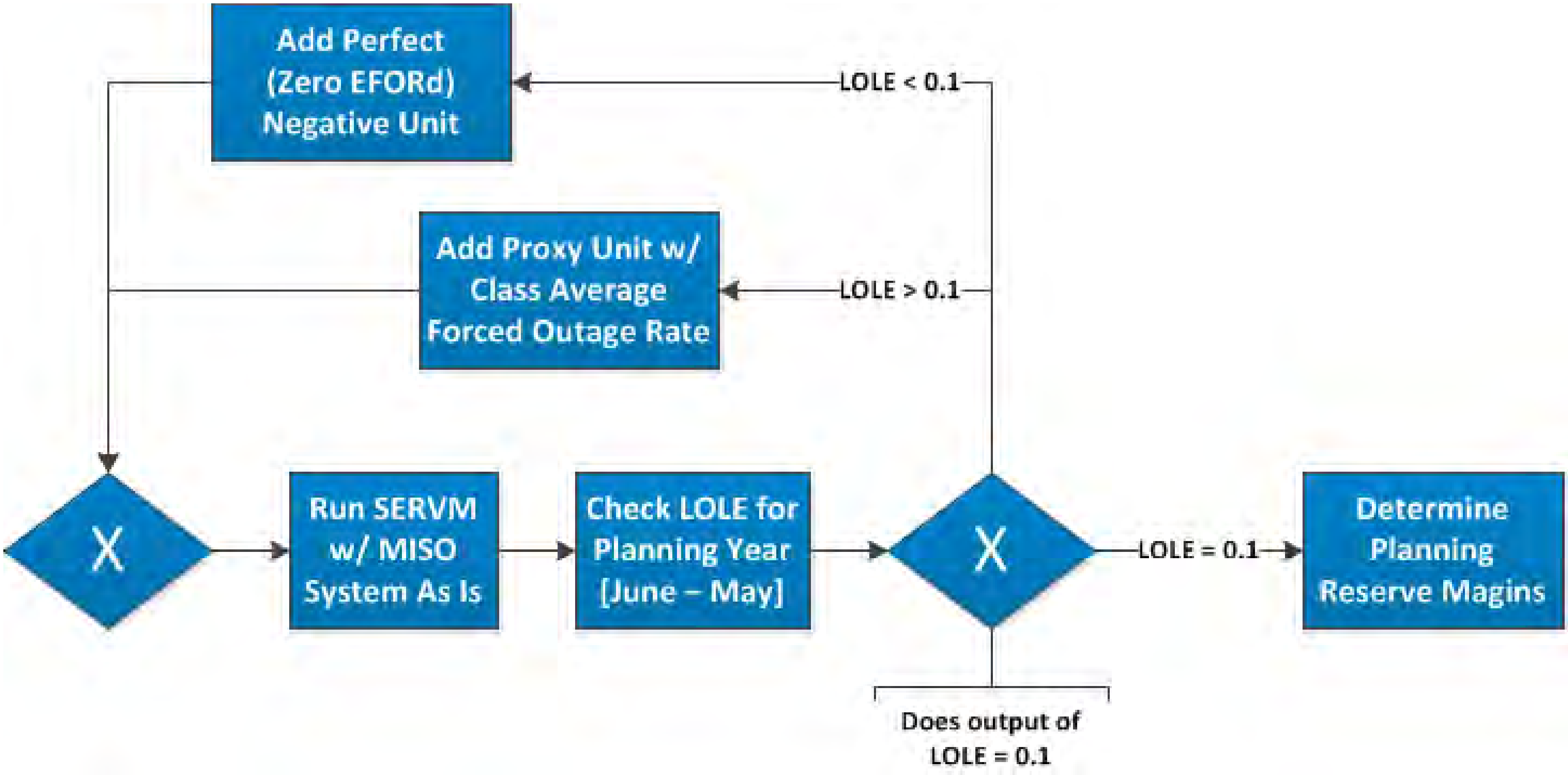
- Capacity that is ineligible for MISO PRA is excluded from MISO and zonal models
- Only units that have capacity obligations outside of MISO are designated as sold in the LOLE model
- External firm exports impact LOLE based on unit characteristics

SERVM Simulation Frameworks

30 Weather Years (equal probability)	x	5 Economic Uncertainties (Normal Distribution)	=	150 Load Scenarios
150 Load Scenarios	x	300 unit outage draws	=	45,000 8760 hour simulations

** Scenarios are an example of framework and are not fixed

Capacity Adjustment Flowchart



LOLE Study Deliverables to MISO's Planning Resource Action (PRA)

- The LOLE study has four deliverables to the Planning Resource Auction
  - MISO PRM UCAP [%]
  - Local Resource Zones (LRZ) Local Reliability Requirement (LRR) per unit
  - LRZ Capacity Import Limit (CIL)
  - LRZ Capacity Export Limit (CEL)
- LOLE deliverables are applied to updated demand forecasts to calculate PRA requirements

Calculation of MISO PRM [%]

MISO Planning Reserve Margin (PRM)	2018/2019 PY	Formula Key
MISO System Peak Demand (MW)	125,805	[A]
Installed Capacity (ICAP) (MW)	149,901	[B]
Unforced Capacity (UCAP) (MW)	138,505	[C]
Firm External Support ICAP (MW)	4,938	[D]
Firm External Support UCAP (MW)	4,764	[E]
Adjustment to ICAP {1d in 10yr} (MW)	-4,550	[F]
Adjustment to UCAP {1d in 10yr} (MW)	-4,550	[G]
ICAP PRM Requirement (PRMR) (MW)	150,289	[H] = [B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	138,719	[I] = [C]+[E]+[G]
MISO PRM ICAP	19.5%	[J]=[H]-[A]/[A]
MISO PRM UCAP	10.3%	[K]=[I]-[A]/[A]
Post-Processing accounting for non-firm external support		
External Non-Firm Support ICAP (MW)	2,987	[L]
External Non-Firm Support UCAP (MW)	2,331	[M]
With External Support ICAP PRM Requirement (MW)	147,302	[N]=[B]+[D]+[F]-[L]
With External Support UCAP PRM Requirement (MW)	136,388	[O]=[C]+[E]+[G]-[M]
With External Support MISO PRM ICAP	17.1%	[P]=([N]-[A])/[A]
With External Support MISO PRM UCAP	8.4%	[Q]=([O]-[A])/[A]

*MISO Capacity Market procures on UCAP

Calculation of Zonal Requirements and Example PRA Requirements

Local Resource Zone (LRZ)	**LRZ-1 MN/ND**	**LRZ-2 WI**	**LRZ-3 IA**	**LRZ-4 IL**	**LRZ-5 MO**	**LRZ-6 IN**	**LRZ-7 MI**	**LRZ-8 AR**	**LRZ-9 LA/TX**	**LRZ-10 MS**	**Formula Key**
2018-2019 Planning Reserve Margin (PRM) Study											
Installed Capacity (ICAP) (MW)	19,055	15,863	11,145	10,638	8,665	19,458	23,225	11,594	23,514	6,756	[A]
Unforced Capacity (UCAP) (MW)	18,095	14,892	10,613	9,481	7,751	18,165	21,196	10,991	21,674	5,657	[B]
Adjustment to UCAP {1d in 10yr} (MW)	2,326	352	202	2,326	2,411	1,782	3,349	-760	1,595	1,581	[C]
Local Reliability Requirement (LRR) UCAP (MW)	20,422	15,244	10,815	11,807	10,162	19,948	24,545	10,231	23,269	7,237	[D]=[B]+[C]
Peak Demand (MW)	17,789	12,858	9,391	9,709	8,199	17,443	21,296	8,072	20,649	4,859	[E]
LRR UCAP per-unit of LRZ Peak Demand	**114.8%**	**118.6%**	**115.2%**	**121.6%**	**123.9%**	**114.4%**	**115.3%**	**126.7%**	**112.7%**	**148.9%**	[F]=[D]/[E]

Important LOLE Fundamentals Takeaways

- LOLE is the measure of how long, on average, the available generation capacity is likely to fall short of the load demand
  - LOLE is used to study Generation(Resource) Adequacy
  - Probabilistic analysis accurately captures uncertainty risk
- MISO Resource Adequacy criteria for Planning Reserve target is the industry standard LOLE objective:
  - 1-day in 10-years
  - Aligns with NERC standards
- Achieving reliability in the bulk electric systems requires that the amount of resources exceeds customer demand by an adequate margin (Planning Reserve Margin)
  - LOLE models utilize an Equivalized Transportation Model to determine Planning Reserve Margin and Local Reliability Requirements
- All Market Participants are encouraged to participate in the stakeholder process through LOLEWG

Reference Materials

- Past LOLE 101 Documents
  - LOLE 101 (Apil 11th, 2017)
- Loss of Load Expectation Reports
  - 2018 Loss of Load Expectation (LOLE) Study Report
  - Loss of Load Expectation Working Group (LOLEWG)
  - 2018 Wind Capacity Report
  - Resource Adequacy Documents
- Resource Adequacy Documents
  - BPM
    - BPM 011 - Resource Adequacy
  - MISO Tariff: Module E-1
  - NERC Standard BAL-502-RF-03

Appendix

LOLE Terms and Definitions

- **Installed Capacity:** The installed capacity that is physically located within the zone. The ICAP is the output that the generator tested for its max summer output.
- **Unforced Capacity:** The installed capacity less forced outage rates. Capacity Resources are quantified by applying forced outage rates to installed capacity values (ICAP) to calculate the Unforced Capacity value (UCAP) for the resource.
- **Adjustment to UCAP:** The UCAP capacity adjustment within the zone to drive the zone to the "1 day in 10" criteria if the zone was an island. If a zone is more reliable than "1 day in 10" capacity needs to be removed in order to drive the model to the LOLE metric.
- **LRR (UCAP):** Zonal specific reserve margin requirement [MW], capacity above zonal peak load, required to meet "1 day in 10" loss of load expectation requirement if the Local Resource Zone is an island (i.e. completely disconnected from external areas and the rest of MISO).

LOLE Terms and Definitions

- **Peak Demand**: The zone's annual peak demand including transmission losses.
- **Time of Peak Demand (ESTHE):** The date and time of the zones annual peak demand.
- **LRR UCAP per-unit of LRZ Peak Demand**: Zonal specific reserve margin [%], capacity above zonal peak load, required to meet "1 day in 10" loss of load expectation requirement if the Local Resource Zone is an island (i.e. completely disconnected from external areas and the rest of MISO).
- **Capacity Import Limit**: The amount of capacity that a zone can import from outside their zone reliably during peak load before observing a transmission constraint.
- **Capacity Export Limit**: The amount of capacity that a zone can reliably export out of their zone during peak load before observing a transmission constraint.

LOLE Terms and Definitions

- **<u>Forecasted LRZ Load at MISO Peak</u>**: Zone's load coincident with MISO's annual peak load.
- **<u>Firm External Support:</u>** Represents the external resources offered into planning year PRA and are modeled at the individual unit level.
- **<u>External Non-Firm Support:</u>** Represents the benefit of being part of the Eastern Interconnection, where 1 MW increase of no-firm support reduces requirement by 1MW.
- **<u>Local Reliability Requirement</u>**: Zonal specific reserve margin requirement [MW], capacity above zonal peak load, required to meet "1 day in 10" loss of load expectation requirement if the Local Resource Zone is an island (i.e. completely disconnected from external areas and the rest of MISO).

LOLE Terms and Definitions

- **<u>Local Clearing Requirement</u>**: The minimum capacity required to be physically located within a zone to meet the "1 day in 10" Loss of Load Expectation requirement. The LCR is LRR minus the CIL and non-pseudo tied exports.
- **<u>Zone's System Wide PRMR</u>**: The zones share of the total MISO Planning Reserve Requirement that the zone needs to procure on a UCAP basis [MW]. The difference of the zones system wide PRMR minus the Local Clearing Requirement is the capacity that can be cleared outside of the zone (able to import at peak load) to meet the Planning Reserve Margin Requirement.
- **<u>Planning Reserve Margin (PRM):</u>** The reserve margin, capacity above peak load, the entire MISO footprint needs to procure to meet the "1 day in 10" Loss of Load Expectation requirement. The "1 day in 10" Loss of load requirement is the industry standard risk metric.

PRM and LRR Calculations

$$\text{PRM ICAP} = \frac{[\text{Installed capacity} + \text{ICAP Adjustment to meet 0.1 days/year LOLE} + \text{Firm Contracts}] - \text{MISO Peak Demand}}{\text{MISO Peak Demand}}$$

$$\text{PRM UCAP} = \frac{[\text{Unforced capacity} + \text{UCAP Adjustment to meet 0.1 days/year LOLE} + \text{Firm Contracts}] - \text{MISO Peak Demand}}{\text{MISO Peak Demand}}$$

$$\text{Each LRZ}'\text{s LRR} = \begin{matrix}\text{LRZ Unforced}\\ \text{Capacity}\end{matrix} + \begin{matrix}\text{LRZ UCAP}\\ \text{Adjustment needed}\\ \text{to meet 0.1 d/y LOLE}\end{matrix}$$

$$\text{LRZ per unit LRR} = \frac{\text{LRR}}{\text{LRZ Peak Demand}}$$

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-26-22

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

Exhibit 39

DOE Order No. 202-22-2

Department of Energy
Washington, DC 20585

Order No. 202-22-2

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and delegated to the Deputy Secretary of Energy by paragraph 1.12(A) of Delegation Order No. S1-DEL-S2-2022 (Mar. 14, 2022), and further delegated by the Deputy Secretary by email correspondence (Sept. 2, 2022), and for the reasons set forth below, I hereby determine that an emergency exists in California due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

On September 2, 2022, the Balancing Authority of Northern California (BANC) filed a *Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department or DOE) "to preserve the reliability of the bulk electric power system in California," and more specifically to allow the BANC Balancing Authority Area (BAA) to request the dispatch of generation within the BANC BAA "that may be necessary for BANC to meet demand in the face of extreme heat." BANC is a joint powers authority whose members include the Sacramento Municipal Utility District and other municipalities, irrigation districts, and public utilities districts. BANC is a registered Balancing Authority with the North American Electric Reliability Corporation and operates as a neighboring BAA to the California Independent System Operator Corporation (CAISO) BAA. On September 4, 2022, BANC filed an *Amended, Supplemented and Clarified Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Amended Application) in response to questions from DOE.

California has experienced several periods of extreme heat, drought conditions, and threat of wildfires. Such conditions are expected to occur over the next several days and threaten the reliable operation of the bulk electric power system in California. The loads from the forecasted heat wave over the next week are expected to push demand for electric energy by BANC members to at or over historical peaks and higher than normally expected planning targets for this time of year. Amended Application at 2.

On August 31, 2022, California Governor Gavin Newsom issued a proclamation declaring a state of emergency regarding electricity from September 2 through September 7, 2022.[1] In declaring a statutory emergency, the proclamation cited a number of factors and observations, including the following:

- A significant heat wave will bring temperatures "in excess of 100 degrees throughout the State and is forecast to bring record temperatures 10–20 degrees

[1] GSS_9534-1E-20220831133826 (ca.gov)

above normal throughout the State, exceeding 110 degrees in some areas (the 'Extreme Heat Event');"

- The extreme heat will put a significant demand and strain on California's energy grid and is forecast to be a "West-wide event" meaning that energy demand will be high across the region and "California will have limited ability to import energy from out-of-state;"

- The CAISO issued a Heat Bulletin forecasting high electric demand during the extreme heat event that will "stress the energy grid, with peak load for electricity projected to reach its highest level of the year, exceeding 48,000 megawatts on September 5, 2022;" and

- The CAISO is forecasting supply deficiencies of "over 3,000 megawatts during evening hours from September 4, 2022, through September 6, 2022" and advised that emergency interventions would allow energy customers to make contingency plans ahead of the Labor Day holiday weekend.

The proclamation authorizes several measures aimed at mitigating the emergency and avoiding jeopardizing public health or safety, including directing the California Air Resources Board (CARB) to "implement its State-funded Climate Heat Impact Response Program (CHIRP) to mitigate emissions from any operation pursuant to this Proclamation." The proclamation also directs the California Energy Commission (CEC) to "provide information requested by [CARB] to assist with its implementation" of CHIRP.

BANC noted that it "has prepared this request in consultation with the California Energy Commission (CEC), the California Governor's Office, and the CAISO." Application at 2.

Description of Mitigation Measures

In its Application, BANC described actions it has taken in order to alleviate the generation shortfall. Electric utilities within BANC, in coordination with CEC, CAISO, and the California Governor's Office, have implemented conservation and other extraordinary efforts to procure additional supply. BANC members have been able to obtain some purchases from the Pacific Northwest (PNW) bilateral wholesale markets to help offset the additional need, but the physical interties with PNW are near physical limits. BANC members have also been making use of demand-side programs, including commercial interruptible load programs, residential peak shaving programs, and public appeals for conservation. Amended Application at 2.

Request for Order

BANC has requested an emergency order to allow the BANC BAA to dispatch the Covered Resource described below within the BANC BAA that may be necessary for the BANC to meet demand in the face of extreme heat, subject to the terms set forth herein.

The generators for which BANC is seeking this emergency order consist of 24 diesel-fired generator units owned by NTT Global Data Centers Americas (NTT), located at 1312 Striker Ave, Sacramento, CA 95834, known as “CA 2” and more fully described in the Application Exhibit A – List of Covered Resources (NTT Generators or Covered Resource). The Covered Resource plans to participate in the CEC-administered Demand Side Grid Support program that facilitates availability of resources for emergency purposes. Application at 3; Amended Application at 3-4. Therefore, while the Covered Resource has an aggregate installed capacity of 48MW, BANC requests that this emergency order apply only to capacity necessary to supply the load at the NTT facility served by the Covered Resource, up to 26.1 MW (Covered Maximum Output). Amended Application at 3-4.

BANC has requested that the Secretary issue the requested emergency order by Sunday, September 4, 2022, or as soon as possible thereafter, authorizing the Covered Resource to operate at the Covered Maximum Output level between 2:00 p.m. and 10:00 p.m., when directed to do so by BANC, notwithstanding air quality or other permit limitations.

ORDER

Given the emergency nature of the expected load stress and generation shortfall, the responsibility of BANC as the Balancing Authority to balance generation and load in its BAA to ensure maximum reliability on its system, and the ability of BANC to identify and dispatch generation necessary to meet additional load if an order is issued, I have determined that, under the conditions specified below, generation from the Covered Resource is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c) up to the Covered Maximum Output. This determination is based on, among other things:

- The expected shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes in the State of California and within the BANC BAA, including as declared in the Governor’s August 31 emergency proclamation and as described in the Application and Amended Application, demonstrate the need for the Covered Resource to contribute to the reliability of the BANC BAA.

- The availability of 26.1 MW of reduced load as enabled by generation from the Covered Resource up to the Covered Maximum Output provides significant assistance by freeing up system generating resources to help alleviate the shortage of generation and meet demand in the BANC BAA.

- The Covered Resource is enrolled in CEC’s Demand Side Grid Support (DSGS) program. The DSGS program establishes procedures for qualification, operation, and reporting to ensure that enrolled generation such as the Covered Resource provides verifiable load reduction and thereby increase available system capacity during energy emergency events.

- The conditions in CEC's DSGS and those specified below restrict operation of the Covered Resource to those circumstances necessary to avoid load shed.

In line with the emergency proclamation's anticipation of near-term energy shortages, this Order is limited to a 5-day period, from September 4, 2022, through September 8, 2022. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation, under the conditions and with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law, and minimize any adverse environmental impacts. BANC anticipates that this Order may result in exceedance of National Ambient Air Quality Standards (NAAQS) under the Clean Air Act and other conflicts with environmental law. This Order would permit operation of the Covered Resource and corresponding emissions of volatile organic compounds (VOCs), nitrogen oxides (NOx), sulfur dioxide (SO_2), coarse particles (PM10), and carbon monoxide (CO), in circumstances not contemplated by the units' Title V permit. Namely, under its Title V permits, the Covered Resource is permitted to operate at certain emission rates during maintenance and when electric service from the serving utility is interrupted by an unforeseeable event, but not in order to assist the utility in avoiding service interruptions for other customers. The Order would permit operation under grid emergency conditions; however, under the conditions specified below, it would not permit exceedance of the emission limits otherwise applicable to the units constituting the Covered Resource, including limits on the pounds of VOC, NOx, SO_2, PM10, and CO emitted per year.

Based on my determination of an emergency set forth above, I hereby order:

A. From September 4, 2022, to September 8, 2022, in the event that BANC determines that generation from the Covered Resource is necessary to preserve the reliability of the bulk electric power system in California, I direct BANC to dispatch such unit or units and to order their operation solely under the following conditions: the issuance and continuation of an Energy Emergency Alert Level 2[2] condition or greater between the hours of 14:00 Pacific Time and 22:00 Pacific Time after exhausting all reasonably and practically available resources.

B. Consistent with good utility practice, BANC shall exhaust all reasonably and practically available resources, including other demand response and

[2] For the purposes of this Order, "Energy Emergency Alert Level 2" has the meaning set forth in Section 3.6.3 of the California ISO System Emergency Operating Procedure, Procedure No. 4420, Version 14.0, Effective Date May 1, 2022 (CAISO Emergency Operating Procedure).

identified behind-the-meter generation resources to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Covered Resource.

C. All operation of the Covered Resource must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators. The Covered Resource must comply with the requirements of the CARB Mandatory Reporting Regulation and California's Cap-and-Trade regulation, to the extent applicable. This Order allows operation of the Covered Resource under operating conditions not otherwise permitted by the Covered Resource's Title V permit but does not provide relief from the obligation to operate the Covered Resource within the equipment-specific or cumulative emission limit requirements specified in the Covered Resource's Title V permit.

D. BANC shall provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department from time to time. By October 10, 2022, BANC shall report source-specific data for all dates between September 4, 2022, and September 8, 2022, on which the Covered Resource was operated, including, for each unit, (1) the hours of operation, as well as the hours in which any permit limit was exceeded, and (2) a preliminary description of each permit term that was exceeded and the manner in which such exceedance occurred. BANC shall also submit a final report by November 14, 2022, with any revisions to the information reported on December 12, 2022. The environmental information submitted in the final report shall also include the following information:

i. Emissions data in pounds per hour for each Covered Resource unit, for each hour of the operational scenario, for CO, NOx, PM10, VOC, and SO_2;

ii. Emissions data must include emissions (lbs/hr) calculated consistent with reporting obligations pursuant to operating permits, permitted operating/emission limits, and the actual incremental emissions above the permit limits;

iii. The number and actual hours each day that each Covered Resource unit operated in excess of permit limits or conditions, e.g. "Generator #1; September 5, 2022; 4 hours; 18:00-22:00 PT";

iv. Amount, type and formulation of any fuel used by each Covered Resource;

v. All reporting provided over the last three years to the United States Environmental Protection Agency or Sacramento Metropolitan Air Quality Management District pursuant to operating permit requirements;

vi. Information provided to the CARB in response to the CARB's development and implementation of the plan to mitigate the effects of additional emissions authorized by the August 31, 2022 proclamation;

vii. Additional information requested by DOE as it performs any environmental review relating to the issuance of this Order; and

viii. Information provided by the Covered Resource describing how the requirements in paragraph C above were met by the Covered Resource while operating under the provisions of this Order.

E. BANC shall inform all affected communities where the Covered Resource operates that BANC has been issued this Order, in a manner that ensures that as many members of the community as possible are aware of the Order, and explain clearly what the Order allows BANC to do, including potential impacts to the community where the Covered Resource is located and communities adjacent to the Covered Resource. BANC shall describe the actions taken to comply with this paragraph in the reports delivered to the Department pursuant to paragraph D above.

F. This Order shall not preclude the need for the Covered Resource to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. BANC shall be responsible for the reasonable third-party costs of performing analysis of the environmental and environmental justice impacts of this Order, including any analysis conducted pursuant to the National Environmental Policy Act.

H. This Order shall be effective upon its issuance, and shall expire at 23:59 Pacific Time on September 8, 2022, with the exceptions of paragraphs F and G and the reporting and analysis requirements in paragraphs D and E. Renewal or amendment of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 16:20 Eastern Time on this 4th day of September, 2022.

Kathleen Hogan
Acting Under Secretary for
Infrastructure

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-26-22

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

Exhibit 40

NERC 2024 Reliability Report

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2024 State of Reliability

June 2024

[2024 SOR Infographic]

[2024 SOR Overview]

[2024 SOR Video]

Technical Assessment of 2023 Bulk Power System Performance

Table of Contents

Chapter 4: Grid Performance

Grid performance is evaluated through established reliability metrics and more in-depth analysis of specific aspects of the BPS:

- **Reliability Metrics**
- **Frequency Response Performance**
- **Generation Performance and Availability**
- **Transmission Performance and Unavailability**

Reliability Metrics

By calculating 2023 reliability metrics[70] and comparing the results to the previous years as well as the five-year average values, the reliability metrics discussed in this chapter can be categorized as either Improving, Stable, Monitor, or Actionable. Measuring and trending the relative state of the BPS in this manner supports NERC's obligation to assess the capability of the BPS. Table 4.1 shows the status of the reliability metrics and includes a reference to the specific metric.

Table 4.1: Reliability Indicators

Metric Name	Metric Performance Status		
M-1: Reserve Margin	**Actionable**		
M-2: Transmission-Related Events Resulting in Loss of Load (Excluding Weather)	**Improving**		
M-3: System Voltage Performance	**Retired**		
M-4: Interconnection Frequency Response	**Improving: Texas Interconnection**	**Stable: Eastern and Western Interconnections**	**Monitor: Québec Interconnection**
M-4.1: Inertia and Rate-of-Change-of-Frequency	**Improving: Texas Interconnection**	**Stable: Eastern and Western Interconnections**	**Monitor: Québec Interconnection**
M-5: Activation of Under Frequency Load Shedding	**Retired**		
M-6: Disturbance Control Standard Failures	**Metric is Under Review**		
M-7: Disturbance Control Events Greater than Most Severe Single Contingency	**Metric is Under Review**		
M-8: Interconnection Reliability Operating Limit (IROL) Exceedance	**Improving: Texas and Western Interconnections**		**Monitor: Eastern and Québec Interconnections**
M-9: Protection System Misoperations Rate	**Stable**		
M-10: Transmission Constraint Mitigation	**Retired**		
M-11: Energy Emergency Alerts	**Improving**		
M-12: Automatic AC Transmission Outages Initiated by Failed Protection System Equipment	**Improving**		
M-13: Automatic AC Transmission Outages Initiated by Human Error	**Improving**		
M-14: Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment	**Improving**		

[70] Current Approved Reliability Metrics; Metrics M-3, M-5, and M-10 are retired.

Table 4.1: Reliability Indicators	
Metric Name	**Metric Performance Status**
M-15: Automatic AC Transmission Outages Initiated by Failed AC Circuit Equipment	**Improving**
M-16: Transmission Element Availability Percentage and Unavailability Percentage	**Stable**
M-17: Transmission Outage Severity	**Stable**

Frequency Response Performance

Frequency response arrests and stabilizes frequency during system disturbances. NERC closely monitors the frequency response of each of the four Interconnections and measures the margin at which under-frequency load shedding (UFLS) would be activated. UFLS provides a vital safety net for preserving Interconnection reliability. Measuring the margin allows NERC and the industry to ensure that there is adequate frequency response on the system.

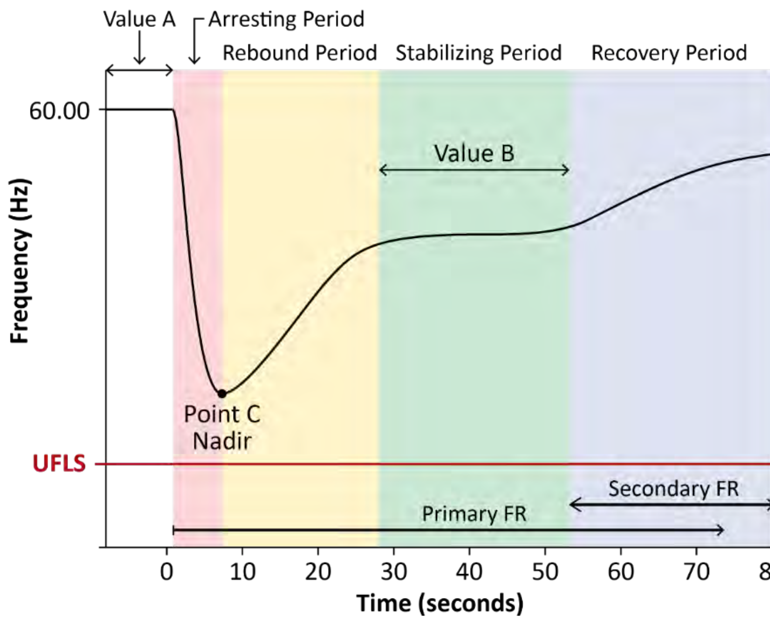


Figure 4.1: Frequency Response Methodology

During the arresting period, the goal is to arrest the frequency decline for credible contingencies before the activation of UFLS. The calculation for Interconnection frequency response obligation (IFRO) under BAL-003 is based on arresting the Point C nadir before the first step of UFLS for resource contingencies at or above the resource loss protection criteria (RLPC)[71] for the Interconnection. Measuring and tracking the margin between the first-step UFLS set point and the Point C nadir is an important indicator of risk for each Interconnection. Figure 4.1 indicates the measurement periods used for analysis of the arresting period of events by looking at the frequency response between Value A and Point C as well as at the margin between Point C and the first-step UFLS set point.

During the stabilizing period, the goal is to stabilize system frequency following a disturbance primarily due to generator governor action. Figure 4.2 indicates the measurement periods used for analysis of the stabilizing period of events by looking at the frequency response between Value A and Value B.

2023 Interconnection Frequency Response

2023 performance and trends frequency response analysis indicate an adequate level of reliability.

- For the stabilizing period, the Interconnection frequency response,[72] the Eastern Interconnection, the Québec Interconnection, and the Western Interconnection showed no statistically significant changes from 2019 through 2023. The Texas Interconnection showed a statistically significant improvement for the stabilizing period from 2019 through 2023.
- For the arresting period, the inertia and rate-of-change-of-frequency (ROCOF),[73] the Eastern and Western Interconnections showed no statistically significant changes from 2019 through 2023. The Texas

[71] BAL-003-2 specifies that the RLPC be based on the two largest potential resource losses in an Interconnection or the largest resource loss due to an N-2 RAS. This value is updated annually through the BAL-003-2 data collection process.
[72] Interconnection Frequency Response, M-4
[73] Inertia and Rate-of-Change-of-Frequency, M-4.1

Interconnection showed a statistically significant improvement. The Québec Interconnection showed a statistically significant decreasing trend.

Of note in 2023, as shown in Table 4.2, the Western Interconnection had two events within the five-year period in which the measured frequency response was less than the IFRO. Both events had a starting frequency well above 60.00 Hz and had a confirmed MW loss under 500 MW. These two factors combined alleviate concerns that the Western Interconnection frequency response is insufficient. Also, of note in 2023 was the decreasing trend in the inertia and ROCOF for the Québec Interconnection. The Québec Interconnection confirmed an overrepresentation of summer events in 2023 compared to other years (2019–2022). Twenty percent of all events in the past five years occurred between May and October 2023 (months that typically have lower inertia), in part due to the wildfire events in the region. The Eastern Interconnection, Québec Interconnection, and Texas Interconnection did not have any events within the five-year period in which the measured frequency response was less than the IFRO for the respective Interconnection.

Table 4.2: 5-Year Statistical Trend

Interconnection	M-4 Interconnection Frequency Response	M4.1 Inertia and Rate-of-Change-of-Frequency	Margin-C-UFLS	Comment
Eastern	neither decreasing nor increasing	neither decreasing nor increasing	neither decreasing nor increasing	No M4 events with FR below IFRO
Texas	increasing	increasing	increasing	No M4 events with FR below IFRO
Québec	neither decreasing nor increasing	decreasing	neither decreasing nor increasing	No M4 events with FR below IFRO
Western	neither decreasing nor increasing	neither decreasing nor increasing	neither decreasing nor increasing	Two M4 events with FR below IFRO

Of note, the Western Interconnection has had the least number of valid events since frequency response evaluation started. This trend in reduction of valid frequency response events is suspected to be due to the retirement of large generating facilities in the Interconnection over the evaluation period and is a positive indicator when considering impacts to Interconnection reliability.

Frequency response for all Interconnections indicates stable and improving performance for the stabilizing period and arresting period as shown in Table 4.3 and Table 4.4.[74]

Table 4.3: 2023 Frequency Response Performance Statistics for Stabilizing Period

	2023 Operating Year Stabilizing Period Performance					
	Number of Events	Mean Frequency Response	Median	Minimum	Maximum	Number of events with FR below the IFRO
Eastern	47	2,685	2,459	1,138	5,176	0
Texas	38	1,410	1,241	682	2,788	0
Québec	65	762	693	260	1,682	0
Western	28	2,049	1,682	912	5,050	2

74 Frequency Response Performance Statistics

Table 4.4: 2023 Frequency Response Performance Statistics for Arresting Period								
	Operating Year (OY)							
	Number of Events	Mean Frequency Response	Median	Minimum	Maximum	Mean UFLS Margin	Median UFLS Margin	Min. UFLS Margin
Eastern	47	2,151	1,969	1,059	3,550	0.454	0.453	0.441
Texas	38	727	738	283	1,604	0.611	0.606	0.579
Québec	65	124	120	48	233	1.022	1.065	0.118
Western	28	868	829	544	1,554	0.415	0.421	0.332

Figure 4.2 represents an analysis of the arresting period of frequency response events. The Y-axis shows the percent UFLS margin from 100% (60 Hz) to 0% (first UFLS set point for the Interconnection). The X-axis represents the MW loss for the event, expressed as a percentage of the RLPC for the Interconnection. The Québec Interconnection had two events at or greater than 100% of the RLPC and maintained sufficient UFLS margin. The largest events for the Eastern Interconnection and Texas Interconnection were 45% and 50%, respectively, as measured by percentage of RLPC.

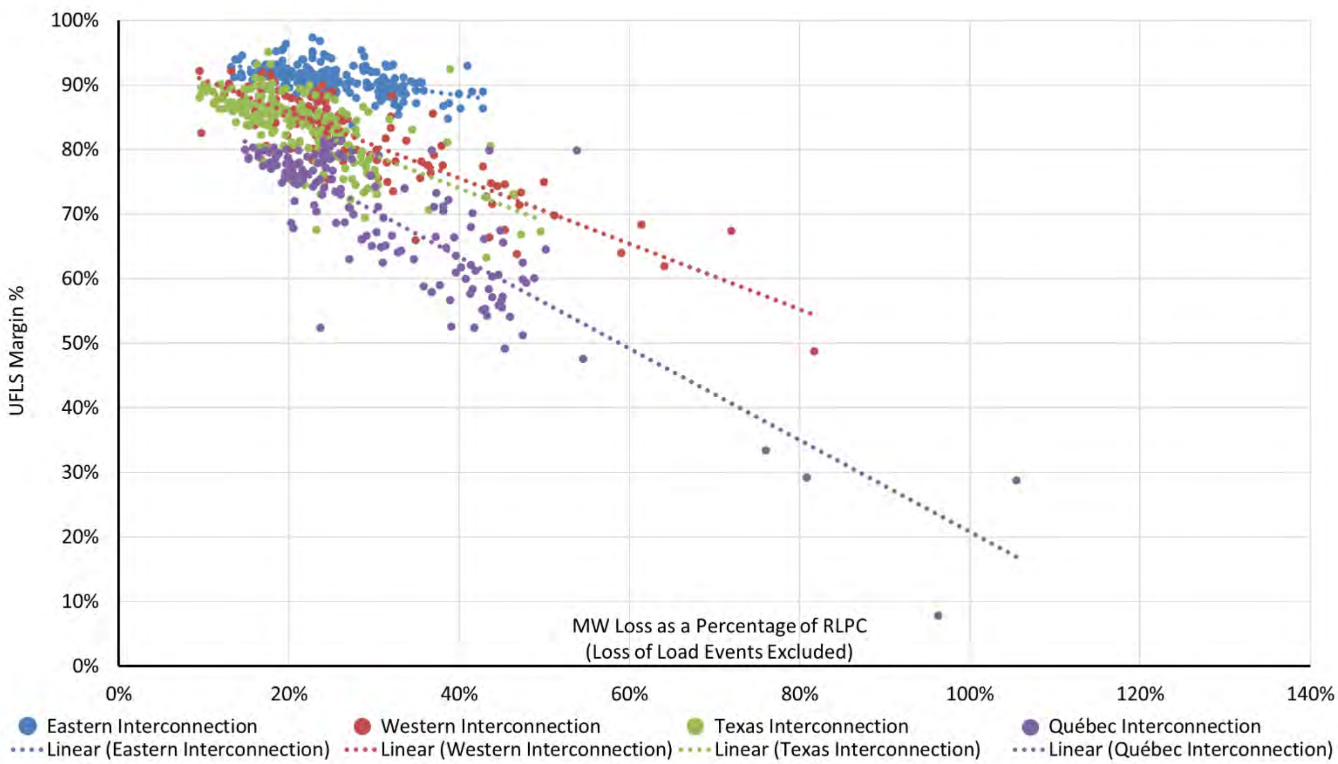


Figure 4.2: Operating Year 2019–2023 Qualified Frequency Disturbances and Remaining UFLS Margin

Interconnection Reliability Operating Limit Exceedances

2023 Performance and Trends

Each RC has a different methodology for determining Interconnection reliability operating limits (IROL)[75] based on the makeup of their area and what constitutes an operating condition that is less than desirable. The following discussion of performance on an Interconnection basis is for clarity, not comparison:

[75] M-8, IROL Exceedance

- **Eastern–Québec Interconnections:** In 2023, there were eight exceedances that lasted more than 10 minutes, less than the five-year average of 19.4 exceedances as shown in Figure 4.3. The 10- to 20-minute range continued to decline from its all-time peak in 2019 with zero exceedances greater than 20 minutes.
- **Western Interconnection:** The trend has been stable with no IROL exceedances reported in 2023.
- **Texas Interconnection:** The trend has been stable with no IROL exceedances reported in 2023.

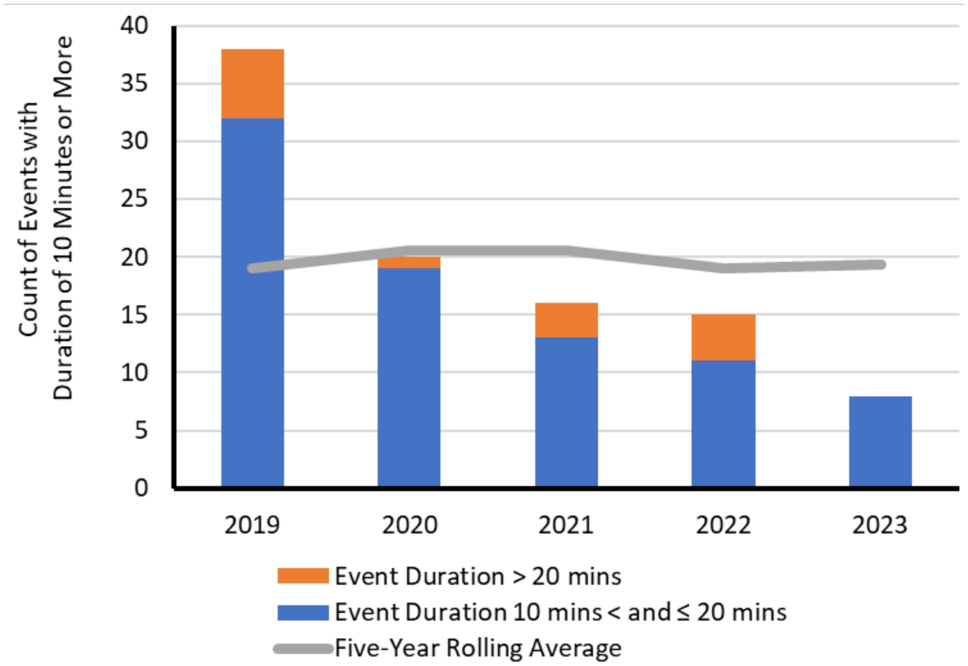


Figure 4.3: IROL Exceedance Counts[76]

Generation Performance and Availability

GADS contains information that can be used to compute reliability measures, such as WEFOR. GADS collects and stores unit operating information by pooling individual unit information, overall generating unit availability, performance, and calculated metrics.

Conventional Generation WEFOR

The horizontal lines in Figure 4.4 show the annual WEFOR compared to the monthly WEFOR columns; the solid horizontal bar shows the WEFOR for all years in the analysis period of 7.4%. While noticeably lower than the two preceding years, the annual WEFOR of 7.8% for 2023 is the third highest since NERC began digitally collecting GADS data in 2013, despite no major outlying winter weather event.

[76] M-8, IROL Exceedance

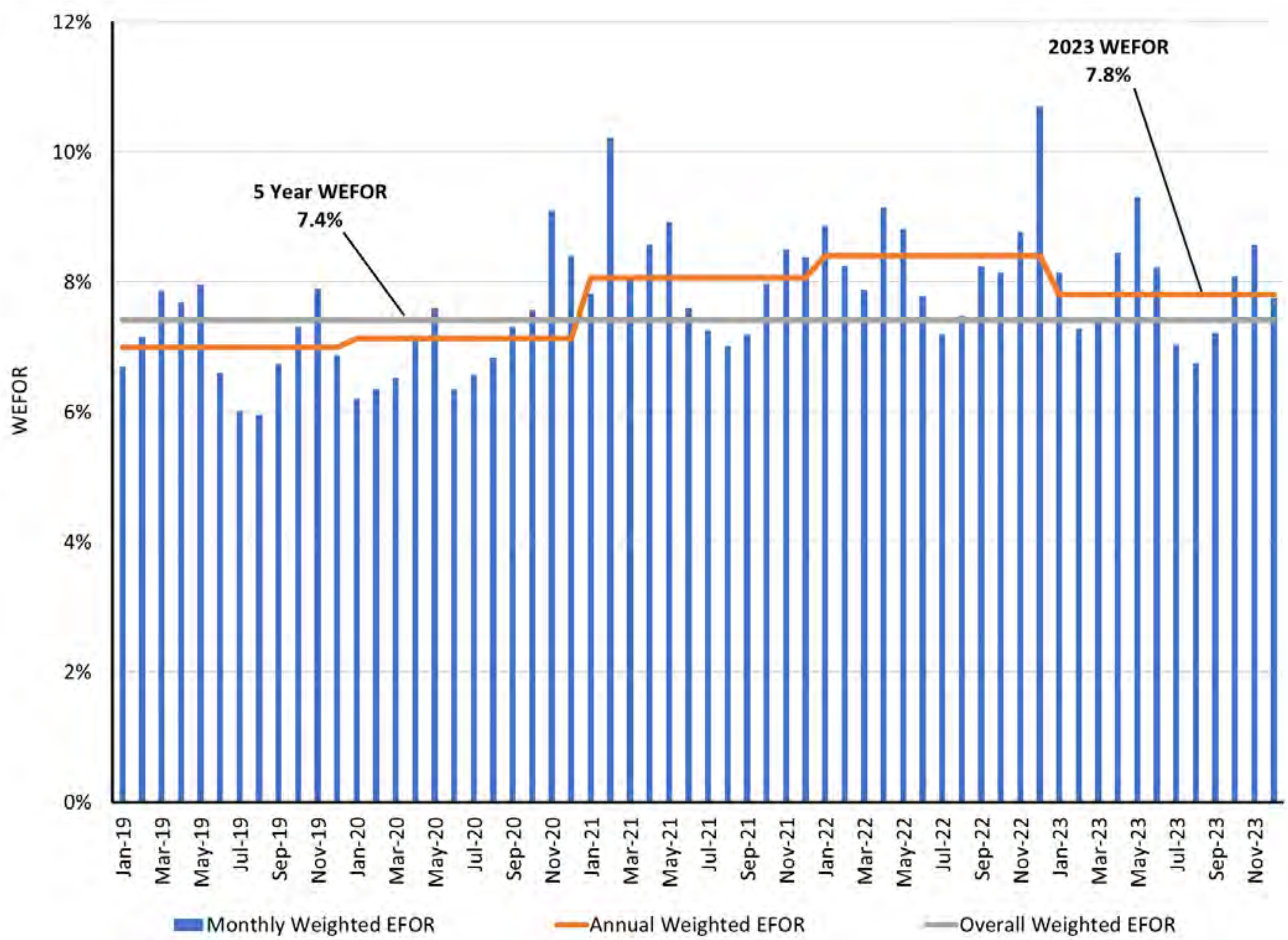


Figure 4.4: Monthly, Annual, and Five-Year WEFOR

To better illustrate 2023's high WEFOR relative to historical norms, Figure 4.5 shows the annual WEFOR by fuel type for the past 10 years. This extended analysis period is presented to illustrate how the abnormally high WEFORs in 2021 and 2022 caused by extreme cold weather conditions obfuscate long-term trends.

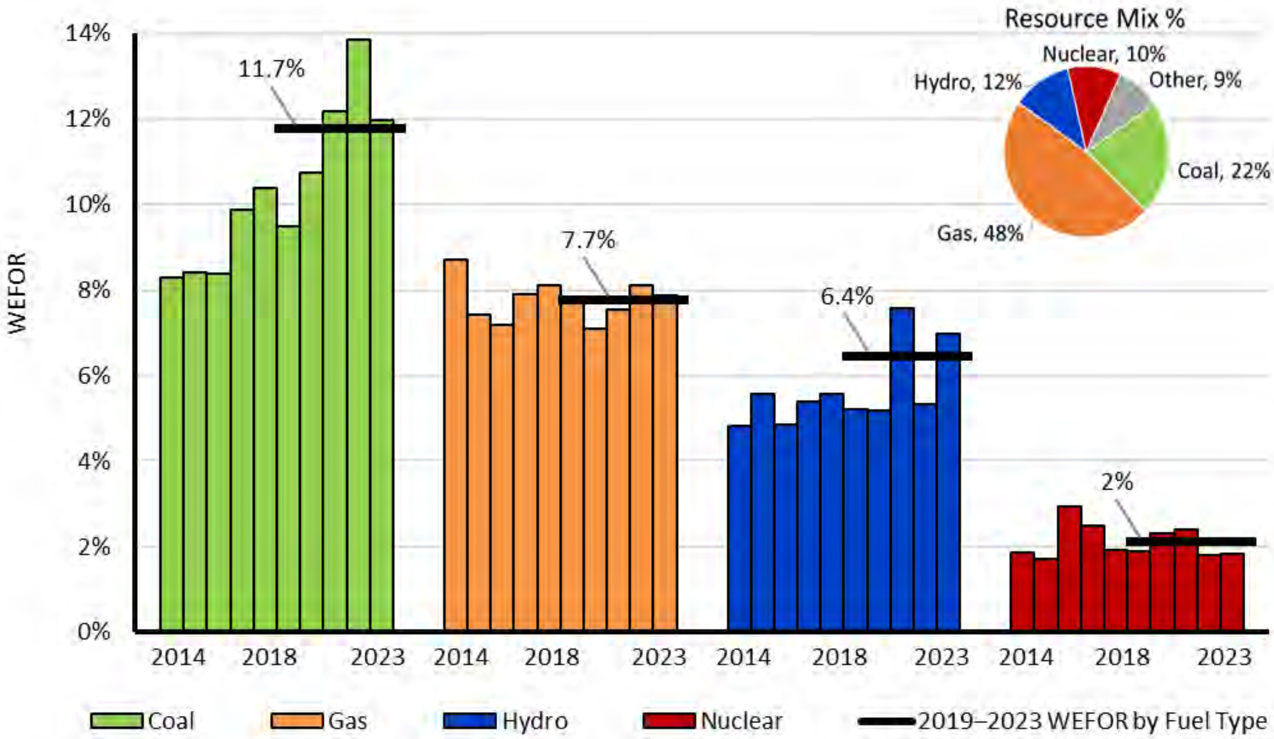


Figure 4.5: 10-Year Annual WEFOR by Fuel Type and 2023 Resource Mix by Net Maximum Capacity

Although coal-fired generation experienced a large decrease in WEFOR in 2023 (12.0% in 2023 versus 13.9% in 2022), it remains above pre-2021 rates. Due to year-over-year variability, coal generation is the primary driver of change in the overall WEFOR despite more energy being produced by both natural gas and nuclear power in 2023 (see Figure 4.6). Further investigation into baseload coal generation indicates that a unit's WEFOR negatively correlates most strongly to capacity factor.[77] Notably, once capacity factor falls below approximately 60%, unweighted average EFORs of units begin increasing more rapidly than those between 60% and 100%. Although forced-outage hours are a definite contributor to lower capacity factor units' increased WEFOR, the disproportionate change appears to be driven more by maintenance/planned outage hours and decreased service hours. This aligns with industry statements indicating that reduced investment in maintenance and abnormal cycling that are being adopted primarily in response to rapid changes in the resource mix are negatively impacting baseload coal unit performance.

Hydro units also experienced an unusually high annual WEFOR (6.9%) for the second time following one in 2021 (7.6%). However, these two relatively high years were both still lower than the associated years' overall WEFOR and do not indicate a trend at this point but warrant continued awareness.

[77] The correlation factor between capacity factor and WEFOR for baseload coal in 2023 was -0.41. While not mathematically indicative of a strong correlation (generally +/-0.7), it is notably stronger than any other aspect that is not a direct component of the WEFOR with the next highest being age (0.18) and planned outage hours (-0.16) given the relatively small sample size and amount of variation between coal units.

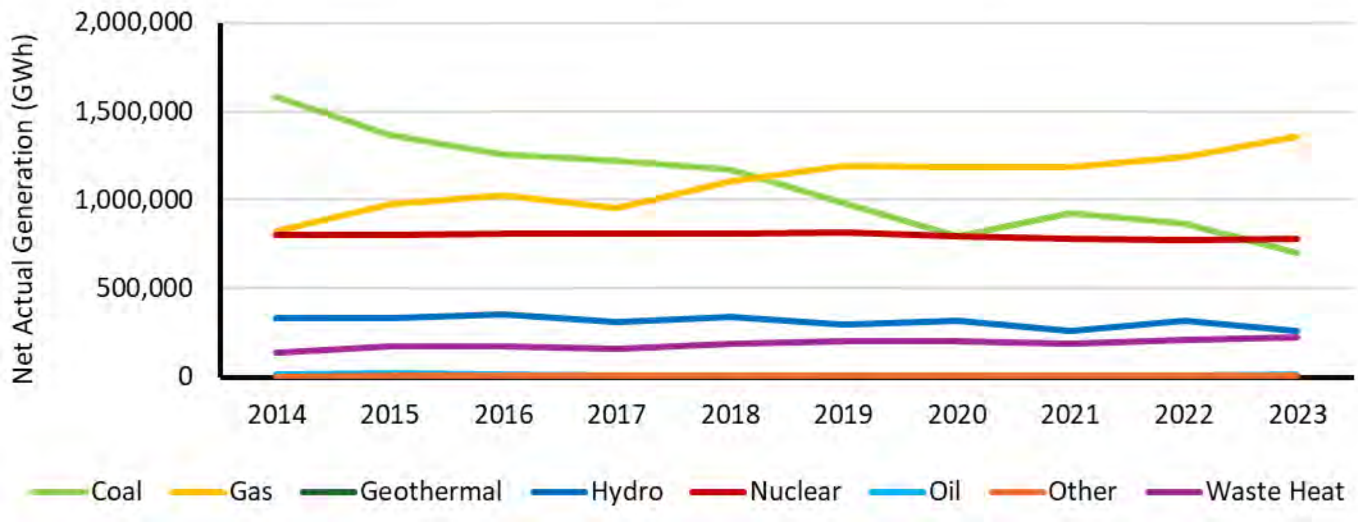


Figure 4.6: 10-Year Annual Conventional Net Actual Generation (GWh) by Fuel Type

Wind Generation Weighted Resource Forced-Outage Rate

NERC began collecting wind performance data with a phased-in approach based on plant size starting with a total installed capacity of 200 MW or greater in 2018 followed by plants with a total installed capacity of 100–199 MW in 2019 and plants with a total installed capacity of 75–99 MW in 2020 (see Figure 4.7). By the end of 2023, data from 137,737 MW of installed capacity, representing 703 wind plants across North America and 13% of nameplate generation, was reported to NERC. Data will continue to be reported separately for the reporting phase groups until sufficient history is available to analyze trends for a five-year rolling period across all wind plants comparable to the analysis for conventional generation. Specific event data collection for wind and solar began in 2024 and will allow for further analysis.

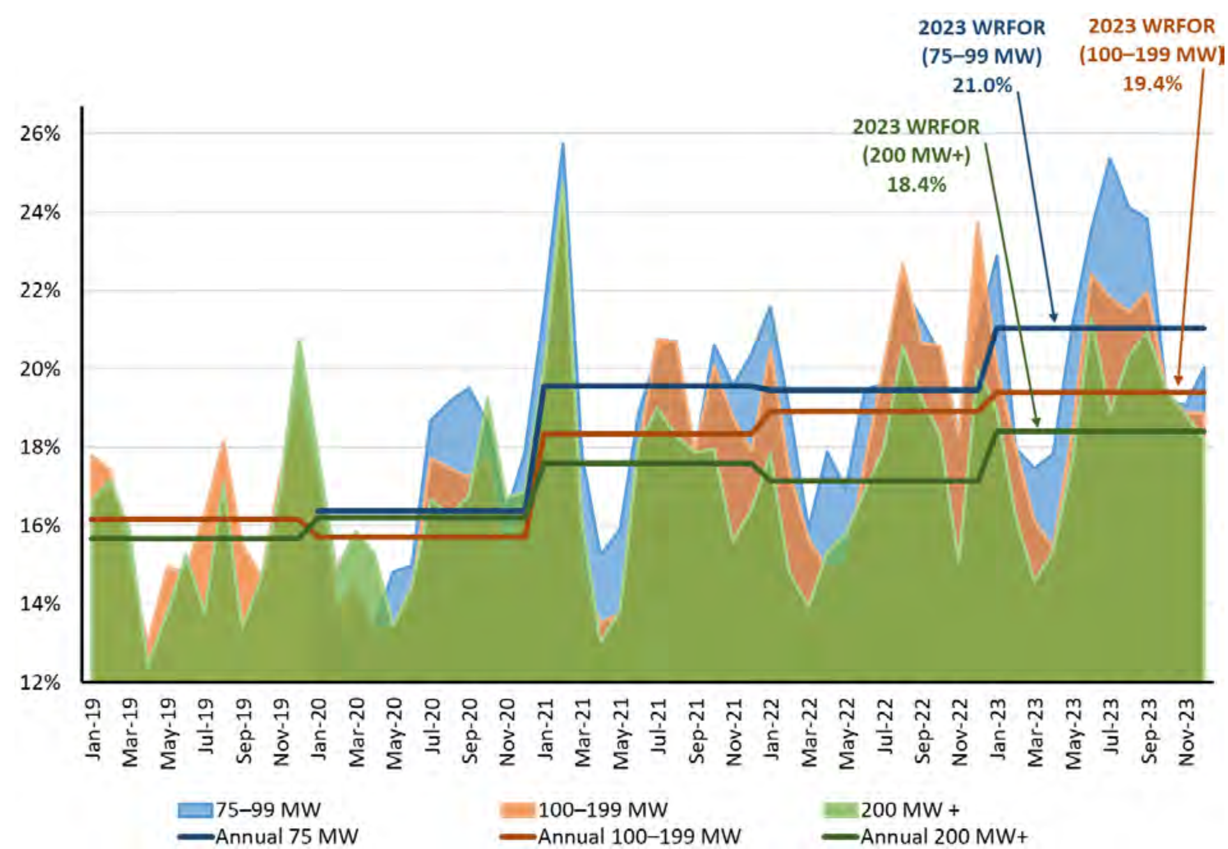


Figure 4.7: Monthly Capacity and Annual Average WRFOR Wind Plant Reporting Group

Transmission Performance and Unavailability

When evaluating transmission reliability, an important concept is that transmission line outages have different impacts on BPS reliability. Some impacts can be very severe, such as those that affect other transmission lines and load loss. Additionally, some outages are longer than others, leaving the transmission system at risk for extended periods of time. Reliability indicators for the transmission system are measured by using qualified event analysis reporting not related to weather and outages reported to TADS. The number of qualified events that include transmission outages that resulted in firm load loss not related to weather is provided in the following subsection.

Transmission-Related Events Resulting in Loss of Load

In 2023, a total of nine distinct non-weather-related transmission events resulted in a loss of firm load that met the ERO EAP reporting criteria (see Figure 4.8). The median firm load loss over the past five years was 97 MW, which is a decrease from 2018–2022's 101 MW. Although, notably, the median load loss was 113 MW in 2023, which is above the five-year median value, no discernible trend in the number of events or amount of loss is identifiable.

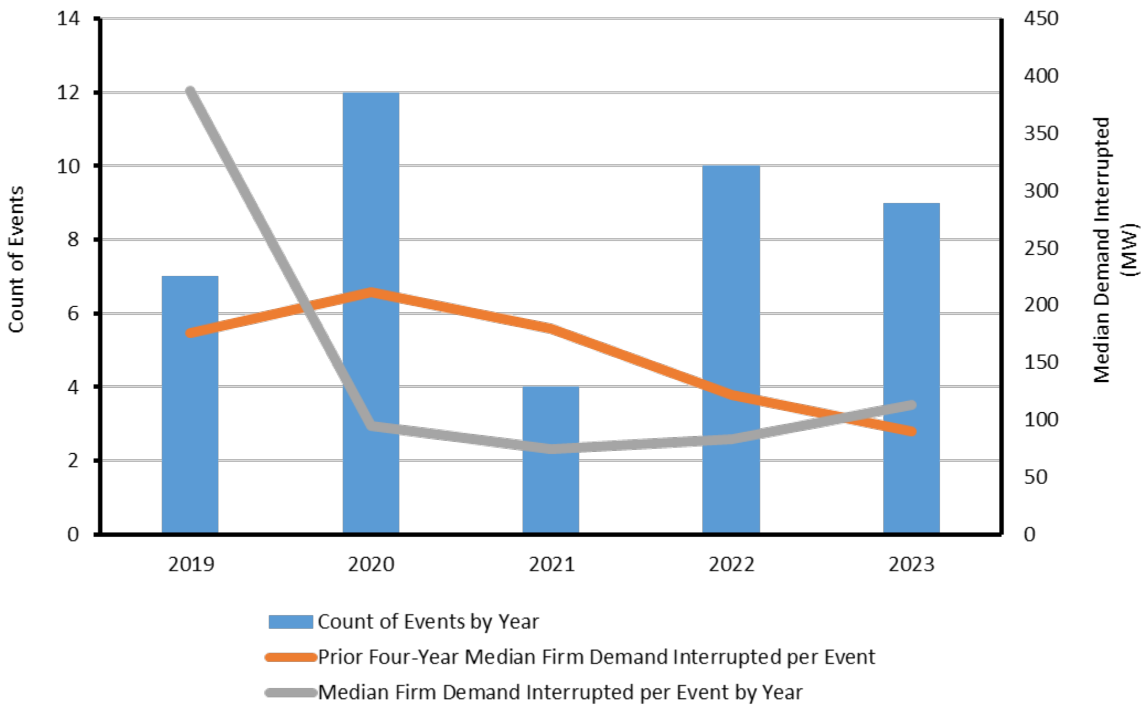


Figure 4.8: Transmission-Related Events Resulting in Loss of Firm Load and Median Amount of Firm Load Loss Excluding Weather-Related Events[78]

TADS Reliability Indicators

A TADS event is an unplanned transmission incident that results in the automatic outage (sustained or momentary) of one or more elements. TADS event information was analyzed for the following indicators in this section:

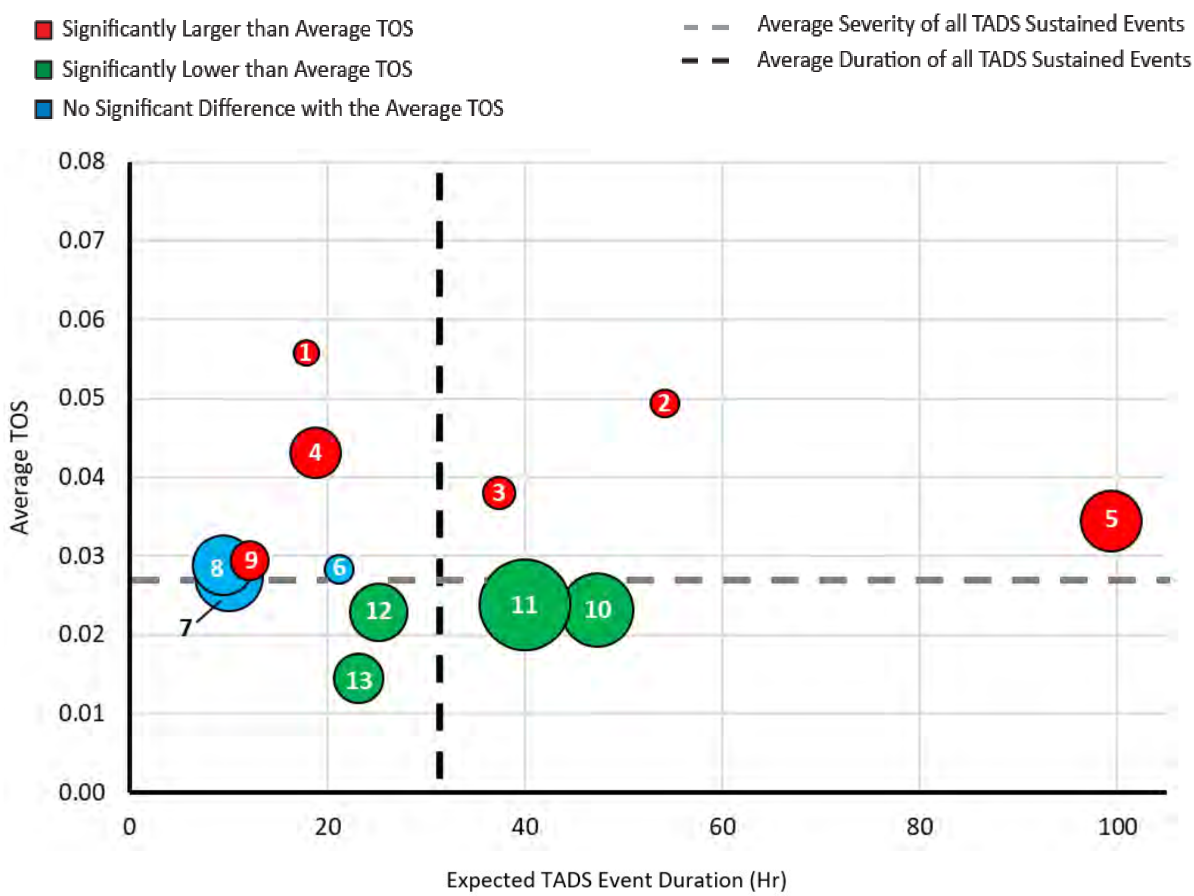
- **Transmission Outage Severity**
- **Automatic AC Transmission Outages**
- **Transmission Element Unavailability**

Transmission Outage Severity

The impact of a TADS event on BPS reliability is called the TOS of the event, which is defined by the number of outages in the event and by the type and voltage class of transmission elements involved in the event. TADS events are categorized by initiating cause codes (ICC). These ICCs facilitate the study of cause-effect relationships between each event's ICC and event severity.

[78] M-2, BPS Transmission Related Events Resulting in Loss of Load (Excluding Weather)

By examining the average TOS, duration, and frequency of occurrence for events with different ICCs (see Figure 4.9), it is possible to determine which ICCs contribute most to reliability performance for the considered period. The average TOS for events with a specific ICC is displayed on the Y-axis. A higher TOS for an ICC indicates that more outages or higher voltage elements were involved in an event. The average duration for events with a specific ICC is displayed on the X-axis; generally, events with a longer duration pose a greater risk to the BPS. The number of ICC occurrences is represented by the bubble size; larger bubbles indicate that an ICC occurs more often. Change in size or position of a bubble with the same number (identifying ICC) may indicate improved or declined performance. Lastly, the bubble colors indicate a statistical significance of a difference in the average TOS of this group and the events from other groups. The number of events per hour, average event duration, and average TOS for each ICC group are shown in Table 4.5.



1. Power System Condition
2. Fire
3. Combined Smaller ICC Groups
4. Misoperation
5. Failed AC Substation Equipment
6. Other
7. Unknown
8. Lightning
9. Human Error
10. Failed AC Circuit Equipment
11. Weather, Excluding Lightning
12. Foreign Interference
13. Vegetation

Figure 4.9: TOS vs. Expected TADS Event Duration

Table 4.5: TOS vs. Expected TADS Event Duration			
TADS Event	**Events per Hour**	**Average TOS**	**Average Event Duration**
Power System Condition	.012	.056	17.9
Fire	.014	.049	54.2
Combined Smaller ICC Groups	.019	.038	37.4
Misoperation	.046	.043	18.8
Failed AC Substation Equipment	.068	.034	99.4
Other	.015	.028	21.2
Unknown	.085	.027	10.0
Lightning	.067	.029	9.5
Human Error	.026	.029	12.2
Failed AC Circuit Equipment	.098	.023	47.3
Weather, Excluding Lightning	.153	.024	40.0
Foreign Interference	.061	.023	25.2
Vegetation	.045	.014	23.2

An analysis of the total TOS by year indicates that 2023 was an outlier from the statistically improving trend identified over the previous five years. Figure 4.10 shows the annual TOS, which is the third highest over the last five years; the shaded area shows the effect of the Québec wildfires on the 2023 TOS.

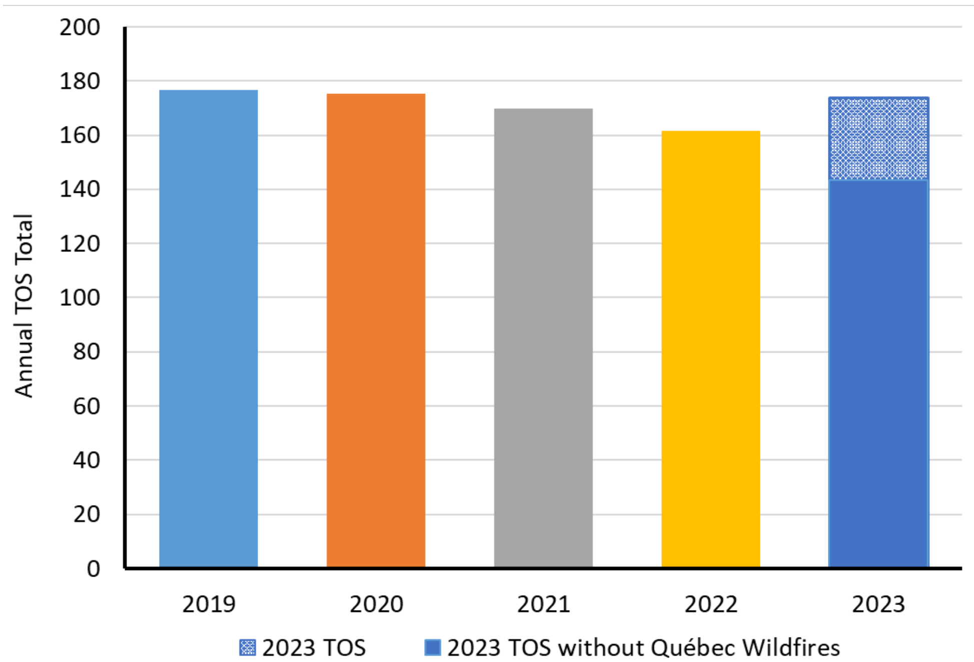


Figure 4.10: TOS of TADS Sustained Events of 100 kV+ AC Circuits and Transformers by Year[79]

Automatic AC Transmission Outages

The average number of outages per circuit due to failed ac substation equipment has continued to improve consistently over the last four years, showing a statistically significant decrease in 2023 compared to 2019–2022 (see Figure 4.11 The number of sustained outages due to failed ac circuit equipment per 100 miles saw a decrease in 2023 (see Figure 4.12).

[79] M-17, Transmission Outage Severity

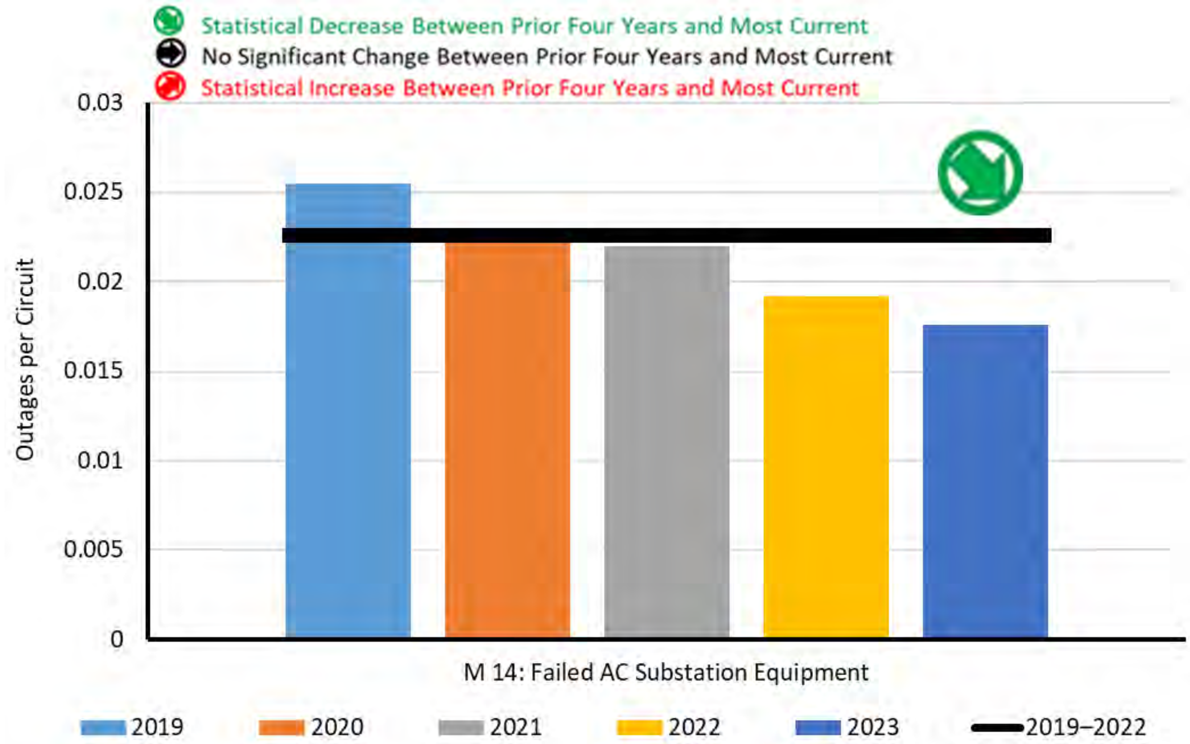


Figure 4.11: Number of Outages per AC Circuit Due to Failed AC Substation Equipment[80]

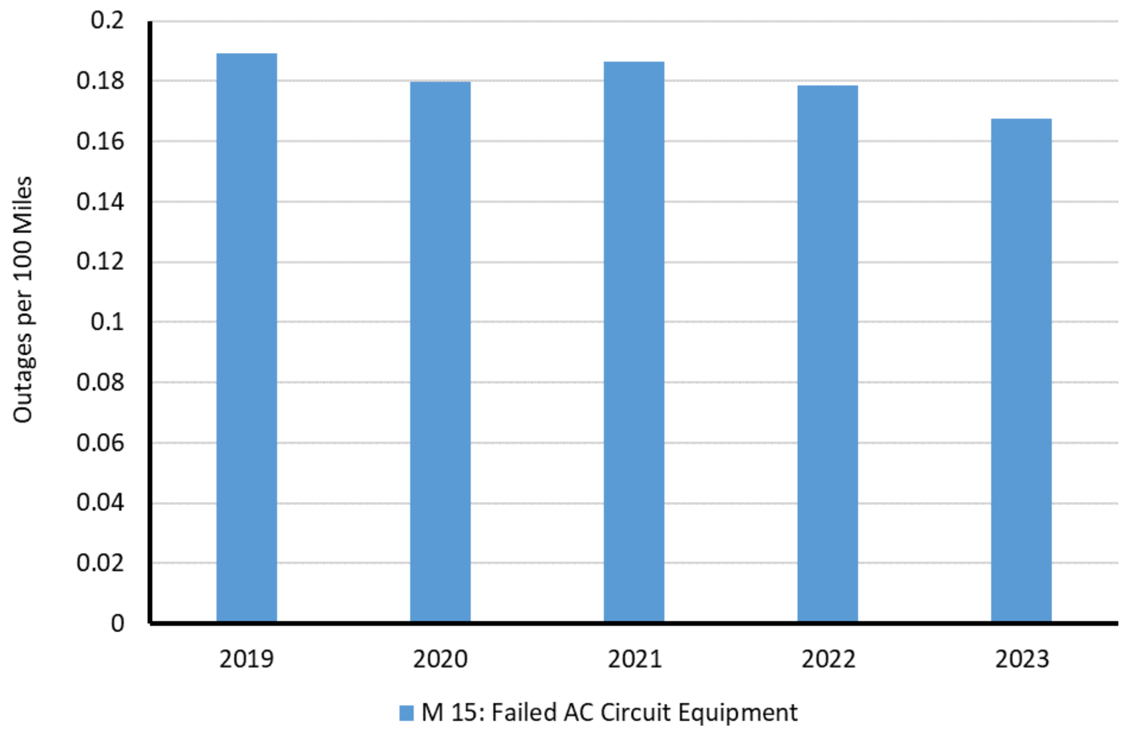


Figure 4.12: Number of Outages per 100 Miles Due to Failed AC Circuit Equipment[81]

[80] M-14, Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment
[81] M-15, Automatic AC Transmission Outages Initiated by Failed AC Circuit Equipment

Automatic AC Transformer Outages

In 2023, the number of automatic ac transformer outages per element caused by failed ac substation equipment was statistically equal to 2019–2022 (see Figure 4.13); the overall average remains stable.

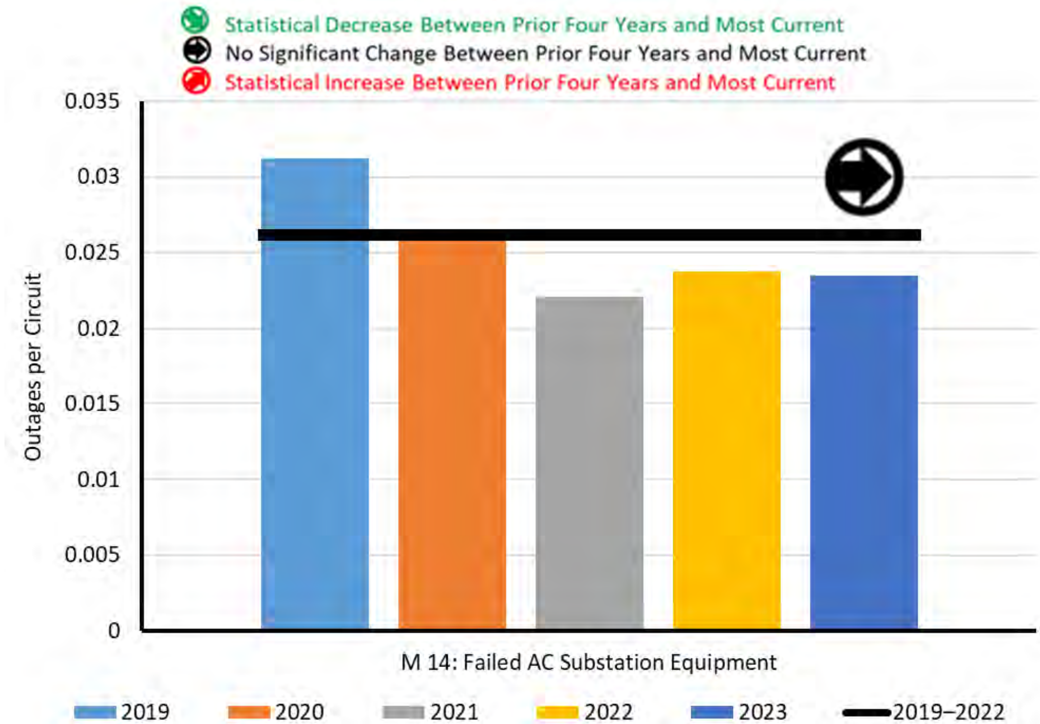


Figure 4.13: Number of Outages per Transformer Due to Failed AC Substation Equipment[82]

Transmission Element Unavailability

In 2023, ac circuits over 200 kV across North America had an unavailability rate of 0.24%, meaning that there is a 0.24% chance that a specific transmission circuit is unavailable due to sustained automatic and operational outages at any given time. Transformers had an unavailability rate of 0.25% in 2023. Figure 4.14 shows that 2023 was the lowest year for ac circuit unavailability of the five-year analysis period. Figure 4.15 shows that 2023 was the second-highest year for transformer unavailability of the five-year analysis period.

[82] M-14, Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment

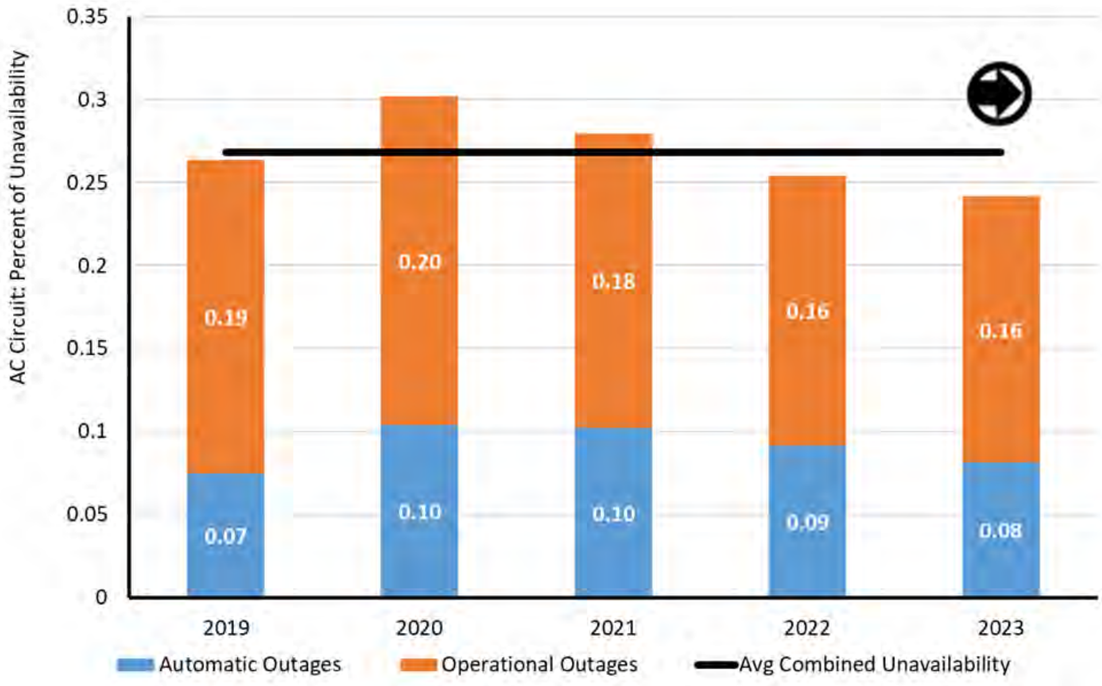


Figure 4.14: AC Circuit Unavailability > 200 kV[83]

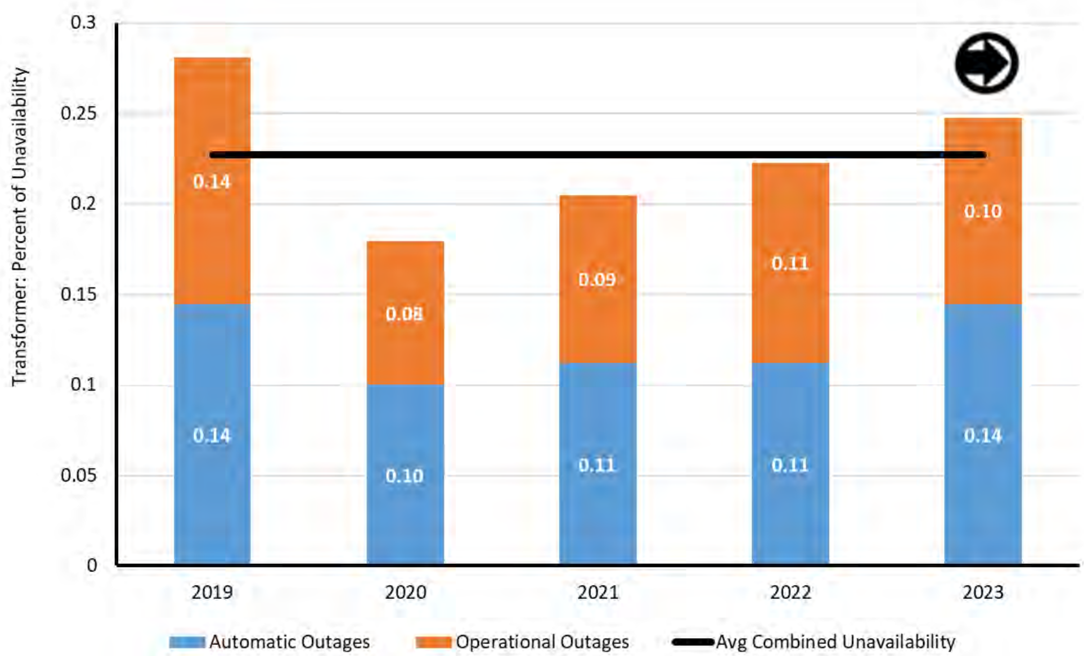


Figure 4.15: Transformer Unavailability[84]

[83] M-16, Element Availability Percentage (APC) & Unavailability Percentage
[84] Ibid.